National Winter Group 2009 Report May 2009

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Purpose

1. The purpose of this report is to advise both the Electricity Commission General Manager and GM System Operations Transpower, of the initial outlook for winter 2009, as identified by the National Winter Group.

National Winter Group 2009

2. 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.

3. 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 next winter[1]. 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.

4. This 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 has sought further information regarding the indented 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.

5. The NWG 2008 has initiated the Demand and Generation forecast work ahead of the consideration of Options to mitigate any issue identified. This is to allow the potential issues for winter 2009 to be first identified and to focus any Options work required.

6. The individual members of the group have been drawn from electricity sector stakeholders and market participants. Details are in Appendix 1.

[1] The stand down of HVDC Pole 1 removes 200-250MW of transfer capability into the North Island at winter peak. The unavailability of New Plymouth would remove 210MW of North Island generation. Collectively this is an 8% reduction in generation input into the North Island.

Nature of this Report

7. As part of the NWG 2008 work it was identified that first establishing the demand and generation balance would provide a greater focus to the any subsequent options work, this methodology has been carried over to the NWG 2009 report.

8. This report therefore is the initial 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 2009 process and results may change when any options work is completed.

9. The views and recommendations expressed in this initial 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.

10. 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 2009.

11. The information, analysis and conclusions in this report have a high level of agreement within the NWG having been discussed and reviewed at a full NWG meeting on 6 May 2009

12. The purpose of this collaboration has been to collectively work to minimise risks in meeting the peak demand in winter 2009.

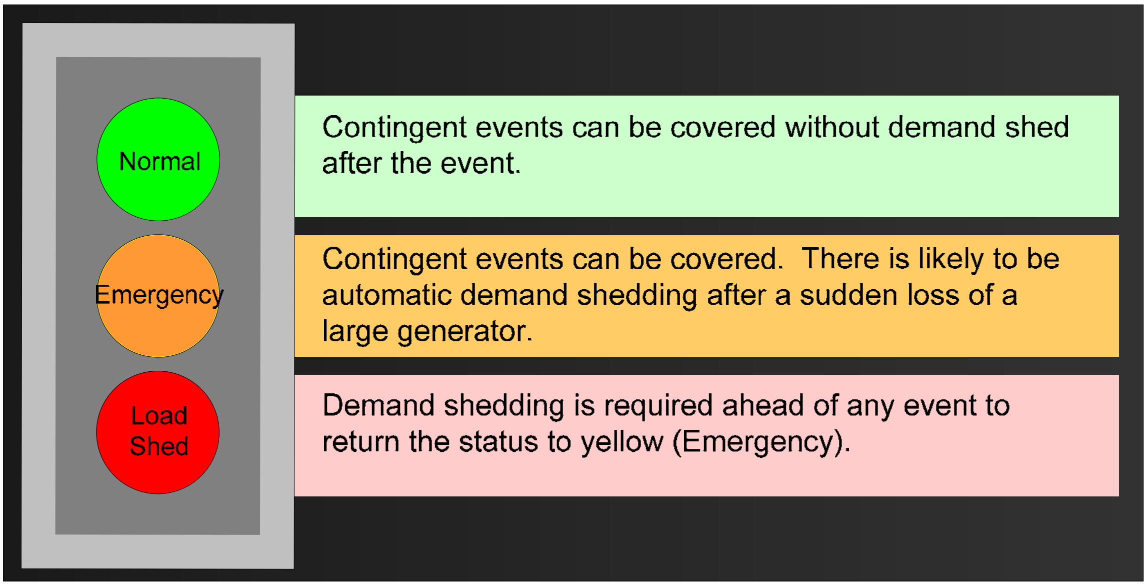
Summary of the Outcomes from NWG work

13. The NWG 2009 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 4842 MW[2] for the North Island, up 4.8% on the actual peak winter demand in 2007 (7.4% on 2008). The prudent demand for the South Island is 2473 MW, up 6% on the equivalent peak demand in winter 2007 (10% on 2008). These demand figures contain significant uncertainty due to
    a. the abnormal year in 2008 where demand savings campaigns and high prices were seen to have effected demand and
    b. the uncertain effect of the economic downturn on peak demand, and
    c. The uncertain return date of the load at Tiwai point smelter

[2] 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)

14. The equivalent prudent assessment of available generation and reserve products to meet peak winter demand over June and July varies from 5471 MW to 5531MW[3] with HVDC Pole 1 unavailable.

15. The results of the analysis of peak winter demand and generation availability for winter 2009 is summarised in the four key questions and answers below. The answers to the questions reflect the ability continue to operate the power system in one of three states
    - Normal secure state – 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.
    - Emergency secure state – Power system status orange. There will be the automatic disconnection of a significant number of consumers,[4] ***only if*** there is a sudden loss of a large generator or the HVDC Pole at the time of winter peak evening demand.
    - 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.[5] There is still a risk that further demand will be shed automatically.



[3] These generation totals are the 90% confidence (P10) and do not include reserves or frequency keeping deductions. They do include notified outages for planned maintenance. Refer to Generation Report in Appendices.
[4] 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.
[5] 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).

16. 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.

17. The answers also refer to Pole 1 being available.

Key Questions

18. The answers are based in the initial assessment for Winter 2009. 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 2009 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 an initial low 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.
However in this situation the HVDC pole 1 would be committed under its agreed operating provisions allowing any residual South Island generation to enter the North Island and in addition allowing some North Island reserves to be committed as generation.
This gives us a medium level of confidence that the system would continue to be operated in the normally secure state.
Should pole 1 not be available then it is likely the system will be operated in the Emergency Secure state (orange) during times of peak demand.

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 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: 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.

Interim view on ability to meet Peak Demand for Winter 2009

19. 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 2009 in this Report that the ability of the power system to meet peak winter demand in 2009 in a normal secure state (status green) is “at risk” if all thermal plant is not available and committed.

20. 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. .

21. 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.

Background

Peak Winter Demand

22. 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 in June and July 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 county within 24 hours.

23. The demand workstream of the NWG has developed a forecast of the prudent system peak for the North and South Islands for winter 2009. This forecast has a very high confidence and is unlikely to be exceeded by the actual winter peak in 2009.

Outlook for Winter 2009

24. The task set for the National Winter Group is to determine the ability of the power system to meet peak winter demand in 2009. The Electricity Commission has separate processes to manage “dry year” risk where there may be insufficient fuel to meet demand.

25. 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.

Enabling the Full Commitment of Generation at System peak

26. 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.

27. 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.

Enabling the Timely Commitment of Slow Starting Generation

28. 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.

29. 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.

Workstream Summaries

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

Demand Workstream

31. 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.

32. 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.

33. The modelling of the prudent peak requires:

- A forecast of mean demand in 2009 (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:
    a. 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 treat in the same way.

b. 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.

c. Impact of the temporarily reduced load at Tiwai point smelter.

- The group noted the reduction in demand at Tiwai point noting also that the return date remains unknown, no attempt has been made to include this demand reduction in the model.

- 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 132MW for losses at system peak is appropriate for the North Island. As 2008 was a dry year, and therefore the generation pattern was unusual, the group felt it was unwise to update their previous forecast for losses.

- 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)	4,479	4,631
Linear Regression (prediction interval)	4,479	4,681
Modified Linear Regression (Hi Growth)	4,495	4,647
Piecewise Linear Regression[6]	4,507	4,727
Consensus		**4,650**
Losses		**132**
Half Hour Variability		**40**
Frequency keeping		**50**
Recommendation for Peak Demand		**4,872**

South Island		
Methodology	*Expected Peak (MW)*	*Prudent Peak (MW)*
Linear Regression (confidence interval)	2,266	2,300
Linear Regression (prediction interval)	2,266	2,316
Modified Linear Regression (Hi Growth)	2,266	2,300

[6] Prediction Interval

Piecewise Linear Regression[1]	2,266	2,316
Consensus		**2,300**
Losses		**111**
Half Hour Variability		**12**
Frequency keeping		**50**
Recommendation for Peak Demand		**2,473**

New Zealand		
Methodology	*Expected Peak (MW)*	*Prudent Peak (MW)*
Linear Regression (confidence interval)	6,713	6,869
Linear Regression (prediction interval)	6,713	6,920
Modified Linear Regression (Hi Growth)	6,727	6,883
Piecewise Linear Regression[1]	6,763	6,980
Consensus		**6,890**
Losses		**242**
Half Hour Variability		**86**
Frequency Keeping		**100**
Recommendation for Peak Demand		**7,318**

Generation Workstream

34. 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.

35. 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 and July.

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

37. 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 five (5) years data.”

38. 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.

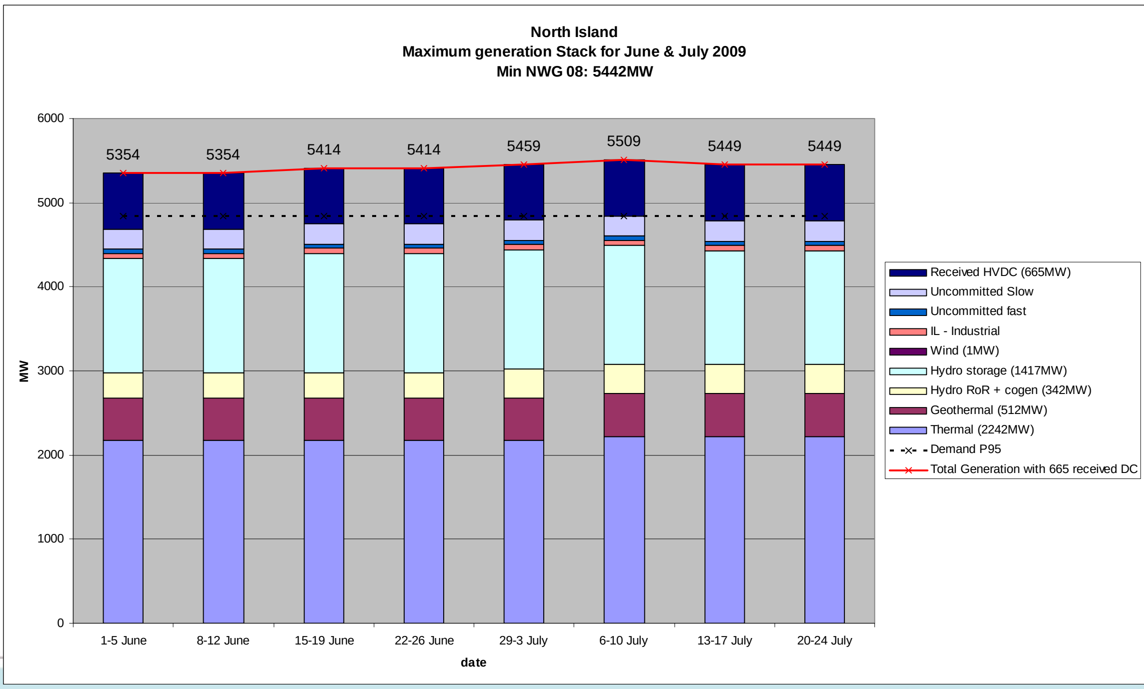
39. The generation capability stack therefore includes:
    - Thermal;
    - Geothermal;
    - Hydro – storage (variable);
    - Hydro – run of river (variable);
    - Wind (variable);
    - Co-generation (variable);
    - Uncommitted – fast start (available within a couple of hours);
    - Uncommitted – slow start (requires a number of hours for a “cold start”).

40. In addition the stack includes:
    - industrial interruptible load (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).

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

42. During the process of developing the Generation stack Contact Energy advised that New Plymouth Power Station would not be available in winter 2009.

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, the each stack has been presented in graphical form.
The North Island stack



43. 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.

44. The demand/generation balance for the South Island indicated that 684 Mw was available for export to the North Island after South Island prudent demand, reserves and frequency keeping were deducted from the available generation. (693 in 2008)

45. The group assumed HVDC transfer was limited to the currently advised maximum of 700 MW sent from the South Island or 665 MW received on Pole 2 only into the North Island at peak. HVDC capability has increased under a Transpower initiative to 700 MW on pole 2 plus 200MW on Pole 1 in circumstances where a short fall may exist however this capability is unlikely to be called over the peak periods as the South Island does not have this level of surplus generation, it will however have a positive effect of reducing North island reserve requirements which can free generation in the North Island that was being held back as spinning reserve.

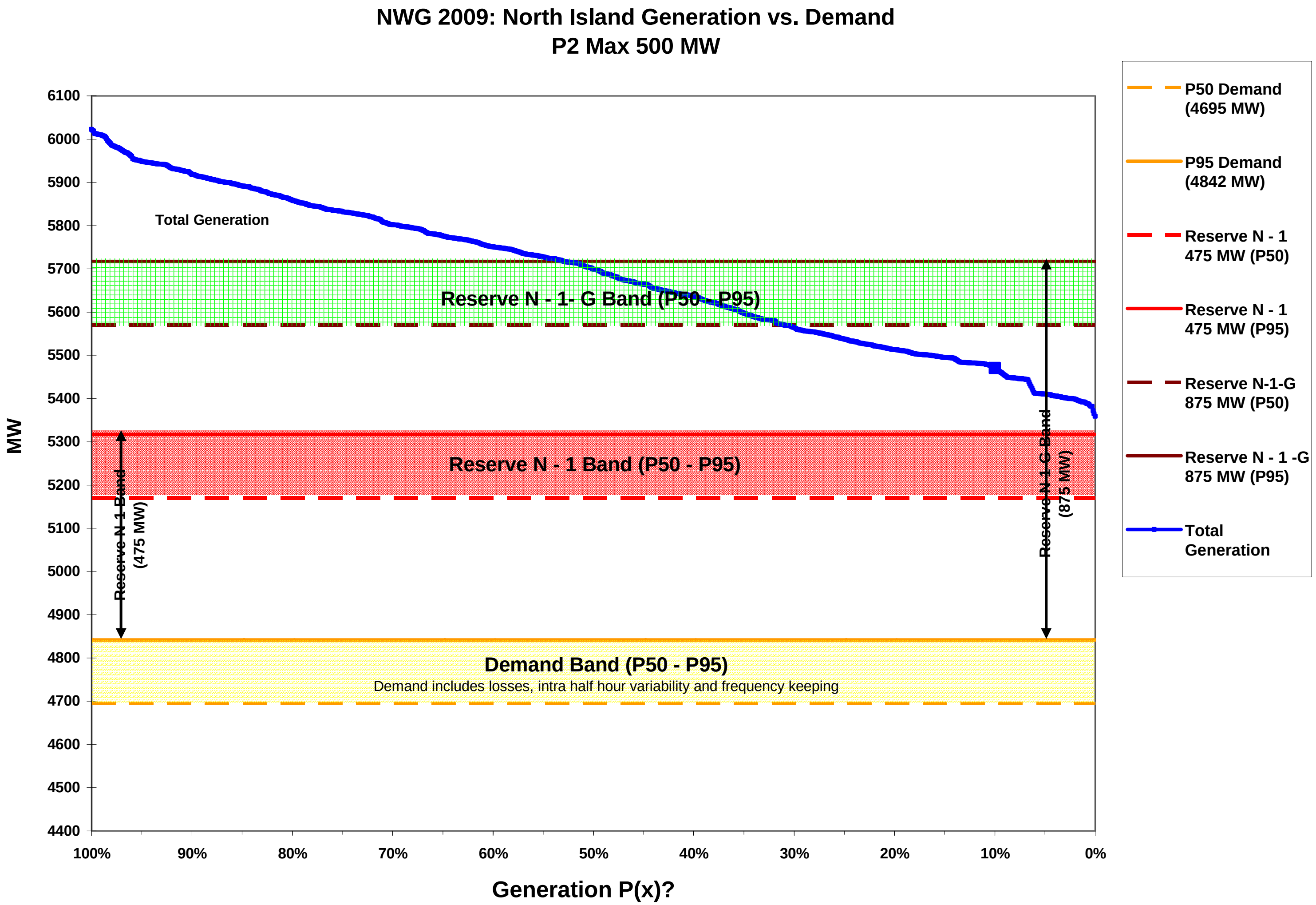
46. The graph above demonstrates that there is sufficient capability within the system to meet the forecast North Island peak demand of 4842MW (which includes system losses) and a margin of 50 MW for frequency keeping.

47. 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.

48. 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).

49. 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.

50. 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.

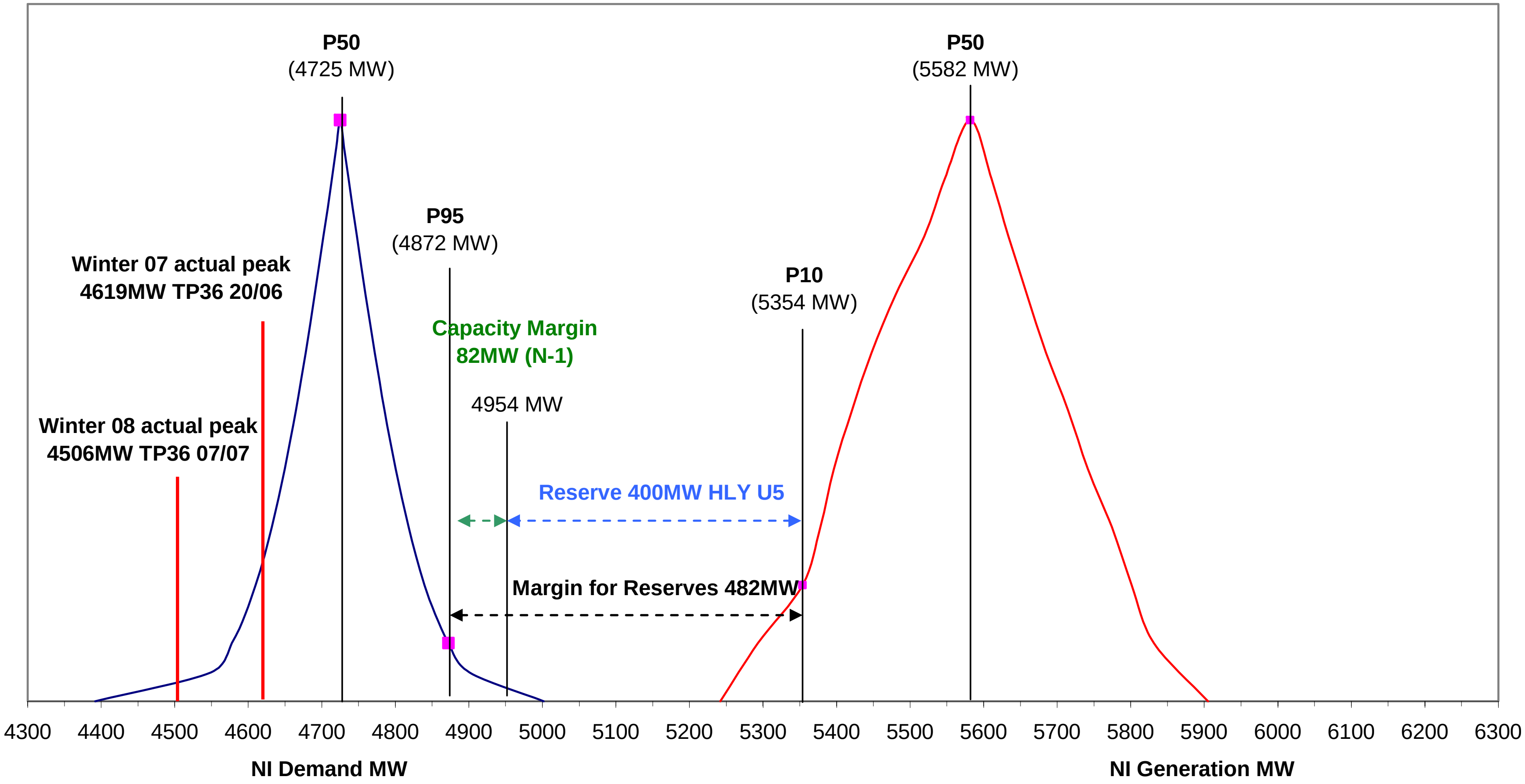


Note: Total Generation refers to the minimum generation on 1-5 June week where there is 60 MW loss due to planned outage.

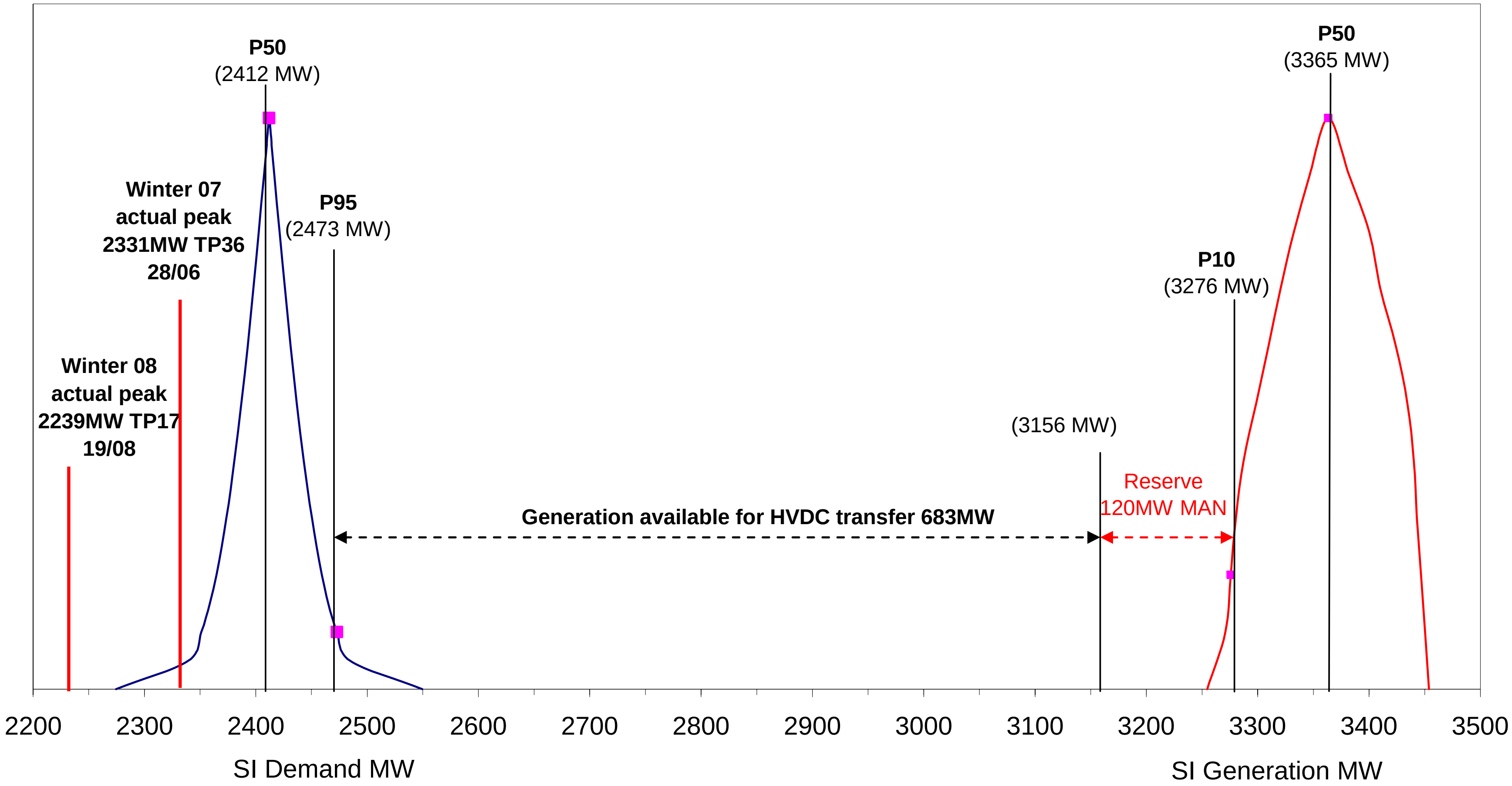
Demand Curve – assumes demand peak values are normally distributed. P95 value is 4842 MW incl 40 MW for half hour variation, and 132 MW for transmission losses.

Generation Curve - Generation stack forecast for the week of 1-5 June 2009, for which the P10 value was 5531 MW. The generation stack includes a fixed and variable generation components. Total generation for this week ranged from a minimum of 5359 MW (0 percentile from the 'variable generation component') to a maximum of 6022 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 ~229 MW which is requires all generation including slow starting thermal generation.

North Island Demand and Generation Balance at Peak Winter 2009
08 May 09 update - with HVDC Pole 1 at 200 MW, Winstone IL offers removed and NPL at 0MW



South Island Demand and Generation Balance at Peak Winter 2009
08 May 09 update



Appendices

NWG Memberships

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
Gari Bickers / Brian Bull	Electricity Commission

Chris Otton	Transpower
Siobhan Procter	Transpower
Ray Basher	Transpower
Kevin Small	Transpower

Demand Forecast

51. Background

The Demand Group has been tasked with building on the work of the 2007 and 2008 National Winter Group in developing a prudent estimate of peak demand for winter 2009 for the North Island, the South Island and New Zealand.

52. 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.

- The group noted that one pot line at the Rio Tinto aluminium refinery has been closed for a considerable period. In the event that this closure is extended the resulting decrease in demand will be implicit in future peak demand data for both the South Island and NZ. No attempt has been made to include the potential effect of this closure in the modelling undertaken to date.

The modelling of the instantaneous prudent peak demand therefore requires:

- A forecast of mean demand in 2009 (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).

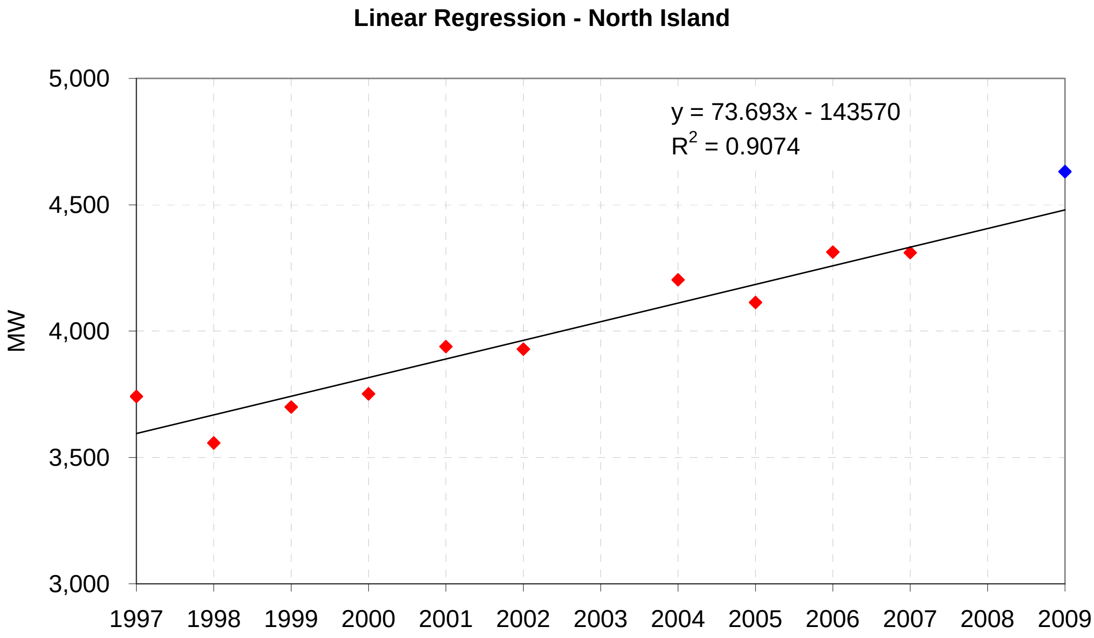
53. Linear Regression

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 2009 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 2009 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 0.9074 suggests that time (movement along the x-axis) explains 90.74% 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.

54. 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 82MW. Variations around the trend line are assumed to be normally distributed with an equal likelihood of the 2009 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 exceedence (PoE) is in the order of 5% or one in twenty years.

55. 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 $_{\text{Linear Regression}}$ = 2009 trend line + standard error x t $_{(.05,\ 8)}$

= 4,479 + 82 x 1.859548

= 4,479 + 152
= 4,631MW

56. Calculation of Standard Error

The standard excel function calculates the standard error assuming the data set has multiple data points for each period. The workgroup has received advice that, as we are endeavouring to predict an individual value, a more complex calculation should be applied to determine the standard error. Applying this calculation produces a prediction interval rather than a confidence interval because a population parameter (the mean) is not being estimated; rather the value of a single individual in the population is being predicted. Applying this formula produces a prudent peak as follows:

Prudent Peak NI $_{\text{Linear Regression}}$ = 2008 trend line + standard error x t $_{(.05,\ 8)}$

= 4,479 + 109 x 1.859548
= 4,479 + 202
= 4,681MW

57. Limitations of Linear Regression

The available data set has just 10 data points (with 2003 and 2008 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 seen in the context.

58. 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 2008 of 4,405MW. This mean value is then grown by an assumed growth rate to generate the mean demand for the 2009 year.

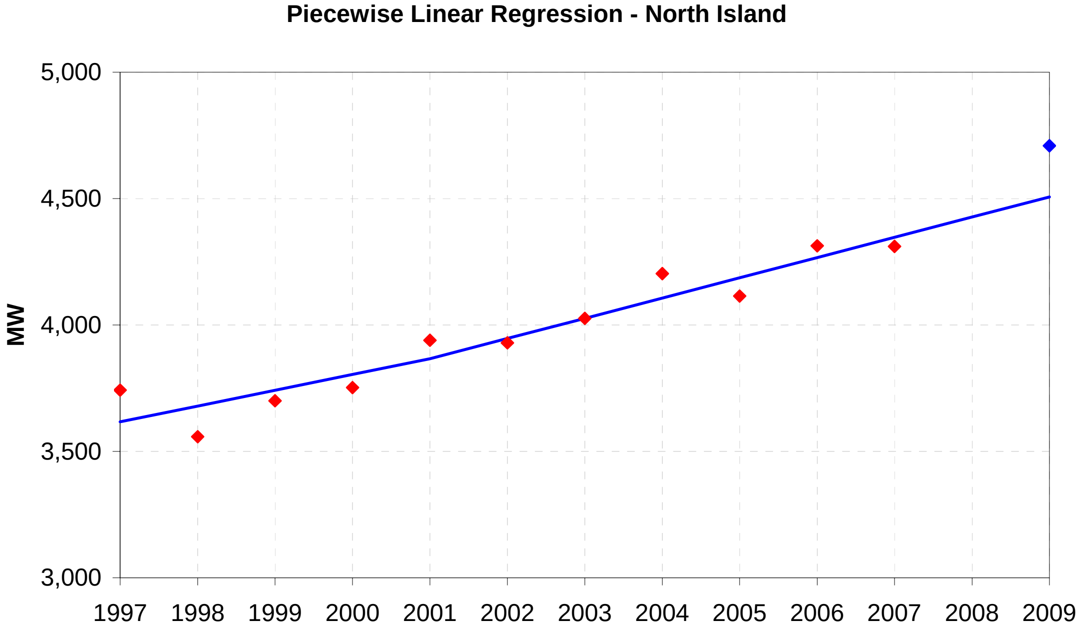
As with linear regression approach, the variance around the mean peak demand is calculated using the standard excel approach to calculating the standard error implicit in the data series multiplied by the appropriate student t factor to give the desired level of confidence.

59. Modified Linear Regression (Hi Growth)

This 2008 expected peak is grown by 2.0% (per EC 2008 SoO) to give an expected forecast of 4,495MW for 2009. The standard error calculated by excel was then applied to generate a prudent peak as follows:

Prudent Peak $_{\text{Mod Hi Growth}}$ = P50 forecast$_{2008}$ + standard error x t $_{(.05,\ 8)}$
= 4,495+ 82 x 1.859548
= 4,495 + 152
= 4,647MW

The following chart illustrates this approach and the forecast generated:



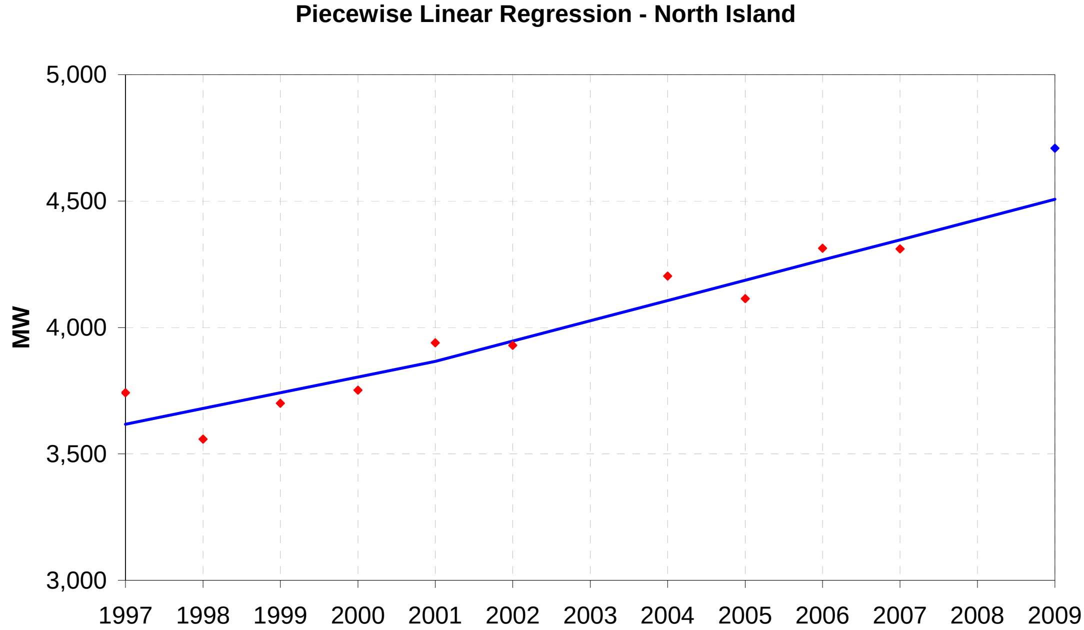
60. Weaknesses of Modified Linear Regression Model

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 2009 expected forecast. The peak demand growth from the EC's 2008 Statement of Opportunities was used as the growth rate in the 2009 year.

61. Piecewise Linear Regression

Piecewise linear regression was also applied as a further methodology to model the prudent peak. This technique applies the principles of linear regression to the data set but rather than fitting a single line, the piecewise approach fits more than one line to the data set. Thus different growth rates (or eras) are modelled by resetting the slope of the line to the underlying growth rate for each era identified.

The following chart illustrates this approach:



62.

In this example the earlier examination of the data set was used to determine two discrete eras. In the first era the compound annual growth rate (CAGR) was less than 1%; in the second era the CAGR exceeds 1%.

63. Prudent Peak Forecast Using Piecewise Linear Regression

The application of piecewise linear regression to the data set produces a prudent peak forecast as follows:

Prudent Peak $_{\text{Piecewise LR}}$ = 2009 trend line + standard error x t $_{(.05,\ 7)}$
= 4,507 + 116 x 1.8946
= 4,507 + 220
= 4,727MW

64. Pivot Point

Piecewise linear regression requires the modeller to determine when a new era has occurred, in the example the CAGR of the data set was used to determine that a new era began in 2001. The earlier lower growth line was pivoted at 2001 allowing a further linear model of the higher growth era to be calculated. The subjective decision as to when to recognise a new era affects the forecast value.

65. Weaknesses of Piecewise Linear Regression

This methodology addresses the inability of a linear regression model to recognise emerging trends, by replacing the single line generated with two or more lines recognising different underlying growth rates. The weakness is that the choice of the pivot point, where one era starts and another finishes is a somewhat arbitrary decision and could be subject to influence. Variations within the half hour

The variability within the half hour was previously analysed by comparing the changes in demand over a half hour with the half hour average demand. This was modelled two ways:

- Comparing the average half hour load to the 10 second load value.
- Comparing the average half hour load to the 5 minute load value.

The group considered the limited data available and concluded that for the North Island a 40MW margin should be allowed for intra half hour variability at the P95 confidence level.

66. 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 132MW for losses at system peak is appropriate for the North Island. As 2008 was a dry year, and therefore the generation pattern was unusual, the group felt it was unwise to update their previous forecast for losses.

67. Economic down turn

No allowance has been made in these forecasts for the effects of the current economic downturn. One of the techniques used (modified linear regression) does include a growth rate for calculating the forecast peak demand and as such implicitly includes an element of lower growth likely as a result of the economic situation.

68. 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)	4,479	4,631
Linear Regression (prediction interval)	4,479	4,681
Modified Linear Regression (Hi Growth)	4,495	4,647
Piecewise Linear Regression[7]	4,507	4,727
Consensus		**4,650**

[7] Prediction Interval

Losses		**132**
Half Hour Variability		**40**
Frequency keeping		**50**
Recommendation for Peak Demand		**4,872**

South Island		
Methodology	*Expected Peak (MW)*	*Prudent Peak (MW)*
Linear Regression (confidence interval)	2,266	2,300
Linear Regression (prediction interval)	2,266	2,316
Modified Linear Regression (Hi Growth)	2,266	2,300
Piecewise Linear Regression[1]	2,266	2,316
Consensus		**2,300**
Losses		**111**
Half Hour Variability		**12**
Frequency keeping		**50**
Recommendation for Peak Demand		**2,473**

New Zealand		
Methodology	*Expected Peak (MW)*	*Prudent Peak (MW)*
Linear Regression (confidence interval)	6,713	6,869
Linear Regression (prediction interval)	6,713	6,920
Modified Linear Regression (Hi Growth)	6,727	6,883
Piecewise Linear Regression[1]	6,763	6,980
Consensus		**6,890**
Losses		**242**
Half Hour Variability		**86**
Frequency Keeping		**100**
Recommendation for Peak Demand		**7,318**

Generation Workstream

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.

Generation

1. Introduction

The purpose of the Generation group is to define the likely available generation during winter period 2009. 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. The maximum HVDC north transfer capability is 700 MW. We compare two cases with this maximum transfer limit. The first case is where P2 is considered to be operated at 700 MW and the other case is where P2 is operated at 500 MW and half pole at 200 MW.

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

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 Appendix.

2.1 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 will be covered in Section 2.7.

Generators	MW	Comment
Stratford TCC	375	
Otahuhu OTC	387	
Southdown SWN	125	
Huntly 1-4 HLY	729	3 unit @243 MW each, 1 is uncommitted slow
Huntly 5 HLY	400	
Huntly 6 HLY	48	
Whirinaki WHI	156	
Total Thermal	**2220**	

2.2 Geothermal

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

Generators	MW	Comment
Poihipi	35	
Ohaaki	62	
Wairakei	165	
Mokai	113	MRP + TPC
Rotokawa	35	Embedded Generator
Kawerau	102	
Total Geothermal	**512**	

2.3 Hydro Run-of-river and Co-generation

2.3.1 North Island

We aggregated hydro run-of-river and some of the co-generations time series data and obtained 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 month of June from 1999 to 2008. 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 and Rangipo. Co-generations in North Island that are aggregated together in the series are Glenbrook and Kapuni. Aniwhenua was not included in the generation stack as they are considered as embedded.

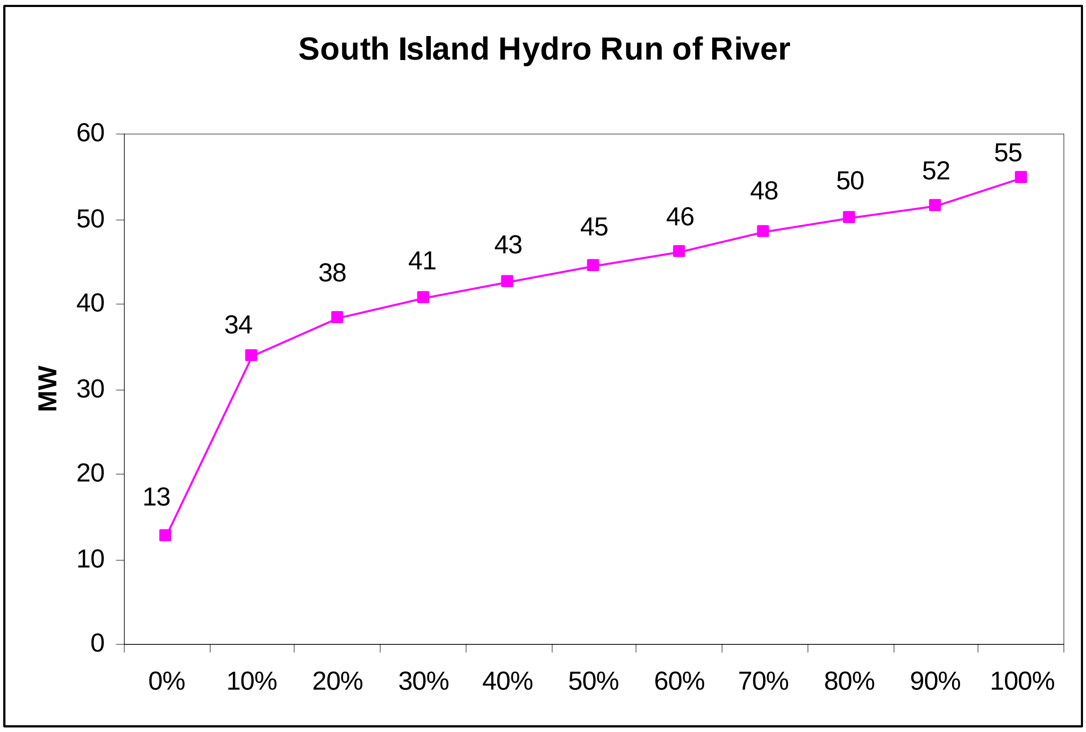
Kinleith (35 MW), Whareroa (60 MW) and TeRapa (45 MW) values are as given to System Operator. .

The table below shows the collective value of 342 MW at P10.

Percentile	Aggregated Hydro Run-of-river and Co-generation (MW)	Collective MW With Kin, WAA, TRC (+140 MW)
0%	141	281
10%	**202**	**342**
20%	217	357
30%	234	374
40%	250	390
50%	265	405
60%	276	416
70%	291	431
80%	308	448
90%	335	475
100%	390	530

2.3.2 South Island

Hydro run-of-river generators in South Island are Branch, Kumara, Highbank and Patearoa. The base data from Trustpower only considers weekdays, trading period 34 to 38, and covering the month of June from 1999 to 2008. The following table shows the generation cumulative distribution from Trustpower. The 10P value is 34 MW.



2.4 Hydro Storage

2.4.1 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**	

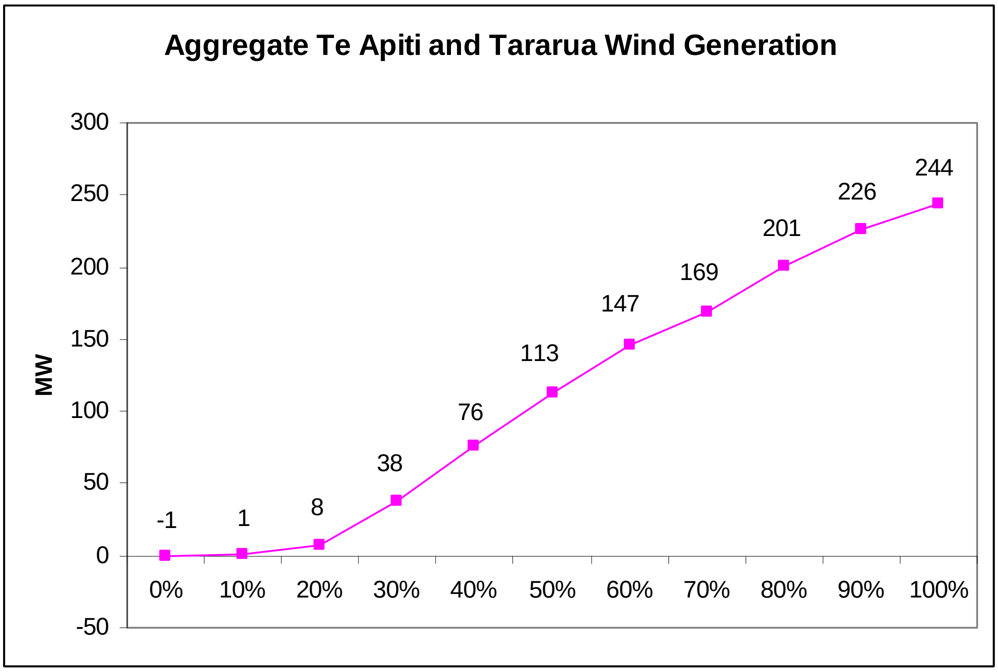
2.4.2 South Island

Total Hydro storage in South Island is 3223 MW.

Generators	MW	Comment
Roxburgh ROX	320	
Clyde CYD	464	
Waitaki River WTK	1665	
Manapouri MAN	729	
Cobb COB	32	
Coleridge COL	35	
Waipori WPI	78	
Total Hydro Storage	**3223**	

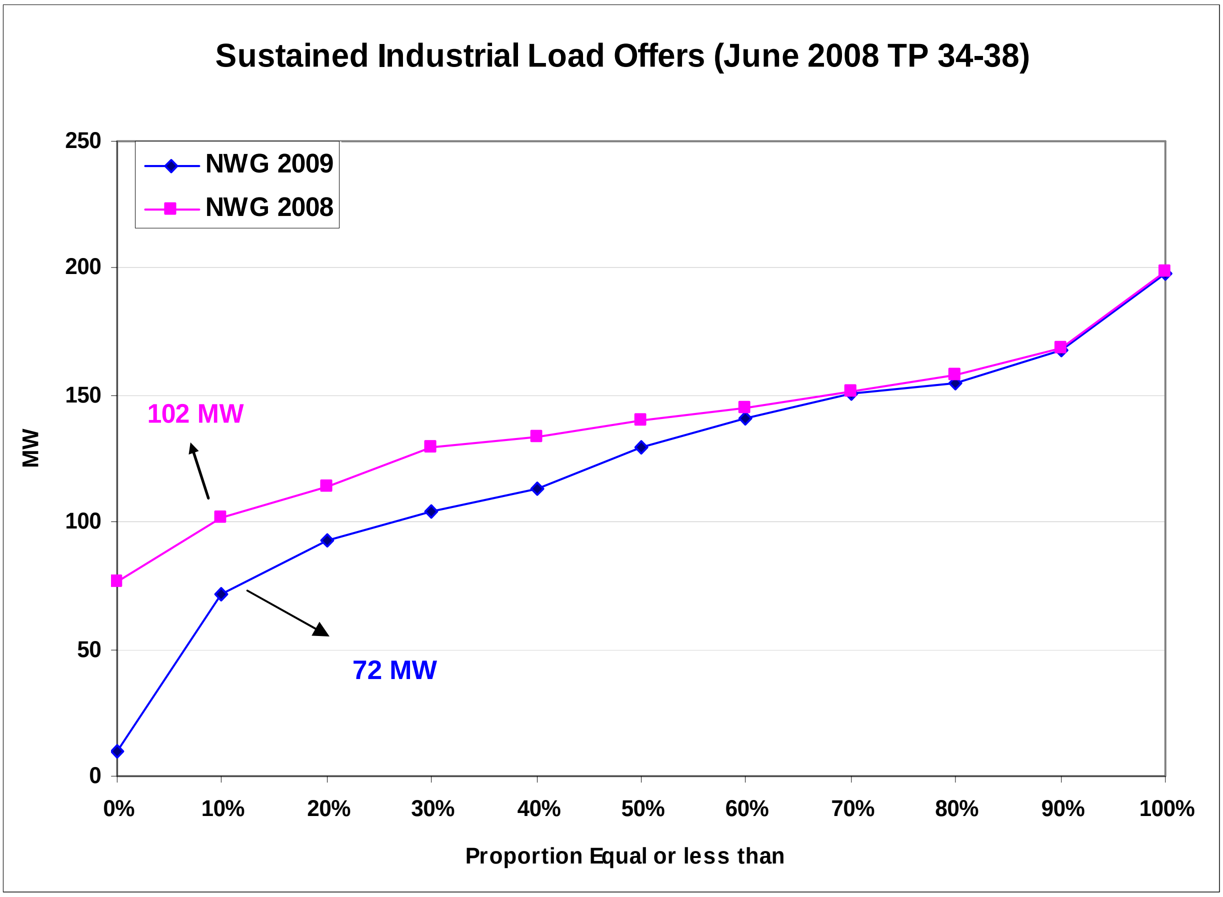
2.5 Wind

Te Apiti and Tararua wind farms data are aggregated from 2005 to 2008 for the month of June, covering trading period 34 - 38. The 10 percentile value is 1 MW as shown in the next chart.



2.6 Interruptible Load

System Operator analysed sustained industrial load offers from NZST, PPAC and SKOG for June – July 2008 period, covering trading period 34 – 38. The chart below shows the resulted sustained load profile and profile produced by NWG 2008. The P10 value decreased by 30 MW from last year but same trend is observed.



2.7 *Uncommitted Fast and Slow*

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

Generators	Fast	Slow	Comment
Huntly 1 unit		243	
Southdown SWN – E105	50		
Total	**50**	**243**	

2.8 *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. The losses for 700 MW of DC sent with 500 MW from P2 and 200 MW coming from half pole is 35 MW.

Maximum P2 transfer of 700 MW

Scenario	Island	MW	Comment
N – G	NI	400	Assume HLY U5/OTB trips
N – 1	NI	650	Assume max DC sent of 700 MW (P2)
N – G – 1	NI	1050	Assume HLY U5/OTB is under outage and DC trips

Maximum P2 transfer of 500 MW and Max Half Pole transfer of 200 MW

Scenario	Island	MW	Comment
N – G	NI	400	Assume HLY U5/OTB trips
N – 1	NI	475	Assume max DC sent of 500 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.

2.9 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	1-5 June	8-12 June	15-19 June	22-26 June	29-3 July	6-10 July	13-17 July	20-24 July
Thermal	50	50	50	50	50	0	0	0
Geothermal	0	0	0	0	0	0	0	0
Cogen	45	45	45	45	0	0	0	0
Hydro Storage	60	60	0	0	0	0	60	60

South Island

Outage type	1-5 June	8-12 June	15-19 June	22-26 June	29-3 July	6-10 July	13-17 July	20-24 July
Hydro Storage	235	250	145	145	90	145	251	145

The followings are the assumptions made (similar to NWG 2008):

- 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

2.10 Summary of Variable MW

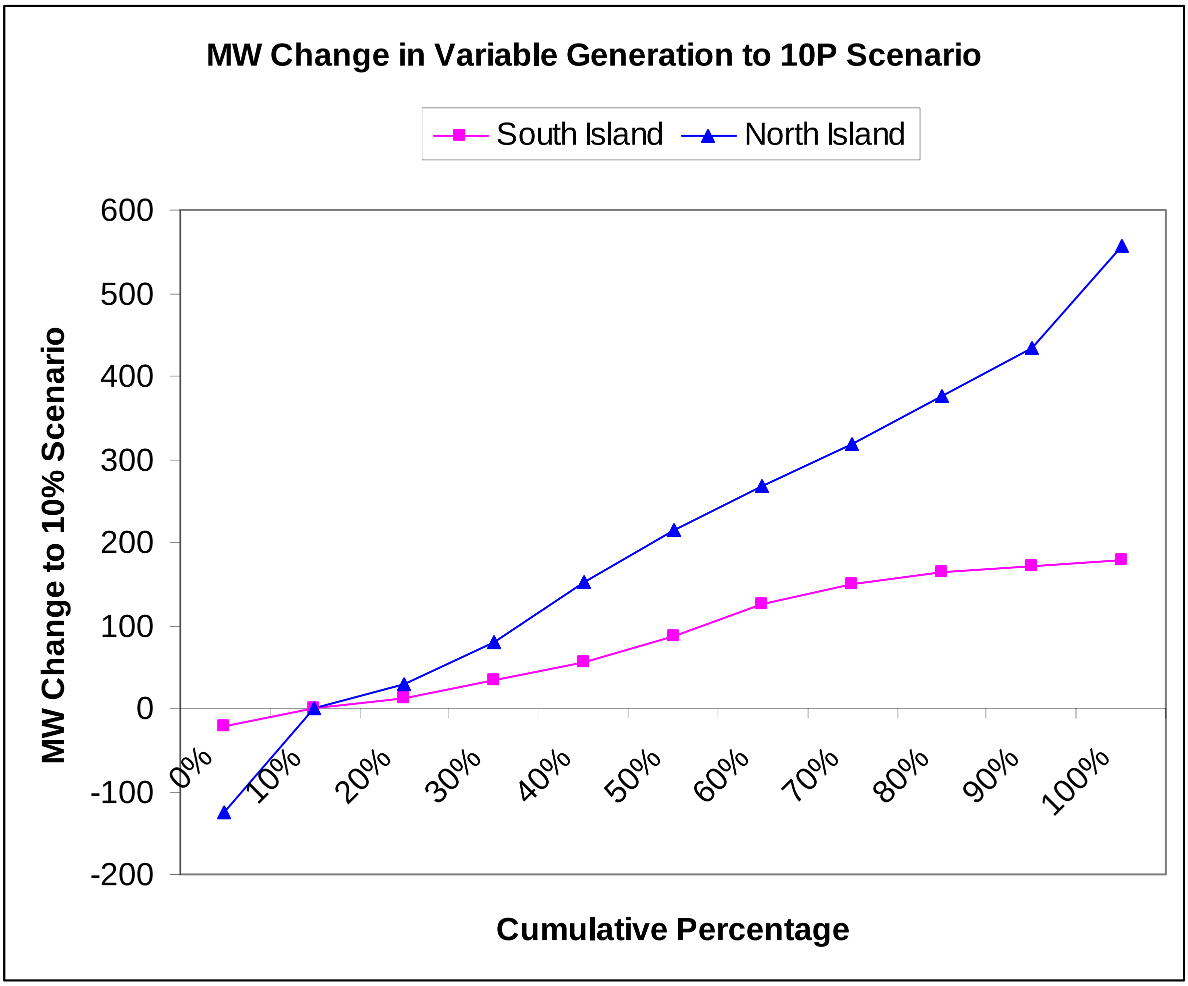
The following table gives an indication of the change in MW available as affected by variable MW components. From the North Island table it can be seen that 50P scenario gives 215 MW extra as compared to the 10P scenario. Likewise, an additional of 88 MW is observed for South Island.

North Island

Percentile	Hydro Run of River + Co-gen (Co-gen: GLN & KPI)	Wind	IL (Offers)	Total Variable MW	MW change from 10% basecase
0%	281	-1	10	290	-125
10%	342	1	72	415	0
20%	357	8	79	444	30
30%	374	38	84	495	81
40%	390	76	100.8	567	153
50%	405	113	112	630	215
60%	416	147	119	682	267
70%	431	169	133	733	318
80%	448	201	140.2	790	375
90%	475	226	149	849	435
100%	530	244	198	972	557

South Island

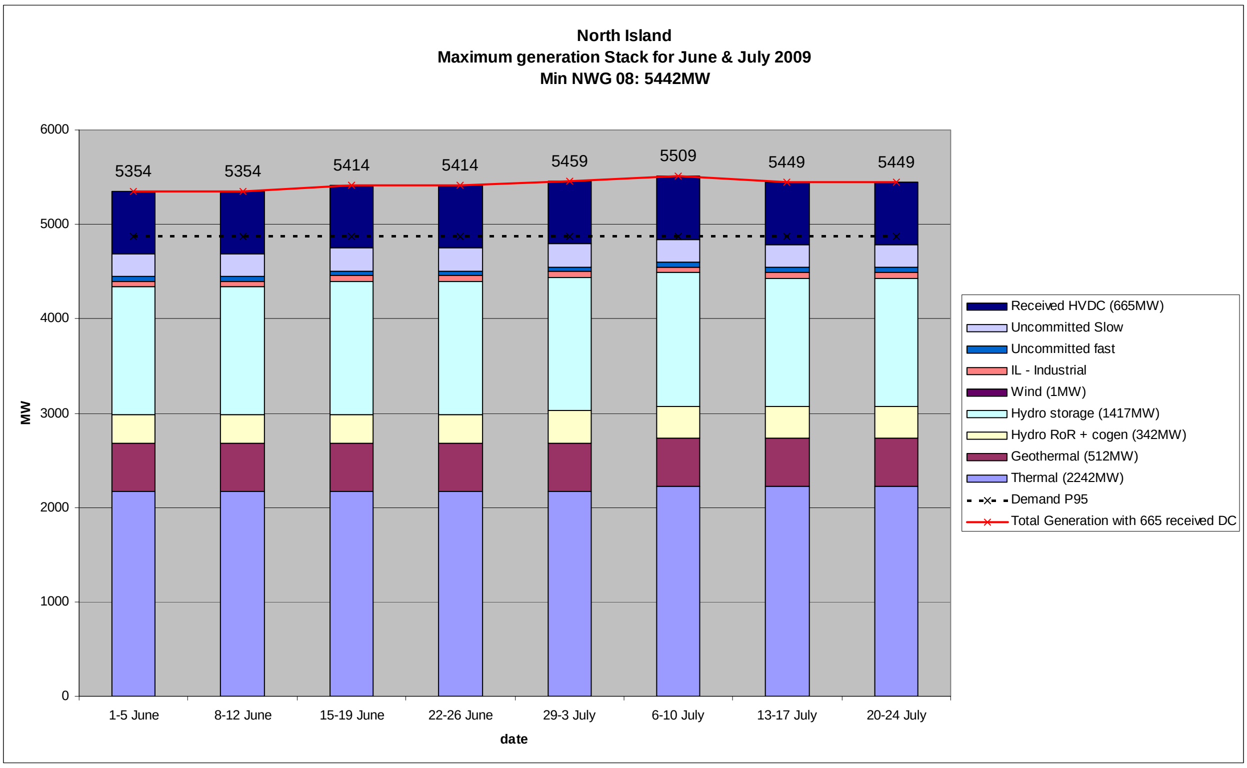
Percentile	Hydro Run of River	Wind	Total Variable MW	MW change from 10% basecase
0%	13	0	13	-21
10%	34	0	34	0
20%	38	7	45	12
30%	41	27	68	34
40%	43	48	90	56
50%	45	77	122	88
60%	46	112	158	124
70%	48	134	182	148
80%	50	148	198	164
90%	52	153	205	171
100%	55	157	212	178


MW Change in Variable Generation to 10P Scenario
South Island
North Island
MW Change to 10% Scenario
600
500
400
300
200
100
0
-100
-200
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Percentage

3. Generation Stack

The chart below consolidates all available generation based on analyses in Section 2. The generation profile is presented in a work week basis.

For each week of the generation stack, planned generation outage has been removed from the generation type.



Generation Type	1-5 June	8-12 June	15-19 June	22-26 June	29-3 July	6-10 July	13-17 July	20-24 July
Thermal (2242MW)	2170	2170	2170	2170	2170	2220	2220	2220
Geothermal (512MW)	512	512	512	512	512	512	512	512
Hydro RoR + cogen (342MW)	297	297	297	297	342	342	342	342
Hydro storage (1417MW)	1357	1357	1417	1417	1417	1417	1357	1357
Wind (1MW)	1	1	1	1	1	1	1	1
IL - Industrial	59	59	59	59	59	59	59	59
Uncommitted fast	50	50	50	50	50	50	50	50
Uncommitted Slow	243	243	243	243	243	243	243	243
Received HVDC (665MW)	665	665	665	665	665	665	665	665
Total Generation with 665 received DC	**5354**	**5354**	**5414**	**5414**	**5459**	**5509**	**5449**	**5449**
Demand P95	4872	4872	4872	4872	4872	4872	4872	4872
Fixed total	4332	4332	4392	4392	4392	4442	4382	4382

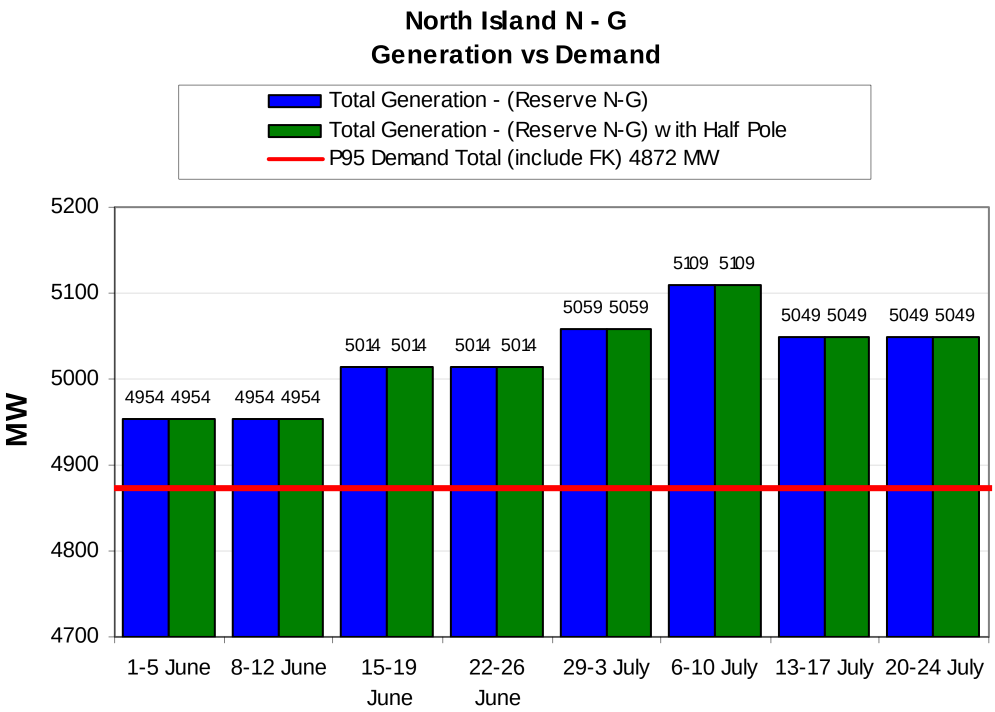
4. North Island Results

4.1 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 (4620 MW), losses (132 MW), intra half hour variability (40 MW) and frequency keeping (50 MW).

N-G (P2 700MW)	1-5 June	8-12 June	15-19 June	22-26 June	29-3 July	6-10 July	13-17 July	20-24 July
Total Generation with Received DC 650 MW	5354	5354	5414	5414	5459	5509	5449	5449
Reserve N-G	-400	-400	-400	-400	-400	-400	-400	-400
Total Generation - (Reserve N-G)	4954	4954	5014	5014	5059	5109	5049	5049
P95 Demand Total (include FK)	4842	4842	4842	4842	4842	4842	4842	4842
Surplus/Deficit	**112**	**112**	**172**	**172**	**217**	**267**	**207**	**207**

N-G (P2 700MW and Half Pole 200MW)	1-5 June	8-12 June	15-19 June	22-26 June	29-3 July	6-10 July	13-17 July	20-24 July
Total Generation with Received DC 665 MW	5354	5354	5414	5414	5459	5509	5449	5449
Reserve N-G	-400	-400	-400	-400	-400	-400	-400	-400
Total Generation - (Reserve N-G) with Half Pole	4954	4954	5014	5014	5059	5109	5049	5049
P95 Demand Total (include FK) 4842 MW	4842	4842	4842	4842	4842	4842	4842	4842
Surplus/Deficit	**112**	**112**	**172**	**172**	**217**	**267**	**207**	**207**

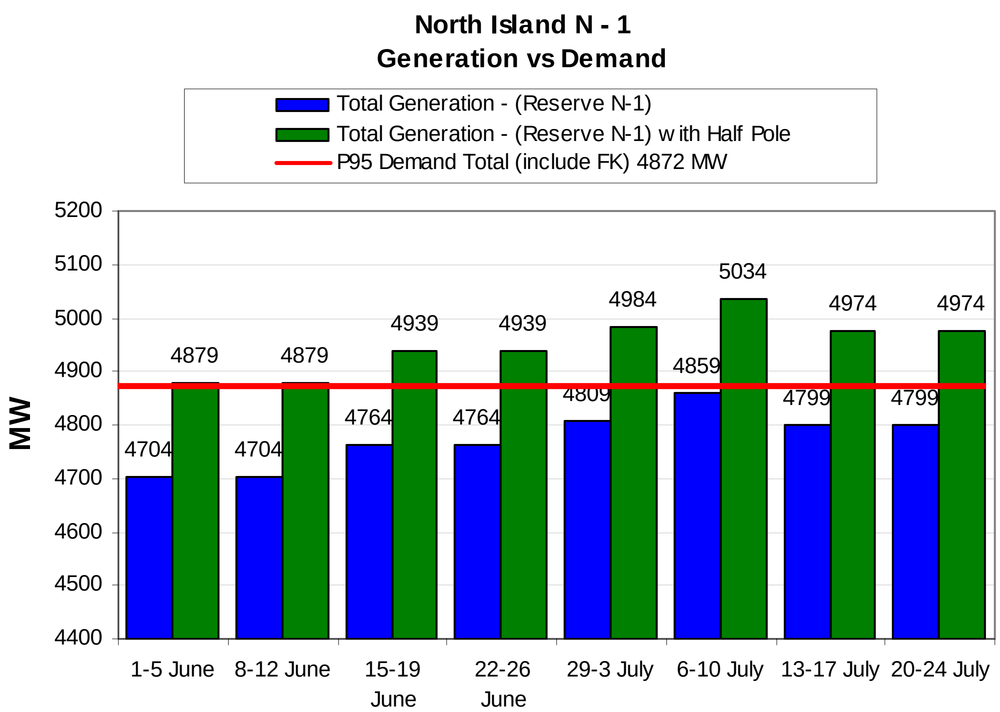


4.2 N-1

Reserve requirement is set as 650 MW and 475 MW.

N-1 (P2 700MW)	1-5 June	8-12 June	15-19 June	22-26 June	29-3 July	6-10 July	13-17 July	20-24 July
Total Generation with Received DC 650 MW	5354	5354	5414	5414	5459	5509	5449	5449
Reserve N-1	-650	-650	-650	-650	-650	-650	-650	-650
Total Generation - (Reserve N-1)	4704	4704	4764	4764	4809	4859	4799	4799
P95 Demand Total (include FK)	4872	4872	4872	4872	4872	4872	4872	4872
Surplus/Deficit	**-168**	**-168**	**-108**	**-108**	**-63**	**-13**	**-73**	**-73**

N-1 (P2 700MW and Half Pole 200MW)	1-5 June	8-12 June	15-19 June	22-26 June	29-3 July	6-10 July	13-17 July	20-24 July
Total Generation with Received DC 665 MW	5354	5354	5414	5414	5459	5509	5449	5449
Reserve N-1	-475	-475	-475	-475	-475	-475	-475	-475
Total Generation - (Reserve N-1) with Half Pole	4879	4879	4939	4939	4984	5034	4974	4974
P95 Demand Total (include FK)	4872	4872	4872	4872	4872	4872	4872	4872
Surplus/Deficit	**7**	**7**	**67**	**67**	**112**	**162**	**102**	**102**

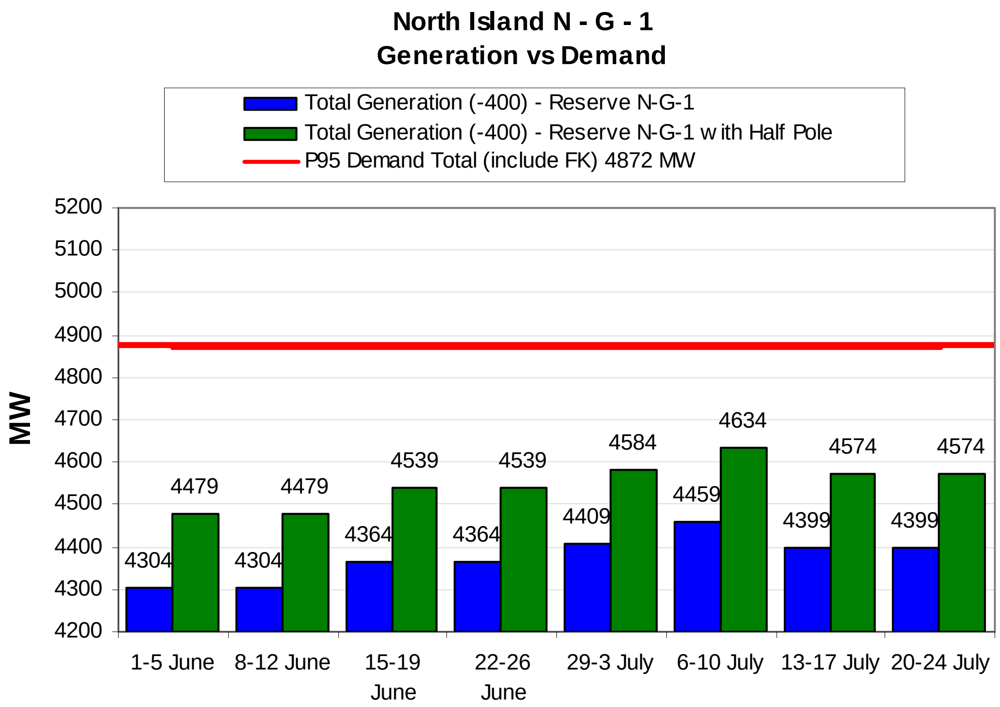


4.3 N-G-1

Reserve is still set as 650 MW and 475 MW. However, 400 MW is subtracted from total generation stack to represent the outage of largest unit.

N-G-1 (P2 700MW)	1-5 June	8-12 June	15-19 June	22-26 June	29-3 July	6-10 July	13-17 July	20-24 July
Total Generation with Received DC 650 MW	4954	4954	5014	5014	5059	5109	5049	5049
Reserve N-G-1	-650	-650	-650	-650	-650	-650	-650	-650
Total Generation (-400) - Reserve N-G-1	4304	4304	4364	4364	4409	4459	4399	4399
P95 Demand Total (include FK)	4872	4872	4872	4872	4872	4872	4872	4872
Surplus/Deficit	**-568**	**-568**	**-508**	**-508**	**-463**	**-413**	**-473**	**-473**

N-G-1 (P2 700MW and Half Pole 200MW)	1-5 June	8-12 June	15-19 June	22-26 June	29-3 July	6-10 July	13-17 July	20-24 July
Total Generation with Received DC 665 MW	4954	4954	5014	5014	5059	5109	5049	5049
Reserve N-G-1	-475	-475	-475	-475	-475	-475	-475	-475
Total Generation (-400) - Reserve N-G-1 with Half Pole	4479	4479	4539	4539	4584	4634	4574	4574
P95 Demand Total (include FK)	4872	4872	4872	4872	4872	4872	4872	4872
Surplus/Deficit	**-393**	**-393**	**-333**	**-333**	**-288**	**-238**	**-298**	**-298**

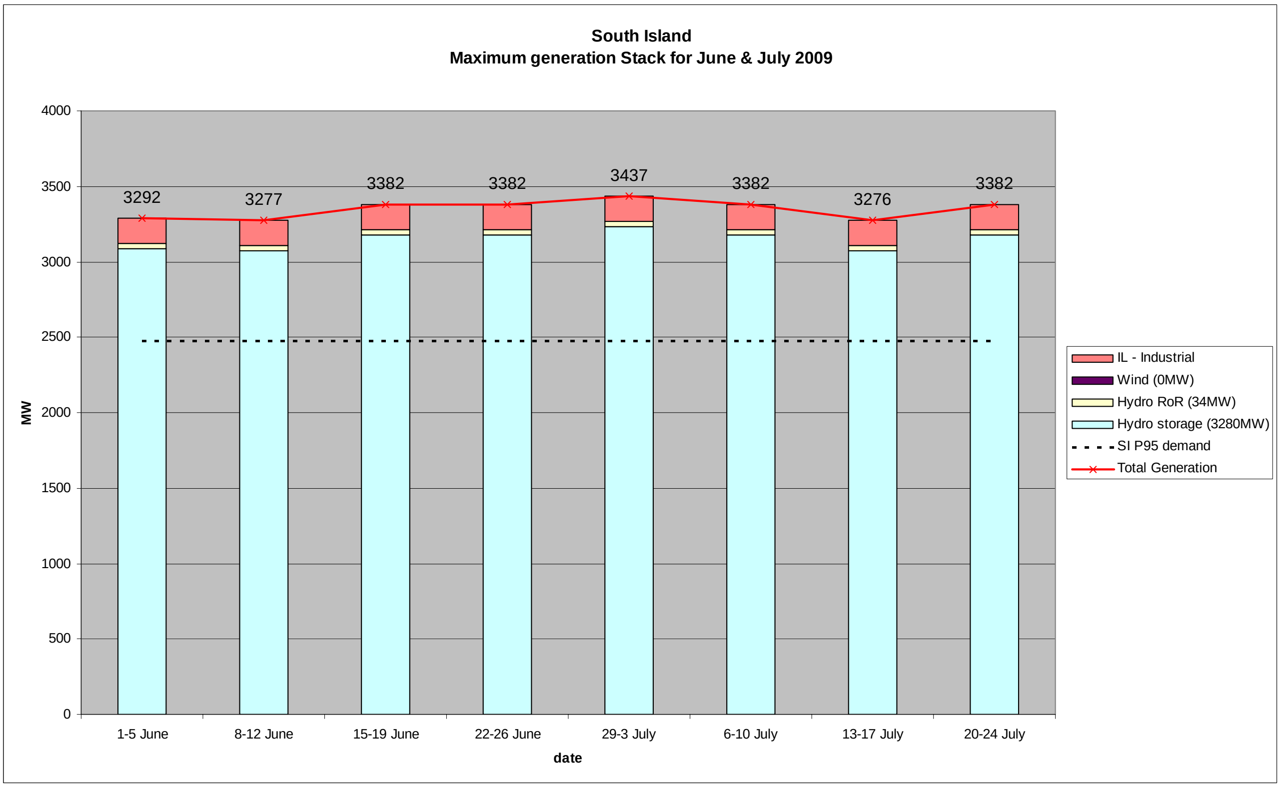


5. South Island Results

Total generation in South Island after taking into consideration allowance for reserve (120 MW) is 3156 MW. With South Island P95 demand of 2473 MW, there will be 683 MW of extra generation available for north transfer.

P95 Demand total refers to the summation of total P95 demand (2300 MW), losses (111 MW), frequency keeping (50MW) and intra half hour variability (12 MW).

Generation Type	1-5 June	8-12 June	15-19 June	22-26 June	29-3 July	6-10 July	13-17 July	20-24 July
Hydro RoR (34MW)	34	34	34	34	34	34	34	34
Hydro storage (3280MW)	3088	3073	3178	3178	3233	3178	3072	3178
Wind (0MW)	0	0	0	0	0	0	0	0
IL - Industrial	170	170	170	170	170	170	170	170
Total Generation	**3292**	**3277**	**3382**	**3382**	**3437**	**3382**	**3276**	**3382**
SI P95 demand	2473	2473	2473	2473	2473	2473	2473	2473
Total Fixed	3258	3243	3348	3348	3403	3348	3242	3348



POCP Outage Information

Plant	Start	End	Type	Owner	Assessment	Planning	MW Remaing	MW Loss	Comment
ARI_7	14/12/2005 13:59	1/07/2016 00:00	continuous	Mighty River	Assessed	Confirmed	24	2	
NPL_1	4/06/2008 13:01	31/12/2010 23:59	continuous	Contact Energy	Assessed	Confirmed	0	120	
NPL_2	4/06/2008 13:01	31/12/2010 23:59	continuous	Contact Energy	Assessed	Confirmed	0	120	
BEN2	2/02/2009 06:00	13/07/2009 18:00	continuous	Meridian	New	Confirmed	0	90	
BEN6	1/05/2009 06:00	1/06/2009 18:00	continuous	Meridian	New	Confirmed	0	90	
TKU3	17/05/2009 00:01	14/06/2009 23:59	continuous	Genesis	New	Confirmed	0	60	
AVI3	1/06/2009 06:00	9/06/2009 21:00	continuous	Meridian	New	Confirmed	0	55	
SWN_1	6/06/2009 00:00	6/06/2009 18:00	continuous	Mighty River	New	Tentative	0	42	W/E
SWN_3	6/06/2009 00:00	6/06/2009 18:00	continuous	Mighty River	New	Tentative	16	20	W/E
TKA1	11/06/2009 06:30	11/06/2009 18:00	continuous	Meridian	New	Confirmed	0	25.2	
TKB3	11/06/2009 06:30	11/06/2009 18:00	continuous	Meridian	New	Confirmed	0	80	
TKU4	15/06/2009 00:01	13/07/2009 23:59	continuous	Genesis	New	Confirmed	0	60	
AVI4	15/06/2009 06:00	23/06/2009 21:00	continuous	Meridian	New	Confirmed	0	55	
HLY6	20/06/2009 00:00	20/06/2009 23:59	continuous	Genesis	New	Confirmed	0	50.8	W/E
MAN5	24/06/2009 06:00	2/07/2009 20:00	continuous	Meridian	New	Confirmed	0	121.5	
SWN_2	27/06/2009 00:00	27/06/2009 18:00	continuous	Mighty River	New	Tentative	0	42	W/E
SWN_3	27/06/2009 00:00	27/06/2009 18:00	continuous	Mighty River	New	Tentative	16	20	W/E
SWN_5	27/06/2009 00:00	27/06/2009 18:00	continuous	Mighty River	New	Tentative	0	50	W/E
MAN5	1/07/2009 06:00	2/07/2009 16:00	continuous	Meridian	New	Confirmed	0	121.5	
MAN3	3/07/2009 06:00	4/07/2009 16:00	continuous	Meridian	New	Confirmed	0	121.5	
MAN4	5/07/2009 06:00	6/07/2009 16:00	continuous	Meridian	New	Confirmed	0	121.5	
AVI1	6/07/2009 06:00	9/08/2009 18:00	continuous	Meridian	New	Confirmed	0	55	
MAN7	7/07/2009 06:00	8/07/2009 16:00	continuous	Meridian	New	Confirmed	0	121.5	
MAN2	9/07/2009 06:00	10/07/2009 16:00	continuous	Meridian	New	Confirmed	0	121.5	
MAN6	11/07/2009 06:00	12/07/2009 16:00	continuous	Meridian	New	Confirmed	0	121.5	
OHB8	13/07/2009 06:00	13/07/2009 18:00	continuous	Meridian	New	Confirmed	0	53	
OHC12	13/07/2009 06:00	13/07/2009 18:00	continuous	Meridian	New	Confirmed	0	53	
MAN1	13/07/2009 06:00	14/07/2009 16:00	continuous	Meridian	New	Confirmed	0	121.5	
OHB9	14/07/2009 06:00	14/07/2009 18:00	continuous	Meridian	New	Confirmed	0	53	
OHC13	14/07/2009 06:00	14/07/2009 18:00	continuous	Meridian	New	Confirmed	0	53	
BEN4	14/07/2009 06:00	8/12/2009 18:00	continuous	Meridian	New	Confirmed	0	90	
OHB10	15/07/2009 06:00	15/07/2009 18:00	continuous	Meridian	New	Confirmed	0	53	
OHC14	15/07/2009 06:00	15/07/2009 18:00	continuous	Meridian	New	Confirmed	0	53	
OHC15	16/07/2009 06:00	16/07/2009 18:00	continuous	Meridian	New	Confirmed	0	53	
OHB11	16/07/2009 06:30	16/07/2009 17:30	continuous	Meridian	New	Confirmed	0	53	
OHA5	17/07/2009 06:30	17/07/2009 18:00	continuous	Meridian	New	Confirmed	0	66	