Electricity Commission
Te Komihana Hiko

Development of a Capacity Adequacy Standard

Consultation Paper

May 2008

CONTENTS

1 Executive Summary

1.1.1 The Electricity Amendment Act 2004 (Act) and the Government Policy Statement on Electricity Governance (GPS) establish a responsibility for the Electricity Commission (Commission) to manage the security of supply of electricity.

1.1.2 The Government has recently published a revision of the GPS[1] which includes a requirement for the Electricity Commission (Commission) to develop a standard for capacity adequacy to meet peak demand. The Commission has considered a broad definition of capacity adequacy, with the analysis capturing variations to demand and supply contingencies across the whole year rather than just at times of highest demand (historically in winter evenings).

1.1.3 This paper proposes the application of an economic approach, trading off the costs of capacity shortfalls against the costs of adding reserve capacity. Techniques for performing this assessment differ principally in the handling of inter-temporal linkages and the degree of detail around the causes and consequences of capacity shortfalls. An approach has been applied which captures the interaction between supply and demand on a probabilistic basis, and focuses on North Island adequacy.

1.1.4 The capacity adequacy standard is intended to apply to at least 2012 so a range of plausible supply and demand scenarios over this time were considered with the intent being to define a standard that is stable over this timeframe.

1.1.5 A North Island winter margin, expressed in MW, was shown to be the most stable of the capacity margins[2]. Supply is measured by derating capacity and demand is the average highest 100 winter daytime demands. The relationship between the South Island supply/demand balance and HVDC capability is also accounted for.

1.1.6 An economic margin of 710 MW has been calculated. It is most sensitive (+/- 70 MW) to the assumptions about the costs of capacity shortfall (or unserved energy). Note that the Commission intends to make a decision on the form and level of the standard after considering submissions to this paper and any additional analysis.

1.1.7 An attempt has been made to separate the issues relating to the development and definition of a standard from the implications of breaching it; this paper is focussed on the former. Once a robust standard is developed, the Commission

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[1] http://www.med.govt.nz/templates/ContentTopicSummary____34016.aspx

[2] Expressed as the amount by which expected North Island supply and HVDC capacity would exceed a measure of peak demand.

will include an assessment of capacity adequacy within its annual review of security. If a future assessment does highlight concern with projected capacity levels, the Commission could respond in a number of ways, ranging from measures to make best use of existing capacity to procuring capacity itself.

1.1.8 The Electricity Commission invites submissions on this paper. The Commission should receive written submissions no later than **5.00pm on 13 June 2007**; the preferred format is described in Section 2.4. Please note that submissions received after this deadline may not be considered.

2 Introduction

2.1 Overview

2.1.1 The Electricity Amendment Act 2004 (Act) and the Government Policy Statement on Electricity Governance (GPS) establish a responsibility for the Commission to manage the security of supply of electricity.

2.1.2 The Government has recently published a revision of the GPS which includes a requirement for the Commission to develop a standard for adequacy of capacity to meet peak demand.

2.1.3 This paper outlines a proposed methodology for determining a capacity adequacy standard, a proposed form of that standard, and an indicative level to apply out to 2012 by which time the GPS indicates the Commission’s Security of Supply Policy will be reviewed.

2.1.4 After reviewing submissions and considering implications of further analysis, the Commission intends to decide on a form and level of a capacity adequacy standard and amend its Security of Supply Policy.

2.2 Purpose of this paper

2.2.1 The purpose of this paper is to:

- Discuss the motivation for the work;
- Discuss conceptual and methodological issues around measuring capacity adequacy;
- Describe the modelling approach and findings on the form and indicative level of a capacity adequacy standard;
- Invite submissions from stakeholders.

2.3 Structure of this paper

Section		Description
1	Introduction	Provides an overview of the paper and outlines the requirements for submissions
2	Background	Background of the work
3	Measuring Capacity Adequacy	Defines some key terms and outlines some important concepts for measuring supply adequacy Reviews international experience with applying capacity adequacy standards in comparable electricity markets
4	Developing a Standard Using an Economic Approach	Outlines some options for applying an economic approach to developing a capacity adequacy standard: • A simple approach • A LDC[3] convolution approach • A full chronological simulation approach Concludes that an LDC convolution approach should be employed in the first instance
5	Implementing an LDC Approach	Describes the LDC convolution methodology applied to the development of a capacity adequacy standard
6	Modelling Results	Summarises the results and a range of sensitivities from applying the LDC convolution methodology Concludes that a capacity adequacy standard expressed in MW terms may have merit Suggests the nature of further work to be undertaken in parallel with consultation process to confirm the approach and firm up the results
7	Conclusions	Summarises the key conclusions from the analysis
8	Next Steps	Outlines the intended plan for consultation with stakeholders and revising the Commission’s Security of Supply policy
Appendix 1		Additional explanatory material on the modelling methodology
Appendix 2		Discusses the demand, transmission, and supply assumptions
Appendix 3		Discusses the cost assumptions for reserve capacity and capacity shortfall
Appendix 4		Discusses the modeling results.
Appendix 5		Glossary of terms.

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[3] Load Duration Curve (LDC).

2.4 Submission requirements

2.4.1 The Electricity Commission invites submissions on this paper. The Commission should receive written submissions no later than 5.00pm on 13 June 2008. Please note that submissions received after this deadline may not be considered.

2.4.2 A number of specific questions that the Commission would like submitters to focus on have been included in the paper. The questions are listed in Section 9.

2.4.3 To assist the Commission in its consideration, please supply evidence of facts and analysis to support your views wherever possible.

2.4.4 The Commission's preference is to receive submissions in electronic form (Microsoft Word). It is not necessary for parties submitting to send the Commission hard copies of their submissions, unless it is not possible to do so electronically. Submissions in electronic form should be emailed with "Security of Supply Policy Consultation Paper" in the subject header. Submissions should be sent:

By email to	info@electricitycommission.govt.nz
By fax to	0-4-460 8879
By hand to	Electricity Commission Level 7, ASB Bank Tower 2 Hunter Street WELLINGTON
By post to	Electricity Commission PO Box 10041 WELLINGTON

2.4.5 The Commission will acknowledge receipt of all submissions by email. Please contact Maree McGregor at the Commission if you do not receive electronic acknowledgement of your submission within two business days.

2.4.6 To foster an informed and transparent process, the Commission intends to publish all submissions received on its website (http://www.electricitycommission.govt.nz).

2.4.7 Please indicate any documents attached in support of your submission in a covering letter and clearly indicate any information that is provided to the Commission on a confidential basis. If your submission contains confidential material, please provide to the Commission both confidential and public versions of your submission, in both electronic and hard copy forms. The responsibility for ensuring that confidential information is not included in a public version of a submission rests entirely with the party making the submission.

2.4.8 Submitters should note that the contents of submissions on this paper provided to the Commission will be among the information the Commission holds which is subject to public release under the Official Information Act 1982 (Official Information Act). If the Commission receives a request for the release of information contained in a submission, it will be required to consider the release of the submission, in whole or in part, in terms of the criteria set out in the Official Information Act. This would be done in consultation with the submitter. The Commission can withhold official information in certain circumstances, which are set out in the Official Information Act. Any decision by the Commission to withhold information is subject to review by the Ombudsman.

2.4.9 In order to test all information contained in submissions as fully as possible in a transparent manner, the Commission discourages requests for non-disclosure of submissions, in whole or in part.

3 Background

3.1.1 The Review of Reserve Energy Policy undertaken by the Commission during 2007 focussed on a security standard for energy capacity adequacy. The recommended “energy margin” that emerged from the review represents an ability to supply electricity over time, while allowing for dry periods.

3.1.2 Many international security of supply standards focus on capacity adequacy in order to assess the ability to supply high electricity demand at any point in time. They focus on capacity adequacy because they are “peak-constrained” rather than “energy-constrained” – in other words they need to construct new supply in order to meet very high (peak) demands over a short time frame rather than supply energy over a longer time frame.

3.1.3 Historically, New Zealand has not had a capacity problem because of the high proportion of hydro capacity with associated flexible fuel supply (storage). We have tended to construct new power station capacity in order to supply energy over time rather than to meet peak demand – in other words New Zealand has been considered as “energy-constrained”

3.1.4 In recent times, the retirement of New Plymouth power station, the growth in peak demand, and the addition of intermittent generation in the form of wind farms, has eroded the margin between capacity and demand at peak times.

3.1.5 The tight supply/demand situations that emerged in June 2006 and February 2008 are indicative of this change. With Government policy favouring renewable supply sources over fossil-fuelled sources, the resilience of the electricity system to meet peak demands is expected to come under further pressure.

3.1.6 While a standard has been defined for ‘energy’ adequacy (or long-term supply adequacy), a need for a corresponding standard for ‘peak’ adequacy (or short-term supply adequacy) was identified. In its recommendations to the Minister in November 2007, the Commission conveyed an intention to develop a standard for capacity adequacy to complement the energy adequacy standard. This was subsequently reflected in the draft Government Policy Statement (GPS) issued in March 2008.

3.1.7 The relevant paragraphs regarding the definition and monitoring are:

Para 59	The Commission should also develop and set security standards for adequacy of capacity to meet peak demand
Para 66	The Commission is expected to be active in monitoring resource availability to meet demand and, in particular, determining whether the market is consistently failing to deliver new capacity sufficient for an adequate energy margin and to meet peak demand

3.1.8 In its review of the Commission's Reserve Energy Policy undertaken during 2007, Castalia Strategic Consultants recommended that an energy security standard be assessed by trading off the costs of reserve plant against the costs of demand restraint. It is possible to apply a similar methodology to deriving a capacity adequacy standard.

3.1.9 This paper outlines the approach that has been used and the conclusions that have been reached. It is worth noting that there are a number of areas where the analysis that is the subject of this paper overlaps with other Commission and stakeholder projects (for example the market design review and consideration of capacity markets, the variable reserves rule change, the National Winter Group (NWG), and the demand-side participation project).

3.1.10 This paper focuses on the development of a capacity adequacy standard as a standalone exercise. Once a robust standard is developed, the Electricity Commission will include an assessment of capacity adequacy within its annual review of security.

3.1.11 If a future assessment does highlight concern with projected capacity levels, the Commission could respond in a number of ways. These include:

- signalling the emergence of a tight capacity situation, and monitoring the extent to which it is addressed by the development of new generation or demand-response resources;
- seeking to address any factors that are impeding the provision of capacity; and/or
- procuring capacity itself (new generation or firm demand-response contracts) using the powers in the Electricity Act.

4 Measuring Capacity Adequacy

4.1 Key terms and concepts

4.1.1 The term “peak” is often used to distinguish short-term demand from energy supply over time. When contemplating capacity adequacy, it is the ability of the power supply system to meet the instantaneous demand for electricity at all times that is important. This naturally tends to focus interest on times of peak demand. However, there can be factors which limit supply at other times of the day or year (e.g., due to supply contingencies) and a capacity adequacy standard needs to capture those situations as well.

4.1.2 A capacity adequacy standard will therefore reflect the ability of supply to meet demand at any time, not just at the time(s) of peak demand. So for this paper we have chosen to use the term “capacity adequacy”.

4.1.3 When considering capacity adequacy, a key issue to address is what should be ‘counted’ when considering the ability of supply to meet demand. The supply chain connecting generation with demand includes transmission and distribution networks. There can be a number of contingencies throughout the supply chain and it is important to recognise that the security of supply experienced by end-consumers results from the combined reliability of fuel supply, generation, transmission and distribution.

4.1.4 For transmission and distribution, the linkage between the state of the networks, investment, and the impact on demand are addressed by existing standards and regulatory frameworks:

- For the transmission network, grid reliability standards drive reliability investments.
- For distribution networks, the Commerce Act regime includes measures relating to the frequency and duration of outages caused by contingencies in the network.

4.1.5 A peak capacity adequacy standard is intended to assess the capability of the generation system to meet electricity demands. Accordingly, the transmission and distribution networks should only be considered where they constrain the ability to deliver generation MW to consumers. For example, if there was a significant capacity shortfall in the North Island, then capacity across the inter-island HVDC transmission could limit the extent to which South Island supply may contribute.

4.1.6 For the development of the capacity adequacy standard it is therefore proposed to focus mainly on the sources of disruption to generation supply, and the variability of demand. The principle applied to transmission is to account for limitations of the HVDC link and, where possible, any other major transmission constraints that could limit the interconnection of generation with demand.

4.1.7 For a given set of assumptions about the capacity and uncertainties around the supply mix (for example MW capacity availability and planned/forced outages) and the variability of demand (usually expressed as a load duration curve), analytical techniques can be used to measure capacity adequacy, and also used to develop a standard. Some of the concepts underlying these techniques are illustrated in Figure 1, where

- Demand variability is represented by a load duration curve (LDC), which is expected or forecast half-hours of demand over a year ranked from highest to lowest inclusive of losses.
- An effective load duration curve (ELDC) can be developed that represents the half-hours of demand over the year adjusted for uncertainty in demand forecasts and uncertainty in supply.

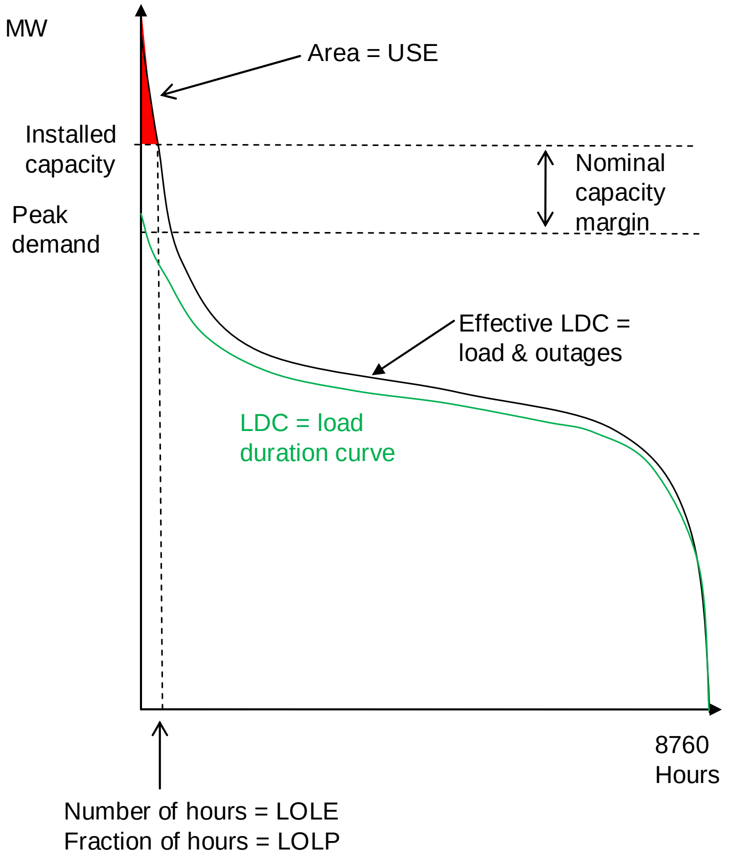
4.1.8 Understanding the development of the ELDC is critical to understanding the approach to the analysis in this paper.

4.1.9 The ELDC acknowledges that there is considerable uncertainty in the electricity demand forecasts, especially at times of peak demand. The conventional LDC will include a “most likely” estimate of peak demand. By definition there will be a 50% probability that this “most likely” estimate will be exceeded in practice (often referred to as a P50 estimate). In addressing capacity adequacy it is important to recognise this uncertainty.

4.1.10 The other major uncertainty in respect of meeting peak demand is the availability of generation. As with demand, there will be uncertainties about the availability of supply from all sources of generation. The techniques described in this paper involve adjusting the ELDC to account for uncertainties in both demand and supply.

4.1.11 There are a number of complexities in developing the ELDC. Typically some form of simulation is required to produce the LDC and then to overlay the uncertainties in demand and supply. For demand, simulation might capture uncertainties due to temperature variation. For supply, simulation might capture different hydro or wind patterns, and forced outage durations. Ultimately, the ELDC is a combination of all these uncertainties and is a probability distribution reflecting the combination of variability in both supply and demand.

Figure 1 Conceptual measures of supply adequacy



4.1.12 The interaction of the ELDC and installed supply capacity enables a number of measures to be derived. In any period where the ELDC exceeds installed capacity, a capacity shortfall exists and load shedding is required to match supply with demand. There are a number of ways this can be measured:

(a) Unserved energy (USE): the expected involuntary restraint measured in MWh (MW of restraint x duration). Often the USE is expressed as a fraction of annual energy demand. USE reflects both the depth and duration of any involuntary restraint.

(b) Loss of load expectation (LOLE): the expected number of hours of involuntary restraint, also equivalent to the number of hours that the ELDC exceeds capacity. LOLE does not reflect the magnitude of any outages.

(c) Loss of load probability (LOLP): the LOLE expressed as a fraction of hours per annum.

(d) Nominal capacity margin: a measure of the MW difference between nominal (installed) capacity and a measure of peak demand (from the LDC). For example, an expected peak demand (P50) might be used. The MW margin is often expressed as a percentage of peak demand. Other versions can be calculated where nominal capacity is de-rated to reflect expected capacity at peak, and where demand is expressed differently.

4.1.13 A capacity adequacy standard can be expressed as a particular value of one of these measures. It is also necessary to apply a definition of how the measure is calculated so that the adequacy of the electricity system can be measured against the standard, given forecasts of supply and demand.

4.1.14 Through the process of discussing the concept of a capacity adequacy standard with stakeholders, it has been observed that there is often some confusion with the concepts of a standard and the process of measurement against that standard. The reason for this is possibly that the analytical approach used for measuring capacity adequacy is also a component of the wider analysis used to develop a standard.

4.1.15 Measuring capacity adequacy for a particular set of assumptions (for example for the next year) can be complicated but is made easier due to assumptions about supply and demand being more certain. For example, the most recent Reserve Energy Needs Assessment and the NWG report both discussed approaches for measuring 2008 capacity adequacy using different measures.

4.1.16 There are numerous measures of capacity adequacy and it is likely that there will be different views expressed by different stakeholders. Ultimately the Commission will need to choose a particular approach to a capacity adequacy standard.

4.2 International experience

4.2.1 Many deregulated electricity markets have some form of capacity adequacy standard (note that the equivalent is often referred to as a “reliability standard”). This section summarises the measurement and expression of the standard for some relevant overseas markets.

4.2.2 Because supply mix, market design, and regulatory environments differ markedly, care is required in attempting to compare overseas standards with that which might apply in New Zealand. Nevertheless, there is merit in examining the approach that is taken and the nature and magnitude of overseas standards. Table 1 summarises the type of standard, the level of standard, the basis for the standard and the scope of application.

Table 1 Capacity adequacy standards in overseas markets

Country	LOLE	USE	Basis for standard	Scope
Australia (NEM)		.002%	Defined by Reliability Panel in 1998 at market start and confirmed by AEMC in 2007 when reviewed	Generation and bulk transmission. Single credible contingencies of generation or bulk transmission
Australia (WA)	MW margin (largest unit) or .002% USE		Unclear	Generation and bulk transmission. Prudent peak demand
Ireland	8 hours per annum		"Appropriate and acceptable" on historic basis	Ability of grid connected generation to meet GIP demand. Transmission limits, but not risks
UK	No formal standard		Monitor and contemplate economic tradeoff, but" far from straightforward in practice"	Nominal capacity and "average cold spill" peak demand.
France	3 hours per annum		Government decision	Grid connected supply. Transmission outages and imports
PJM	2.4 hours per annum (one day in 10 years)		Formulation of NERC in 1965	Generation capacity. No transmission risk. LOL = invoking emergency operations procedures beyond demand resources and IL for reliability
Ontario	2.4 hours per annum		Follows NPCC standard (Northeast Power Coordinating Council)	Ad hoc transmission adjustments on supply

4.2.3 From this sample, it is clear that different countries adopt different approaches to developing and specifying a standard. In markets where a standard is defined, there are subtle differences in the way demand restraint and uncertainties are measured, often capturing the features of the particular market. It is not always clear what the implications of breaching a standard are or what the mechanisms for intervention might be.

4.2.4 There is reasonable consistency in the level of LOLE standards (ranging from 2.4 to 8 hours per annum). The LOLE corresponding to the .002% USE standard employed in Australia was recently estimated as 3.5 hours per annum and providing a 16% installed capacity margin over peak demand. In Western Australia, a market with a similar size to the North Island of New Zealand, a 320 MW margin is used corresponding to the largest supply contingency.

4.2.5 The basis upon which standards are defined is often non-scientific (USA, Australia, and Ireland). In the United Kingdom there is no specified standard, but capacity margins are monitored on a regular basis. The Australian NEM standard was reviewed in 2007, with USE preferred over alternative measures due to it being familiar, easy to measure, reflective of the economic impact on typical users, and equally applicable to different regions.

4.2.6 While there are nuances in the way in which adequacy standards are expressed, there is reasonable consistency about scope, with transmission and distribution uncertainties typically excluded, and supply/demand variation included. Of particular importance is a clear definition of the various components of demand and how they are accounted for.

4.2.7 As illustrated by Figure 1, the individual measures are not separable; selecting one measure of capacity adequacy implies values for the other measures (for example the .002% USE adopted in the NEM is equivalent to a LOLE of 3.5 hours per annum). In determining a standard, the rationale for selecting one measure over another needs to be consistent with the approach used to derive the measure and the intended consequences if it is not met.

5 Developing a Standard Using an Economic Approach

5.1 A simple approach

5.1.1 The approach to developing an optimal capacity adequacy standard follows that used to develop an optimal energy standard as recommended by the Castalia Review. Castalia pointed out that we all know that absolute security of supply is not a sensible objective because of the massive redundancy in plant and fuel supplies that would be needed. From an economic perspective, the optimal level of capacity adequacy is derived by trading off the cost of capacity against the cost of demand restraint and outages.

5.1.2 If we know the fixed cost of a peak supply plant (F \$/MW/yr) and the cost of capacity shortfalls is assumed to be constant (CS \$/MWh) i.e. does not change with the depth or the duration of the shortfall, then we can calculate the optimum number of hours of capacity shortfall.

5.1.3 It can be shown that at the optimum[4] F = CS / h, or h = F/CS.

5.1.4 If the fixed cost of a peak supply plant is \$120,000/MW/yr and the cost of capacity shortfall is \$20,000/MWh then the number of hours of capacity shortfall at the optimal supply margin will be \$120,000/20,000 = 6hrs per annum.

5.1.5 If all these assumptions hold then it would be possible to represent the economic standard by the LOLE or LOLP. It is not possible to derive optimal capacity margins or expected unserved energy (USE) measures using this simple approach since these measures will depend on the nature of supply and demand.

5.1.6 In reality we know that the cost of capacity shortfalls will depend on the depth of shortfall. Small shortfalls can be met by demand side response (e.g. extended control of water heating load). Shortfalls up to around 400MW can also be met by relaxing short term instantaneous reserve (IR) requirements. This involves running a greater than normal risk of automatic under frequency load shedding (AUFLS) in the event of a sudden loss of a generation unit or the HVDC transmission. However the expected cost is only a fraction of the full cost of pre-event load shedding since the risk of a sudden loss of a large generation unit is of the order of 1% per hour.

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[4] This was given in the Castalia Review (May 2007, page 39). Castalia calculated LOLE= 3hrs using this approach, but this was based on \$90,000/MW/yr cost for peak capacity and a fixed CNS at \$30,0000. 3 = 90,000/30,000. For the Australian NEM analysis McClennan Magasinik Associates used a typical peaker cost of \$A100,000/MW/yr and a CNS of \$A30,000/MWh. This would imply a LOLE of 3.3 hrs/year.

5.1.7 Larger shortfalls greater than around 400MW in the North Island will involve instructed emergency load shedding to restore the system to a state where it can survive a sudden loss of generation without system collapse. In this situation distribution companies are obliged to reduce load to the level instructed by the system operator. They can sometimes achieve small reductions at a relatively low cost by extending their normal water heating cuts or from voluntary cuts by big users. However larger cuts usually require selective blackouts. These are normally targeted to less sensitive and costly residential areas, but inevitably affect some commercial and manufacturing users. The social cost of selective blackouts is estimated to be of the order of $11,000 to $33,000/MWh ($10 to $30/kWh or of the order of 100 times the typical domestic electricity price). If the instructed load shedding is very large then it may not be possible to avoid cutting sensitive and costly loads (such as central business districts and hospitals) and so the social costs will be greater in this case.

5.2 LDC convolution approach

5.2.1 A more complex approach is required to recognise that the cost of a capacity shortfall depends on the depth of shortfall, and to derive alternative measures such as USE and capacity margin in addition to the LOLE.

5.2.2 The simplest alternative approach is the LDC convolution approach. This involves taking the probability distribution of system loads (the LDC incorporating demand uncertainty) and subtracting the probability distribution of supply capacity (accounting for plant outages and other factors affecting supply capability) to derive a capacity shortfall probability curve (CSC). This identifies the probability of exceeding different levels of capacity shortfall.

5.2.3 The expected cost of shortfalls calculated from this curve can account for the depth (MW) of shortfall. These calculations can be repeated for different levels of peak supply capacity (i.e. by adding extra open cycle gas turbine peaking plant) and the total cost of outages and supply capacity can be plotted and a minimum total cost can be found.

5.2.4 The expected hours or quantity of demand restraint (megawatt hours) and outages at this optimum can be derived as well as the optimum capacity margin. These measures can be considered as candidates to represent the economic standard.

5.2.5 Mathematical techniques for doing these calculations are well developed and are used regularly in power systems around the world. This approach was successfully applied in New Zealand to assess winter 2008 capacity adequacy in the Reserve Energy Needs Assessment carried out in October 2007.

5.2.6 While this LDC approach is best suited to flexible thermal systems or hydro systems with significant storage; it can be adapted to systems with less flexible hydro, run of river hydro, inflexible cogeneration, and other intermittent generation (e.g. wind, tidal). It is also possible to account for correlations between wind supply and demand if this proves significant, and to account for planned outages and seasonal variations in wind and profiled hydro by applying the approach to separate time zones and combining the results.

5.2.7 This approach is relatively straight-forward to implement and has been well tested. However it has some limitations in that it cannot directly account for chronological constraints, such as inflexibilities in thermal start up and river constraints affecting the available capacity of the hydro stations. These effects can be approximated through the use of scenarios, or by modifying some of the inputs as follows:

- The random outage rate for slow start thermals can be increased to account for the risk that a unit may have been shut down overnight due to high inflows or wind generation and hence be unable to be started quickly enough to meet an unexpected demand fluctuations or unit outages, or sudden drop in hydro or wind generation.
- It is also possible to increase the random outage rates for controllable hydro units to account for the fact that river chain constraints may mean that in situations with low inflows and storage releases some of the full peaking capacity of the river chain can’t be achieved for enough hours following a significant change in the system (for example a shift in demand, loss of wind, or loss of a major power station unit) to avoid a capacity shortfall.

5.3 Full chronological simulation

5.3.1 To properly account for the chronological constraints it is necessary to go to a significantly more complex simulation which involves modelling the operation of the whole system on a period-by-period basis over a typical day or week for each season taking into account demand uncertainty (including ripple control of load), transmission capacity and HVDC outages, wind uncertainty, hydro inflow uncertainty, reservoir storage uncertainty, forecast accuracy, river chain scheduling constraints, thermal start up times and participant behaviour in response to forecast prices and risks.

5.3.2 A full chronological simulation approach would also allow the costs of supply shortfall to vary as a function of duration (studies have shown that the cost of outages typically varies with both depth and duration[5]).

5.3.3 It would be challenging to develop a full chronological simulation model that can run fast enough to deal with all the combinations of uncertainties that could give rise to capacity shortfalls and to calculate stable estimates of USE, LOLE and the cost of shortfalls. It may also turn out to be an unnecessary refinement, given the very significant uncertainty regarding the underlying key parameters such as the cost of supply shortfalls and the cost of new peaking capacity.

5.4 Conclusion on modelling approach

5.4.1 A decision was made to pursue the LDC convolution approach in the first instance, with the rationale being that:

- Development of a chronological approach had the potential to be consuming of time and resources with no guarantee of more robust results;
- The LDC convolution approach was expected to be relatively quick to develop and implement and could build on an existing assumptions set;
- The LDC convolution approach would be amenable to testing the economic approach, and investigating the sensitivity of both the methodology and results to the core assumptions.

5.4.2 The potential impact of ignoring some of the chronological issues can be explored using sensitivity analysis.

Q1. Do you agree with the recommended approach of using an economic approach for establishing a security standard?

Q2. Do you agree that the approach developed by trading off the cost of demand restraint against the cost of reserve energy is an appropriate means of implementing an economic approach?

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[5] See MMA "Estimation of Economically Optimal Reliability Standard for the NEM" June 2006, page37.

6 Implementing the LDC Convolution Approach

6.1 Overview of the approach

6.1.1 This section provides an overview of the LDC convolution approach used to estimate an optimum capacity adequacy standard. It is not intended to be detailed, but rather to outline the key steps in the modelling process. Further discussion of the approach is included in Appendix 1.

6.1.2 The assumptions and distributions for supply and demand used in the analysis are discussed in the modelling results section later in the paper, and described in Appendix 2.

6.1.3 The LDC convolution approach involves the following steps:

(a) Distributions of supply and demand are generated for each island, reflecting the uncertainties in both parameters that were discussed in the previous section.

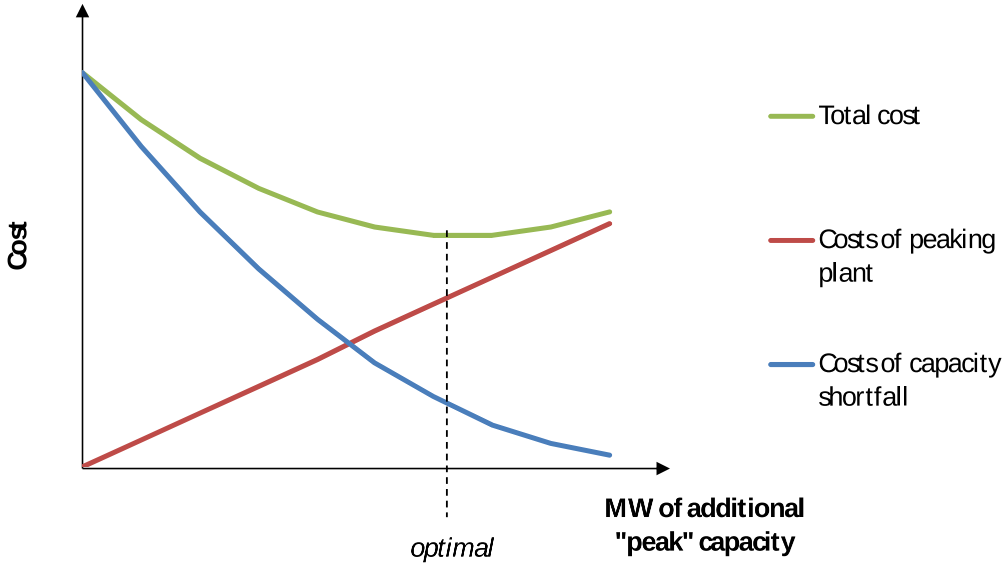
(b) Using a Monte Carlo simulation, the supply and demand curves are sampled and the contribution to North Island demand from South Island supply is calculated (adjusted for HVDC transmission constraints and reserve requirements). The output is the capacity shortfall probability curve (CSC) providing a probability distribution of possible capacity deficits.

(c) For a given mix of power stations representative of the current system, the CSC can be used to derive an expected cost of capacity shortfall (or USE) using a cost of capacity shortfall function derived for this purpose and discussed in a following section.

(d) Reserve power stations (assumed to be open-cycle gas turbines providing firm MW capacity) are added and subtracted from the supply mix and the cost of capacity shortfall is recalculated.

6.1.4 The optimum level of capacity is explored by calculating the total expected costs of reserve capacity and USE for varying levels of reserve capacity i.e., repeating the above steps for varying levels of reserve capacity. The trade-off between costs of reserve capacity and capacity shortfall is illustrated in Figure 2:

Figure 2 Illustration of cost trade-off



6.1.5 The optimal capacity margin is that which achieves the minimum combined cost of reserve energy and USE. Having established the optimal capacity margin it is then possible to determine the optimum USE and LOLE.

6.2 Cost of reserve capacity assumptions

6.2.1 For the base case analysis the annualised cost of reserve MW was estimated as that of an open cycle gas turbine (OCGT) unit at $124/kW/yr[6]. This is derived from:

- $24/kW/yr fixed O&M costs;
- $100/kW/yr of annualised capital costs.

6.2.2 The sensitivity of the results to this assumption is discussed later in the report.

6.3 Cost of capacity shortfall assumptions

6.3.1 The analysis requires some key assumptions concerning the cost of demand restraint and/or outages when there is a capacity shortfall. In contrast to energy demand restraint, there is very little warning of the need for demand restraint. This limits the expected response from the market and increases the cost of outages considerably.

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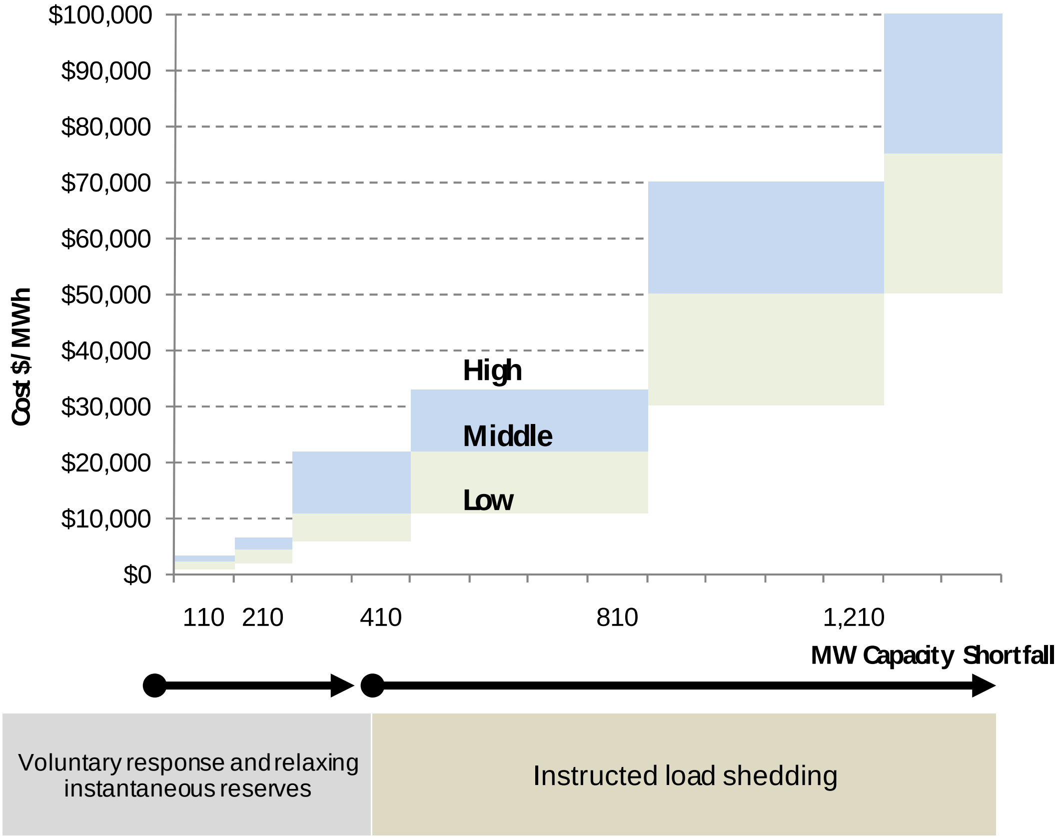
[6] This is based on cost estimates from PB Power as discussed in Appendix 4.

6.3.2 The approach to deriving the cost of capacity-shortfall is examined in Appendix 3 and yields a function that provides rising costs with the depth of the shortfall as described in Figure 3.

Figure 3 Costs of capacity shortfall



6.3.3 This chart indicates costs rising from $500 per MWh for very small capacity shortfalls to $100,000 per MWh for very large shortfalls. Note that up to around 400MW of shortfall, the shortfall is met by a small amount of voluntary demand side response and by relaxing short term instantaneous reserve requirements (which involves running a higher than normal risk of automatic under frequency load shedding). Actual instructed pre-event load shedding (involuntary restraint) does not occur until the shortfall exceeds 400MW.

6.3.4 The nature and basis for these estimated costs of each tranche of capacity shortfall is fully described in Appendix 3 and summarised in Table 2.

Table 2 Capacity shortfall costs

	MW Shortfall		Marginal Cost $/MWh			
	Step	Total	Low	Mid	High	Basis of cost estimate
Demand side 1	10	10	$500	$1,100	$1,200	Voluntary low cost response to expected high price eg. extended ripple control
Emergency Secure 1	100	110	$1,000	$2,200	$3,300	Risk of AUFLS with 100MW IR shortfall
Emergency Secure 2	100	210	$2,000	$4,400	$6,600	Risk of AUFLS with 200MW IR shortfall
Demand side 2	-	210	$4,000	$8,800	$11,000	Voluntary high cost response to expected high price eg. Load management
Emergency Secure 3	200	410	$6,000	$11,000	$22,000	Conservative higher risk of AUFLS with 300-400MW IR shortfall
Load Shedding 1	400	810	$11,000	$22,000	$33,000	Cost of selected lower cost load shedding based on GIT values for unserved energy
Load Shedding 2	400	1,210	$30,000	$50,000	$70,000	Cost of deeper forced load shedding
Load Shedding 3	2,000	3,210	$50,000	$75,000	$100,000	Cost of very deep load shedding including high cost sectors such as CBDs

6.3.5 The sensitivity of the results to these assumptions is discussed later in the report.

Q3. Do you agree with the assumptions used to cost peak supply plant?

Q4. Do you agree with the assumptions used to cost capacity shortfalls?

Q5. Do you agree with the supply assumptions outlined in Appendix 2?

Q6. Do you agree with the demand assumptions outlined in Appendix 2?

7 Modelling Results

7.1.1 This section summarises the results from applying the LDC convolution approach to a base case set of input assumptions and the sensitivity of the results to changes to input assumptions that are particularly uncertain (for example the costs of capacity shortfall) and across a range of future supply scenarios.

7.1.2 The scenarios are described briefly in Table 3. All scenarios included operation of half-Pole 1 to assist at times of capacity shortfall. Appendix 4 sets out the results in more detail.

Table 3 Base case scenarios

Scenario	Description
Base ’08	2008 forecast demand 2008 capacity mix
Wind ’08	2008 forecast demand 2008 capacity mix with 400MW of additional wind assumed correlated with Tararua,
Base ’12	2012 forecast demand 2008 capacity mix with additional firm capacity (eg geothermal) to meet demand growth
Wind ’12	2012 forecast demand 2008 capacity mix with 400MW of additional wind assumed correlated with Tararua

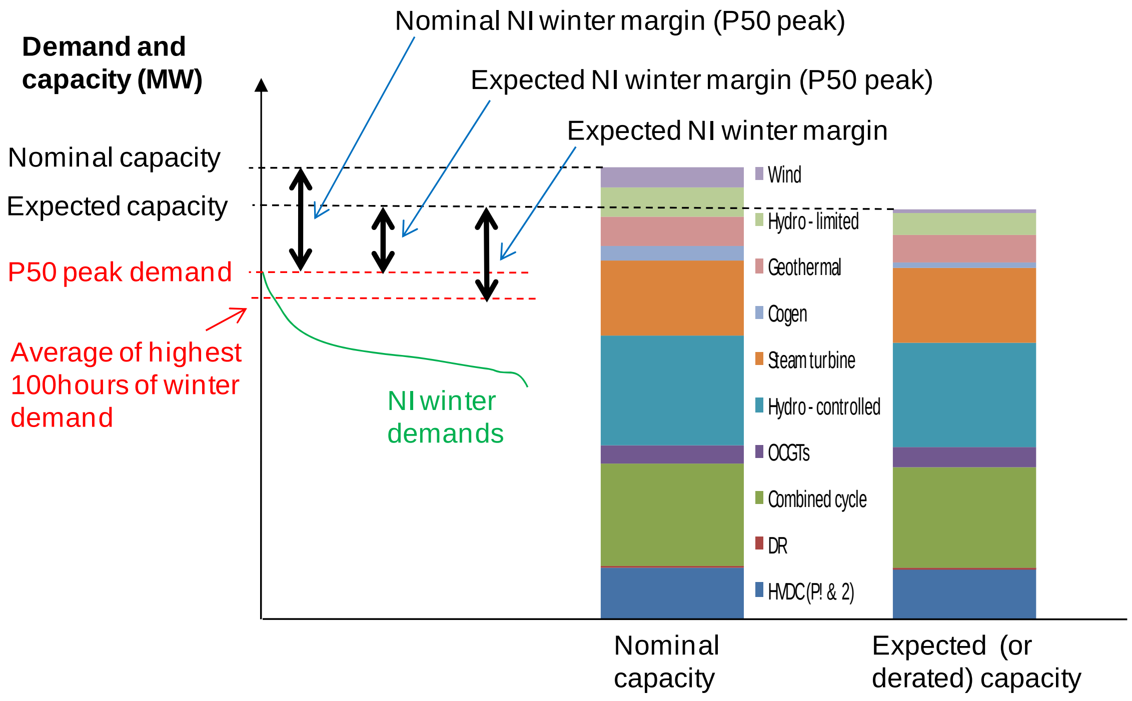
7.1.3 In order to explore the robustness of the “capacity margin” measures of capacity adequacy, the analysis has considered how different definitions of these measures vary across the scenarios, as described in Table 4 and illustrated in Figure 4.

Table 4 Definitions of winter capacity margins

Scenario	Description
Nominal NI winter margin (P50 peak)	Total installed NI MW capacity + effective HVDC received + voluntary demand response – expected highest half-hour winter demand
Expected NI winter margin	Expected (or derated) NI MW capacity + effective HVDC received + effective voluntary demand response – average of the highest 100 hours of winter daytime demand
Expected NI winter margin (P50 peak)	Expected (or derated) NI MW capacity + effective HVDC received + effective voluntary demand response – expected highest half-hour winter demand

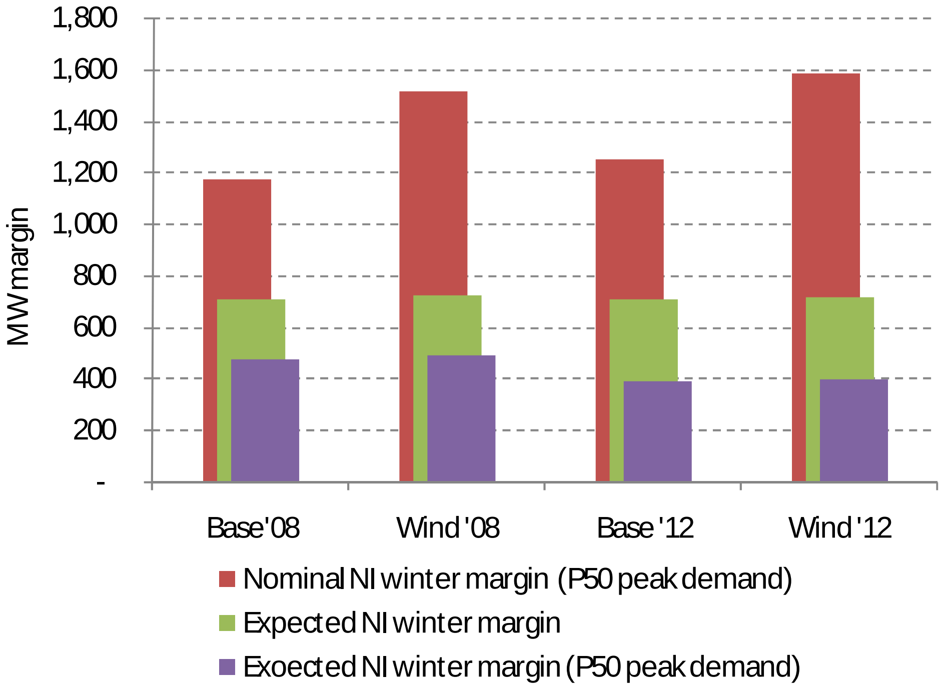
Demands include losses.

Figure 4 Illustrative margin calculations



7.1.4 Figure 5 summarises the capacity margin results across a range of supply scenarios.

Figure 5 Capacity margins (MW)



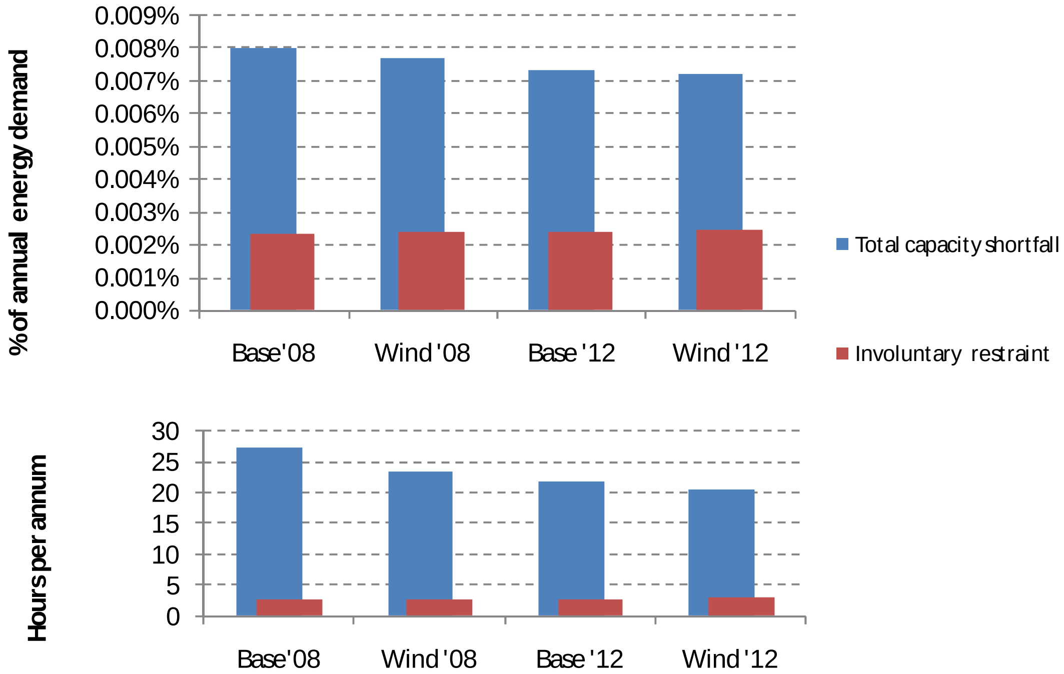
7.1.5 The most stable capacity margin measure is the "expected NI winter margin" shown in green, which yields an optimum across a range of scenarios in the range of 710 ±10 MW for the North Island. This margin is calculated by de-rating all power station plant by various factors according to their reliability and controllability. The margin is measured relative to the average of the highest 100 hours of winter daytime demand. On this basis, it represents a margin of 16-17% in 2008.

7.1.6 The other capacity margin measures are included to enable comparison with other more traditional capacity margin measures. The traditional international measure shown in red, is the optimal nominal winter margin relative to the expected, or P50, peak half hourly load. This is 19% to 30% expressed as a percentage of peak demand. The typical international standards vary from 15% to 30%. Note that this measure is less useful in that it depends on the plant mix. For example, the optimal nominal margin would have to be higher if there was a higher percentage of unreliable wind capacity.

7.1.7 The purple margin measure has expected (or derated) capacity but is measured relative to the expected single peak half hourly demand rather than the average of the highest 100 hours of winter daytime demand. This measure is less relevant in New Zealand as capacity shortfalls typically result from combinations of large unit outages and relatively high demands, rather than just the highest half hourly demand.

7.1.8 For comparison with international benchmarks, Figure 6 illustrates the optimal LOLE and USE corresponding to the optimal reserve capacity.

Figure 6 USE and LOLE



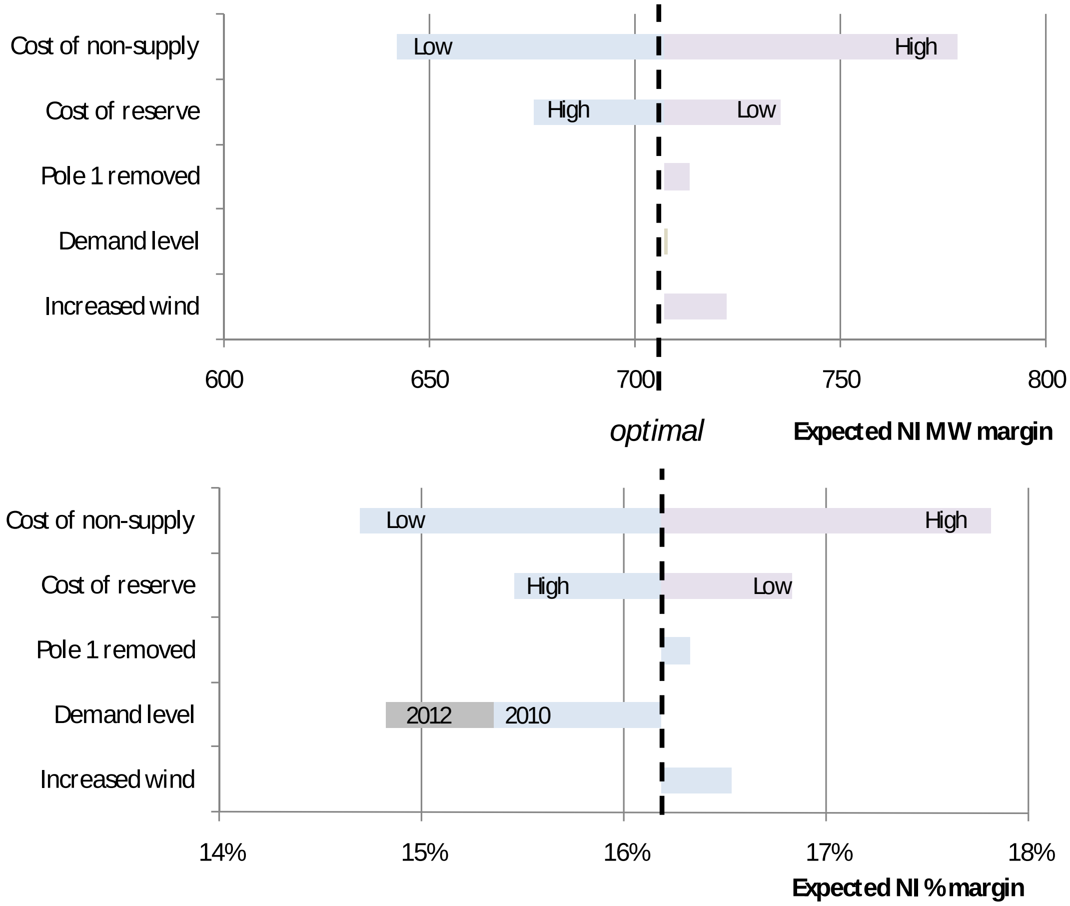
7.1.9 The capacity shortfalls in Figure 6 are achieved through a combination of low cost measures that effectively reduce security of supply (reducing reserves cover, operating half Pole 1) and involuntary restraint (load shedding).

7.1.10 The results indicate that the low cost measures make up the bulk of the capacity shortfall and the involuntary restraint levels are the measures that should be compared with international benchmarks for USE and LOLE.

7.1.11 The international standards are typically LOLE of 2-3 hours per annum or 0.002% USE. The optimum levels indicated in the chart are generally consistent with these overseas standards.

7.1.12 The sensitivity of the results has been assessed against a range of other factors, the most important of which is variations in the costs of capacity shortfall and the cost of reserve capacity. The results are summarised in Figure 7 for the "expected North Island margin" expressed in MW and as a percentage margin.

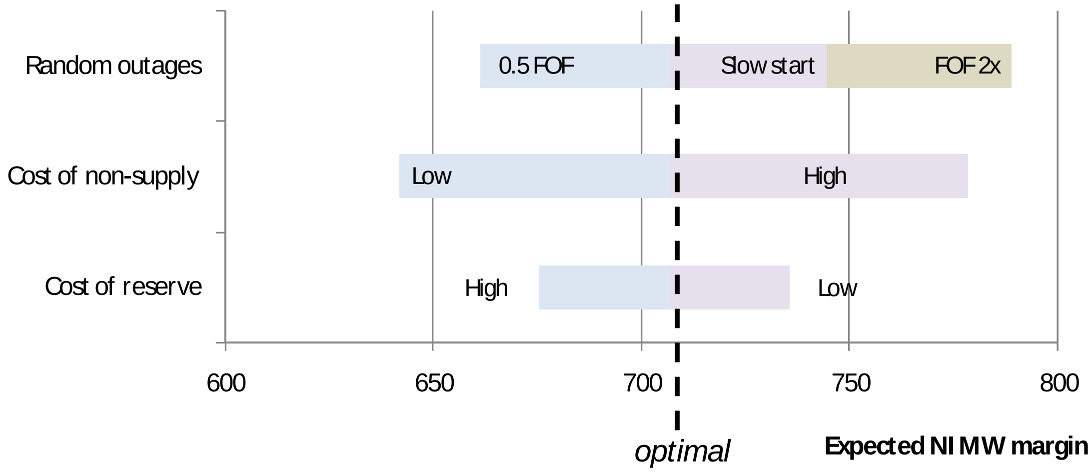
Figure 7 Sensitivity analysis



7.1.13 This demonstrates that the optimal margin is most sensitive to a plausible range of capacity shortfall costs and a plausible range of reserve plant costs with the optimal margin varying by +/- 70 MW and +/- 1.5% of the average of the highest 100 hours of winter demand.

7.1.14 The discussion on modelling approach indicated that to properly account for chronological constraints it may be necessary to undertake a significantly more complex simulation to take into account (amongst other things) river chain scheduling constraints and thermal start up times. In order to test the possible sensitivity to these issues the impact of doubling the forced outage factors (FOF) was tested. In addition the impact of slow starting Huntly units was approximated by increasing the forced outage rate of one Huntly unit from 3% to 23%. The impact of these modelling assumptions is compared with the other key sensitivities in Figure 8:

Figure 8 Forced outage sensitivity



7.1.15 This tends to confirm that the chronological constraints may be at least as important as the costs of capacity shortfall and the cost of peaking capacity, and suggests that it could be prudent to undertake further work to refine the modelling approach before defining the appropriate capacity adequacy standard to apply through the next few years.

Q7. Do you agree that the most appropriate expression of the standard for measuring capacity adequacy over the medium-term is the expected North Island winter MW margin (as defined in the report)?

8 Discussion and Conclusions

8.1.1 A capacity adequacy standard can be defined in terms of a MW capacity margin, levels of expected unserved energy (USE) or in loss of load expectations (LOLE or LOLP).

8.1.2 The options for determining a capacity adequacy standard range from assessments of historical performance of the system, to direct estimation of the adequacy measures and the application of criteria or judgement to the outcomes. Internationally, standards are commonly expressed as USE or LOLE, although other measures are often monitored. LOLE standards are typically around 3 hours per annum and USE is typically around .002%.

8.1.3 This paper proposes the application of an economic approach, trading off the costs of capacity shortfalls against the costs of adding reserve capacity. Techniques for performing this assessment differ principally in the handling of inter-temporal linkages and the degree of detail around the causes and consequences of capacity shortfalls. An LDC convolution approach was applied which captures the interaction between supply and demand on a probabilistic basis.

8.1.4 For the purposes of testing the economic approach and sensitivity of measures to assumptions, the LDC convolution approach was considered preferable to the more detailed chronological approach due to its track record as an analytical technique, previous use and exposure to stakeholders, and the ability to utilise existing assumption sets.

8.1.5 These results indicate that a North Island margin expressed in MW terms is a potentially stable measure of capacity adequacy for the period through to 2012 (at least). The analysis focussed on North Island adequacy, though explicitly accounted for the interaction of South Island supply/demand and northward transmission capability. The MW margins were calculated as the difference between expected winter supply and transmission and a measure of winter demand.

8.1.6 Because approximately half the North Island capacity is supplied by large thermal units (of the order of 25% of supply), the system is susceptible to capacity shortfalls at times of very high demand rather than just the “peak” half hour demand. To this end, the reference demand was defined as the average of the highest 100 hours of forecast winter daytime demand.

8.1.7 Base case results suggest an expected North Island winter margin of 710MW, or 16.2% of the highest 100 hours of winter daytime demand. Sensitivity analysis resulted in variation of +/- 70 MW for variation in either costs of capacity shortfalls, costs of reserve capacity, and peak availability. This

710MW margin is broadly consistent with the heuristic standard adopted by the National Winter Group in their assessment of peak adequacy for winter 2008[7], although is defined differently. It is also broadly consistent with international LOLP and USE standards as discussed above.

8.1.8 Several areas of additional analysis will be carried out prior to confirming a standard. This will involve refining aspects of the methodology and assumptions discussed in this paper. In particular, some of the most significant chronological issues need to be considered via either adapting the modelling approach or analysing via scenarios. Results of this additional work will be communicated to stakeholders during the consultation.

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[7] See Appendix 4, section A4.4.

9 Next Steps

9.1 Submissions

9.1.1 Submissions on this paper are required by 13 June 2008. Following their receipt the Commission expects to consider submissions and consider amendments to its Security of Supply Policy.

9.1.2 The revised policy will then become the basis for the Commission's activities in monitoring and managing security of supply.

9.2 Timetable

9.2.1 The expected timetable for developing the capacity adequacy component of the Commission's security of supply policy is outlined in the following timetable:

Step	Indicative timing
Issues considered by Security Advisory Group	June 2008
Submissions due on peak capacity adequacy standard	13 June 2008
Electricity Commission considers "capacity adequacy" component of Security of Supply Policy	1/2 July 2008

9.3 List of consultation questions

9.3.1 The table below is a useful format for making a submission on the questions included in the paper

Q1	Do you agree with the recommended approach of using an economic approach for establishing a security standard?
Q2	Do you agree that the approach developed by trading off the cost of demand restraint against the cost of reserve energy is an appropriate means of implementing an economic approach?
Q3	Do you agree with the assumptions used to cost peak supply plant?
Q4	Do you agree with the assumptions used to cost capacity shortfalls?
Q5	Do you agree with the supply assumptions outlined in Appendix 2?
Q6	Do you agree with the demand assumptions outlined in Appendix 2?
Q7	Do you agree that the most appropriate expression of the standard for measuring capacity adequacy over the medium-term is the expected North Island winter MW margin (as defined in the report)?

9.4 Format for submissions

9.4.1 The table below is a useful format for making a submission on the questions included in the paper

Question	Comment	Response
Q1	[Submitter] considers that…	[Submitter] recommends that…

Appendix 1 Methodological Issues

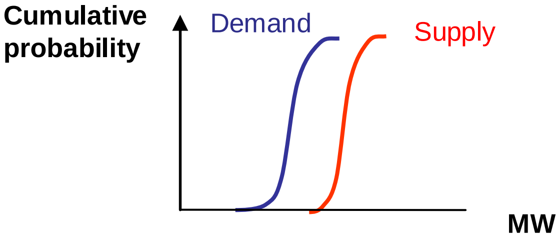
A1.1 Description of LDC approach

This section provides a conceptual overview of the LDC approach used to estimate a capacity adequacy standard. It is intended to outline the key steps in the modelling process as applied in this paper. The supply and demand assumptions used in the analysis are discussed in Appendix 2.

There are two phases of the analysis. The first phase involves calculating North Island capacity shortfall probability curves (CSCs). The second phase involves finding the optimal level of reserve capacity, and uses the CSCs as an input. Each of these phases is briefly described below.

Phase 1: Developing capacity shortfall curves

Firstly, distributions of supply and demand are derived for each island. For the assumed plant mix, supply distributions reflect the combined probability of units being available (e.g. the probability of several thermal stations being coincidentally on a forced outage is a point on the curve, albeit with a small probability). Demand distributions represent its inherent variability.



A Monte Carlo simulation samples demand and supply from the distributions and calculates the contribution to North Island demand from South Island demand (including assumptions about HVDC transfer capabilities and reserve requirements). Consistent with the analysis by the NWG and Reserve Energy Needs Assessment on South Island adequacy, the focus is on North Island adequacy.

The simulation model has been implemented using a programming language called Scilab[8] and performs the following steps:

1. Import supply and demand assumptions

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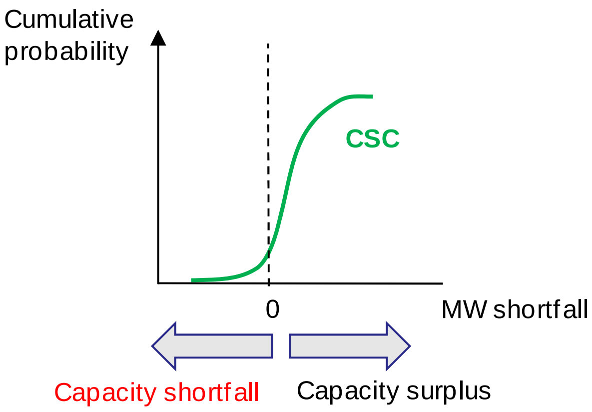
[8] Scilab is an open source platform for numerical computation and free to download from www.scilab.org.

    - Demand distributions for each epoch are adjusted for frequency keeping, losses and intra-half hour variation.
    - Supply distributions are either MW capacity and forced outage factor or probability distributions of output for single/combined units.
2. Create aggregate supply distributions for each island by convolving supply distributions
3. Derive CSC from Monte Carlo simulation
    - Simulate supply demand balance for each epoch and year
    - Assess implications of HVDC transfers, losses, and NI reserves (see assumptions section for more detail)
    - Calculate value of capacity shortfall/surplus in North Island

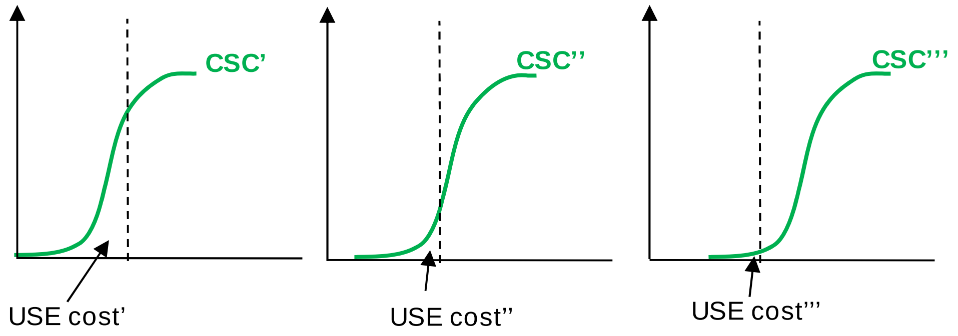
The output from this process is a probability distribution of capacity deficits or a capacity shortfall probability curve (CSC) for each epoch of each year. Large deficits imply some degree of involuntary load shedding, whereas smaller deficits imply a reduction in reserve cover.



Phase 2: Calculating the optimal level of reserve capacity

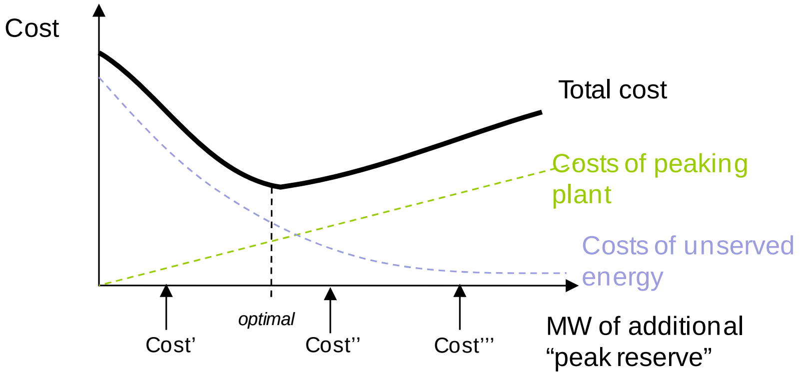
Having developed the CSCs for an initial assumed plant mix, the optimal trade-off between the costs of firm MW from reserve capacity and costs of capacity restraint can be made. This process is handled inside an Excel workbook using macros.

Firstly, the CSCs for each epoch are progressively shifted across the x-axis, reflecting the subtraction and addition of firm MW to the supply mix. The example below shows the effect on the CSC of increasing the assumed reserve MW (left to right)

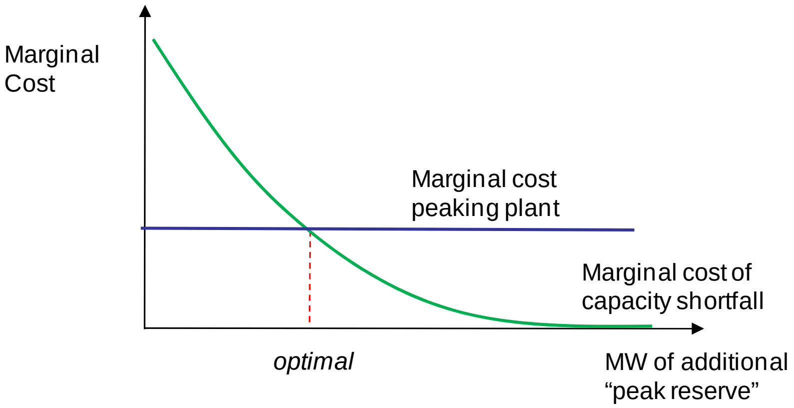


A number of measures are calculated at each increment of reserve capacity. These include costs of capacity shortfall, cost of reserve capacity, USE, LOLE/LOLP, and system capacity (e.g., nominal and derated).

The expected costs are weighted by the number of hours in each epoch and added to produce a total expected cost curve. Total expected costs are the sum of costs of capacity shortfall and reserve capacity. The optimal level of reserve is at the point where total costs are minimised, as illustrated in the figure below.

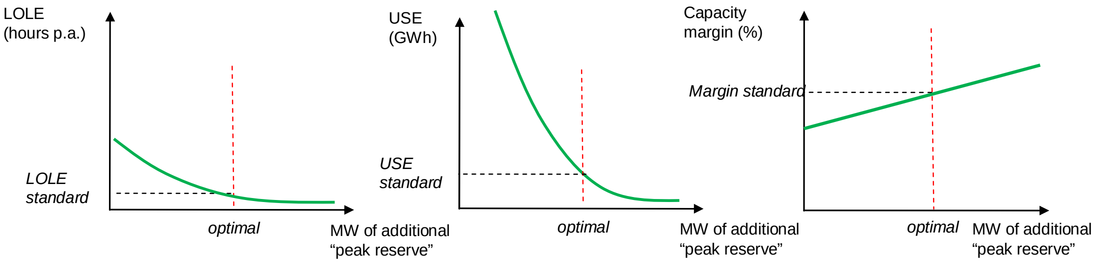


The cost trade-off can also be considered in marginal terms where reserve MW is progressively added in small increments with the CSCs shifting to the right and incrementally reducing capacity shortfall costs. For each assumed level of reserve MW, the reduction in the cost of the area under the CSCs is measured.



The optimum occurs where the cost of another unit of reserve MW equals the reduction in the expected cost of capacity shortfall (corresponding to the minimum of the total cost curve). The optimum using either representation of the costs is identical.

Having identified the optimal level of reserve capacity, the adequacy measures corresponding to that level of capacity reserve are calculated. Note that the analysis is performed using discrete increments of reserve plant, but the optimal reserve (and associated measures) are calculated by interpolating between the closest adjacent points. Illustrations of that process for several adequacy measures are shown below.



The entire process can be repeated for different combinations of assumptions about supply, demand, and costs. For example, the demand year being considered, plant mix and forced outage assumptions, level of capacity shortfall and reserve costs. In each case, an optimal reserve capacity is found from the weighted expected costs across the epochs, and the implied adequacy measures corresponding to that point can be calculated.

A1.2 Comments on sampling procedure

As described earlier, aggregate supply and demand distributions are generated for the North Island and South Island. These distributions are an input to a

Monte Carlo simulation which is used to produce the North Island capacity shortfall curve (CSC). We make the following observations about sampling demand and supply

- North and South Island demand is sampled from the North and South Island demand profiles. A demand distribution is defined for each epoch and year (e.g., 2008 winter day, or 2012 summer night). Demand in each island is assumed to be correlated, so the same random number is used to sample demands in both islands. For example, an extremely high sampled South Island demand level will be combined with an extremely high North Island demand level (and vice versa). This is a plausible, if conservative, assumption since demand is closely linked between both islands due to temperature correlation and time factors.
- North and South Island supply is sampled from each island's aggregate output distributions. These distributions are treated as being independent so independent random numbers are used when sampling.

A sample size of 100,000 (i.e., 100, 000 instances of NI supply and demand and South Island supply and demand) produced satisfactorily stable CSC curves for this analysis and an appropriate balance between computational time and accuracy. The effect of sample size on the stability of the CSC was tested by comparing the tail of the CSC. Increasing the sample size had the effect of smoothing the tail of the CSC. Comparing CSCs using samples of 100,000 and 500,000 indicated no change to the distribution, so a sample size of 100,000 was used.

All random numbers were created within Scilab. They were generated using the "Keep It Simple Stupid" Algorithm written by G. Marsaglia. It has period of about 2^123 and is defined by 4 integers or "seeds". The seeds were input manually, and were chosen as 1, 3 million, 2 million and 30 million. These seeds are redefined for every demand profile, so that the results are consistent irrespective of how many demand profiles are run concurrently.

Appendix 2 Demand, Transmission, and Supply Assumptions

A2.1 Model resolution

Calendar years were split in to 4 “epochs”: summer/winter and day/night. Table 5 summarises the definitions of the epochs used throughout the analysis.

Table 5 Epoch definitions

Epoch	Months	Hours	Average hou p.a.
Summer.Day	November-March	7am-9:59pm (15 hours)	2,274
Summer.Night		10pm-6:59am (7 hours)	1,364
Winter.Day	April-October	7am-9:59pm	3,201
Winter.Night		10pm-6:59am	1,921

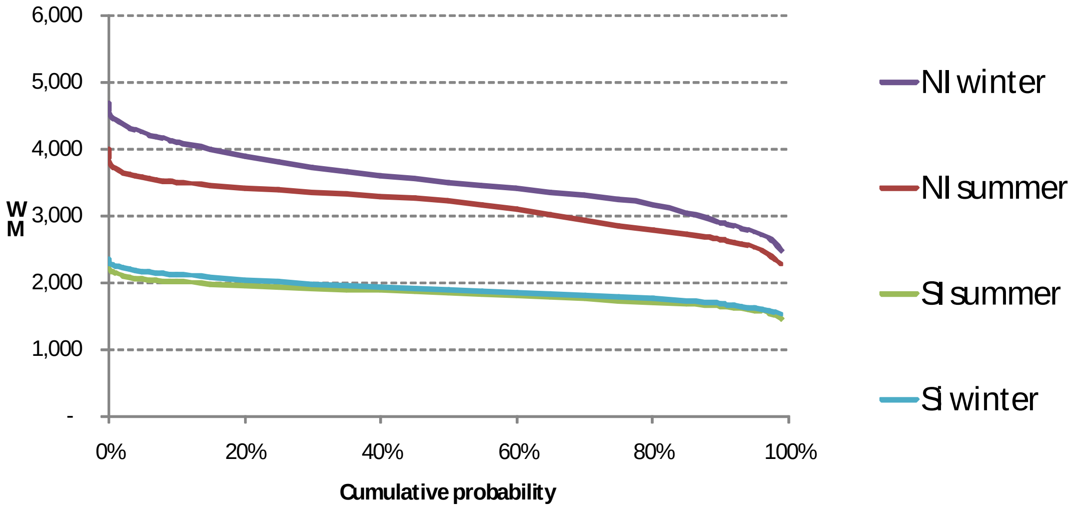
Simulations were performed for each epoch, with assumptions about supply, demand, and transmission intended to align with these definitions. Where necessary, assumptions are also created on a North/South Island basis.

A2.2 Demand assumptions

Load duration curve forecasts were used that were consistent with the Commission’s energy and peak demand forecasts used for the Reserve Energy Needs Assessment (October 2007).

Forecasts were provided for the period 2008-2012 for North/South Islands and for each epoch. Figure 9 illustrates the 2008 load duration curves.

Figure 9 2008 expected load duration



Note that these expected LDCs are sometimes referred to as “load probability curves” because they do not represent one year of load, but rather the probability weighted average of many simulated LDCs. Because they are forecasts, the 2012 LDCs have a larger tail to the distribution because they include a degree of forecast uncertainty which increases over time.

The Commission’s forecasts are at the GXP level, and have been adjusted for estimates of intra-half hour variation and losses. The assumptions used here are consistent with those reported in the NWG’s February 2008 report, as shown in Table 6.

Table 6 Adjustments to demand and ancillary services

Epoch	North Island	South Island
Losses	2.88%	4.88%
Intra-half hour variation	40 MW	12 MW
Frequency keeping	50 MW	50 MW
Reserves	400 MW	120 MW

The capacity margin calculations referred to in the report used a measure of winter demand based on the average of the highest 100 hours of winter daytime demands (including losses by excluding intra-half hour variation).

These values are shown in Table 7. For reference, the expected highest half hour peak (including losses) from the demand distributions is also included.

Table 7 Demand inputs to capacity margin calculations

	2008	2010	2012
North Island expected peak	4,604	4,850	5,065
North Island average of highest 100 hours of winter daytime demand	4,369	4,576	4,746
South Island expected peak	2,317	2,413	2,507
South Island average of highest 100 hours of winter daytime demand	2,230	2,313	2,397

All figures include losses and exclude any intra-half hour adjustments

A2.3 Modelling of HVDC transfers

The simulation model assesses the level of surplus capacity in the South Island which is available for transfer to the North Island via the HVDC link. There are two options for HVDC flows:

- Flows are on Pole 2 only
- Flows are on both Pole 1 and 2

A CAN was issued on May 8, 2008 by the System Operator that outlined the operating procedure for Pole 1. The model aims to comply with that notice, as described in Table 8 which outlines the rules included in the CAN and the way in which the model represents them.

Table 8 Pole 1 operation

Pole 1 operating rule	Representation in simulation model
Operated only in response to a grid emergency	Pole One is only activated when • There is a South Island supply surplus exceeding 400MW (received at North Island) • The HVDC transfer required to cover North Island reserves exceeds Pole 2 capability

Operated in current control mode, north transfer only	Only northward transfers are allowed
A minimum run time once started of 4 hours A maximum run time of 240 hours in a calendar year and/or a maximum number of 20 starts in a calendar year (whichever is reached first) A minimum time between load changes of 4 hours	These two limits are unable to be modelled explicitly using the LDC convolution approach, although the expected hours of run time can be calculated and implications assessed.
•A minimum loading of 130MW and maximum loading of 200MW.	When Pole 1 is operated, it is assumed to be at 200MW, with Pole 2 making up residual transfers on Pole 2.

The CAN points out that there is provision for Pole 1 to operate in overload mode up to 284 MW, which at 668MW (700MW less losses) implies reserves cover of 384MW. As this is less than the 400MW supply-side reserve, there is the potential for pole 2 to operate at 500MW should there be a sufficient South Island surplus.

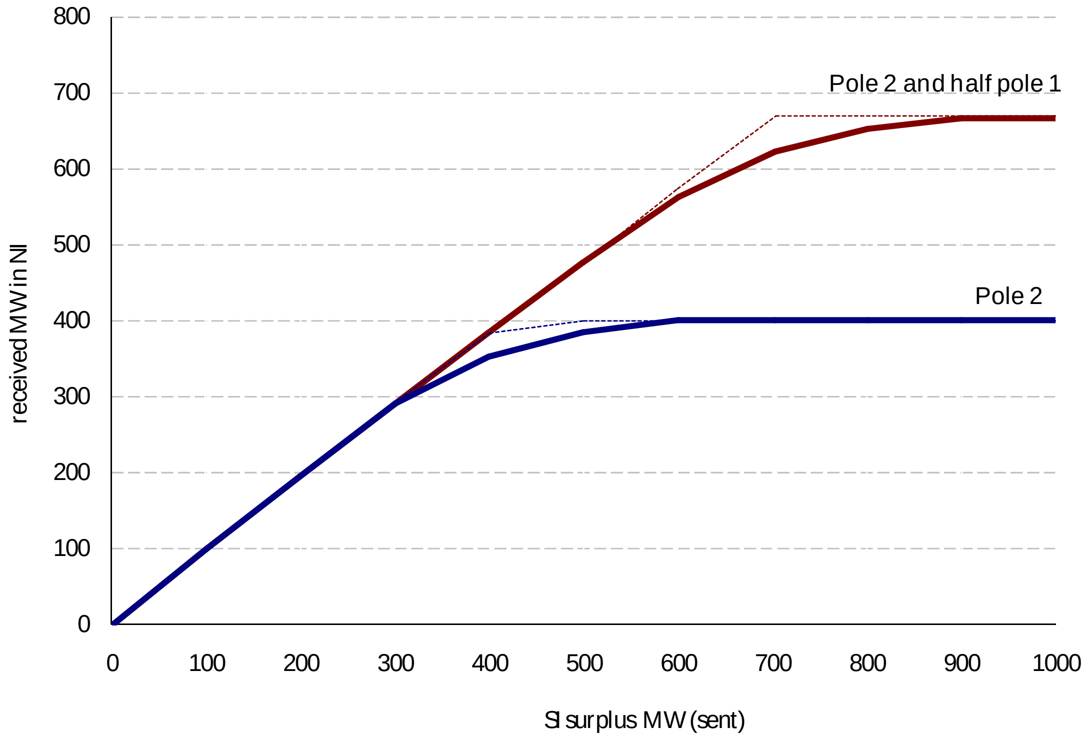
When North Island reserves can be met without Pole 1, any contribution of a South Island surplus to North Island demand is only via transfers on Pole 2. The effective contribution is limited to 400MW (received), since any additional flows would need to be covered by additional reserves, so would not, in net terms, make any difference to the sum of demand and reserves,

There are several assumptions which apply for both configurations

- If flows are below maximum capacity, then a contribution of 25 MW to North Island reserves is included. This reflects the ability of Pole Two to temporarily increase flow to cover an unexpected outage
- A forced outage factor of 0.25% is applied to either configuration. This is based on an assessment of and was discussed in the Reserve Energy Needs Assessment.
- Losses on Pole 2 flows are based on the formula .0000995xflow^2. At a flow of 500MW on pole 2, losses are around 24MW. Losses for Pole 1 are based on the formula .00025xflow^2. At a flow of 200MW on pole 1, losses are 10MW. With maximum flow of 700 across both poles, the received flow after losses is 665MW, which is comparable with the maximum of 668 referred to in the CAN.

Figure 10 shows the aggregate flow across Pole 1 and Pole 2 for varying levels of South Island supply surplus.

Figure 10 Contribution of South Island surplus to North Island margin



9.4.2 The dotted lines show the maximum flow and the solid lines are curves which have been derived empirically to represent the effective maximum contribution of the HVDC to the North Island for use in the (North Island) expected winter margin calculation. The SI surplus MW used in the calculation is the total expected South Island capacity minus the average of the highest 100 hours of winter daytime demand minus 185MW[9].

A2.4 Supply assumptions

Supply assumptions are defined for each epoch in terms of the expected availability at times of high demand. These assumptions reflect assumptions about forced outage rates, planned outages and controllability of output. Using the current plant mix, summer/winter supply curves were developed for the North and South Islands.

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[9] The offset accounts for instantaneous and frequency keeping reserves and z diversity factor. This is found empirically by fitting a curve to the actual capacity value in a number of scenarios with different SI MW margins.

Supply was categorised into classes of plant and two different approaches used to represent the availability of the plant:

- For units considered ‘controllable’, availability is defined from the installed MW capacity less any planned outages, and a forced outage factor. This indicates that there is a small chance the unit is non-operational, and the rest of the time the unit can operate at maximum capacity (adjust for planned outages). This is the technique primarily used for thermal units and hydro stations with controlled storage. Planned and forced outage assumptions are adjusted for summer/winter.
- For profiled plant, a distribution of output for a unit or aggregation of units is generated for each epoch. Profiles are generated from historical data during each epoch. They are used for plants such as run-of-river hydro, less flexible stations within hydro schemes, cogeneration, geothermal, and wind.

The capacity and methodology applied to the plant categories is summarised in Table 9.

Table 9 Summary of supply inputs by plant category

Plant category	Installed MW	Input data	Treatment in expected margin calculations
Controlled hydro	1380 (NI) 2846 (SI)	Nominal capacity and forced outage factors applied to units. Adjustment made on scheme by scheme basis for planned outages.	Nominal capacity less planned and forced outages over winter daytime periods.
Thermal	2525 (NI)	Forced outage factors applied to assumed capacity adjusted for planned outages.	Nominal capacity less planned and forced outages over winter daytime periods.
Profiled hydro	373 (NI) 454 (SI)	Profile of historic output for each epoch.	Median (P50) output over winter daytime periods
Wind	252 (NI) 58 (SI)	Profile of historic output at each epoch. For White Hill, profile developed from 4 months of summer output.	20% of installed capacity.

Plant category	Installed MW	Input data	Treatment in expected margin calculations
Cogeneration	177 (NI)	Profile of historic output for each epoch.	Median (P50) output over winter daytime periods
Geothermal	416 (NI)	Profile of historic output for each epoch.	Median (P50) output over winter daytime periods
Interruptible load	102	As assumed in NWG analysis	As assumed in NWG analysis.

For each island and epoch, the LDC convolution approach combines each unit's availability curve with all other units to produce supply curves that represent the coincidence of availability across all units.

The remaining sections discuss and illustrate the supply assumptions for each plant category. Where possible, reference is made to NWG assumptions and 'expected winter margin' calculations.

Although there are differences between this and the NWG analysis in terms of how capacity is 'counted', the aggregate North Island capacity is similar. The North Island expected winter daytime supply for this analysis is 4,647MW. The NWG analysis assessed North Island supply over June/July ranging of 4770[10] (ignoring planned outages), approximately 120MW more than that assumed here. This difference is due to several differences in the way capacity is 'counted'. We make the following summary observations about the alignment of the North Island supply assumptions.

- The assumed supply mix is almost identical between the two analyses, with some small differences due to consistency between the inclusion/exclusion of cogeneration and small hydro plant and demand assumptions.
- The NWG assumptions count wind at 0MW, whereas the wind farms in the Tararua ranges are counted at 50MW (20% of nominal capacity).
- The NWG assumptions count thermal plant at nominal capacity whereas capacity is derated for planned and forced outage factors.

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[10] See page 46 in Appendix 3.

- Several hydro plant are considered as “storage” hydro in the NWG analysis are treated as profiled plant where a P50 output is used (e.g., Rangipo, Karapiro).

Because the 2008 plant mix is used as the starting point for the modelling in this report, broad alignment of assumptions is desirable. It is important to note that the NWG analysis contemplated the supply/demand balance in the coming winter, whereas the capacity adequacy analysis is intended to produce a standard applicable over a multi-year horizon with potential, and unknown, changes to the plant mix and demand forecasts.

Thermal plant

Assumptions about thermal plant are presented in the Table 10 below. The summer and winter distributions reflect the aggregate MW availability given planned and forced outage assumptions:

- Forced outage factors are those applied and consulted on in the annual Reserve Energy Needs Assessment.
- A Huntly unit is assumed to be unavailable over the entire summer period, reflecting the effect of sequential planned Huntly unit outages over that period.
- TCC has its summer forced outage factor increased by 40%, which reflects the expected time over summer where e3p, OTA-B, and TCC are on planned outage (around 58 days per year on average). Applying the derating to a single unit reflects the sequential nature of the outages.
- Summer derating factors were estimated for controllable hydro plant based on planned outage data.

The maximum nominal winter MW (at the 100th percentile) is identical to the NWG value of 2,525MW.

Table 10 Thermal plant inputs

		Planned outage adjustment (MW)		Forced outage fact adjustment			
Unit nan	**Nominal capacity**	**Summer**	**Winter**	**Summer**	**Winter**	**Annual FOF**	**Expected winter day M**
HLY_1	243.00					3.0%	235.71
HLY_2	243.00					3.0%	235.71
HLY_3	243.00					3.0%	235.71
HLY_4	243.00	243.00				3.0%	235.71
HLY_5	400.00					2.0%	392.00
HLY_6	45.00					2.0%	44.10
OTA_1	385.00					2.0%	377.30
SWN_1	42.00					2.0%	41.16
SWN_2	42.00					2.0%	41.16
SWN_3	36.00					2.0%	35.28
SWN_4	50.00					2.0%	49.00
SFD_1	397.00			0.40		2.0%	389.06
WHI_1	51.67					2.0%	50.63
WHI_2	51.67					2.0%	50.63
WHI_3	51.67					2.0%	50.63
Total	2524						2464

Geothermal

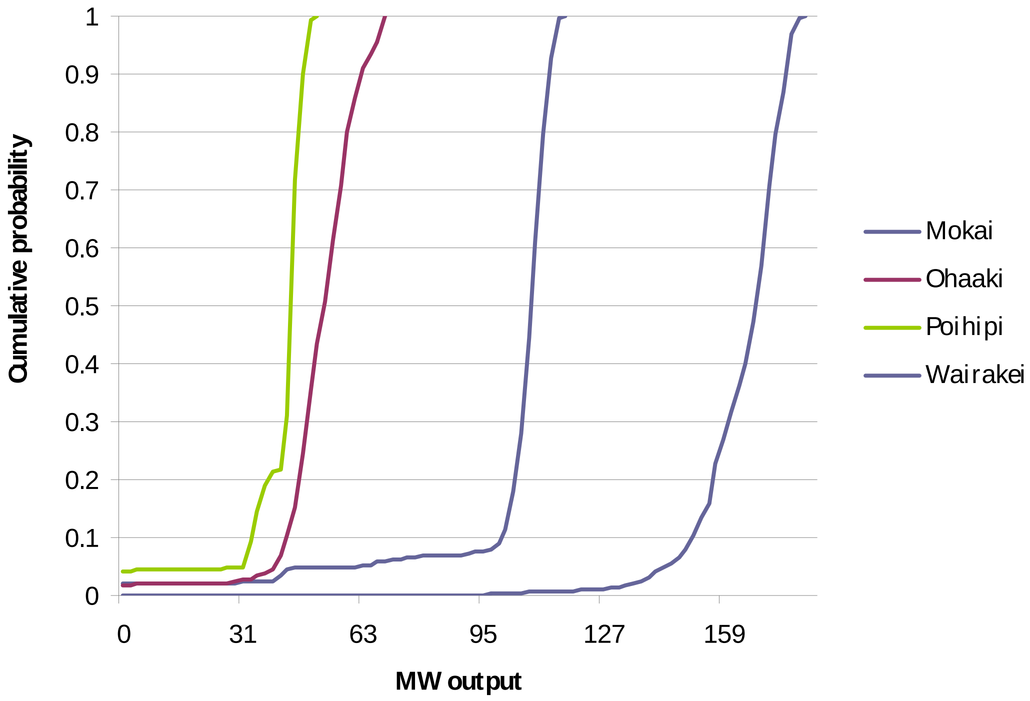
Assumptions about geothermal plant are presented in Table 11 and Figure 11. All plant geothermal plant are located in the North Island.

The nominal installed MW is 418 MW, but when the profiles of actual output over peak times for each geothermal source are assessed, the P50 MW is 368MW. The NWG analysis used 373MW for geothermal plant. When calculating expected winter day output, a P50 value has been taken from each distribution, totalling 368MW. This small difference between P10 and P50 values reflects the low variability in output from geothermal plant.

Table 11 Geothermal plant inputs

Unit nam	Installed M	Expected Winter Daytime MW (P	NWG (P10)
Mokai	117	107.7	112
Ohaaki	69	52.8	45
Poihipi	51	43.9	40
Wairakei	181	167.6	176
Total	416	372	373

Figure 11 Geothermal generation profiles (winter daytime)



North Island profiled hydro and cogeneration

Assumptions about cogeneration and profiled hydro plant are presented in the table and figures Figure 12 below[11]. For calculating expected winter margins, a P50 value from the profile has been used and totals 311MW.

Table 12 North Island hydro and cogeneration inputs (profiled)

Unit name	Station categ	Nominal MW	Expected winter day MW (P
Karapiro	Hydro	96	66.9
Mangahao	Hydro	42	23
Matahina	Hydro	80	28.9
Rangipo	Hydro	120	67.6
Wheao	Hydro	26	11.6
Hydro 1	Hydro	7	4
Hydro 2	Hydro	2	1

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[11] Note that each profiled station is treated as independent in the modelling. This is appropriate for cogeneration and geothermal, but may not be so appropriate for uncontrolled hydro if there are significant correlations in inflows. This is not thought to be a significant effect and will be explored in the additional modelling work.

Unit name	Station catego	Nominal MW	Expected winter day MW (P
Kaponga/Kapuni	Cogeneration	25.3	15
Kinleith	Cogeneration	40	32.5
Te Rapa	Cogeneration	42	38.9
Whareroa	Cogeneration	69.6	21.8
Total		Hydro 373 + Cogen 177 Total 550	Hydro 203 + Cogen 108 Total 311

Figure 12 Distributions of profiled North Island hydro plant (winter daytime)

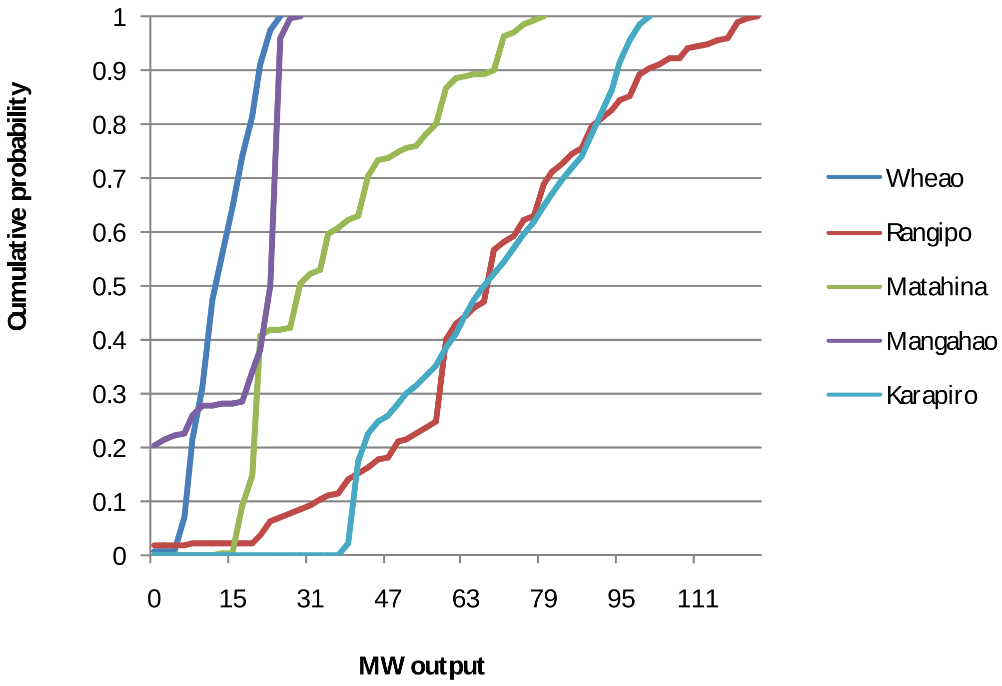
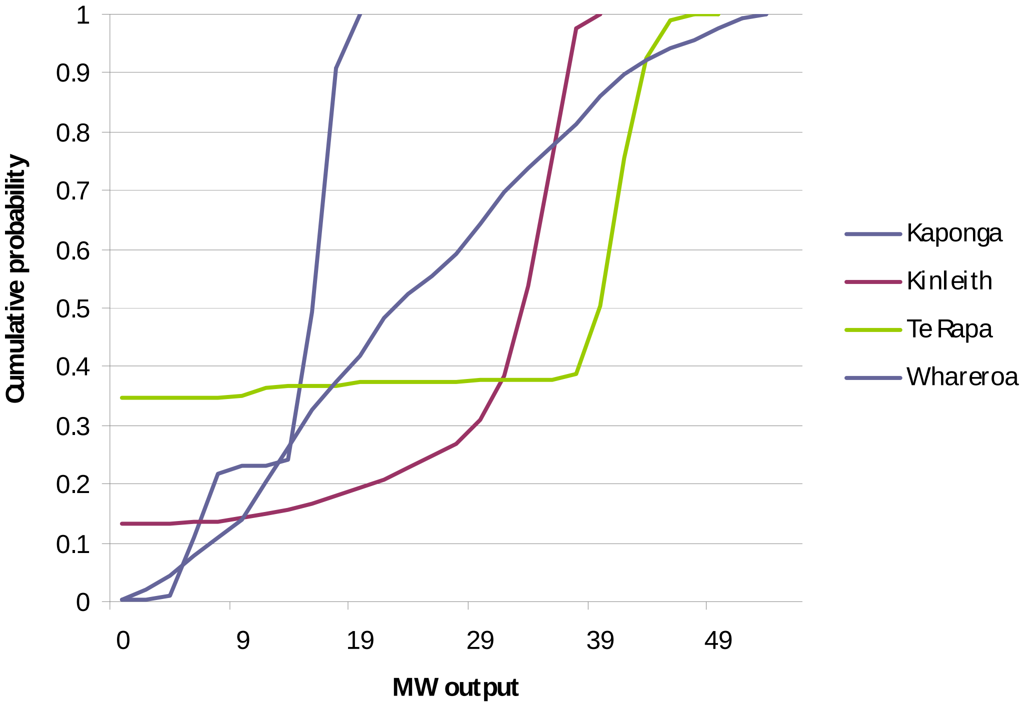


Figure 13 Distributions of profiled North Island cogeneration plant (winter daytime)



North Island hydro (controlled)

Assumptions used for North Island hydro plant are presented in Table 13.

Table 13 North Island controlled hydro plant inputs

		Planned outage adjustment (MW)		Forced outage fact adjustment			
Unit name	**Nominal capacity**	**Summer**	**Winter**	**Summer**	**Winter**	**FOF**	**Expected winter day M**
ARI_1	22.75					2.3%	22.23
ARI_2	22.75					2.3%	22.23
ARI_3	22.75					2.3%	22.23
ARI_4	22.75					2.3%	22.23
ARI_5	22.75					2.3%	22.23
ARI_6	22.75					2.3%	22.23
ARI_7	22.75					2.3%	22.23

		Planned outage adjustment (MW)		Forced outage fact adjustment			
Unit name	Nominal capacity	Summer	Winter	Summer	Winter	FOF	Expected winter day M
ARI_8	22.75					2.3%	22.23
ARA_1	28					2.3%	27.36
ARA_2	28					2.3%	27.36
ARA_3	28					2.3%	27.36
ATI_1	19					2.3%	18.56
ATI_2	19					2.3%	18.56
ATI_3	19					2.3%	18.56
ATI_4	19					2.3%	18.56
KTW_1	18.50					2.3%	18.07
KTW_2	18.50					2.3%	18.07
MTI_1	36			0.50		2.3%	35.17
MTI_2	36			0.50		2.3%	35.17
MTI_3	36			0.50		2.3%	35.17
MTI_4	36			0.50		2.3%	35.17
MTI_5	36					2.3%	35.17
MTI_6	36					2.3%	35.17
MTI_7	36					2.3%	35.17
MTI_8	36					2.3%	35.17
MTI_9	36					2.3%	35.17
MTI_10	36					2.3%	35.17
OHK_1	27					2.3%	26.38
OHK_2	27					2.3%	26.38
OHK_3	27					2.3%	26.38
OHK_4	27					2.3%	26.38
HWAyyy_1	10					2.3%	9.77
HWAyyy_2	10					2.3%	9.77
HWAyyy_3	10					2.3%	9.77

		Planned outage adjustment (MW)		Forced outage fact adjustment			
Unit name	**Nominal capacity**	**Summer**	**Winter**	**Summer**	**Winter**	**FOF**	**Expected winter day M**
HWAyyy_4	1.50					2.3%	1.47
PRI_1	22					2.3%	21.49
PRI_2	22					2.3%	21.49
TKU_1	60					2.3%	58.62
TKU_2	60					2.3%	58.62
TKU_3	60					2.3%	58.62
TKU_4	60					2.3%	58.62
TUI_1	20					2.3%	19.54
TUI_2	20					2.3%	19.54
TUI_3	20					2.3%	19.54
WPA_1	19					2.3%	18.56
WPA_2	19					2.3%	18.56
WPA_3	19					2.3%	18.56
WKM_1	25					2.3%	24.43
WKM_2	25					2.3%	24.43
WKM_3	25					2.3%	24.43
WKM_4	25					2.3%	24.43
Total	1379						1348

Hydro output from non-profiled plant was modelled using a forced outage factor applied to individual units. As noted in the October 2007 Reserve Energy Needs Analysis, forced outage rates of 2.3% (based on international benchmarks) is conservative, with rates in the order of 0.5% generally used within the industry in New Zealand. This conservative approach is considered appropriate as it will partly account for hydro scheduling constraints that can occasionally limit the MW capability.

As a proxy for the potential limitations on output of hydro schemes, output from selected hydro stations within the schemes were profiled (e.g., Karapiro and

Rangipo). The additional work on chronological issues is intended to inform the appropriateness of these allocations and assumptions.

South Island hydro

South Island hydro output is modelling by a combination of controllable and profiled plant. These assumptions can be summarised as follows:

- For the Waitaki system, the Waitaki station is treated as profiled and remaining units at other stations treated as controllable. A Benmore turbine is treated as being on permanent outage in summer and winter to reflect transformer limitations on Benmore station output. A 90% summer planned outage factor is applied for another Benmore unit, reflecting the average of rotating planned outages at the station.
- Manapouri units are treated as controllable. A 40% forced outage factor is applied to one of the units over summer reflecting the combined effect of planned unit outages.
- For the Clutha system, Roxburgh output is profiled and Clyde output treated as controllable.
- Cobb and Coleridge are treated as controllable.
- A number of small hydro are treated as profiled due to their uncontrolled inflows e.g., Argyle, Opuha, Teviot.

Figure 14, Table 14, Table 15 summarise and illustrate the assumptions made for South Island profiled and controlled hydro plant. Of the profiled plant, the dominant distributions are those assumed for Waitaki and Roxburgh.

Table 14 South Island profiled hydro plant inputs

Unit name	Nominal MW	Expected winter day MW
Argyle	11	6.5
Opuha	7.5	0.8
Teviot	14.8	1.4
Waitaki	90	48.5
Kumara/Dillmans/Duffers (K/D/D)	10.5	5.4
Roxburgh	320	198.1
Total	454	261

Figure 14 Distributions of profiled South Island hydro plant (winter daytime)

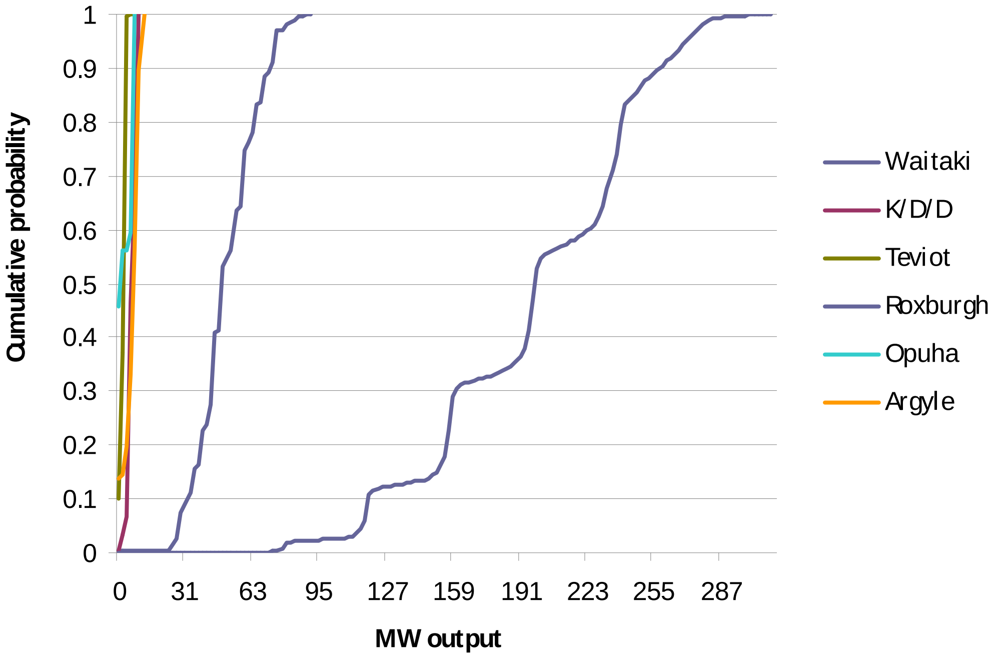


Table 15 South Island controlled hydro plant inputs

		Planned outage adjustment (MW)		Forced outage fact adjustment			
Unit nam	Nominal capacity	Summer	Winter	Summer	Winter	FOF	Expected win day MW
AVI_1	55					2.3%	53.74
AVI_2	55					2.3%	53.74
AVI_3	55					2.3%	53.74
AVI_4	55					2.3%	53.74
BEN_1	90	90	90			2.3%	-
BEN_2	90			0.90		2.3%	87.93
BEN_3	90					2.3%	87.93
BEN_4	90					2.3%	87.93
BEN_5	90					2.3%	87.93
BEN_6	90					2.3%	87.93
CYD_1	105					2.3%	102.59

		Planned outage adjustment (MW)		Forced outage fact adjustment			
Unit nam	Nominal capacity	Summer	Winter	Summer	Winter	FOF	Expected win day MW
CYD_2	105					2.3%	102.59
CYD_3	105					2.3%	102.59
CYD_4	105					2.3%	102.59
COB_1	10					2.3%	9.77
COB_2	10					2.3%	9.77
COB_3	3					2.3%	2.93
COB_4	3					2.3%	2.93
COB_5	3					2.3%	2.93
COB_6	3					2.3%	2.93
COL_1	10					2.3%	9.77
COL_2	10					2.3%	9.77
COL_3	10					2.3%	9.77
COL_4	10					2.3%	9.77
MAN_1	112.43					2.3%	109.84
MAN_2	101.43					2.3%	99.10
MAN_3	101.43					2.3%	99.10
MAN_4	101.43					2.3%	99.10
MAN_5	101.43					2.3%	99.10
MAN_6	101.43					2.3%	99.10
MAN_7	101.43			0.40		2.3%	99.10
OHA_4	66					2.3%	64.48
OHA_5	66					2.3%	64.48
OHA_6	66					2.3%	64.48
OHA_7	66					2.3%	64.48
OHB_8	53					2.3%	51.78
OHB_9	53					2.3%	51.78
OHB_10	53					2.3%	51.78

		Planned outage adjustment (MW)		Forced outage fact adjustment			
Unit nam	Nominal capacity	Summer	Winter	Summer	Winter	FOF	Expected win day MW
OHB_11	53					2.3%	51.78
OHC_12	53					2.3%	51.78
OHC_13	53					2.3%	51.78
OHC_14	53					2.3%	51.78
OHC_15	53					2.3%	51.78
TKA_1	25					2.3%	24.43
TKB_2	80					2.3%	78.16
TKB_3	80					2.3%	78.16
Total	2846						2,693

Wind

Output for Tararua 1/2/3 and Te Apiti is aggregated in to a single profile to capture the correlation of the output from similarly sited turbines (also referred to as NI wind)[12]. Although there is some data available for White Hill (or SI wind) output, analysis indicated it was too limited for deriving representative distributions. In the absence of robust data, the profile for NI wind was applied to White Hill. The output profiles are illustrated in Figure 15.

When calculating the expected winter margin, a factor equivalent to 20% of nominal capacity was used. The Commission has used the factor when assessing the contribution to peak from wind plant for other long-term modelling exercises. Analysis of the effective contribution wind capacity indicated a value of 18-19% for scenarios where capacity was added at the same sites.

Table 16 Wind plant inputs

Unit name	Nominal MW	Expected winter day M (20% of nominal)
Tararua (aggregate)	252	50.4

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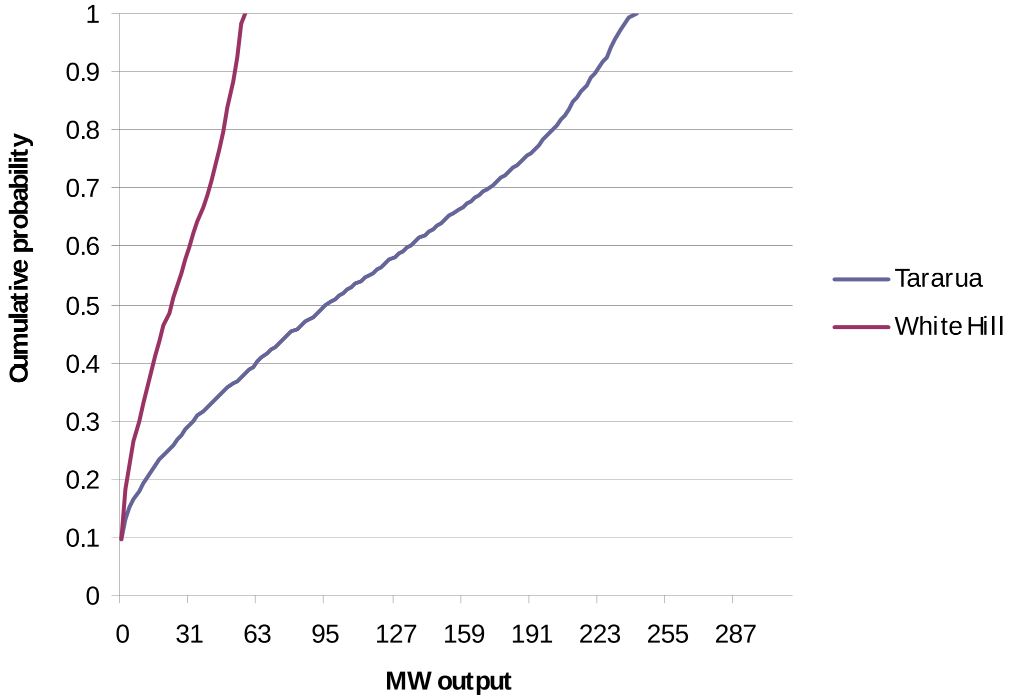
[12] Note that is a conservative approach. New wind farms in the North Island such as West Wind, are likely to be somewhat correlated with Tararua, but not completely.

Unit name	Nominal MW	Expected winter day M (20% of nominal)
White Hill	58	11.6

Figure 15 Distributions of profiled wind farm output (winter daytime)



Interruptible load

Both the NWG and Reserve Energy Needs Analysis discuss the variability in provision of interruptible load supplied for instantaneous reserves, with supply ranging up to 200MW at times of peak demand. For this analysis, a constant assumption of 102MW has been used, which is the same as the P10 value used by the NWG. No interruptible load is assumed in the South Island. This is a conservative assumption as New Zealand Aluminium Smelters can at times provide interruptible load.

Appendix 3 Cost Assumptions

A3.1 Costing reserve capacity

For the base case, annualised cost of reserve MW was estimated as that of an open cycle gas turbine (OCGT) unit at $124/kW/yr. This is derived from

- $24/kW/yr fixed O&M costs
- $100/kW/yr of annualised capital costs (based on 25 year life and 9% nominal post-tax WACC).

This is based on a report prepared by PB Power for the Electricity Commission dated April 2008[13]. This provided a costing for a 50 to 100MW peaking plant with around 2% capacity factor and around 30 starts per annum operating on gas or liquid fuels at a greenfields plant close to existing infrastructure.

Their recommended capital cost estimates including an allowance for North Island location specific costs are $1,008 (100MW Industrial gas turbine) to $1,514 $NZ/kW (50MW Aero derivative Gas Turbine). This can be compared with Contact Energy's reported cost of $1,250/kW for its proposed 200MW gas fired OCGT at Stratford.

Their recommended fixed operating cost is around $24/kW/yr for this mode of operation (including $10/kW/yr for fuel management). The variable operating costs are estimated to be around $7 to $12/MWh, on top of the cost of gas or liquid fuel (greater than $200/MWh).

PB Power note that cost estimates are subject to significant uncertainty with 20 to 30% price rises having occurred during the last 18 months.

The base case annualised cost is derived from the 100MW industrial gas turbine cost. For sensitivity testing we have used a range from $100/kW/yr to $180/kW/yr [14]

A3.2 Costing capacity shortfalls

The analysis requires some key assumptions concerning the cost of demand restraint and/or outages. In contrast to energy demand restraint, there is very

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[13] See "Cost Estimates for Thermal Peaking Plant", Draft report for the Electricity Commission, PB Power, April 2008.

[14] In addition to the variation in the estimated costs of a peaking plant there is a conceptual issue regarding the effective cost of additional peaking plant. This arises from an interaction with the "energy" shortages. An additional MW of OCGT may contribute to both "energy" and "peak" security. For this reason the effective incremental cost for "peak" capacity may be less than the full cost of a new OCGT plant. This is ignored for this analysis as it is considering peak standards only. The issue should be considered in the context of policy options in the event that the economic capacity margin was breached. It is important that the threshold for policy response recognises that intervention in the market may have additional costs not reflected in this analysis.

little warning of the need for restraint over the time frame considered in this analysis. This limits the expected response from the market and increases the cost of outages considerably.

A capacity shortfall is identified when there is insufficient capacity, or Interruptible Load (IL), available to meet “normal” peak period demand plus “normal” instantaneous and frequency regulation reserve.

Demand restraint is measured relative to demand expected at normal peak period pricing (i.e. less than $200/MWh). We only consider demand response over and above “normal” peak management (e.g. via ripple control of water heating load).

There are two components of demand restraint – voluntary and involuntary.

- The voluntary restraint can occur in response to market participants forecasting a risk of high prices, or in response to System Operator warnings. It can also be contracted demand-side response.
- Involuntary restraint (or outages) can occur either from Automatic Under Frequency Load Shedding (AUFLS) during a system contingency (tripping of a large generation unit or transmission line), or from pre-contingent load shedding instructed by the System Operator.

Involuntary load shedding

The New Zealand electricity system has two levels of protection against contingencies (the sudden loss major generation units or transmission lines). The first level involves the system operator contracting with generators or loads for instantaneous reserves (IR) capable of responding within seconds of a contingency. The first level is designed to cover single large contingencies (the loss of the largest generation unit or transmission link).

The second level of protection involves the use of Automatic Under Frequency Load Shedding (AUFLS) relays. These automatically disconnect one or two 16% blocks of load if there is double contingency (the simultaneous loss of two or more large units or links).

The purpose of these levels of protection is to avoid “system collapse”. This can occur if the frequency falls so much that generation units become unstable and must be disconnected. In this case the entire North or South Island supply system will fail and it may take several hours to restore supply. The social and personal cost of “system collapse” is very high as hospitals, central business districts, computer systems, transport systems, factories etc are all affected. It makes sense to disconnect just a portion of the less sensitive loads (e.g. residential) to avoid system collapse in a contingency.

Normally the System Operator will procure sufficient instantaneous reserve in addition to forecast demand to ensure that single large contingent events can be covered without involuntary load shedding[15].

However if there is insufficient capacity available and offered to the market then the system operator will operate with a lower level of instantaneous reserve if necessary. This is said to be an "emergency secure state". The system is still secure, in that it is not likely to collapse, but there is a risk of automatic load shedding if there is a sudden loss of a large generation unit or transmission line (e.g. a CCGT unit or the HVDC). The extent of the risk will depend on the shortfall in instantaneous reserve.

Normally around 400MW of instantaneous reserve is procured at peak times when the CCGT units are operating at full capacity. If there is a shortfall of 100MW, then the first of the 2 AUFLS blocks would be shed if there is a sudden loss of greater than around 300-400MW of generation or HVDC transfer. If the capacity shortfall is greater than 100MW then a smaller contingency (such as the loss of around 200MW unit) could result in AUFLS. There are twice as many generation units above 200MW, than 300MW, and hence the risk of AUFLS increases as the capacity shortfall increases.

The probability of a sudden loss of a significant generator or HVDC on the NZ system is relatively low. Historically there have been around 10-20 system events (greater than 200MW[16]) per annum, but only 2-10 large system events (greater than 300MW[17]). Very large system events (greater than 800MW) have only occurred a few times over the last 20 years, typically being both poles of the HVDC contingency, or a single pole of the HVDC combined with a large thermal unit).

Conservative estimates of system event risk probabilities are as follows:

- system events (around 150-250MW) = 0.6% per half hour trading period (an event in up to 100 periods per annum),
- large system events (around 300-400MW) = 0.1% per trading period (an event in up to 20 periods per annum),

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[15] In a normal secure state the System Operator will procure sufficient instantaneous reserves to avoid the frequency falling below 48Hz with the lost of a single generating unit or pole on the HVDC. This avoids tripping of the AUFLS relays. If necessary the system operator will also procure additional reserves to avoid the frequency falling below 47 Hz with a bi-pole trip. This effectively covers some generator double contingencies (e.g. a simultaneous trip of two CCGT units). This utilises the AUFLS, but avoids system collapse.

[16] These typically cause the system frequency to fall below 49.5 Hz.

[17] These typically cause the system frequency to fall below 49.0Hz.

- very large system events (greater than 800MW) = 0.01% per trading period (1 very large event per annum)

The expected level of automatic under frequency load shedding depends on these risks and also on the size of the AUFLS block or blocks tripped and the time to restore load.

When all this is taken into account the expected level of AUFLS is conservatively estimated to be less than 2% for the first 100MW shortfall, rising to up to around 5% for shortfalls greater than 200MW. The estimated expected shortage cost of this is of the order of $500 to $6,000/MWh.

It is more difficult to estimate the risks[18] and costs for capacity shortfalls beyond 200MW and less than 400MW so a very conservative 20% AUFLS risk and an expected cost of $8,000 to $20,000 has been assumed.

If the capacity shortfall is greater than the total instantaneous reserve then the system operator will instruct distributors to shed load to maintain an emergency secure state. The average cost of this is likely to be in the range $11,000 to $100,000/MWh depending on the depth of the cuts[19]. The Commission currently uses a load weighted average of $22,000/MWh for transmission planning studies, so this same level is used for the first 400MW (around 8%) of instructed load shedding. It is assumed the marginal cost increases progressively towards $100,000/MWh as the depth of load shedding increases.

Contracted demand-side response

In principle, voluntary demand side response can be contracted. An example of this is the Demand-side Participation Pilot that is being trialled by Transpower as a potential alternative to transmission investment in the Upper South Island.

The Transpower pilot study is useful in that it indicates the potential for demand-side response. In 2007, Transpower called for tenders for demand-

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[18] As the safety margin decreases there is a risk of cascade or flow on effects resulting from very rapid falls in frequency. These are difficult to quantify and so a very conservative approach is taken.

[19] Note that the standard cost of unplanned load shedding for transmission planning in NZ is taken to be $20,000/MWh. In Australia the cost of unserved energy used by MMA in a June 2006 Estimation of the Economically Optimal Reliability Standard for the National Electricity Market was between $300/MWh and $100,000/MWh ($30,000 load weighted average). The value of unserved energy is currently set at $20,000/MWh (Dec 2004 dollars) for the Grid Investment Test. The Grid investment Test required sensitivities of $10,000 and $30,000/MWh to be tested. The value was recommended by Frontier Economics in June 2004 and was the subject of consultation in 2004 and 2005. The Commission received a wide range of views but the proposed $20,000/MWh value was not strongly contested and a CRA report provided by Meridian suggested that the $20,000/MWh figure was a good starting point given previous NZ and overseas work. The Centre for Advanced Engineering was commissioned to update their 1992 assessment and derived a VoLL for NZ of $20,950/MWh on the basis of a VENCorp study adjusted for New Zealand electricity use percentages. Castalia reviewed the value in August 2006 for Transpower and suggested a range of $22,000 to $48,000/MWh with a central value of $32,000/MWh. All of these assessments assume an equal sharing of outages across all sectors. As discussed above it is likely the lower cost sectors will be targeted initially and hence the simple weighted average cost will over estimate the cost of the first block of load.

side response in the Upper South Island. They received offers of 50MW (around 5% of load) with prices in the range $700 to $12,000/MWh as shown below.

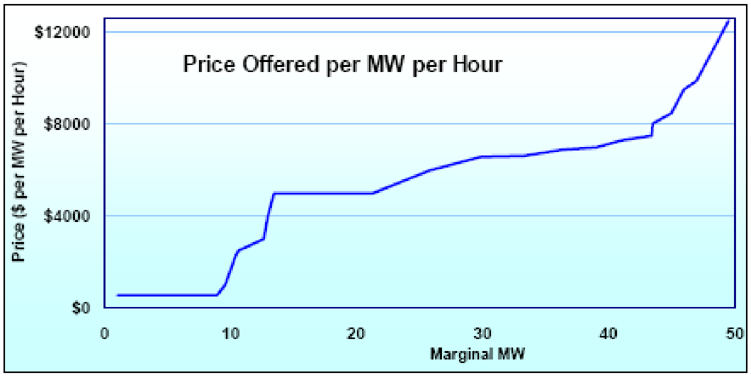


Figure 4: Cost per MW per hour for each additional MW

They selected 14 offers (4 participants) with a total of 14MW or around 1.5% of the load in the area. This was split 50% industrial, 20% cold store and 30% generation and had offered prices from around $700 to $5,000/MWh. The demand side responded with a reliability of around 75% during the trial.

While there is no specific plan to contract for demand-side response for energy adequacy at this time, the pilot does quite clearly indicate the potential for the demand side to respond to price signals in the range $1,000 to $5,000/MWh.

Spontaneous demand-side response

This demand-side response can occur spontaneously if customers are exposed to spot prices and they have an expectation that ex-post prices will rise to this level during a capacity shortfall. Under current market arrangements there is a significant risk that ex-post prices will not reach these levels in this event and so the spontaneous market response is limited.

If the market mechanisms were improved to provide more information relating to the risk of capacity shortfalls and more predictable pricing in these events then significantly more spontaneous demand side response might be expected. This analysis only assumes a nominal 10MW (0.2%) spontaneous response to expected shortfalls and system operator warnings.

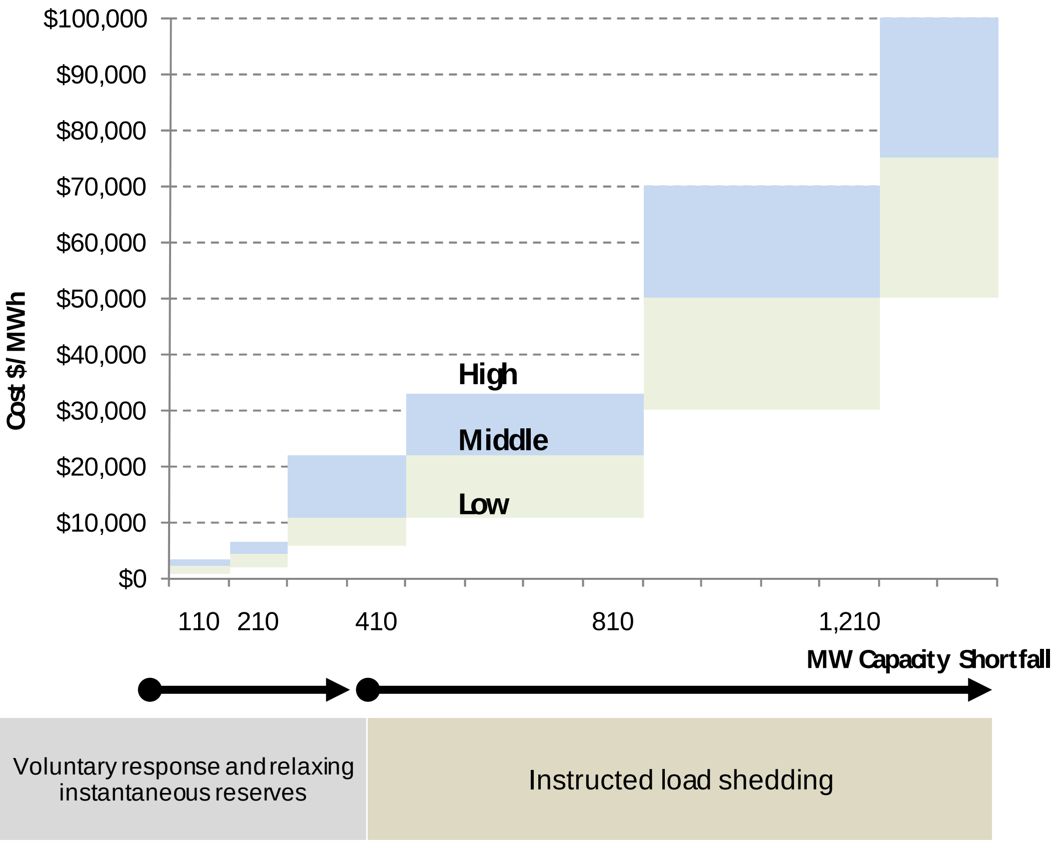
Summary

Table 17 and Figure 16 summarise the cost and quantity assumptions used in this analysis. The “mid” cost curve is used for the base case analysis, with the low and high curves treated as sensitivities.

Table 17 Cost of shortfall assumptions ($/MWh)

	MW Shortfall		Marginal Cost $/MWh			
	Step	Total	Low	Mid	High	Basis of cost estimate
Demand side 1	10	10	$500	$1,100	$1,200	Voluntary low cost response to expected high price eg. extended ripple control
Emergency Secure 1	100	110	$1,000	$2,200	$3,300	Risk of AUFLS with 100MW IR shortfall
Emergency Secure 2	100	210	$2,000	$4,400	$6,600	Risk of AUFLS with 200MW IR shortfall
Demand side 2	-	210	$4,000	$8,800	$11,000	Voluntary high cost response to expected high price eg. Load management
Emergency Secure 3	200	410	$6,000	$11,000	$22,000	Conservative higher risk of AUFLS with 300-400MW IR shortfall
Load Shedding 1	400	810	$11,000	$22,000	$33,000	Cost of selected lower cost load shedding based on GIT values for unserved energy
Load Shedding 2	400	1,210	$30,000	$50,000	$70,000	Cost of deeper forced load shedding
Load Shedding 3	2,000	3,210	$50,000	$75,000	$100,000	Cost of very deep load shedding including high cost sectors such as CBDs

Figure 16 Cost of capacity shortfall curves



Appendix 4 Modelling Results

A4.1 Base case analysis

This section describes the results from applying the LDC modelling approach to a base case set of input assumptions, along with the sensitivity of these results to changes to input assumptions that are particularly uncertain (e.g., costs of capacity shortfall).

The capacity adequacy standard is intended to be resilient for a minimum of 3 years out to 2012. Given the potential change in plant mix over that time, two plant mix scenarios and two demand scenarios were used as the "base case" set. LDCs for 2008 and 2012 were combined with two sets of supply mix assumptions:

- "Base" scenario: the current plant mix; and
- "Wind" scenario: the current plant mix with 400MW of wind added to the North Island (assumed correlated with at Tararua). The additional wind in 2008 would increase the capacity share of wind from approx 5% to 10% in the North Island.

For clarity, these scenarios are outlined in Table 18, and all include the operation of half Pole 1 at times of capacity shortfall.

Table 18 Base case scenarios

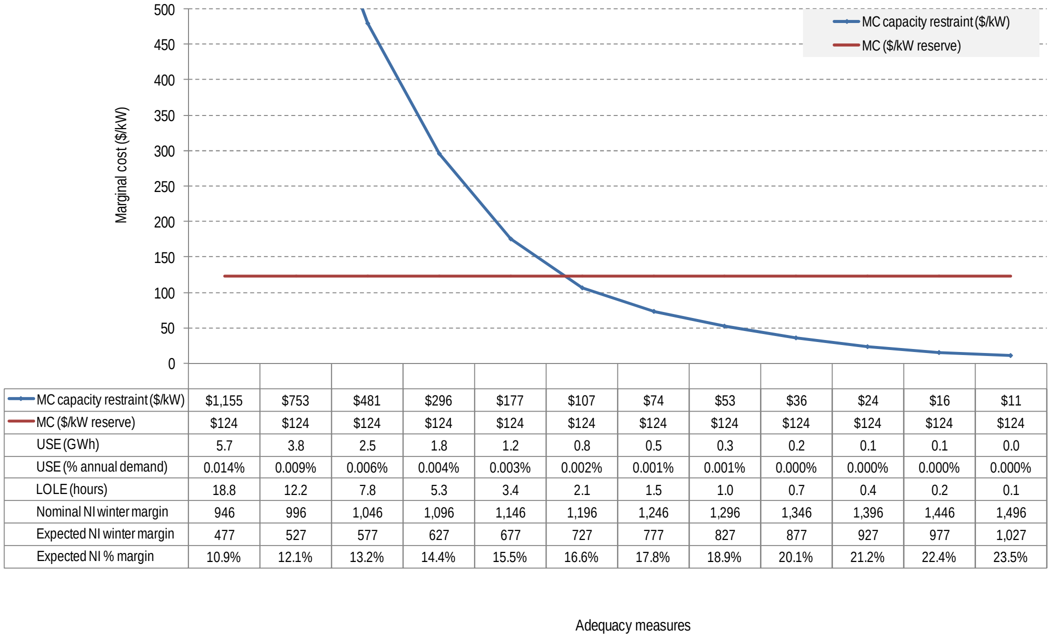
Scenario	Description
Base '08	2008 forecast demand 2008 capacity mix (wind is 5% of NI nominal capacity)
Wind '08	2008 forecast demand 2008 capacity mix with an extra 400MW added wind correlated with Tararua site (wind is 10% of NI nominal capacity)
Base '12	2012 forecast demand 2008 capacity mix with demand growth met entirely from firm capacity such as geothermal (wind 5% NI nominal capacity)
Wind '12	2012 forecast demand 2008 capacity mix with an extra 400MW added wind correlated with Tararua site (wind 10% NI nominal capacity)

For all four cases, the same generic assumptions were made about summer/winter planned and forced outages.

The intention of the wind scenario was to increase the variability to the supply mix at peak times using a plausible assumption. This scenario is valuable for assessing the stability measures, and the methodology. It is important to recognise that future supply scenarios where new “firm” capacity (storage hydro, thermal and geothermal supply) is added are implicitly, and approximately, addressed by the modelling approach via the addition and subtraction of firm capacity to determine the optimal cost trade-off.

Figure 17 illustrates the marginal cost-trade off and adequacy measures for the Base 2008 case (based on expected annual costs).

Figure 17 Optimal trade-off for Base 2008



MC capacity restraint ($/kW)	$1,155	$753	$481	$296	$177	$107	$74	$53	$36	$24	$16	$11
MC ($/kW reserve)	$124	$124	$124	$124	$124	$124	$124	$124	$124	$124	$124	$124
USE (GWh)	5.7	3.8	2.5	1.8	1.2	0.8	0.5	0.3	0.2	0.1	0.1	0.0
USE (% annual demand)	0.014%	0.009%	0.006%	0.004%	0.003%	0.002%	0.001%	0.001%	0.000%	0.000%	0.000%	0.000%
LOLE (hours)	18.8	12.2	7.8	5.3	3.4	2.1	1.5	1.0	0.7	0.4	0.2	0.1
Nominal NI winter margin	946	996	1,046	1,096	1,146	1,196	1,246	1,296	1,346	1,396	1,446	1,496
Expected NI winter margin	477	527	577	627	677	727	777	827	877	927	977	1,027
Expected NI % margin	10.9%	12.1%	13.2%	14.4%	15.5%	16.6%	17.8%	18.9%	20.1%	21.2%	22.4%	23.5%

The adequacy measures have been defined as follows

(a) USE (GWh): expected annual GWh of involuntary restraint.

(b) USE (% annual demand): expected GWh of load shedding as a fraction of expected 2008 GXP energy demand (excluding losses).

(c) LOLE: expected number of hours of involuntary restraint per annum.

(d) NI nominal winter margin: total of installed NI MW capacity – highest winter half hour demand (P50 peak demand).

(e) Expected NI winter margin: This is the difference between expected North Island winter supply and demand, defined as follows:

Term	Calculation
Expected North Island MW capacity	Calculated by derating plant based on type. Hydro and thermal capacity is counted at nominal capacity adjusted for planned and forced outages. Profiled plant is counted at the P50 value of the distribution of output during winter days. Wind is counted at 20% of nominal capacity (as per the contribution to peak factors used in the Grid Planning Assumptions).
+ effective HVDC transfer capability	This is derived as a function of the SI surplus MW given in Appendix 2. SI surplus MW is defined as the expected South Island capacity minus the average of the highest 100 hours of winter daytime demands minus 185MW (an allowance for SI frequency and instantaneous reserves and a diversity factor).
+ effective voluntary demand response	Any demand response is treated as having a 50% contribution at times of peak
- highest 100 winter demand	This is the average of the highest 100 hours of winter daytime demand (including losses)

(f) Expected NI % Margin: 100* (Expected North Island winter capacity / average of the highest 100 winter demand -1)

The adequacy measures have been included on the x-axis to assist with understanding the implications at the optimum as charts later in the report only refer to the measures at the optimal point.

For the Base 2008 case, the optimum level of reserve capacity corresponds to a North Island winter capacity margin of 707 MW (or 16.2% margin), expected involuntary load shedding of 0.95GWh (0.0023% of annual demand), and a loss of load expectation of 2.7 hours.

Observe from Figure 17 that changes to the assumptions about the costs of reserve MW can be derived by shifting the horizontal line to the desired $/kW cost and finding the intersection with the marginal cost of capacity restraint.

- An $80/kW/yr increase in the cost of reserve capacity to $180/kW/yr would reduce the expected winter margin by 32MW to 675MW.
- A $24/kW/yr reduction in the cost of reserve capacity to $100/kW would increase the expected winter margin by 28MW to 735MW.

Figure 18 shows the optimal North Island winter margins (in MW) for all four base scenarios, with Figure 19 expressing them as a percentage of demand. Of particular interest here is the impact of additional wind capacity and changes to the demand forecast on the measures. In addition to the average of the highest 100 hours of demand, margins have been calculated from the expected peak demand ("P50 peak"), which is the highest expected half-hour demand. An alternative supply measure, based on nominal MW capacity, is also shown. Internationally the conventional margin is based on nominal peak capacity and P50 peak demand.

Figure 18 Base case optimal capacity margins (MW)

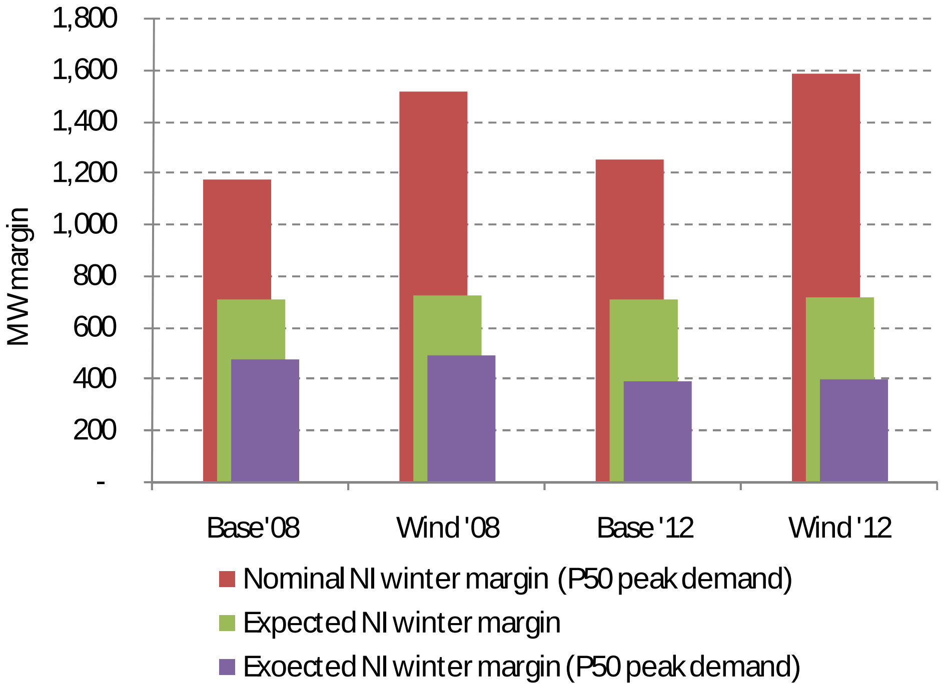
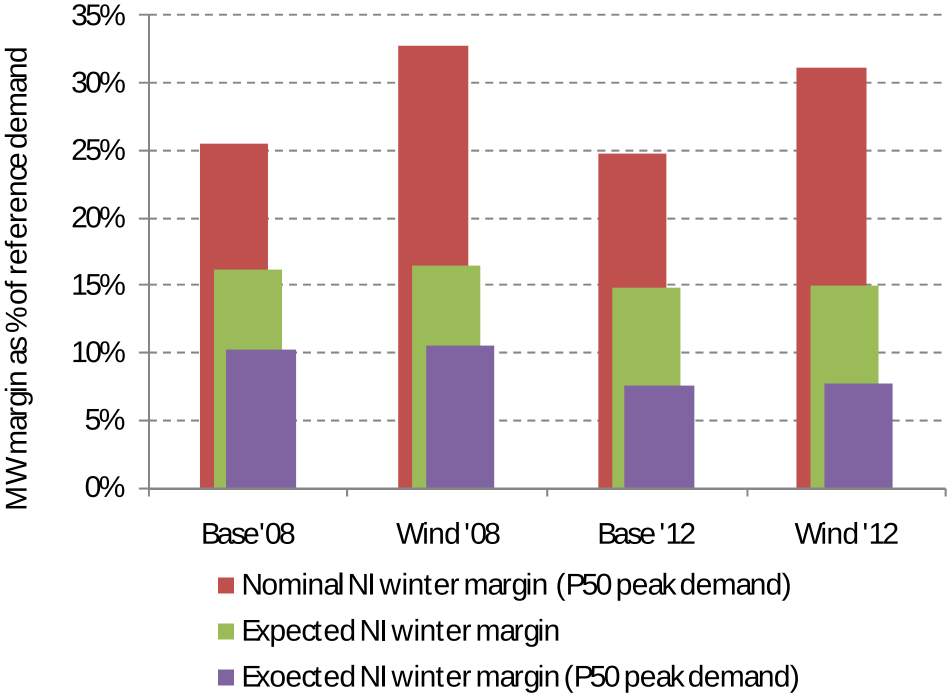


Figure 19 Base case optimal capacity margins (%)

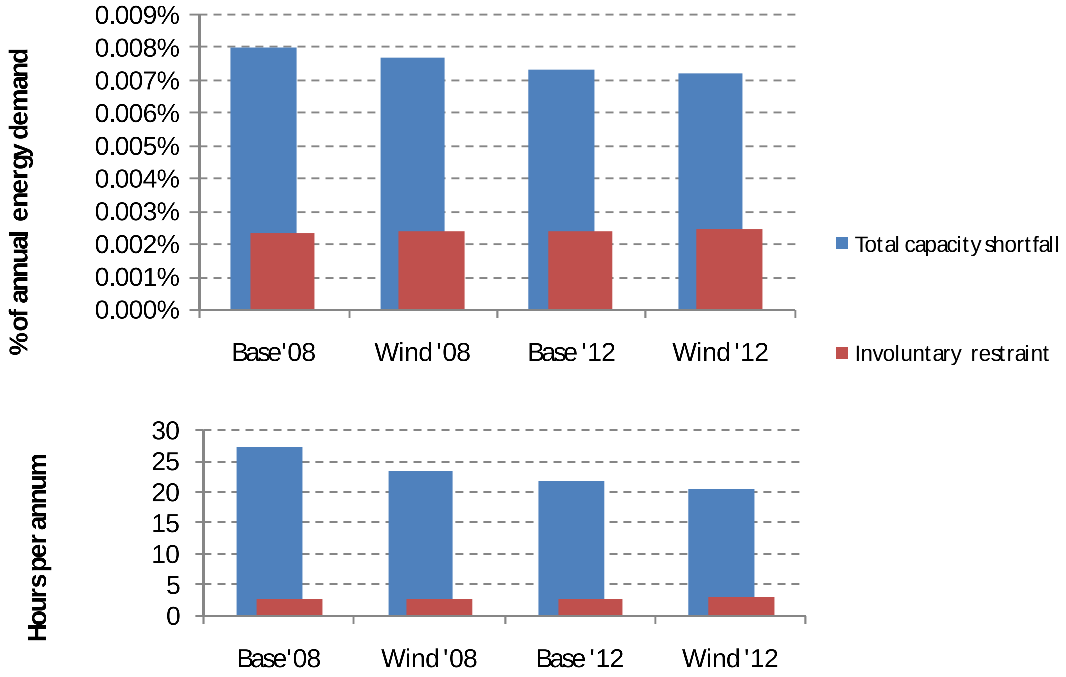


Observe that:

- The most stable measure across the supply mix and demand scenarios is the expected NI winter margin. This has an optimal value of around 700-720MW.
- Whether expressed in MW or as a percentage, margins calculated using nominal capacity or P50 peak demand are less stable across the scenarios.
- The optimal nominal NI winter margin increases if additional wind capacity is added. This is because the effective capacity value of wind is much closer to the 20% factor used in the expected margin calculation.
- The expected NI margin over the “expected peak half-hour” varies from 385-485MW, broadly consistent with an N-1/N-G level.

For completeness, and comparison with international benchmarks, Figure 20 illustrates the optimal LOLP and USE for the base cases. Recall that the difference between total restraint and involuntary restraint is that the former includes all hours where there is a capacity shortfall, whereas the latter only includes involuntary restraint.

Figure 20 Base case optimal USE and LOLE



The quantum of involuntary restraint ranges from 0.0023% to 0.0025% of annual demand, broadly aligning with the 0.002% level applied for the Australian NEM. Involuntary restraint ranges from 2.6 – 2.8 hours, similar to the 2.4 hour standard applied in many of the North American markets, and also similar to the 3.5 hours in Australia.

Internationally most capacity adequacy margins are expressed in terms of nominal MW and P50 peak demands. Typical values are in the range 15% to 30% expressed on this basis[20]. The optimal NI margin expressed on a similar basis is between 25% and 33% depending on the percentage of wind capacity and the peak demand level (2008 or 2012). While the NZ margins appear to be at the high end of the international range, it is difficult to know the significance of this given the very different size and nature of the NZ system compared with these international comparators.

Figure 21 shows the impact of including or excluding half of Pole 1 of the HVDC.

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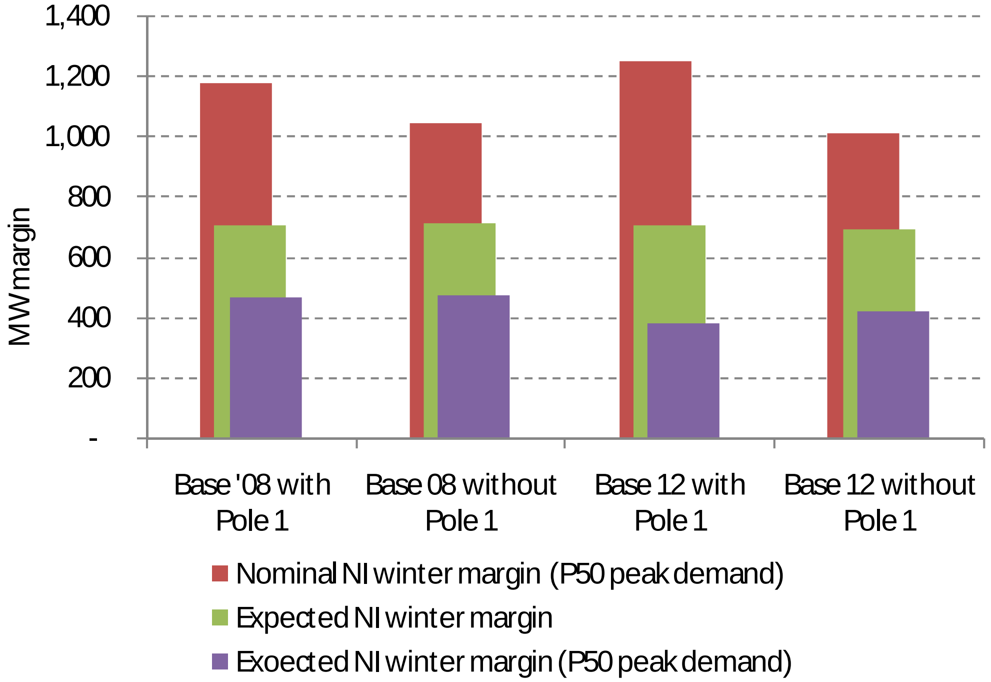
[20] See "Review of Methodology and Assumptions Used in NEMMCO 2003/4 Minimum Reserve Assessment", KEMA, Jan 2005.

Figure 21 Effect of excluding Half Pole 1 on MW capacity margins



The expected NI winter margin (which includes the contribution from half of Pole 1) is relatively insensitive to the availability of half of Pole 1 of the HVDC. In effect, if it is contributing to North Island adequacy and unavailable then at the optimal capacity adequacy level it would need to be replaced with the equivalent MW from new (peaking) capacity; this dynamic is captured in the margin calculations. The implied level of half Pole 1 utilisation corresponding to the optimal standard is approximately 60 hours per annum (40 hours in winter and 20 hours in summer).

Expressed in MW terms, the expected NI winter margin (calculated using the formula defined earlier) is a good candidate for a capacity adequacy standard due to its stability over the next few years and its relative insensitivity to the percentage of wind capacity. The derated expected capacity (with wind counted at 20% of its capacity) minus the average of the highest 100 hours of winter daytime demands is a good proxy for the economically optimum standard based on balancing the cost of new peaking capacity against the cost of capacity restraint.

Furthermore, in the process of deciding upon the form of the winter energy margins (17% NZ, 30% SI) it was apparent that a measure that was simple to communicate and calculate was desirable. Using the same logic a margin expressed in MW which can be derived from assumptions about supply and demand will be preferable to LOLP or USE measures as an assessment would require supply and demand assumptions to be combined together using an approach along the lines of that described in this paper.

The next section discuses the sensitivity of the adequacy measures to changes in other key assumptions.

A4.2 Sensitivities to economic drivers

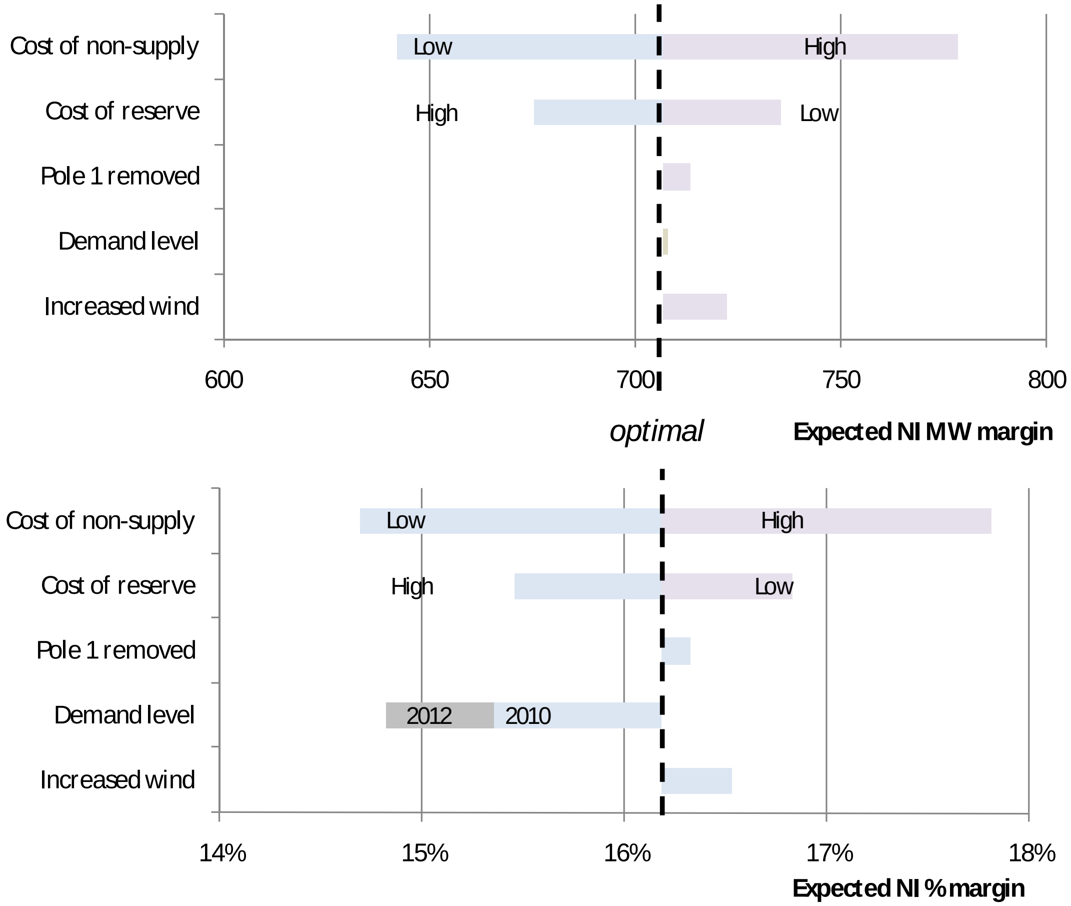
Although the expected NI winter margin appears to be a relatively stable indicator of the optimal capacity margin, its level will depend on the key economic drivers.

The optimal level will clearly depend on the shape and level of the cost of capacity shortfalls assumed and the annualised cost of new peaking capacity.

Figure 22 below shows the sensitivity of the optimal expected margins (in MW and percentage terms) to variations in these drivers. The figure also shows the variation due to plant mix (high or low wind), the availability of Pole 1 and to the demand level (2008 to 2012).

- The high and low costs of capacity shortfall curves were described earlier. The first block of involuntary load shedding varies from \$11,000/MWh to \$33,000/MWh (base assumption \$22,000/MWh).
- The annualised costs of new reserve capacity varies from \$100/kW/yr to \$180/kW/yr (base assumption is \$124/kW/yr)

Figure 22 MW and % margin sensitivities (2008 base)



As can be seen the optimal margin changes by +/- 70 MW (1.5%) depending on the cost of capacity shortfall, whereas variations in the cost of new peaking capacity, demand level, plant mix and availability of half Pole 1 have less than +/- 30MW effect.

While it is possible to refine the estimated cost of new peaking capacity, it is very difficult to refine the estimated range of shortage costs as they are inherently difficult to measure.

A4.3 Sensitivities to outage rates and modelling limitations

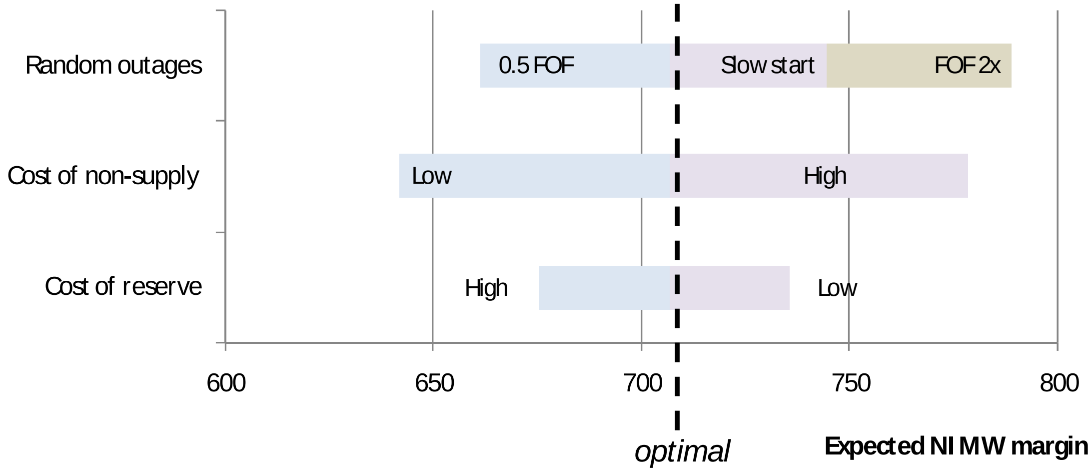
The other key factors affecting the level of the optimal NI winter margin (the margin) relate to the outage rates on the key plant. The base case assumes forced outage rates in the range of 2% to 3% for most thermal and hydro plant.

If the forced outage rates increase or decrease then the margin will change. As a rule we would not expect a significant change in these rates over the next few years, however they are difficult to estimate and so it is important to assess the impact that a change would have on the optimal margin. For comparison Australia uses forced outage rates the range 1 to 5%, whereas North American utilities typically use 4 to 6%. To assess the impact of this key assumption the forced outage rates of all hydro and thermal plant were doubled (to 4-6%) and halved (to 1-1.5%).

In addition there is some concern that the modelling approach may overstate the true availability of large inflexible thermal plant because it ignores issues related to unit commitment. To test this, Huntly unit had 20% added to its 3% forced outage factor to reflect potential impact of at least one of the 4 units being offline and unable to become available following a significant change in the system (demand increase, wind reduction, major unit outage).

Figure 23 below shows the impact of these sensitivities.

Figure 23 Sensitivities of margin to outage rates (2008 base)



This shows that assumptions concerning random outage rates and the potential impact of modelling limitations relating to commitment of large slow start thermal units are as significant as the assumptions concerning the cost of non supply.

This indicates that it would be prudent to do some additional analysis to better assess these parameters and to consider refinements to the modelling approach to factor in some of the most significant chronological issues before setting a standard for the next few years. It would also be important to review the standard in the future if these issues become more important as the plant mix changes. This is likely to be the case as the percentage of wind increases.

A4.4 Comparison with National winter Group (08) assessment

The National Winter Group (NWG) updated its outlook for winter 2008 in February[21]. In this report the NWG updated its assessment of available generation to meet North Island peak demand over June and July.

The NWG believes that there should be a positive margin between the P10 generation capacity and the P95 peak demand (a prudent 1 in 20 year peak demand) plus normal instantaneous reserves. The group initially assessed the margin without pole 1 as -107MW. When Pole 1 was subsequently made available, it assessed that there is a 83MW surplus in 2008 based on an instantaneous reserve requirement of 475MW to cover failure of pole 2 of the HVDC operating at 500MW.

In May 2008, Transpower advised that the instantaneous reserve requirement when half of pole 1 is operating is reduced to 400MW due to half of pole 1 having a short term overload capacity which will cover around 84MW of a pole 2 trip. This would increase the NWG N-1 margin to 158MW.

The comparison between the NWG's peak adequacy assessment for 2008 (adjusted for the change to the instantaneous reserves requirement) and the expected winter margin as calculated using the analysis described in this paper is shown in Table 19.

Table 19 Comparison with NWG assessment of winter 2008

	Without Pole 1		With 1/2 pole 1	
	NWG	EC	NWG *	EC
Expected capacity		5,066		5,196
P10 Supply	5,170		5,360	
Top 100hr demand		4,369		4,369
P95 peak demand	4,802		4,802	
1 Contingency	475		400	
Economic Margin		710		710
Surplus N-1 Margin P95	(107)		158	
Surplus Economic margin		(13)		117

The assessment of peak adequacy differs from the NWG's in many respects. The margin is assessed differently; it uses a different (more conservative) measure of expected peak capacity, a different benchmark of demand (the average of the highest 100 hours of winter daytime demand rather than a prudent peak) and a different required margin (710MW rather than a single contingency of around 400MW). In addition, the expected margin has been

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[21] See National Winter Group 2008 Update Report 15 February 2008.

derived by an economic trade-off between the cost of capacity shortfalls and the cost of new peaking capacity taking into account the full range of variation in demand and plant breakdowns[22].

However as shown in the table above the conclusions are quite similar. Both approaches indicate that peak adequacy would not be achieved in 2008 without pole 1 of the HVDC, and that there is a degree of “surplus” capacity above the required standard with pole 1. The NWG’s standard indicates a higher surplus, but also a higher shortfall without pole 1. On average the NWG’s required standard is slightly higher than the proposed economic standard.

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[22] As noted, the methodology allows other adequacy measures to be estimated. For example, the implied LOLE for the current plant mix is 1 hour and expected involuntary capacity restraint is 0.3 GWh

Appendix 5 Glossary

Ancillary service - The system operator has contracts with generators, customers, retailers and distributors to provide ancillary services, which comprise black start, over frequency reserve, frequency keeping reserve (also known as frequency regulating reserve), instantaneous reserve and voltage support. The system operator obtains instantaneous reserve on a half-hourly basis through the market.

AUFLS - Automatic Under-Frequency Load Shedding

Automatic under-frequency load shedding - Automatic shedding of electrical load when frequency falls below a preset frequency.

Benmore - The location on the national grid at which Benmore power station injects electricity. Benmore is the southern end of the HVDC. Benmore is one of the more commonly used ‘reference’ nodes.

Brown out - A drop in voltage in an electrical power supply, so named because it typically causes lights to dim, as distinguished from a blackout, which is a total power failure or power outage.

Capacity shortfall - A situation where available supply cannot meet demand plus reserves and frequency keeping.

Capacity shortfall curve (CSC)- A cumulative distribution of capacity shortfalls.

Combined cycle generation - Combined cycle is a term used when a power producing engine or plant employs more than one thermodynamic cycle. Heat engines are only able to use a portion of the energy their fuel generates (usually less than 50%). The remaining heat from combustion is generally wasted. Combining two or more "cycles" results in improved overall efficiency.

Consumption - The electrical energy consumed by a 1,000 watt (1 kilowatt) appliance in an hour is one kilowatt-hour (kWh). A kilowatt-hour is also known as a ‘unit of electricity’ and is the unit in which retail sales of electricity are measured.

Demand side initiative - An initiative that encourages or facilitates electricity consumers to modify their usage in way that reduces consumption in a specific time period or shifts consumption from one time period to another.

Dispatch instruction - An instruction issued by the system operator to generators and ancillary service agents in accordance with the dispatch schedule.

Dispatch prices - Dispatch prices are forecast prices calculated in the four hours before dispatch takes place. Dispatch prices are produced in the schedule of dispatch prices and quantities (SDPQ) and are generally more accurate than prices from the pre dispatch schedule (PDS).

Dispatch schedule - The schedule which the system operator bases dispatch instructions on to achieve the dispatch objective.

Distributor - A company that owns or operates the power lines that transport electricity on local low voltage networks.

Domestic consumer - Users of electricity for personal, domestic or household use. This does not include users who purchase electricity for re-supply, or for use in production or manufacture.

Electricity Act 1992 - The Act, as amended by later Acts, that regulates the New Zealand electricity industry, and under which the Commission operates.

Electricity Commission - The Electricity Commission established under subpart 1 of part 15 of the Electricity Act, also known as the Commission. The Commission is composed of six members appointed by the Minister of Energy to oversee the governance, operation and development of the New Zealand electricity industry.

Embedded generation - Generation that is connected to a local network rather than to the national grid.

Forecast price - Forecast prices are calculated from the pre dispatch schedule (PDS) up to 35 hours ahead of the start of any half-hour period and every two hours from then until the start of the specific trading period.

Frequency - The frequency of the New Zealand grid is normally maintained at 50 Hertz frequency.

Frequency Keeping Reserve or Frequency Regulating Reserve (FRR) - An ancillary service that keeps the frequency of the grid within its normal band. The frequency keeping station increases or decreases generation within a set band to ensure that supply equals demand on a second by second basis.

Generator - A company that generates electricity connected to the grid or a local network.

Gigawatt hours (GWh) - One gigawatt hour is equal to one million kilowatt hours. New Zealand’s annual demand is approximately 38,000 GWh.

Grid - The high-voltage electricity transmission network, which transmits electricity throughout New Zealand over more than 12,000km of transmission lines, from generators to distributors and major industrial users. It is also referred to as the national grid, and it is owned by state-owned enterprise Transpower.

Grid Injection Point (GIP) - A point of connection where electricity flows into the national grid from generating stations.

Grid exit point (GXP) - A point of connection where electricity flows out of the national grid to local networks or direct consumers.

Grid owner – Transpower is the owner of the high voltage transmission grid, also referred to as the national grid.

HVDC – High Voltage Direct Current transmission link which runs between Benmore in the central South Island, and Haywards near Wellington. A section of the link runs under Cook Strait via submarine cables.

Hydro spill - Hydro spill refers to water flowing past a power station that is not being used to generate electricity.

Instantaneous reserves (IR) - Generation capacity that is made available to be used in the event of a sudden failure of a generating or transmission facility in order to maintain system frequency at 50 Hz. Fast instantaneous reserve is available within six seconds and must be able to operate for one minute. Sustained instantaneous reserve is available within 60 seconds and must be available for 15 minutes.

Interruptible load (IL) - A type of instantaneous reserve that is provided by load that can be quickly disconnected, e.g. hot water heating.

Involuntary demand restraint – Involuntary restraint (or outages) can occur either from Automatic Under Frequency Load Shedding (AUFLS) during a system contingency (tripping of a large generation unit or transmission line), or from pre-contingent load shedding instructed by the System Operator.

Kilowatt-hour (kWh) - A kilowatt-hour is also known as a ‘unit’, and is the basis of retail sales of electricity.

Load duration curve (LDC) – A distribution of annual half-hour demands sorted from highest to lowest.

Load probability curve (LPC) – a LDC which is based on the average of many LDC forecasts.

Load Shedding - The forced disconnection of load, in stages. This is either manual or automatic

Local network - The lines and substations used by distributors to transport electricity from grid exit points (GXPs) to points of connection with consumers.

Losses - As electricity travels through the national grid, a proportion of energy is lost as heat due to the resistance in the lines. The greater the distance the electricity travels and the lower the voltage of the line, the higher the losses are.

Megawatt hour (MWh) - One megawatt hour is equal to 1,000 kilowatt hours. Megawatt hours are the metering standard unit for the wholesale market.

NZEM (New Zealand Electricity Market) - The multi-party trading arrangement under which, until 1st March 2004, the majority of New Zealand’s wholesale electricity was bought and sold.

National grid - The transmission network that transports high-voltage electricity from the major power stations to the local distribution networks operated by lines companies. It is also known as the grid and is owned by Transpower.

Network - The grid, a local network or an embedded network.

Nodal pricing - In New Zealand the nodal price is calculated for approximately 244 market nodes, in addition to over 200 transfer nodes.

Node - A point on the national grid where electricity either enters or exits the grid (a grid injection point or a grid exit point) or flows through (a transfer node).

Offer - An offer to sell a quantity of electricity at a specified price.

PDS (Pre Dispatch Schedule) - This schedule is produced by the system operator, and includes expected levels of generation, instantaneous reserves, demand and forecast energy and reserve prices. If produced before 13:00 hours, the PDS covers the remaining trading periods of the day. If produced after 13:00 hours, it covers the remaining trading periods of the day and the trading periods of the following day.

Reserve - Energy that can be produced within seconds to maintain frequency in the event or generation or transmission line outage.

Retailer - A company that sells electricity to customers.

Spot market - The buying and selling of wholesale electricity is done via a ‘pool’, where electricity generators offer electricity to the market and retailers and major users bid to buy the electricity. This market is called the spot or physical wholesale market.

Spot price - The half-hour price of wholesale (‘spot’) market electricity published by the pricing manager.

System Operator (SO) - Service provider responsible for scheduling and dispatching electricity, in a manner that avoids fluctuations in frequency or disruption of supply. The system operator is currently Transpower.

Transpower - The state-owned enterprise which owns the high-voltage transmission network (the national grid) and is the system operator.

Voltage support - Reactive support capabilities procured in regions of the grid (Auckland and top of South Island) to support voltage. The services are procured from generators.

Voluntary demand restraint – demand reductions that occur in response to market participants forecasting a risk of high prices, or in response to System Operator warnings. It can also be contracted demand-side response