

Consultation Paper

Annual Security Assessment 2009

Prepared by the Electricity Commission

1 December 2009

Executive summary

A key part of the Commission's security of supply role is the annual publication of medium to long-term security assessments. This paper presents a new draft security assessment, which assesses both dry-year energy and peaking capacity, covering the period from 2010 to 2019. Feedback on the assumptions and conclusions of the assessment is sought.

The Commission's security assessments are intended to provide information to assist participants to assess risk and investment decisions. They also help the Commission assess the need for the procurement of additional Reserve Energy or Capacity, by determining whether supply exceeds demand by a pre-defined margin:

- the Commission will consider procuring Reserve Energy if the Winter Energy Margin is forecast to fall below 17% for New Zealand or 30% for the South Island; and
- the Commission will consider procuring Reserve Capacity if the Winter Capacity Margin is forecast to fall below 780 MW.

However there is a strong preference for security of supply to be provided by market participants and processes, rather than being a result of regulatory intervention.

The assessment methodology is set out in the Security of Supply Policy.¹ This assessment is very similar in approach to the 2008 assessment, with key differences being that:

- it introduces a distinction between *technical capacity* (ability of generation to meet peak demand, assuming all available plants are committed) and *market capacity* (ability of generation to meet peak demand, given that some slow-start plants may not be committed for commercial reasons);
- rather than including a new demand forecast, it uses a revised version of the 2008 forecast (on the assumption that underlying demand growth has not been affected by the recession); and
- it considers the impact of reduced availability (and eventual retirement) of some major existing generation.

Key conclusions are that:

- there is no need at this point for the Commission to procure Reserve Energy to support dry-year security in 2010, 2011 or 2012;
- extended dry periods and/or multiple asset failures could still lead to energy shortage situations. Under the existing Reserve Energy Scheme framework, the Commission can still procure Reserve Energy on shorter lead times if necessary;

¹ <http://www.electricitycommission.govt.nz/pdfs/opdev/secsupply/policy/sos-policyOct08.pdf>

- there is not a shortfall of technical capacity that would lead the Commission to procure Reserve Capacity to support peak security in 2010 or 2011 at this point. Although the projection for 2011 is tight, there is still time for the market to provide additional peaking capacity;
- however, there is the potential for unit commitment problems to have a serious adverse effect on security of supply at peak times. If slow-start generation is not committed in advance then it cannot contribute to meeting peak. The Commission is considering market-based options for achieving better unit commitment outcomes in winter 2010;
- the Commission should continue to monitor unit commitment over the coming months. If market-based measures do not improve unit commitment outcomes, other options should be considered;
- a significant amount of new generation investment will be needed to maintain security margins from 2013 onwards. Given the lead time of new generation, some investments will need to be committed within the next year; and
- despite the need for new generation, investment appears to be slowing. Over 600 MW of new generation that was rated as “medium” or higher probability for 2010 or 2011 in the 2008 assessment has since been deferred until at least 2013 or cancelled.

This assessment adds weight to the view that New Zealand, formerly seen as an “energy-constrained system”, is now both energy and capacity constrained. Capacity margins are more likely to bind in the next few years than energy margins. Consequences may include:

- more difficulty in meeting winter peak demand;
- more difficulty in meeting peak demand at other times of year, due to factors such as increasing summer demand, increasing reliance on wind generation, and generation and/or transmission outages;
- more occasions when instantaneous reserves cannot be maintained; and
- a generally “tighter” power system. |

Glossary of abbreviations and terms

Act	Electricity Act 1992
AUFLS	Automatic underfrequency load shedding
CCGT	Combined cycle gas turbine
Commission	Electricity Commission
ERP	The Commission's Emergency Response Plan
GPS	The Government Policy Statement
Market capacity	Ability of generation to meet peak demand, given that some slow-start plants may not be committed for commercial reasons (cf. technical capacity)
Minister	Minister of Energy and Resources
NZ-WEM	New Zealand Winter Energy Margin – see Winter Energy Margin below.
RAFs	Reserve Adjustment Factors
Regulations	Electricity Governance Regulations 2003
Reserve Capacity	Energy procured by the Commission to meet objectives relating to capacity adequacy – i.e. to help supply demand when there is insufficient generation to meet demand at peak time
Reserve Energy	Energy procured by the Commission to meet objectives relating to energy adequacy – i.e. to help supply demand when there are shortages of water for hydro generation and/or fuel for thermal generation
Rules	Electricity Governance Rules 2003
SI-WEM	South Island Winter Energy Margin – see Winter Energy Margin below.
Technical capacity	Ability of generation to meet peak demand, assuming all available plants are committed (cf. market capacity)
WCM	See Winter Capacity Margin below.
Winter Capacity Margin	A margin measured by comparing winter peaking capacity (in MW) to peak demand. The Commission will consider procuring Reserve Capacity if the Winter Capacity Margin is forecast to fall below 780 MW.
Winter Energy Margin	A margin measured by comparing potential winter supply (in GWh) to winter demand. The Commission will consider procuring Reserve Energy if the Winter Energy Margin is forecast to fall below 17% for New Zealand or 30% for the South Island.

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1. Introduction and purpose of this paper

1.1 Introduction

1.1.1 A key part of the Commission's security of supply role is the annual publication of medium to long-term security assessments, as required by the Government Policy Statement² and the Commission's Security of Supply Policy.³ The last such assessment was published in late 2008.⁴

1.1.2 These assessments are intended to provide information to assist participants to assess risk and investment decisions. They also help the Commission assess the need for the procurement of additional Reserve Energy or Capacity, by determining whether supply exceeds demand by a pre-defined margin.

1.1.3 The Government and the Commission have a strong preference for security of supply to be provided by market participants and processes, rather than being a result of regulatory intervention. All previous assessments have concluded that dry-year reserve needs were being met by the market and that there was no need for the Commission to procure more Reserve Energy.

1.1.4 The 2008 assessment was the first to assess peaking capacity adequacy. It concluded that peaking capacity needs were being met by the market and that there was no need for the Commission to procure more Reserve Capacity for 2009. It also noted that maintaining security margins for 2010/11 was reliant on new plant being committed.

1.1.5 This paper presents a new draft security assessment for stakeholder feedback. It assesses both dry-year energy and peaking capacity, covering the period from 2010 to 2019.

1.2 Purpose of this paper

1.2.1 The purpose of this paper is to consult with participants and persons that the Commission thinks are representative of the interests of persons likely to be substantially affected by the Commission's assessment of security of supply.

² http://www.med.govt.nz/templates/ContentTopicSummary_21482.aspx, paras 20-21

³ <http://www.electricitycommission.govt.nz/pdfs/opdev/secsupply/policy/sos-policyOct08.pdf>, sections 1-2
A "plain language" explanation of the Security of Supply Policy and Emergency Response Plan is provided, for the benefit of readers who are not familiar with the industry, at <http://supplyline.electricitycommission.govt.nz/Home/AbouttheEC/RoleofECinsecurityofsupply.aspx>.

⁴ <http://www.electricitycommission.govt.nz/pdfs/opdev/secsupply/policy/ASA-2008.pdf>

1.3 Submissions

The Commission's preference is to receive submissions in electronic format (Microsoft Word). It is not necessary to send hard copies of submissions to the Commission, unless it is not possible to do so electronically. Submissions in electronic form should be emailed to submissions@electricitycommission.govt.nz with Consultation Paper—Annual Security Assessment 2009 in the subject line.

If submitters do not wish to send their submission electronically, they should post one hard copy of their submission to the address below.

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- 1.3.1 Submissions should be received by 5 pm. on 29 January 2010. Please note that late submissions are unlikely to be considered.
- 1.3.2 The Commission will acknowledge receipt of all submissions electronically. Please contact Lisa DuFall if you do not receive electronic acknowledgement of your submission within two business days.
- 1.3.3 If possible, submissions should be provided in the format shown in Appendix 1. Your submission is likely to be made available to the general public on the Commission's website. Submitters should indicate any documents attached, in support of the submission, in a covering letter and clearly indicate any information that is provided to the Commission on a confidential basis. However, all information provided to the Commission is subject to the Official Information Act 1982.

2. Structure of this report

2.1.1 To simplify presentation, overall assessments of energy and capacity margins and Reserve Energy and Reserve Capacity needs are summarised in the body of this report. Detailed assumptions and analysis are set out in appendices or cited documents.

2.1.2 The report is structured as follows:

- (a) Section 3 describes the Commission's Security of Supply role and the Annual Security Assessment process, and discusses differences from previous assessments;
- (b) Section 4 sets out the assumptions used in the analysis (baseline and sensitivities);
- (c) Section 5 summarises an energy margin assessment from 2010 to 2019;
- (d) Section 6 summarises a capacity margin assessment from 2010 to 2019; and
- (e) Section 7 sets out draft conclusions on energy and capacity needs.

2.1.3 The following appendices are attached:

- (a) Appendix 1 - format for submissions;
- (b) Appendix 2 - detailed supply assumptions for the baseline scenario;
- (c) Appendix 3 - detailed demand forecast assumptions for the baseline scenario; and
- (d) Appendix 4 - rationale for including "poor unit commitment" sensitivity scenarios, which assess the impact of commitment of slow-start plants on the ability of the system to meet peak demand.

3. Background

3.1 The Commission's role in security of supply

3.1.1 As set out in the Commission's Security of Supply Policy and Emergency Response Plan (ERP)⁵, the Commission's approach to ensuring security of supply includes:

- (a) a strong focus on providing information and analysis of supply and demand and security of supply, in order to maximise the opportunity for market participants to manage security of supply risks;
- (b) monitoring security of supply in the long-term (up to 10 years) and publishing forecasts to provide information to assist participants to assess future supply risk and investment decisions;
- (c) assessing Reserve Energy and Capacity needs in the medium term (2 to 5 years) by forecasting supply and demand and calculating the Winter Energy Margin and the Winter Capacity Margin. If insufficient new generation or demand side initiatives are forthcoming then additional Reserve Energy or Capacity may be required to be contracted. The decision to contract will be delayed as long as possible in order to provide as much opportunity as possible for other solutions to be implemented and to reduce the possibility of redundant Reserve Energy or Capacity;
- (d) shorter-term monitoring;
- (e) triggering the operation of Reserve Energy and Capacity if necessary; and
- (f) triggering the operation of emergency measures if necessary.

3.1.2 Reserve Energy is defined in the Security of Supply Policy as "energy procured to meet objectives relating to energy adequacy" – i.e. to help supply demand when there are shortages of water for hydro generation and/or fuel for thermal generation. Generally Reserve Energy would be most likely to be required to operate in long dry periods (such as the autumn and winter of 2008).

3.1.3 Reserve Capacity is defined as "energy procured to meet objectives relating to capacity adequacy" – i.e. to help supply demand when there is not enough generation to meet peak demand. Generally, Reserve Capacity would most likely be required to operate in cold winters (such as 2006), during morning and evening peak periods.

3.1.4 Factors that might increase the likelihood of Reserve Capacity needing to operate (once procured) could include:

⁵ <http://www.electricitycommission.govt.nz/pdfs/opdev/secsupply/policy/ERP-May09.pdf>

- (a) generation or transmission asset outages;
- (b) low output from intermittent generation such as wind farms; and/or
- (c) slow-start thermal generation not being committed in advance.

3.1.5 The Security of Supply Policy sets out that:

- (a) the Commission will consider the procurement of Reserve Energy if, within a period of three years from a time of an assessment:
 - (i) the Winter Energy Margin is forecast to fall below 17% for New Zealand as a whole; or
 - (ii) the Winter Energy Margin is forecast to fall below 30% for the South Island;
- (b) the Commission will consider the procurement of Reserve Capacity if, within a period of two years from the time of the assessment, the Winter Capacity Margin is forecast to fall below 780 MW; and
- (c) procurement of Reserve Energy or Capacity is contingent on the Commission considering that it is unlikely that sufficient new supply-side or demand-side options will be put in place by any market participant.

3.2 Previous security assessments

3.2.1 As per paragraph 3.1.1(c), the Commission must regularly assess Reserve Energy and Capacity needs in the medium term, and must also provide longer-term forecasts of security of supply.

3.2.2 The Commission has published the following medium to long-term security assessments since its inception, with the assistance of Concept Consulting:

- (a) Annual Security Assessment 2008 – published November 2008⁶, conclusion and summary of submissions also available;⁷
- (b) Annual Security and Reserve Energy Needs Assessment – October 2007;⁸
- (c) 2007 Reserve Energy Needs Assessment – published October 2005;⁹
- (d) 2006 Reserve Energy Needs Analysis – published November 2004.¹⁰

⁶ <http://www.electricitycommission.govt.nz/pdfs/opdev/secsupply/policy/ASA-2008.pdf>

⁷ <http://www.electricitycommission.govt.nz/pdfs/opdev/secsupply/policy/ASA-2008-InfoPaper.pdf>

⁸ <http://www.electricitycommission.govt.nz/pdfs/opdev/secsupply/pdfsconsultation/annual-security-assessment.pdf>

⁹ <http://www.electricitycommission.govt.nz/pdfs/opdev/secsupply/pdfsconsultation/2007-needs-assessment.pdf>

¹⁰ <http://www.electricitycommission.govt.nz/pdfs/opdev/secsupply/pdfsconsultation/consultation-2006-assessment-report.pdf>

- 3.2.3 A security assessment for 2005 was commissioned by the Ministry of Economic Development in 2004, since the Commission was not yet in a position to prepare it.¹¹
- 3.2.4 See also the Security Assessment Archive, which provides context and some supporting material.¹²
- 3.2.5 None of these assessments had recommended that additional Reserve Energy or Reserve Capacity be procured. To date, the only Reserve Energy or Capacity that has been contracted by the Commission is the output of Whirinaki Power Station (Whirinaki), under an agreement with the Crown.¹³ The procurement of Whirinaki as Reserve Energy was not the result of a formal medium-term needs assessment. Rather, it was part of the Government's response to dry years in 2001 and 2003. The intention was that Whirinaki would be able to improve supply security in very dry years.
- 3.2.6 The Commission also considered the procurement of Reserve Energy during the winter of 2008 as a result of a shorter-term security assessment, but concluded after issuing a Request for Proposals that procurement was no longer necessary.
- 3.2.7 The assessment process has improved in parallel with the Commission's security of supply policy framework. The Annual Security Assessment 2008 introduced the 'Winter Energy Margin' and 'Winter Capacity Margin' as straightforward ways of measuring reserve needs. It also introduced long-term assessment of peaking capacity – as opposed to the 2007 assessment, which covered energy adequacy for 2008-2016 but peak adequacy for 2008 only.

3.3 Key differences from previous assessments

- 3.3.1 This assessment is very similar in approach to the 2008 assessment.
- 3.3.2 Key methodological differences are that:
- (a) this assessment introduces a distinction between *technical capacity* (ability of generation to meet peak demand, assuming all available plants are committed) and *market capacity* (ability of generation to meet peak demand, given that some slow-start plants may not be committed for commercial reasons);
 - (b) this assessment does not include a new purpose-built demand forecast. Rather, it uses a modified version of the forecast used in the 2008 assessment, for reasons explained in Section 4.2; and

¹¹ <http://www.electricitycommission.govt.nz/opdev/secsupply/pdfsconsultation/2005reservesassessment.pdf>

¹² <http://www.electricitycommission.govt.nz/opdev/secsupply/reserveenergy/Archives>

¹³ <http://www.electricitycommission.govt.nz/pdfs/opdev/secsupply/pdfssecurity/Whirinaki%20Agreement.pdf>

- (c) this assessment considers the impact of reduced availability (and eventual retirement) of some major existing generation.

4. Input assumptions

4.1 Framework

4.1.1 The input assumptions of the assessment relate to:

- (a) generation (existing plants and proposed new projects);
- (b) electricity demand (including demand response); and
- (c) inter-island transmission capability.

4.1.2 This assessment includes a baseline scenario and a list of sensitivity scenarios. The baseline assumptions are set out in Section 4.2, and the alternate assumptions used in the sensitivity scenarios are in Section 4.3.

4.1.3 A key uncertainty relates to the pace of new generation development. Accordingly, new generation projects have been allocated to four categories – committed, “high probability”, “medium probability”, and “low probability”. Each scenario includes four cases, with:

- (a) existing and committed generation only;
- (b) existing, committed and “high probability” generation;
- (c) existing, committed, “high and medium probability” generation; and
- (d) existing, committed, “high, medium and low probability” generation.

4.1.4 All scenarios cover the period from 2010 to 2019.

4.1.5 Standard assumptions that are implicit in the calculation of Winter Energy and Capacity Margins are covered in Sections 5.1 and 6.1.

4.1.6 The Commission welcomes submitters' comments on the assumptions made.

4.2 Baseline assumptions

4.2.1 Assumptions about generation are largely based on information received from generators on a confidential basis. The Commission thanks Genesis Energy, Meridian Energy, Contact Energy, Mighty River Power, Trustpower and Todd Energy for the information provided.

4.2.2 Some publicly available information is also used.

Existing generation assumptions

- 4.2.3 Retirement of existing generation is a topical issue with the potential to have a major effect on security of supply. Contact Energy retired the last unit at New Plymouth Power Station in 2008; Genesis Energy recently published a Statement of Corporate Intent¹⁴ that indicated that two coal-fired Huntly units would soon be retired.
- 4.2.4 One or more generators have provided information about their plans to reduce the availability of some of their existing generation over the next few years. This information was provided under confidence and cannot be reproduced here, but it has been used in the assessment. Both energy and capacity margins are affected.
- 4.2.5 Otherwise, there are relatively few changes to existing generation assumptions since the 2008 assessment.
- 4.2.6 As in the 2008 assessment, it is assumed that New Plymouth Power Station and Fonterra's cogeneration at Te Awamutu will be completely unavailable.
- 4.2.7 All other existing generation is expected to be physically available, subject to normal limitations (e.g. the variability of intermittent generation, the dependence of hydro on inflows, the outage rates of thermal and hydro plants, derating to allow for ancillary service requirements).
- 4.2.8 The recently commissioned Kawerau and Ngawha 2 geothermal plants are included, as is the near-complete Project West Wind.
- 4.2.9 Contact Energy have advised that the combined output of Clyde and Roxburgh will be limited to 680 MW for transmission pricing reasons (cf. the technical capability of 752 MW).
- 4.2.10 See Appendix 2 for detailed baseline assumptions about existing generation.

¹⁴ <http://www.genesisenergy.co.nz/genesis/get-to-know-us/about-genesis-energy/en/statement-of-corporate-intent.cfm>

New generation assumptions

- 4.2.11 Information provided by generators has been converted into a set of new generation assumptions for publication. The conversion process includes:
- (a) anonymising confidential projects;
 - (b) further masking the original data by aggregating projects and changing some dates, capacities and other details;
 - (c) augmenting the generator information with some publicly available data; and
 - (d) applying judgement to categorise uncommitted projects as “high”, “medium” or “low probability”.
- 4.2.12 The resulting assumptions are set out in Table 1.
- 4.2.13 See Appendix 2 for detailed baseline assumptions about new generation.

Table 1: New generation assumptions in the baseline scenario

First available winter	Plant	Developer	Technology	Capacity (MW)	Island	Probability
2010	Stratford - turbine 1	Contact	Gas turbine	100	N	Committed
2010	Nga Awa Purua	MRP	Geothermal	132	N	Committed
2010	Te Rere Hau	NZ Windfarms	Wind	20	N	Committed
2011	Stratford - turbine 2	Contact	Gas turbine	100	N	Committed
2011	Tauhara Binary	Contact	Geothermal	23	N	Committed
2011	Benmore Refurb.	Meridian	Hydro	10	S	Committed
2011	Te Uku	Meridian	Wind	64	N	Committed
2012	Cogeneration 1		Cogen	50	N	Medium
2012	Mahinerangi 1	Trustpower	Wind	30	S	Medium
2013	Gas-fired peaker 1		Gas turbine	60	N	Medium
2013	Geo 1		Geothermal	50	N	High
2013	NI Wind 1		Wind	200	N	Medium
2013	Hydro 1		Hydro	40	S	Medium
2013	SI Wind 1		Wind	150	S	Medium
2014	NI Wind 2		Wind	200	N	Low
2014	Taranaki CCGT	Todd	CCGT	200	N	Medium
2014	Geo 2		Geothermal	150	N	Medium
2015	Gas-fired peaker 2		Gas turbine	150	N	Medium
2015	SI Wind 2		Wind	200	S	Low
2015	Geo 3		Geothermal	150	N	High
2015	NI Wind 3		Wind	200	N	Medium
2016	NI Wind 4		Wind	300	N	Low
2016	Geo 4		Geothermal	100	N	Medium
2017	Hydro 2		Hydro	200	S	Low
2017	SI Wind 3		Wind	150	S	Low
2018	NI Wind 5		Wind	200	N	Low
2018	Geo 5		Geothermal	100	N	Low
2018	Hydro 3		Hydro	200	S	Medium

- 4.2.14 There are significant changes to new generation assumptions since the 2008 assessment, with:
- (a) Nga Awa Purua coming forward;
 - (b) Stratford, Tauhara Binary and Te Mihi moving back; and
 - (c) considerable delays to the development of other wind, geothermal, hydro and gas-fired projects.
- 4.2.15 As an illustration of the delays in new projects, the 2008 assessment specified that the following projects were all at least “medium probability” for the 2010 and 2011 calendar years:
- (a) Hayes Stage 1 (150 MW wind in 2010);
 - (b) Titiokura / Te Waka (147 MW wind in 2011);
 - (c) “Wind 2” (82 MW in 2010);
 - (d) “Wind 3” (97 MW in 2011);
 - (e) Te Mihi (net 62 MW geothermal in 2011);
 - (f) “Thermal 1” (75 MW gas-fired peaker in 2010); and
 - (g) “Hydro 2” (110 MW in 2010).

In this assessment, the only one of these projects expected to take place during 2010 or 2011 is Te Uku (which could be considered to represent “Wind 2” or “Wind 3”). The remainder have been postponed until at least 2013 or cancelled.

Thermal fuel assumptions

- 4.2.16 In the 2008 assessment, it was stated that “thermal fuel supply arrangements over 2009 and 2010 are not expected to constrain thermal generation capability” (Appendix 1.7).
- 4.2.17 It appears that this assumption no longer holds. In 2009, one or more generators have indicated that their fuel supply arrangements may constrain their thermal generation capability in 2010 and future years.
- 4.2.18 Based on the information provided, the combined contribution of thermal plants to energy margins has been derated by 400 GWh per winter (nearly 2% of total winter demand).
- 4.2.19 Capacity margins are unaffected, since there is no indication that fuel supply arrangements will limit the ability of thermal generation to contribute to peak demand. Any further information on this issue would be appreciated.

Demand forecast assumptions

- 4.2.20 Assumptions about demand are based in part on information received from distributors, retailers, major consumers and consumer groups on a confidential basis. The Commission thanks all respondents for the information provided. Their efforts are appreciated; even null responses are useful.
- 4.2.21 Publicly available market data is also used.
- 4.2.22 The 2008 assessment used a purpose-built demand forecast.¹⁵ For reasons set out below, a new demand forecast has not been prepared this year – rather, the 2008 forecast has been modified on the basis of information received from participants.
- 4.2.23 The demand forecast has two key elements:
- (a) projections of industrial demand and embedded generation, based on information provided by participants; and
 - (b) a statistical projection of historical demand over the last decade, using a regression approach.
- 4.2.24 Since the 2008 forecast was prepared, new information on historical demand includes:
- (a) confirmation of winter energy and peak demand for 2008; and
 - (b) estimates of winter energy and peak demand for 2009.
- 4.2.25 Demand in winter 2008 was heavily affected by voluntary savings as a result of the dry winter, and is of little value in assessing underlying demand growth.
- 4.2.26 In winter 2009, demand at the Tiwai smelter was significantly reduced due to technical problems. Excluding Tiwai demand, 2009 peak and winter energy were higher than in 2007, but not nearly as high as was predicted in 2008.
- 4.2.27 The low demand in winter 2009 is generally ascribed to economic conditions. Some parts of the winter period were unusually cold, and had this not been the case, demand would have been even lower.
- 4.2.28 There is a valid question as to whether 2009 demand is reflective of reduced underlying growth, or is a ‘blip’ caused by the recession. If the former is true, then forecasts for future years should be reduced; if the latter is true, then demand can be expected to grow rapidly as the economy recovers, and the existing forecasts should stand.

¹⁵ <http://www.electricitycommission.govt.nz/opdev/modelling/demand/security/index.html>

- 4.2.29 The Commission takes the view that security assessments should not rely on low demand growth, and has therefore excluded the 2009 demand from the statistical analysis.
- 4.2.30 Given that there is no new information on underlying growth, there are no grounds for changing the statistical component of the forecast. Only the industrial and embedded generation components have been reviewed. The resulting changes, relative to the 2008 forecast, are:
- (a) a reduction in South Island winter energy demand of 350 GWh in 2010;
 - (b) a reduction of South Island peak demand of 45 MW in 2010;
 - (c) a reduction in North Island winter energy demand of 100 GWh in all future years; and
 - (d) a reduction in North Island peak demand of 25 MW in all future years.
- 4.2.31 The key drivers for these changes are:
- (a) reduced projections of demand at existing industrial sites; and
 - (b) delays in development of new industrial/commercial sites.
- 4.2.32 See Appendix 3 for detailed assumptions about demand forecasts in the baseline scenario.
- 4.2.33 This assessment also explores the impact of demand being significantly higher or lower than the baseline forecast. See Section 4.3 for the relevant sensitivity cases.

Inter-island transmission assumptions

- 4.2.34 This assessment does not incorporate detailed modelling of transmission. However, it does make assumptions about:
- (a) the amount of energy that can be transferred from the North Island to the South Island during a dry period (which affects the South Island Winter Energy Margin); and
 - (b) the amount of power that can be transferred from the South Island to the North Island during peak demand (which affects the Winter Capacity Margin).
- 4.2.35 The main change to inter-island transfer since the 2008 assessment is that Transpower has relaxed the conditions around use of HVDC Pole 1. However, the 2008 assessment did not model the Pole 1 operating regime in detail, so there is no need to revise assumptions on this basis.
- 4.2.36 Accordingly, there are no changes to inter-island transmission assumptions for 2010 or 2011.

- 4.2.37 It is expected that HVDC Pole 3 will become available in 2012. The security impact is now modelled in the assessment of capacity margins (it was not included in the 2008 assessment). The new Pole will increase the amount of power that can be transferred northwards at peak times (to the extent that there is surplus South Island capacity). Reduced DC losses and increased ability for the DC to cover its own reserve risk both contribute.
- 4.2.38 See Appendix 2 for detailed assumptions about inter-island transmission.

4.3 Sensitivities

- 4.3.1 Table 2 (on the following pages) describes the sensitivity scenarios that are included in this assessment.
- 4.3.2 Note that, in reality, the outcomes described are not mutually exclusive – for instance, it is unlikely but possible that 2010 demand will be high *and* new generation will be delayed *and* inflows will be low. Some combinations of outcomes have been modelled as sensitivities, but not all.
- 4.3.3 Most sensitivities relate to *technical capacity* – the ability of generation to meet peak demand, assuming all available plants are committed. In contrast, the “Poor commitment” scenarios relate to *market capacity* – the ability of generation to meet peak demand, given that some slow-start plants may not be committed for commercial reasons.
- 4.3.4 See Appendix 4 for a discussion of the rationale for including these “Poor commitment” scenarios.

Q1.	Do you agree that the baseline and sensitivity scenarios presented are appropriate for use in this assessment?
Q2.	Do you consider that any specific assumptions are incorrect? If so, which and why?

Table 2: Sensitivity scenarios

Scenario	Affects energy	Affects technical capacity	Affects market capacity	Rationale	Assumptions made
Delay Stratford	Y (2010 only)	Y (2010 only)	Y (2010 only)	Although it is expected that at least one of Contact's two new 100 MW gas-fired units at Stratford will be available for winter 2010, delays are always possible.	Stratford is not available for the winter of 2010.
Delay Nga Awa Purua <i>and</i> Stratford	Y (2010 only)	Y (2010 only)	Y (2010 only)	Although it is expected that Mighty River Power's new 132 MW geothermal plant will be available before winter 2010, delays are always possible.	Neither Stratford nor Nga Awa Purua is available for the winter of 2010.
High demand growth	Y	Y	Y	Factors such as economic conditions or new industrial and agricultural developments could lead to higher-than-expected demand growth.	Peak and energy growth of 2.5% p.a., starting from the forecast figure for 2009. See Figure 1 below.
Delayed demand growth	Y	Y	Y	Factors such as economic conditions, electricity efficiency, or price response could lead to lower-than-expected demand growth.	Peak and energy growth of nil in 2010, 1% in 2011, and 2.5% thereafter, starting from the forecast figure for 2009. See Figure 1 below.
No dry-year demand response	Y	N	N	The baseline includes a 2% reduction in demand during extended energy shortages, representing price response. In theory this might not happen.	No allowance for demand response in the calculation of Winter Energy Margins.

Scenario	Affects energy	Affects technical capacity	Affects market capacity	Rationale	Assumptions made
No new wind generation	Y (after 2011)	Not substantially		There is a significant amount of new wind investment modelled in the baseline scenario. Some parties have expressed doubts as to whether these projects will go ahead.	No new wind generation is modelled, other than committed projects.
Limited south transfer in dry years	Y	N	N	The baseline assumption is that southward transfer would rise to an average of over 400 MW during an extended dry period – but, as noted in the Winter Review ¹⁶ , various factors can combine to prevent this. During June-August 2008, the average net southward transfer over the HVDC link was approximately 300 MW.	In the calculation of energy margins, inter-island transfer is limited to 1,315 GWh over April-September (mean of 300 MW).
Low inflows	Y	N	N	It has been theorised ¹⁷ that, due to climate factors, New Zealand is currently in an extended period of lower-than-average inflows. The Commission seeks to explore this scenario (without entering into a debate about climate change).	In the calculation of energy margins, inflows and initial hydro storage are reduced by 5%.
Limited wind contribution	N	Y	Y	Some parties have expressed concern about the effects of increased wind penetration on the ability of the power system to meet peak demand. The baseline assumption is that wind has a 20% capacity factor (contributes 20% of its nameplate capacity to meet peak). ¹⁸ This scenario explores the impact of assuming that wind has a nil capacity factor.	Wind makes no contribution to capacity margins.

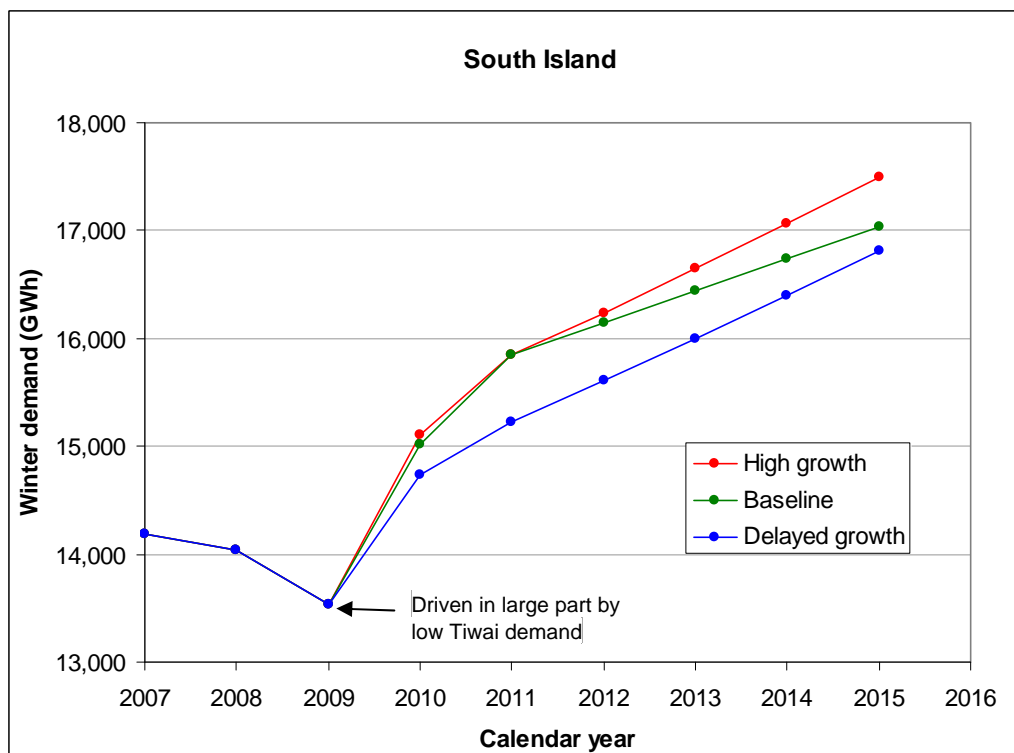
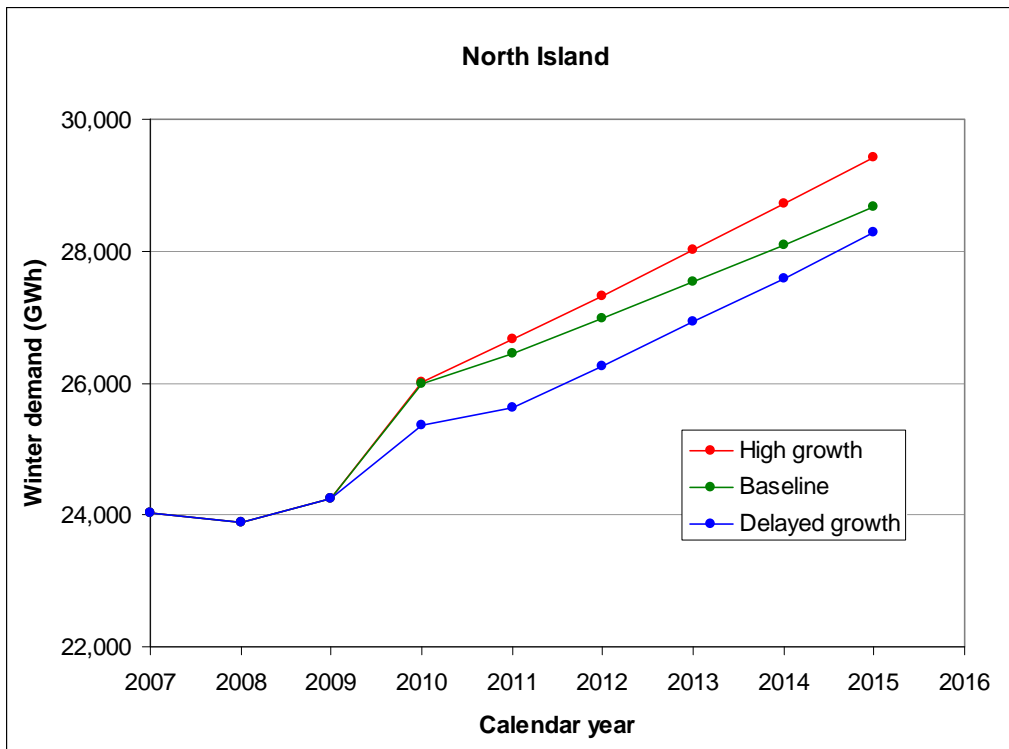
¹⁶ <http://www.electricitycommission.govt.nz/pdfs/opdev/secsupply/pdfsconsultation/Winter-Review-Report.pdf>

¹⁷ See, for instance, <http://www.niwa.co.nz/our-science/energy/publications/all/csu/2006-14/climate>.

¹⁸ The baseline assumption of a 20% capacity factor for wind was based on stochastic modelling, and was part of the work done in the development of the capacity standard. It accounted for hourly distributions of wind output across sites. The conclusion of the analysis was that a 100 MW wind farm provides peaking capacity equal in value to a 20 MW fast-start peaking plant.

Scenario	Affects energy	Affects technical capacity	Affects market capacity	Rationale	Assumptions made
No Pole 1 at peak times	N	Y (2010-2011)	Y (2010-2011)	This scenario explores the impact of complete unavailability of HVDC Pole 1 on the ability to meet North Island peak demand in 2010 and 2011. From 2012 onwards it is assumed that Pole 3 will be available.	South Island contribution to the Winter Capacity Margin is capped at 400 MW in 2010 and 2011.
Poor unit commitment	N	N	Y	When some slow-start plants are not committed at peak times, market capacity is less than technical capacity. See 3.4.1.	200 MW is subtracted from the Winter Capacity Margin in all years.
Poor unit commitment <i>and</i> delay Stratford	N	N	Y	As above.	As per 'Poor unit commitment', and Stratford is not available for the winter of 2010.
Poor unit commitment <i>and</i> limited wind	N	N	Y	As above. One of the factors that makes unit commitment decisions difficult is the unpredictability of wind generation output. (At this stage, though, the unpredictability of demand is probably more significant.)	As per 'Poor unit commitment', and wind makes only 10% contribution to capacity margins.

Figure 1: Comparison of demand forecasts between baseline and sensitivities



Note: demand is measured according to the definition in Appendix 3.1.1. 2007 and 2008 figures are actuals, 2009 figures are extrapolated from actual year-to-date.

5. Energy margin assessment

5.1 Methodology

5.1.1 The assessment of energy margins follows the methodology set out in the Security of Supply Policy. There are two key measures:

- (a) the New Zealand Winter Energy Margin (NZ-WEM), defined in Table 3 and summarised as $\left(\frac{\text{expected NZ winter supply capability}}{\text{expected NZ winter demand}} - 1 \right) \times 100\%$; and
- (b) the South Island Winter Energy Margin (SI-WEM), defined in Table 4 and summarised as $\left(\frac{\text{expected SI winter supply capability} + \text{southward DC transfers}}{\text{expected SI winter demand}} - 1 \right) \times 100\%$.

Table 3: Calculating the New Zealand Winter Energy Margin (NZ-WEM)

	Component	Description
[Expected Supply Capability (GWh)]	=	<i>Thermal GWh</i>
	+	<i>Wind GWh</i>
	+	<i>Base-load GWh</i>
	+	<i>Mean Hydro GWh</i>
Divided by Expected Demand (GWh)		Expected winter demand, allowing for the normal demand response to periods of high spot prices (excluding any response due to savings campaigns or forced rationing).
- 1] x 100% = Energy Supply Margin (%)		

Table 4: Calculating the South Island Winter Energy Margin (SI-WEM)

	Component	Description
[Expected Supply Capability (GWh)]	= <i>HVDC GWh</i>	Expected winter (1 April to 30 September) HVDC transfers received in the South Island.
	+ <i>Wind GWh</i>	Expected winter (1 April to 30 September) wind generation based on long-run average supply.
	+ <i>Mean Hydro GWh</i>	Expected winter (1 April to 30 September) hydro generation based on mean inflows and including expected 1 April start storage of 2,400 GWh.
Divided by Expected Demand (GWh)		Expected winter demand, allowing for the normal demand response to periods of high spot prices (excluding any response due to savings campaigns or forced rationing).
- 1] x 100% = Energy Supply Margin (%)		

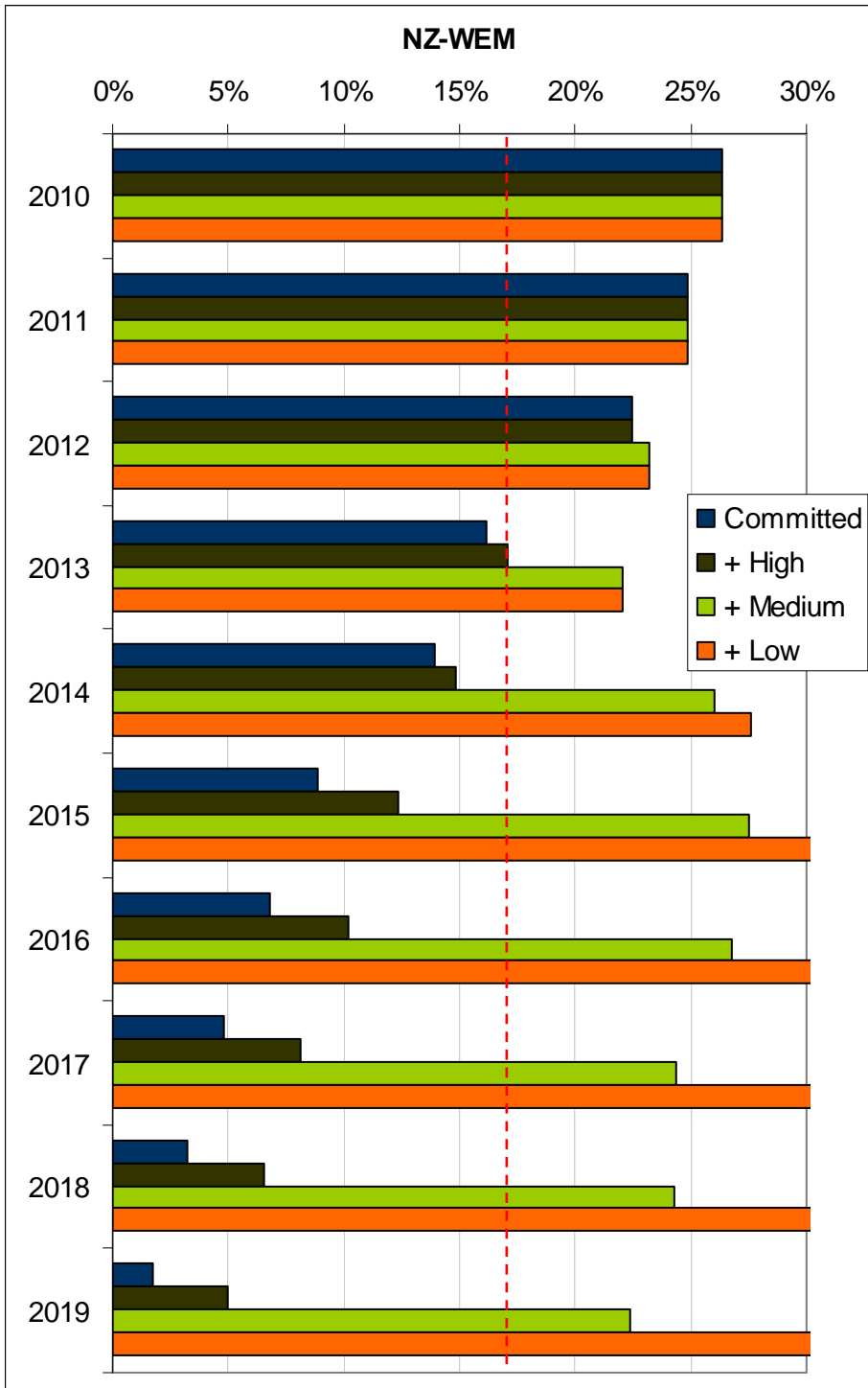
- 5.1.2 The Security of Supply Policy specifies that the Commission will consider the procurement of Reserve Energy if, within a period of three years from the time of the assessment,
- (a) NZ-WEM is forecast to fall below 17%; or
 - (b) SI-WEM is forecast to fall below 30%.
- 5.1.3 A detailed explanation of the basis for Winter Energy Margin calculations and the 17% and 30% thresholds can be found in the Review of the Reserve Energy Policy.¹⁹

5.2 Energy margin results

- 5.2.1 This section summarises the projected Winter Energy Margins, based on the input assumptions that are summarised in Section 4 and described in more detail in Appendix 2 and Appendix 3.
- 5.2.2 Projections of NZ-WEM and SI-WEM under the baseline scenario are shown in Figure 2 and Figure 3.
- 5.2.3 Sensitivity results are presented for the four “critical years” of 2010, 2011, 2013 and 2015, in Figure 4 through Figure 11.

¹⁹ <http://www.electricitycommission.govt.nz/consultation/reserveenergypolicy07>

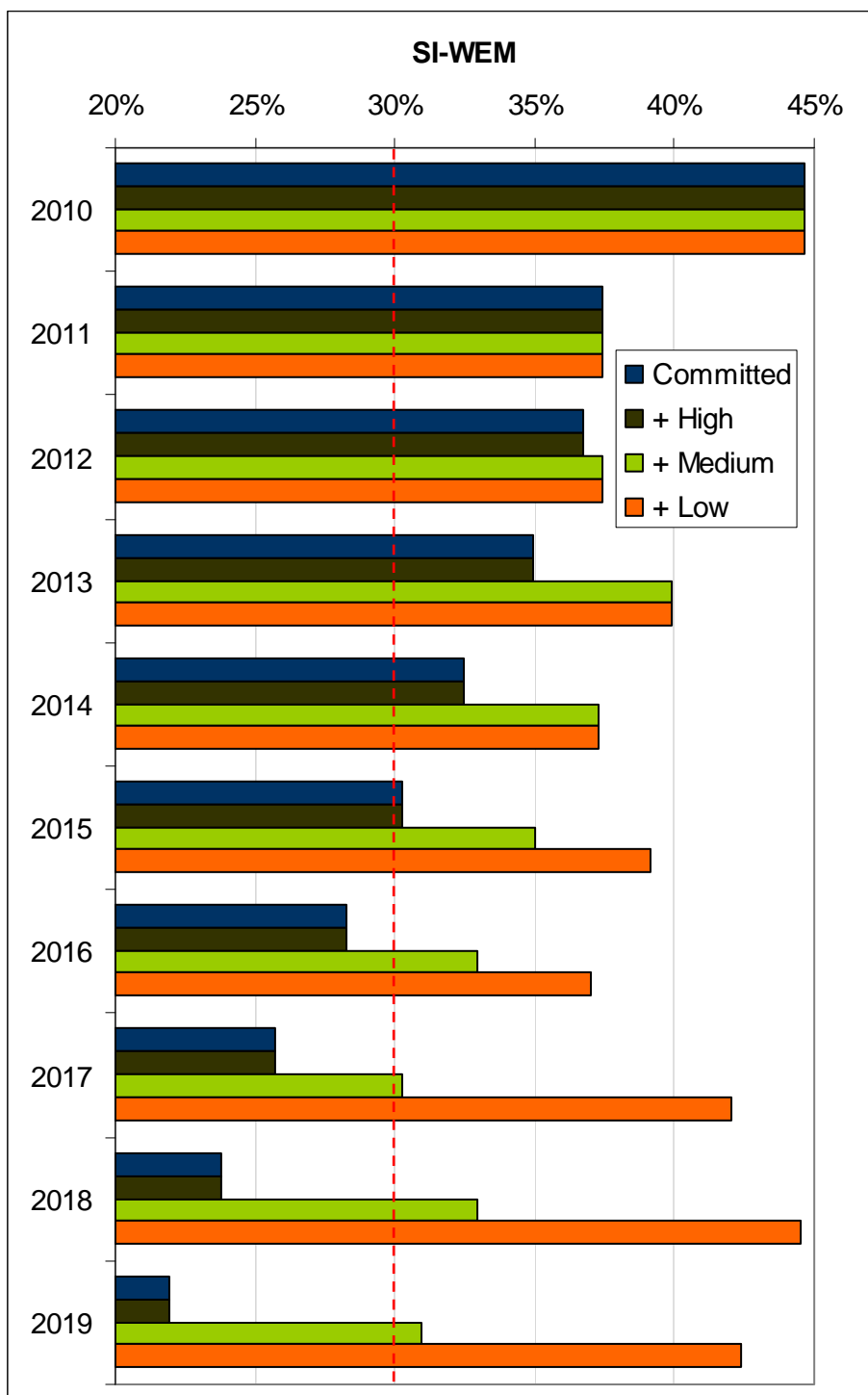
Figure 2: Base-case projections of New Zealand Winter Energy Margins (NZ-WEM)



(Red dashes indicate 17% security threshold.

The Security of Supply Policy sets out that the Commission will consider procuring Reserve Energy if NZ-WEM is projected to fall below 17% within three years of the assessment.)

Figure 3: Base-case projections of South Island Winter Energy Margins (SI-WEM)



(Red dashes indicate 30% security threshold.

The Security of Supply Policy sets out that the Commission will consider procuring Reserve Energy if SI-WEM is projected to fall below 30% within three years of the assessment.)

5.2.4 Under the base case:

- (a) with committed generation only, NZ-WEM and SI-WEM are projected to be well above the security threshold over 2010-2012;
- (b) “medium probability” or equivalent generation will be required to keep energy margins over security thresholds from 2013 onwards; and
- (c) with committed, “high probability” and “medium probability” generation, NZ-WEM and SI-WEM are projected to be above the security threshold over the ten-year horizon.

5.2.5 Key sensitivity results are that:

- (a) even in the more conservative sensitivity scenarios, NZ-WEM and SI-WEM are still projected to be well above the security threshold in 2010-2012 (the horizon for considering reserve energy procurement);
- (b) for 2013 and 2015, there are several possible factors which could lead to poor dry-year security. These include:
 - (i) high demand growth;
 - (ii) lack of demand response in dry years; and
 - (iii) low inflows;
- (c) for all sensitivity scenarios in all years, energy margins can be held above the security thresholds *if* sufficient new generation is built and operated.

5.2.6 In interpreting these results, it is useful to look at energy margins from recent years. Over the last decade, if NZ-WEM had been assessed on an annual basis, it would have consistently been above 25%. Specifically, NZ-WEM would have been assessed to be:

- (a) over 30% between 1997 and 2002 (contributing to the effective management of the 2001 dry winter);
- (b) dipping towards 25% between 2003 and 2006;
- (c) over 30% for 2007, reflecting the impending commissioning of Huntly e3p;
- (d) dipping towards 25% for 2008, if the reduced availability of New Plymouth Power Station was known in advance.

5.2.7 Projections of NZ-WEM for 2010 and 2011 are, therefore, similar to those experienced in some recent years. The baseline projections for 2012 and 2013 are tighter, while remaining above the security threshold.

Figure 4: Sensitivity projections of NZ-WEM - for 2010

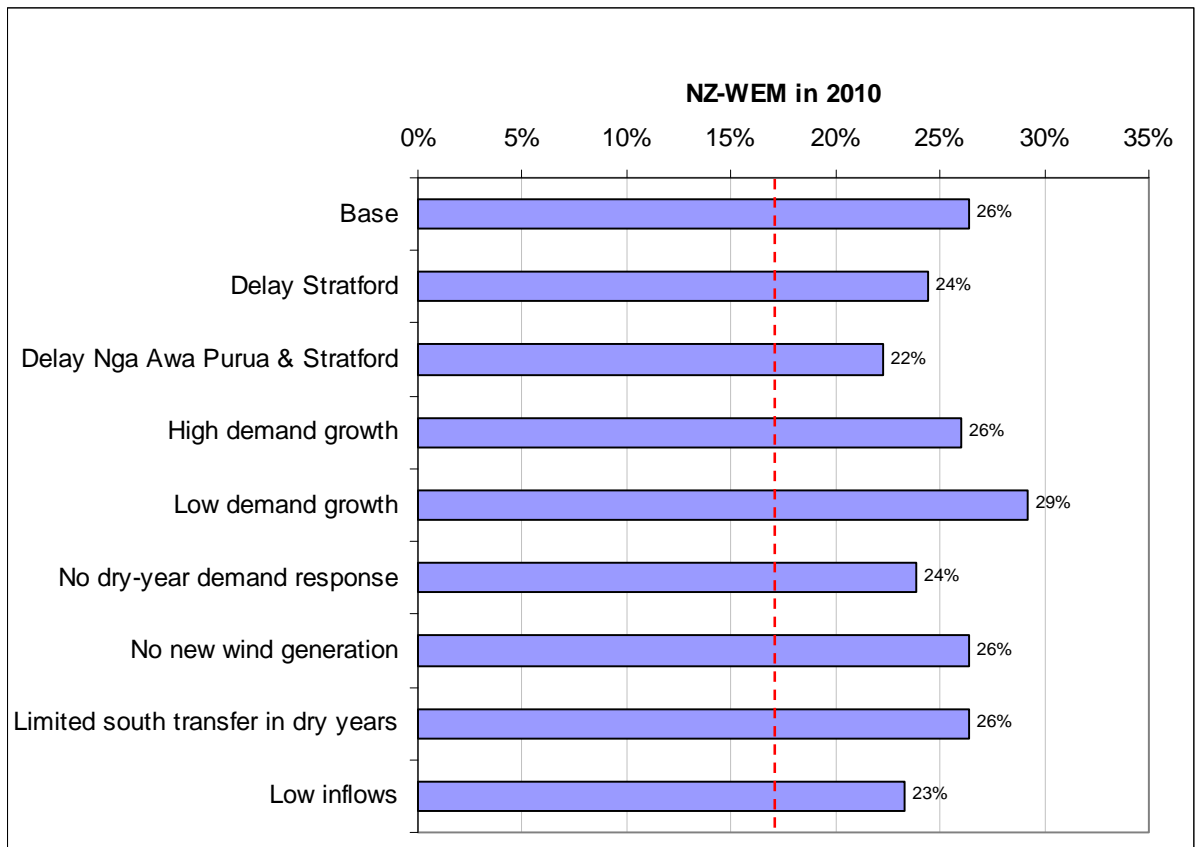


Figure 5: Sensitivity projections of SI-WEM - for 2010

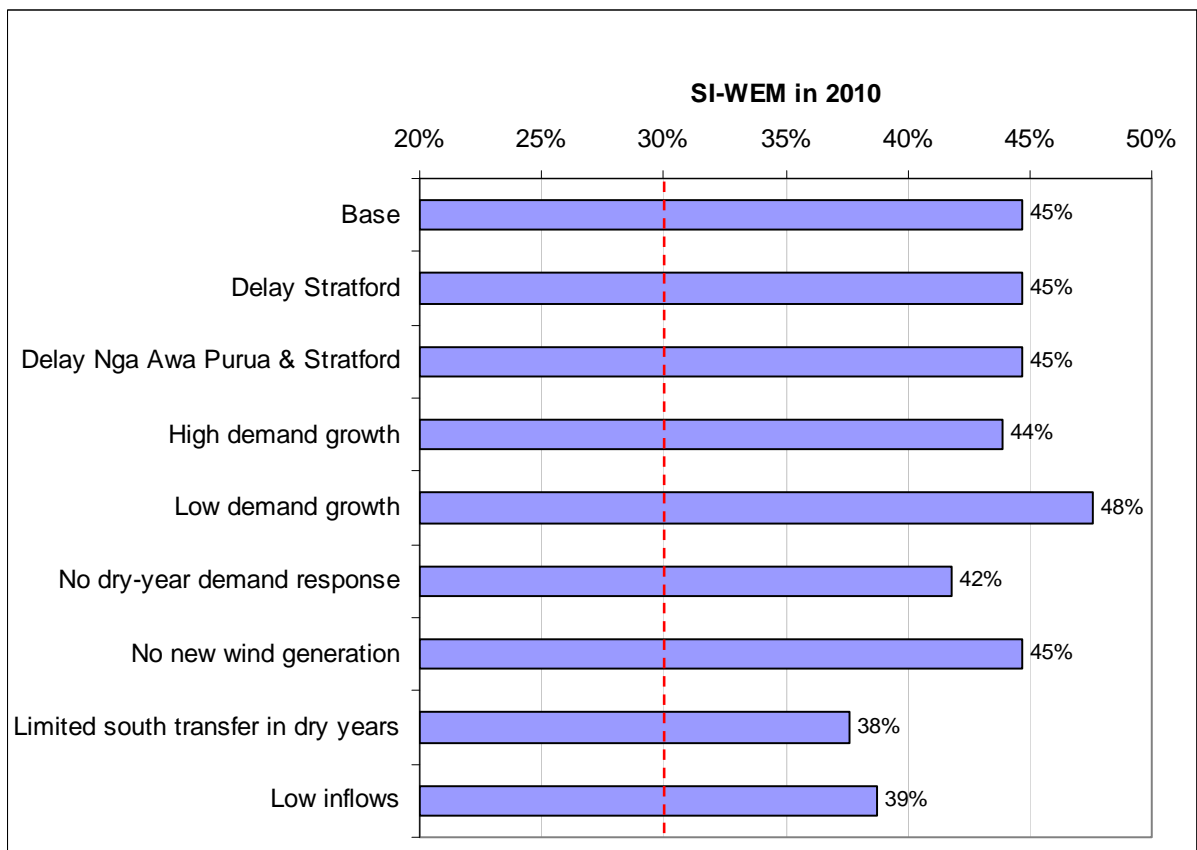


Figure 6: Sensitivity projections of NZ-WEM - for 2011

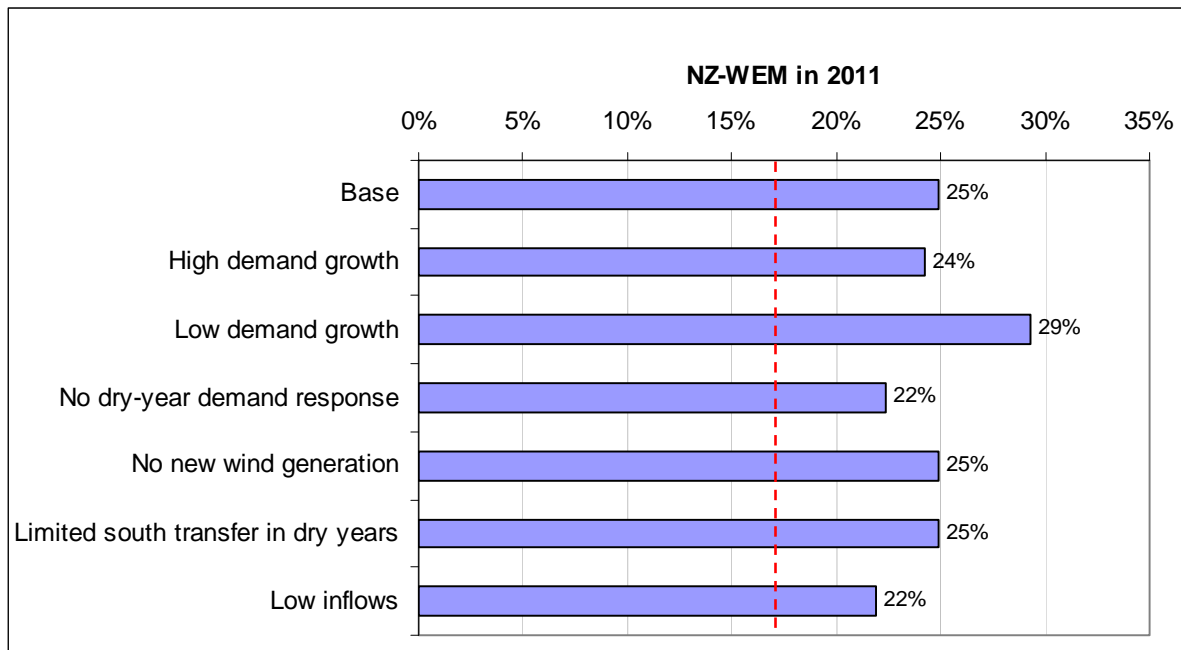


Figure 7: Sensitivity projections of SI-WEM - for 2011

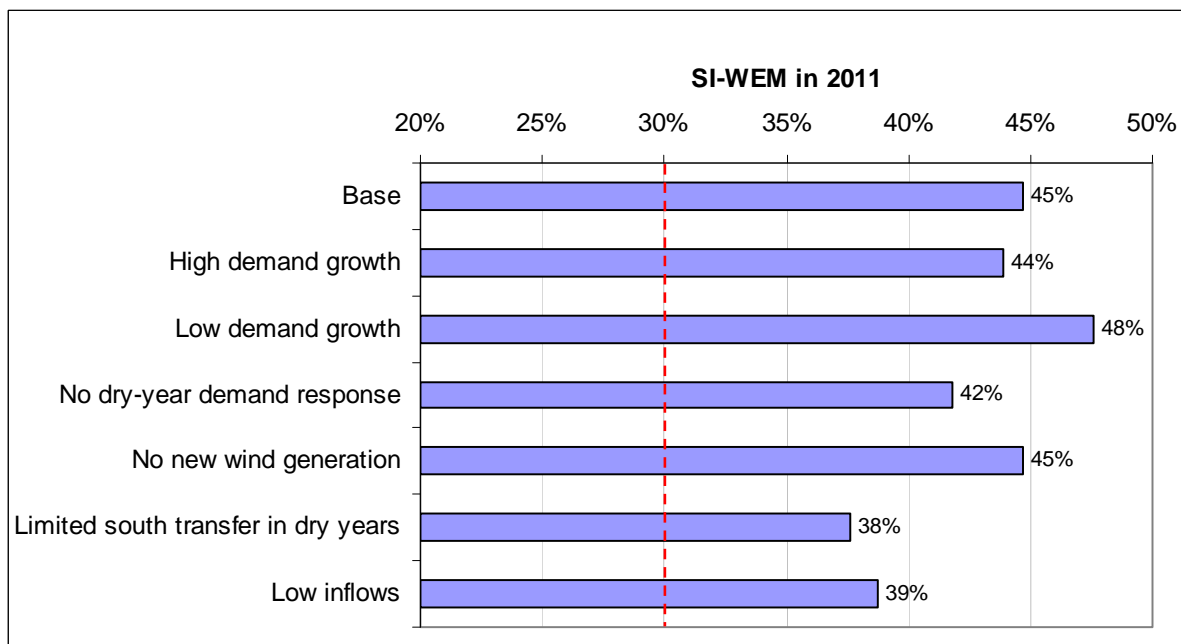


Figure 8: Sensitivity projections of NZ-WEM - for 2013

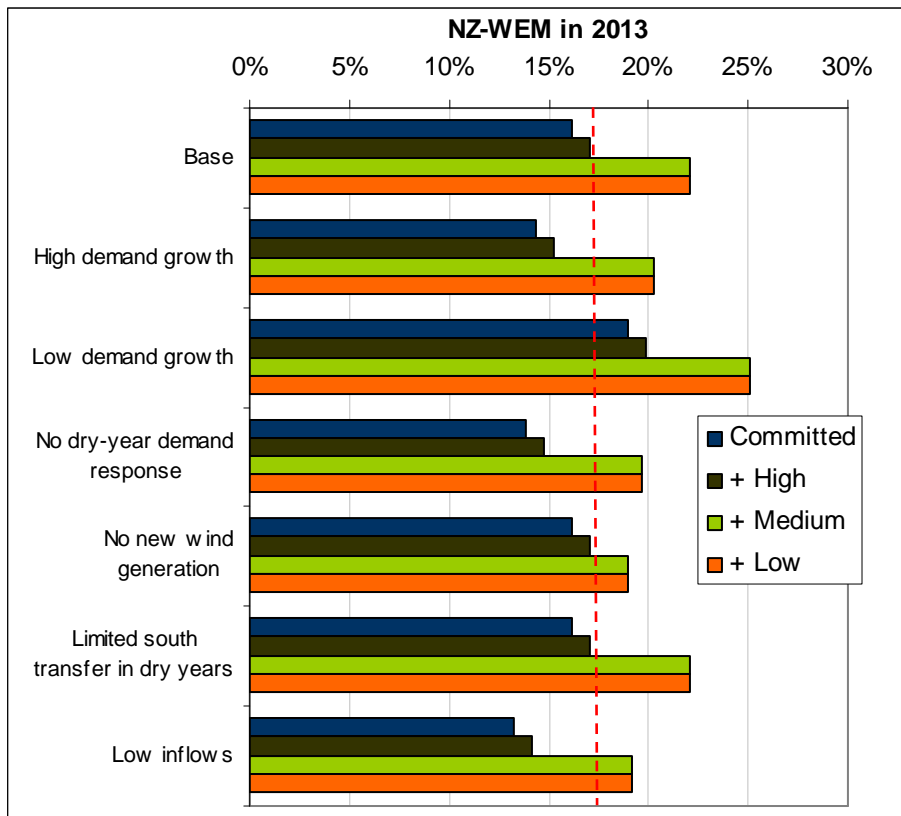


Figure 9: Sensitivity projections of SI-WEM - for 2013

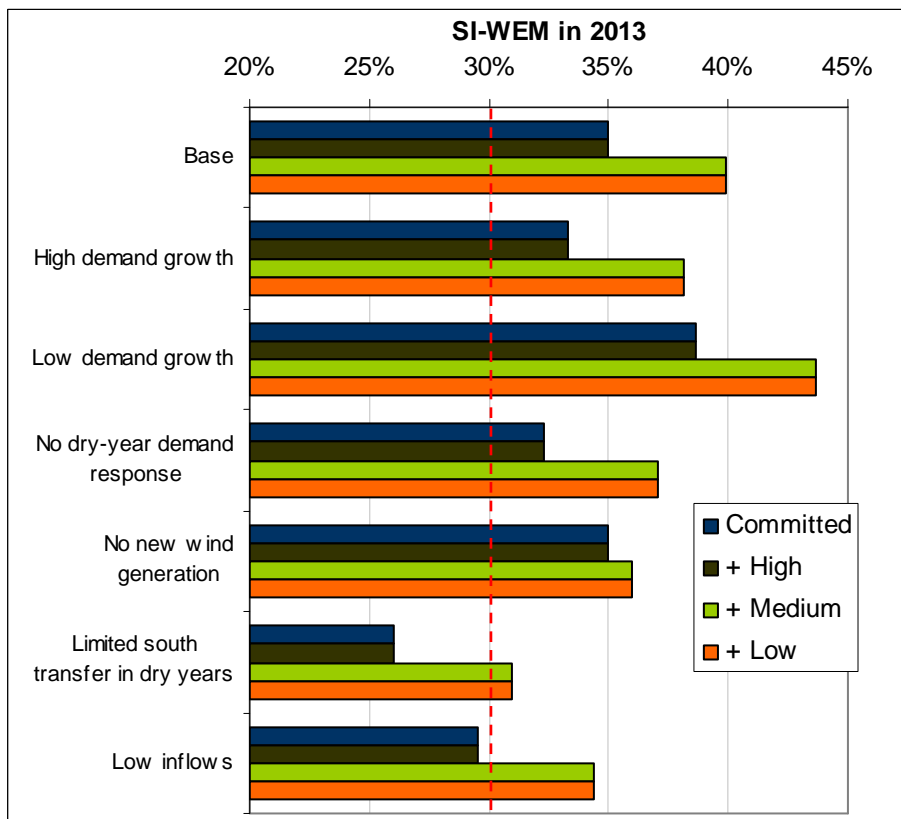


Figure 10: Sensitivity projections of NZ-WEM - for 2015

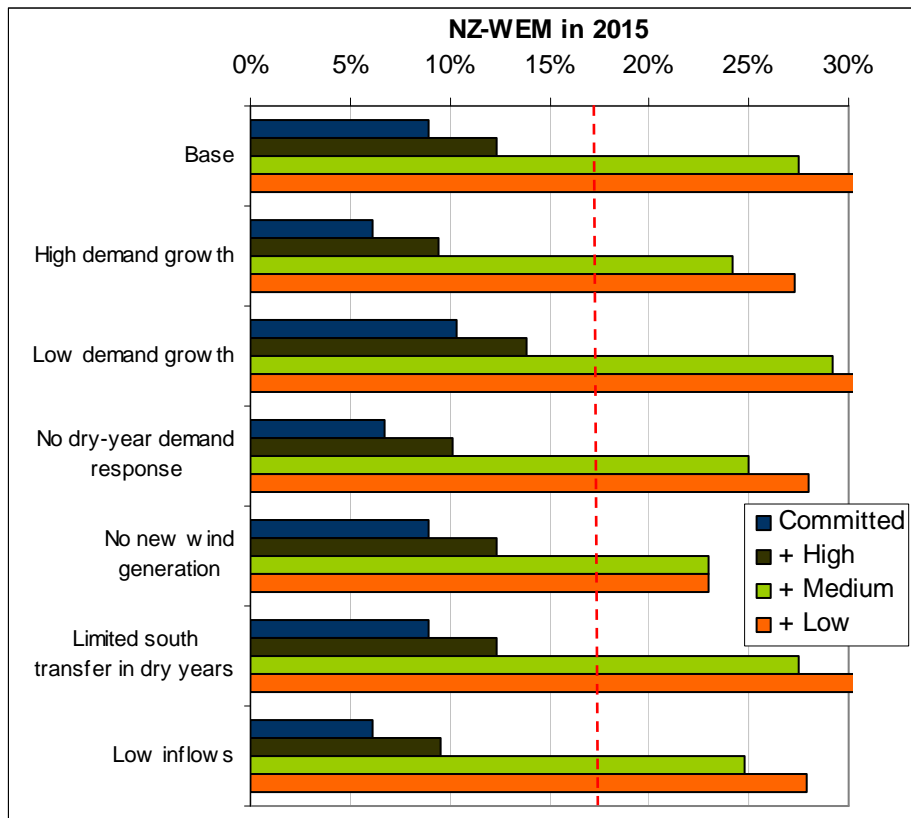
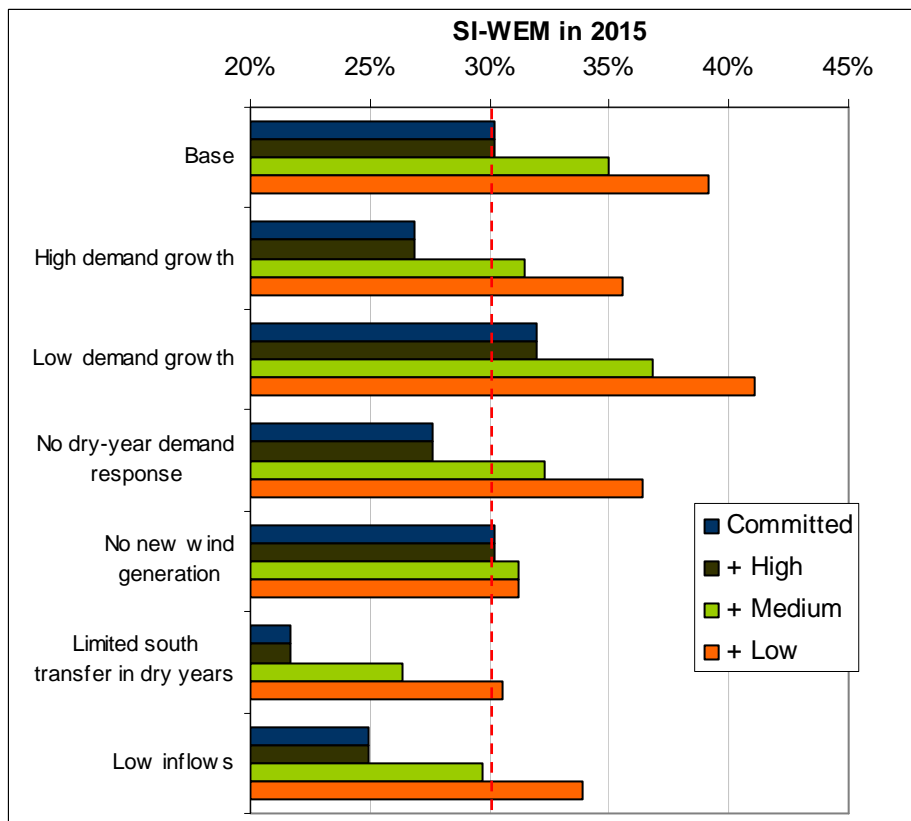


Figure 11: Sensitivity projections of SI-WEM - for 2015



6. Capacity margin assessment

6.1 Methodology

6.1.1 The assessment of capacity margins follows the methodology set out in the Security of Supply Policy. There is a single key measure: the North Island Winter Capacity Margin (WCM), defined in Table 5 and summarised as

$$(\text{North Island supply capability} + \text{northward DC transfers}) - \text{high North Island demand}.$$

Table 5: Calculating the North Island Winter Capacity Margin (WCM)

	Component	Description
Expected NI Supply Capacity (MW)	= NI Thermal MW	Installed capacity of North Island thermal generation sources allowing for forced and scheduled outages.
	+ NI Wind MW	20% of North Island wind capacity.
	+ NI Base-load MW	Expected winter daytime (1 April – 31 October between 7am and 10pm) generation available from North Island geothermal plants, the aggregate of all North Island cogeneration plants, and the aggregate of all North Island uncontrolled hydro schemes.
	+ NI Demand Response and Interruptible Load MW	Expected demand response and interruptible load over the highest 200 half hours of winter demand (1 April – 31 October between 7am and 10pm).
	+ NI Hydro MW	Installed capacity of North Island controllable hydro schemes allowing for forced and scheduled outages and derated to account for energy and other constraints which affect output during peak times.
	+ South Island MW	The effective contribution of South Island capacity to North Island demand accounting for factors such as transmission limits and South Island demand.
Less Expected NI H200 Demand (MW)		Expected average of top 200 trading period demands, plus losses.
= NI Capacity Margin (MW)		

6.1.2 The Security of Supply Policy specifies that the Commission will consider the procurement of Reserve Capacity if, within a period of two years from the time of the assessment, WCM is forecast to fall below 780 MW.

6.1.3 A detailed explanation of the basis for WCM calculations and the 780 MW threshold can be found in the "Development of a Capacity Adequacy Standard" paper.²⁰

6.2 Capacity margin results

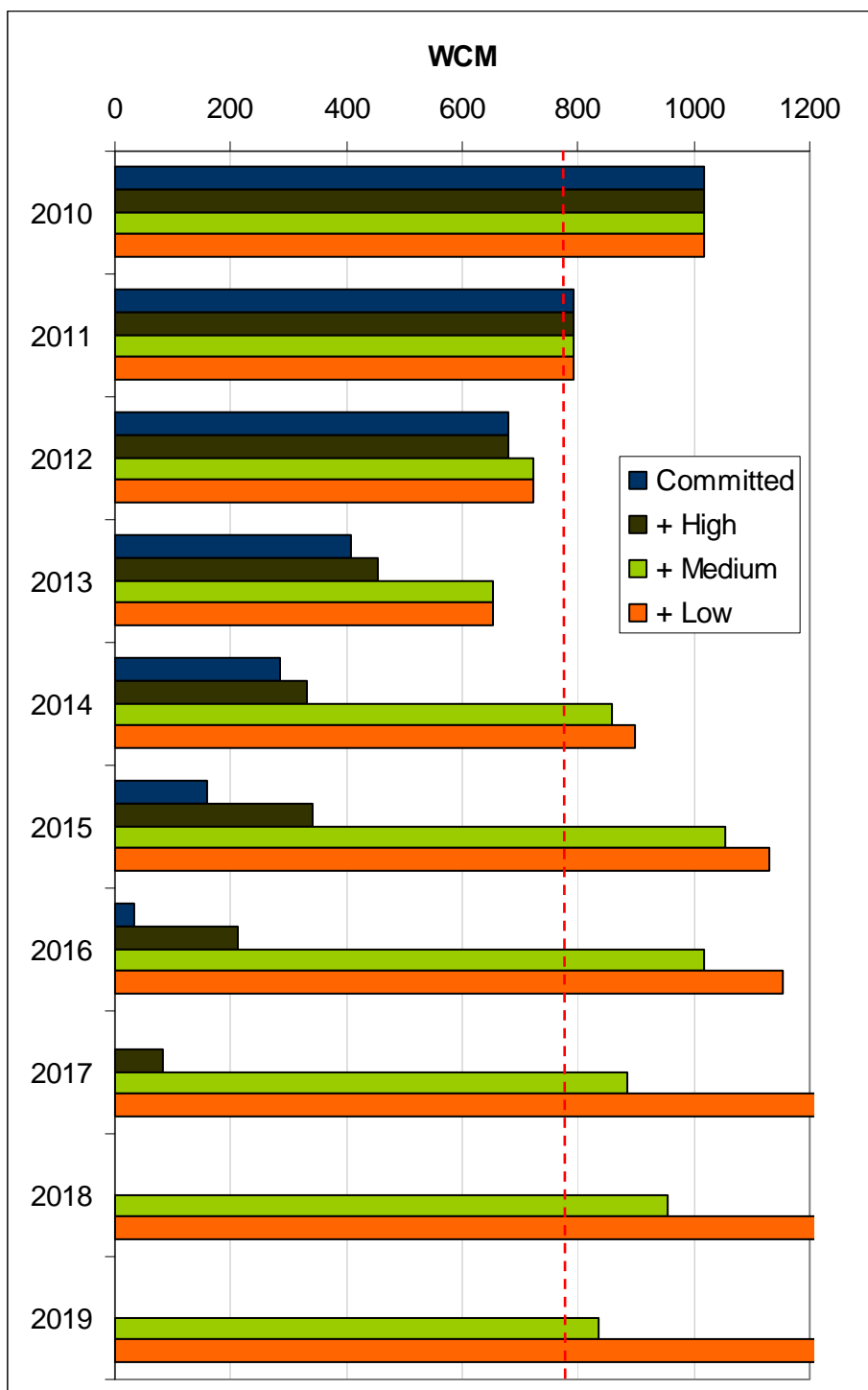
6.2.1 This section summarises the projected Winter Capacity Margins, based on the input assumptions that are summarised in Section 4 and described in more detail in Appendix 2 and Appendix 3.

6.2.2 Projections of WCM under the baseline scenario are shown in Figure 12.

6.2.3 Sensitivity results are presented for the four "critical years" of 2010, 2011, 2013 and 2015, in Figure 13 through Figure 16.

²⁰ <http://www.electricitycommission.govt.nz/pdfs/opdev/secsupply/policy/capacity-adequacy-standard.pdf>

Figure 12: Base-case projections of Winter Capacity Margins (WCM)



(Red dashes indicate 780 MW security threshold.

The Security of Supply Policy sets out that the Commission will consider procuring Reserve Capacity if WCM is projected to fall below 780 MW within two years of the assessment.)

Figure 13: Sensitivity projections of WCM - for 2010

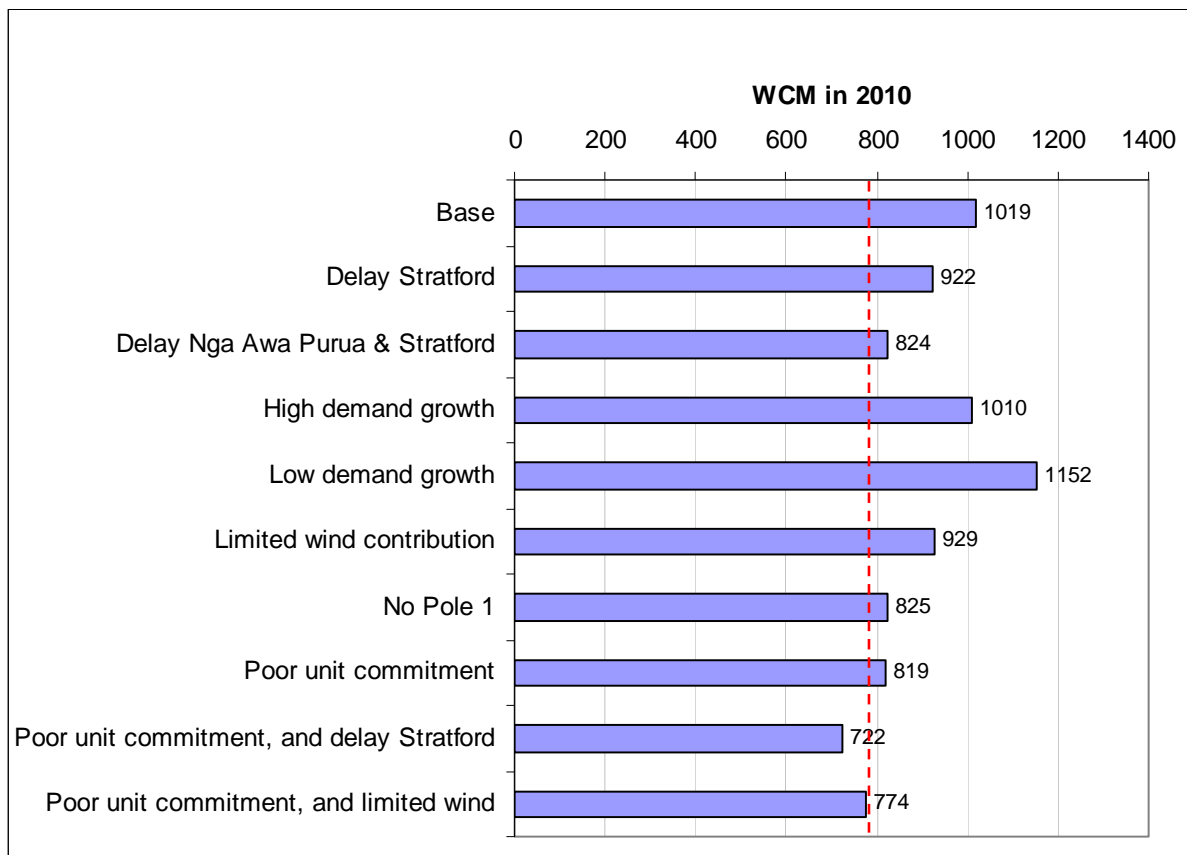


Figure 14: Sensitivity projections of WCM - for 2011

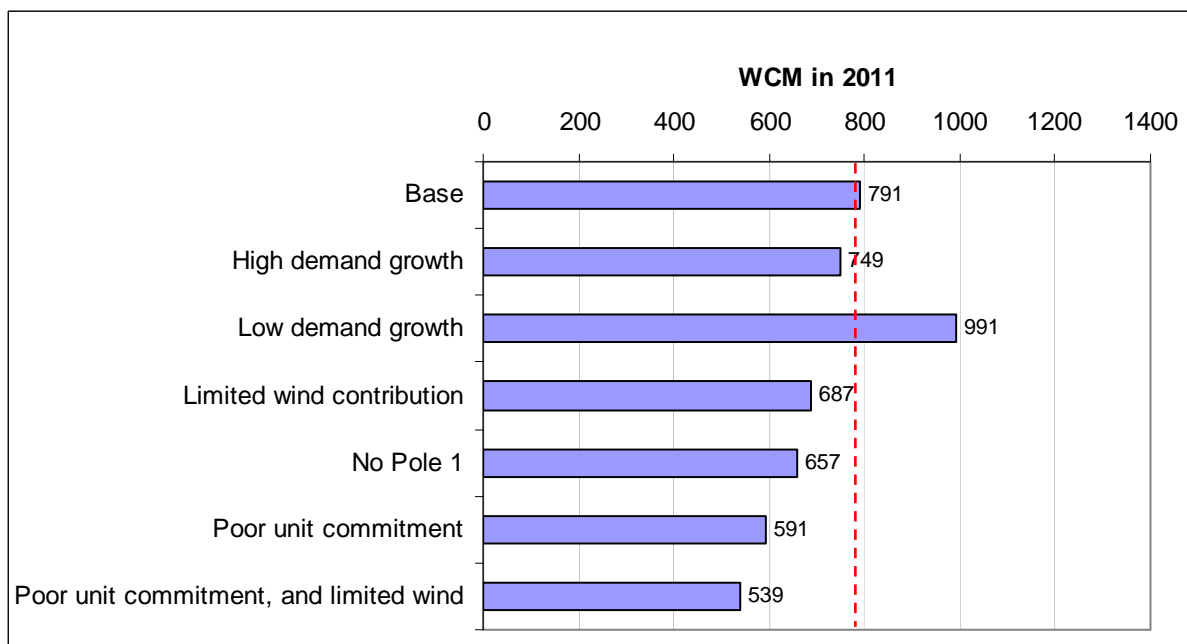


Figure 15: Sensitivity projections of WCM - for 2013

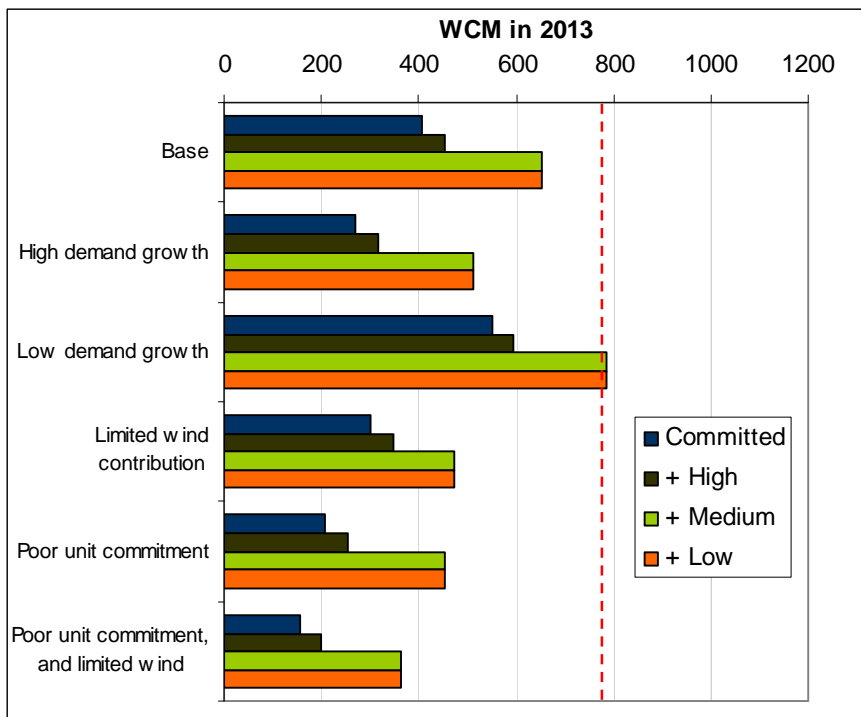
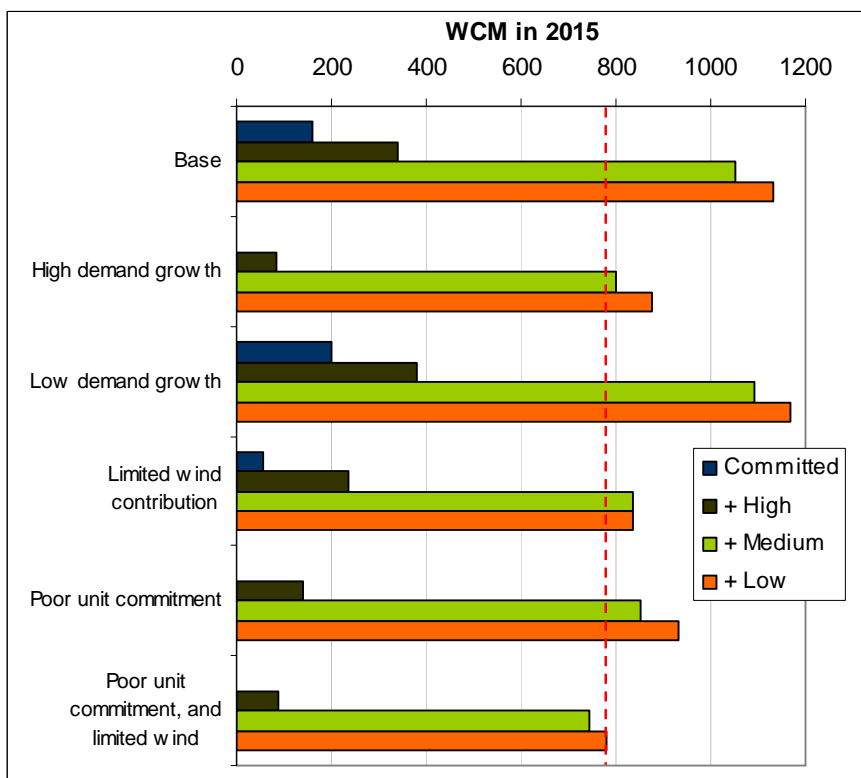


Figure 16: Sensitivity projections of WCM - for 2015



Results – technical capacity

6.2.4 Under the base case:

- (a) with committed generation only, the technical capacity margin (WCM) is projected to be well above the security threshold in 2010;
- (b) even with all committed, “high, medium and low probability” generation, capacity margins are projected to fall close to the security threshold in 2011, and below it in 2012 and 2013; and
- (c) in later years, capacity margins are projected to be above security thresholds, provided all committed, “high and medium probability” generation (or equivalent) is available.

6.2.5 Key sensitivity results are that:

- (a) technical capacity margins are projected to be above the security threshold in 2010 in all sensitivity scenarios;
- (b) in 2011 and 2012, a combination of high demand growth and/or Pole 1 unavailability could lead to unacceptably low technical capacity margins; and
- (c) for 2013, technical capacity margins are below the security threshold in all sensitivity scenarios except “low demand growth” – even if all committed, “high, medium and low probability” generation becomes available.

Results – market capacity

6.2.6 The issue of market capacity is introduced in Appendix 4. Market capacity margins are assessed in the “poor unit commitment” sensitivity scenarios.

6.2.7 In the basic “poor unit commitment” scenario, the projected WCM for 2010 is just 820 MW. With reduced wind capacity factor and/or delayed commissioning of Contact’s Stratford peaker²¹, the projected WCM falls below the security threshold.

6.2.8 Projected WCMs in 2011-2013 under the “poor unit commitment” scenarios are well below the security threshold.

6.2.9 Unavailability of slow-start generation at peak times has the potential to have a very significant impact on security of supply.

²¹ i.e. neither of the two 100 MW units available for winter 2010.

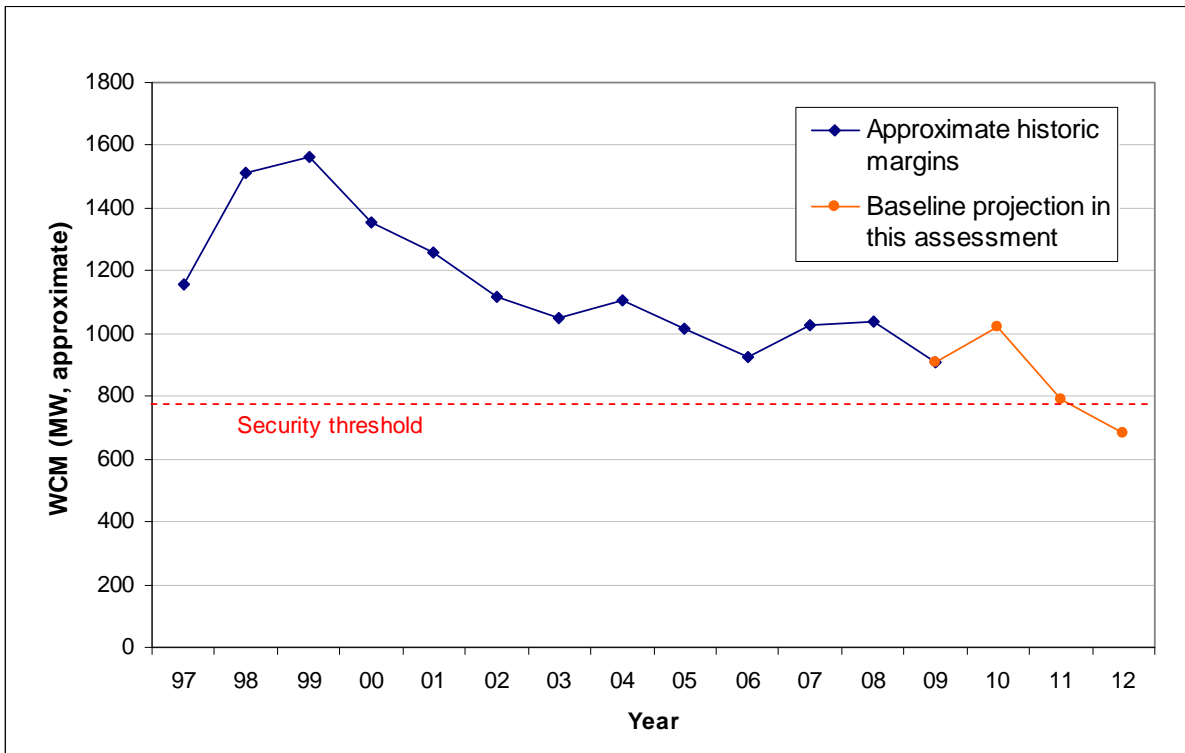
6.3 Capacity margins – context

Comparison of projected capacity margins with recent history

- 6.3.1 Historically, peaking capacity has not received much attention because of the high proportion of hydro capacity with associated flexible "fuel" supply. New Zealand has 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".
- 6.3.2 In recent times, the retirement of New Plymouth Power Station, the growth in peak demand, the limited availability of HVDC Pole 1 and the addition of intermittent generation in the form of wind farms have eroded capacity margins.²²
- 6.3.3 The 2008 assessment included projections of WCM. The baseline projections, including existing, committed and "highly likely" generation, were:
- (a) 910 MW in 2009 (threshold + 130 MW);
 - (b) 1,095 MW in 2010 (threshold + 315 MW);
 - (c) 1,080 MW in 2011 (threshold + 300 MW); and
 - (d) 1,190 MW in 2012 (threshold + 410 MW).
- 6.3.4 The projection for 2009 turned out to be conservative, as it did not take into account the demand reduction at the Tiwai smelter.
- 6.3.5 The new baseline projection of WCM for 2010 is similar to that in the previous assessment. However, the new baseline is 290 MW lower for 2011, and 510 MW lower for 2012, compared to the previous assessment. (These are projections of *physical* capacity, and are not driven by assumptions about unit commitment.)
- 6.3.6 Figure 17 attempts to put the projections in this assessment in the context of recent history. Please note that the plotted data is *approximate* and should be treated with caution. WCMs were not calculated prior to 2008, and cannot be reconstructed with certainty for earlier years. The difficulty lies in determining the forecasts of supply and demand that would have been used if capacity assessments had been carried out in the past. Recall that WCM and WEM are *forward-looking* measures, based on forecasts of supply and demand, rather than being based on actual observations of supply and demand during winter.

²² On the other hand, the construction of some thermal peaking plant (Whirinaki, Huntly p40, Southdown E105) has helped to bolster peaking capacity – as will Contact's Stratford peaker.

Figure 17: Historic and projected WCMs



6.3.7 The technical capacity margin projected for 2010 is similar to recent years, but the projection for 2011 is lower than in recent years, and the projection for 2012 is significantly lower than New Zealand has experienced in the last quarter-century.

6.3.8 It should be noted that the historical margins plotted in Figure 17 are an attempt to model the projections that would have been made if capacity assessments had been carried out a year in advance. For example, the cold weather experienced during winter 2006 (and consequent high demand) is not factored into the projections because it would not have been expected in advance.

Consequences of low capacity margins

6.3.9 The approach used to develop the 780 MW capacity standard²³ involved the use of simulation modelling to capture a large range of supply and demand scenarios so as to understand the implications of the system having more or less capacity. This work was carried out and consulted on in 2008. The chronological simulation model used in the development of the standard has been rerun, to assess the consequences of low capacity margins.

²³ <http://www.electricitycommission.govt.nz/pdfs/opdev/secsupply/policy/capacity-adequacy-standard.pdf>

- 6.3.10 Note that these results are a probability-weighted average of many possible outcomes. In practice, the consequences might be nil (in a mild winter with generation and transmission assets performing reliably) or many times worse than indicated (in a severe winter with simultaneous extended outages of major assets).
- 6.3.11 The “Poor unit commitment” sensitivity projects a WCM of 820 MW for 2010 (40 MW above the security threshold). The simulation model indicates that, in this scenario, there would be an expected 8 hours during 2010 in which instantaneous reserve cover was not maintained. Reduced RAF events could occur at any time of year, but would be most likely to occur during the May-September period.
- 6.3.12 For comparison, in winter 2009, RAFs were reduced for a total of approximately 10 hours.
- 6.3.13 The “Poor unit commitment *and* delay Stratford” sensitivity projects a WCM of 720 MW for 2010 (60 MW below the security threshold). The simulation model indicates that, in this scenario, there would be an expected 20 hours during 2010 in which instantaneous reserve cover was not maintained. Very occasionally, it would still be impossible to match supply to demand, and there would be a need for pre-emptive load shedding.
- 6.3.14 During periods of reduced RAFs, system security is compromised. The power system may not be able to manage a contingent event, such as the loss of an HVDC pole or single large generating unit, without triggering AUFLS (automatic under-frequency load shedding). If sufficient time is spent without adequate instantaneous reserve cover, then eventually AUFLS will be triggered. Avoiding this situation should be a high priority.

7. Conclusions

7.1 Need for additional (dry-year) energy

7.1.1 The Security of Supply Policy sets out that the Commission will consider the procurement of Reserve Energy if, within a period of three years from a time of an assessment:

- (a) NZ-WEM is forecast to fall below 17% for New Zealand; or
- (b) SI-WEM is forecast to fall below 30%.

7.1.2 In the base case and all sensitivity scenarios considered, the energy margins are projected to be above the security thresholds in 2010.

7.1.3 Energy margins are also projected to be above security thresholds in 2011 and 2012 – even if only committed generation projects proceed.

7.1.4 On the basis of these results, there is no need for the Commission to procure Reserve Energy for 2010, 2011 or 2012 at this point.

7.1.5 Extended very dry periods and/or multiple asset failures could still lead to energy shortage situations. Under the existing Reserve Energy Scheme framework, the Commission can still procure Reserve Energy on shorter lead times if necessary.

Q3. Do you agree that the criteria for the Commission to procure additional Reserve Energy are not met at this point?

7.2 Need for additional (peaking) capacity

7.2.1 The Security of Supply Policy sets out that the Commission will consider the procurement of Reserve Capacity if, within a period of two years from a time of an assessment, WCM is forecast to fall below 780 MW.

7.2.2 For 2010, *technical* capacity margins are projected to be above the security threshold.

7.2.3 The technical capacity margin projected for 2010 in the base case of this assessment is higher than the capacity margin projected for 2009 in the base case of last year's assessment.

7.2.4 From 2011 onwards, projected capacity margins fall. In the 2011 baseline, the technical capacity margin is projected to be just above the security threshold. It falls below the threshold in sensitivities where demand growth is high and/or HVDC Pole 1 is unavailable.

- 7.2.5 Projected *technical* capacity margins do not indicate a clear need for Commission procurement of Reserve Capacity for 2010 or 2011 at this point. Although the projection for 2011 is tight, the baseline is still above the security threshold. Further, there is still time for the market to provide additional peaking capacity (through investment in generation and/or demand-side resources).
- 7.2.6 However, projected *market* capacity margins are of concern. Unit commitment issues contributed to reduced security during winter 2009. If these problems are not resolved, they have the potential to significantly reduce peak security in 2010 and 2011. In sensitivity scenarios which model poor unit commitment, projected market capacity margins are close to or below the security threshold.
- 7.2.7 It may be possible to achieve better unit commitment outcomes through market-based approaches, which might include:
 - (a) improving price signals at times of capacity scarcity; and/or
 - (b) improving pre-dispatch information about the possibility of high spot prices.
- 7.2.8 The peak security situation for 2010 and 2011 should be regularly reviewed over the coming months, with a focus on:
 - (a) commitment of slow-start plants at peak times;
 - (b) retirement of existing generation;
 - (c) progress of new generation projects;
 - (d) demand growth; and
 - (e) ability of wind to contribute at peak times.
- 7.2.9 If at any point it becomes clear that the market will not deliver adequate peak security, other solutions should be considered.
- 7.2.10 There are also serious concerns about peak security during winter 2012, with capacity margins projected to be below the security threshold in the baseline and most sensitivities. The outlook for 2012 should be reevaluated in 2010.

Q4.	Do you agree that unit commitment issues pose a significant risk to security at peak times in 2010 and 2011?
Q5.	If so, do you have any comment on what market-based measures should be taken to promote unit commitment decisions that support security of supply?
Q6.	Do you agree that the criteria for the Commission to procure additional Reserve Capacity are not met at this point?

7.3 Generation investment

- 7.3.1 Significant generation investment is currently in progress. West Wind, Nga Awa Purua, Stratford and Tauhara will jointly contribute nearly 500 MW of new generation by the end of 2010.
- 7.3.2 However, very little investment has been committed for 2011 and future years. This assessment indicates that a substantial amount of new generation will be needed to maintain security of supply.
- 7.3.3 In particular, a substantial amount of new firm generation will be needed by 2013 in order to maintain WCM above the security threshold.
- 7.3.4 There are various possible build plans that would meet this criterion. One would be to proceed with all committed and “high and medium probability” generation projects scheduled for 2010-2013, plus an additional 200 MW of thermal peaking plant. This build plan would include:
- (a) Contact’s Stratford peaker and an additional 300 MW of thermal generation and cogeneration;
 - (b) Mighty River’s Nga Awa Purua, Contact’s Tauhara binary, and an additional 50 MW of geothermal;
 - (c) NZ Windfarms’ Te Rere Hau expansion, Meridian’s Te Uku, and an additional 400 MW of wind and run-of-river hydro generation.
- 7.3.5 Given the lead time of generation investment, it would be necessary for some of these projects to be committed within the next year. Commitment decisions on thermal peaking plant and wind could be delayed further, providing consented sites were available.
- 7.3.6 It is concerning that many generation projects have been postponed by generators. The amount of generation investment planned for the next three years has declined sharply since the 2008 assessment.

Q7. Do you have any comment on what is required to promote appropriate generation investment?
--

7.4 Other conclusions

- 7.4.1 Other comments follow, in no particular order.
- 7.4.2 This assessment adds weight to the view that New Zealand, formerly seen only as an “energy-constrained system”, is now both energy and capacity constrained. Capacity margins are more likely to bind in the next few years than energy margins. Consequences may include:

- (a) more difficulty in meeting winter peak demand;
- (b) more difficulty in meeting peak demand at other times of year, due to factors such as increasing summer demand, increasing reliance on wind generation, and generation and/or transmission outages;
- (c) more occasions when instantaneous reserves cannot be maintained; and
- (d) a generally “tighter” system.

7.4.3 Retirement of existing generation is likely to have a major influence on security of supply over the next few years. In order for participants to manage their risks, it would be valuable for up-to-date, detailed information on generation retirement plans to be made available. There is currently no requirement on generators to publish this information.

7.4.4 In the next few years, the availability of thermal fuel is expected to be a minor but significant constraint on the ability of generators to respond to an extended energy shortage. This situation is likely to continue indefinitely and there will be a need for continued monitoring of thermal fuel supplies. (This is somewhat analogous to the need for monitoring of water levels in key hydro lakes.)

7.4.5 The ability to transmit large amounts of energy from the North Island to the South Island remains key to dry-year security. Care needs to be taken that the transmission system is capable of doing so. The robustness of the South Island instantaneous reserve market will also be an important factor, especially until HVDC Pole 3 becomes available.

7.4.6 The ability to transmit power from the South Island to the North Island is also key to peak security. The commissioning of Pole 3 will help in this regard.

7.4.7 The amount of transmission upgrade work taking place will increase rapidly over the next few years. In order for this work to be completed, many transmission outages will be required. Careful coordination will be needed, and it will not be possible to carry out all this work at times when the power system is lightly loaded. The effects of these outages should be considered as part of the 2010 annual security assessment.

Q8. Do you have any further comments on the Commission’s conclusions?
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Appendix 1 Format for submissions

Question No.	Question	Response
1	Do you agree that the baseline and sensitivity scenarios presented are appropriate for use in this assessment?	
2	Do you consider that any specific assumptions are incorrect? If so, which and why?	
3	Do you agree that the criteria for the Commission to procure additional Reserve Energy are not met at this point?	
4	Do you agree that unit commitment issues pose a significant risk to security at peak times in 2010 and 2011?	
5	If so, do you have any comment on what measures should be taken to promote unit commitment decisions that support security of supply?	
6	Do you agree that the criteria for the Commission to procure additional Reserve Capacity are not met at this point?	
7	Do you have any comment on what is required to promote appropriate generation investment decisions?	
8.	Do you have any further comments on the Commission's conclusions?	

Appendix 2 Detailed supply assumptions in the baseline scenario

2.1 Introduction

- 2.1.1 This Appendix sets out key supply assumptions used in the energy and capacity margin assessments.
- 2.1.2 The focus is on grid-connected generation. As discussed in Appendix 3, most embedded generation has already been netted off the demand forecasts used for this assessment, and should not be modelled on the supply side.
- 2.1.3 For convenience, this Appendix is set out under the same headings as Appendix 1 of the Annual Security Assessment 2008.
- 2.1.4 Assumptions about existing generation have not changed since the 2008 assessment, except where specifically noted.

2.2 Existing supply

- 2.2.1 Table 6 and Table 7 summarise assumed existing supply, including contribution to the Winter Energy Margin and Winter Capacity Margin defined in Sections 5 and 6.
- 2.2.2 The changes to assumptions since the 2008 assessment are that:
 - (a) Kawerau's capacity has been changed to 100 MW (was 90 MW);
 - (b) Several small South Island hydro schemes have been removed. These schemes are embedded and should not have been modelled on the supply side since they are already netted off the forecast demand;
 - (c) The peak contribution of Contact's Clutha generation has been reduced to 666 MW (was 706 MW); and
 - (d) Project West Wind has been added as an 'existing' plant.
- 2.2.3 There are also some changes to the projected availability of some major existing generation plants. These changes have been incorporated in the assessment, but are not included in the tables (because they were provided under confidence).
- 2.2.4 Note that Glenbrook, Highbank, Aniwhenua and Waipori are specifically not included (because they, too, are already netted off the forecast demand). Whareroa and Te Rapa are *not* netted off the forecast demand and are included on the supply side.
- 2.2.5 The 2008 assessment provides more detail on the calculation of energy and capacity margin contributions for each type of plant.

Table 6: Existing North Island supply

Scheme	Type	MW	Assumed contribution to energy margins (potential GWh over Apr-Sep)	Assumed contribution to capacity margins (MW)
Otahuhu B	Thermal	390	1657	378
Taranaki CC	Thermal	380	1614	369
Huntly 1-4	Thermal	243 per unit	922 per unit	233 per unit
Whirinaki	Thermal	155	659	150
Huntly U5 (e3p)	Thermal	385	1636	373
Huntly U6 (P40)	Thermal	50	212	49
Southdown	Thermal	175	744	170
Kaponga	Cogen	20	73	90 combined
Kinleith	Cogen	41	133	
Whareroa	Cogen	54	127	
Te Rapa	Cogen	49	90	
Tararua 1-3	Wind	161	303	32
Te Apiti	Wind	91	179	18
West Wind	Wind	143	269	29
Mokai	Geothermal	110	395	464 combined
Ohaaki	Geothermal	65	158	
Poihipi	Geothermal	53	100	
Wairakei	Geothermal	163	650	
Wairakei binary	Geothermal	14	59	
Kawerau	Geothermal	100	394	
Ngawha II	Geothermal	15	62	
Waikato	Hydro	1063	2311 + April storage	983
Waikaremoana	Hydro	141	306 + April storage	138
Tokaanu/Rangipo	Hydro	360	700 + April storage	340 combined
Mangahao	Hydro	42	87 + April storage	
Matahina	Hydro	80	57	
Patea	Hydro	32	160	
Wheao	Hydro	27	56	

Table 7: Existing South Island supply

Scheme	Type	MW	Assumed contribution to energy margins (potential GWh over Apr-Sep)	Assumed contribution to capacity margins (MW)
Waitaki	Hydro	1723	2886 + April storage	1600
Manapouri	Hydro	728	2363 + April storage	713
Clutha	Hydro	720	1583 + April storage	666
Cobb	Hydro	32	102 + April storage	31
Coleridge	Hydro	40	121	39
Argyle	Hydro	11	27	6
White Hill	Wind	58	110	12

2.3 New supply

- 2.3.1 Since 2008, the list of potential future generation projects has been completely revised. The new assumptions are set out in Table 8 (North Island projects) and Table 9 (South Island projects).
- 2.3.2 Paragraph 4.2.11 of the main paper sets out how these assumptions are derived from confidential generator information.

Table 8: Potential new generation projects - North Island

First available winter	Plant	Developer	Technology	Capacity (MW)	Assumed contribution to energy margins (potential GWh over Apr-Sep)	Assumed contribution to capacity margins (MW)	Probability
2010	Stratford - turbine 1	Contact	Gas turbine	100	425	97	Committed
2010	Nga Awa Purua	MRP	Geothermal	132	541	117	Committed
2010	Te Rere Hau	NZ Windfarms	Wind	20	38	4	Committed
2011	Stratford - turbine 2	Contact	Gas turbine	100	425	97	Committed
2011	Tauhara Binary	Contact	Geothermal	23	96	21	Committed
2011	Te Uku	Meridian	Wind	64	121	13	Committed
2012	Cogeneration 1		Cogen	50	110	38	Medium
2013	Gas peaker 1		Gas turbine	60	255	58	Medium
2013	Geo 1		Geothermal	50	208	45	High
2013	NI Wind 1		Wind	200	377	40	Medium
2014	NI Wind 2		Wind	200	377	40	Low
2014	Taranaki CCGT	Todd	CCGT	200	850	194	Medium
2014	Geo 2		Geothermal	150	624	135	Medium
2015	Gas peaker 2		Gas turbine	150	637	146	Medium
2015	Geo 3		Geothermal	150	624	135	High
2015	NI Wind 3		Wind	200	377	40	Medium
2016	NI Wind 4		Wind	300	565	60	Low
2016	Geo 4		Geothermal	100	416	90	Medium
2018	NI Wind 5		Wind	200	377	40	Low
2018	Geo 5		Geothermal	100	416	90	Low

Table 9: Potential new generation projects - South Island

First available winter	Plant	Developer	Technology	Capacity (MW)	Assumed contribution to energy margins (potential GWh over Apr-Sep)	Assumed contribution to capacity margins (MW)	Probability
2011	Benmore Refurbishment	Meridian	Hydro	10	25	10	Committed
2012	Mahinerangi 1	Trustpower	Wind	30	57	6	Medium
2013	Hydro 1		Hydro	40	88	32	Medium
2013	SI Wind 1		Wind	150	283	30	Medium
2015	SI Wind 2		Wind	200	377	40	Low
2017	Hydro 2		Hydro	200	438	194	Low
2017	SI Wind 3		Wind	150	283	30	Low
2018	Hydro 3		Hydro	200	438	194	Medium

2.4 Planned outages

- 2.4.1 The energy and capacity margin calculations are focused on winter (Apr-Sep) availability. Outages outside the winter period are not reflected in the margin calculations, but were captured in the analysis used to develop the margin.
- 2.4.2 The 2008 assessment allowed for planned outages at Huntly in April and May 2009. It can be expected that similar planned outages of Huntly and other thermal generators will occur in subsequent years. Rather than modelling them individually, Huntly 1-4 have been derated by 1% in both energy and capacity margin assessments, which has a similar effect.
- 2.4.3 Otherwise, the base case of this assessment makes no specific allowance for planned outages, beyond the routine Huntly maintenance described in paragraph 2.6.1 of this Appendix.

2.5 Forced outages

- 2.5.1 As in the 2008 assessment, energy and capacity margin assessments derate thermal generation capacity by 3% to allow for forced outages.

2.5.2 As in the 2008 assessment, the capacity margin assessment also derates hydro generation by 2% to allow for forced outages. Forced outages of hydro generation are not considered in the energy margin assessment.

2.5.3 The treatment of intermittent generation is described in the 2008 assessment.

2.6 Other deratings

2.6.1 As in the 2008 assessment, Huntly has been derated in the energy margin assessment to allow for:

- (a) *Maintenance outages*: one of the Huntly units is assumed to be out of service for maintenance three weekends in four. This equates to 190 GWh (or a constant 43 MW over a 6 month winter period); and
- (b) *Ancillary services requirements*: Huntly has been de-rated by 130 MW overnight to reflect spinning reserve (80 MW) and frequency keeping (50 MW) requirements. This equates to 303 GWh (or a constant 69 MW over a 6 month winter period).

2.6.2 Some hydro schemes have been derated in the capacity margin assessment:

- (a) the Waikato scheme has been derated by 60 MW (~6%) to account for the impact of chronological constraints;
- (b) Matahina, Patea and Tokaanu have been derated by 13 MW, 5 MW and 20 MW respectively to account for their limited short-term storage; and
- (c) the Waitaki scheme has been derated by 90 MW due to transmission-related restrictions on the output of a single Benmore unit at times of high South-North transfer. This is expected to continue until late 2012.

2.6.3 In the 2009 capacity margin assessment, the Clutha scheme has also been derated by 40 MW on the basis of advice from Contact.

2.7 Thermal generator fuel

2.7.1 Based on information provided by generators about thermal fuel supply arrangements, the assumed combined contribution of thermal plants to energy margins has been reduced by 400 GWh per winter.

2.7.2 Capacity margins are unaffected, since there is no indication that fuel supply arrangements will limit the ability of thermal generation to contribute to peak demand.

2.8 Transmission

- 2.8.1 Inter-island transmission assumptions are required for the assessments of energy and capacity margins. The calculation of the South Island energy margin needs to account for the extent to which North Island supply can contribute in a dry year, and the calculation of the North Island capacity margin needs to account for the extent to which South Island supply can contribute at peak times.
- 2.8.2 A baseline assumption of this assessment is that HVDC Pole 1 will continue to be available, under something like the current operating regime, until it is replaced by Pole 3 during 2012.
- 2.8.3 Since the 2008 assessment, Transpower has relaxed the conditions around use of Pole 1. However, the 2008 assessment did not model the Pole 1 operating regime in detail, so there is no need to revise assumptions on this basis.
- 2.8.4 The inter-island transmission assumptions in the baseline assessment of energy margins are the same as in the 2008 assessment. Table 10 shows the figures, which are based on simulation analysis carried out by EnergyLink. A key assumption is that maximum southwards transfer will increase from 489 MW to 550 MW in 2012, as a result of Pole 3 becoming available. This allows higher average transfers.

Table 10: Assumed maximum southward transfer for energy margin calculations

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
GWh (Apr-Sep)	1,873	1,871	2,033	2,086	2,076	2,087	2,116	2,089	2,085	2,085
Average MW	428	427	464	476	474	476	483	477	476	476

- 2.8.5 Note that actual southward transfer during June-August 2008 was rather less than assumed in Table 10. The Winter Review²⁴ canvassed some of the reasons for this. This assessment includes a sensitivity with considerably less southward transfer allowed.
- 2.8.6 For 2010 and 2011, the inter-island transmission assumptions in the baseline assessment of capacity margins are also the same as in the 2008 assessment. South Island surplus is calculated using a similar formula to the WCM, and a curve

²⁴ <http://www.electricitycommission.govt.nz/pdfs/opdev/secsupply/pdfsconsultation/Winter-Review-Report.pdf>

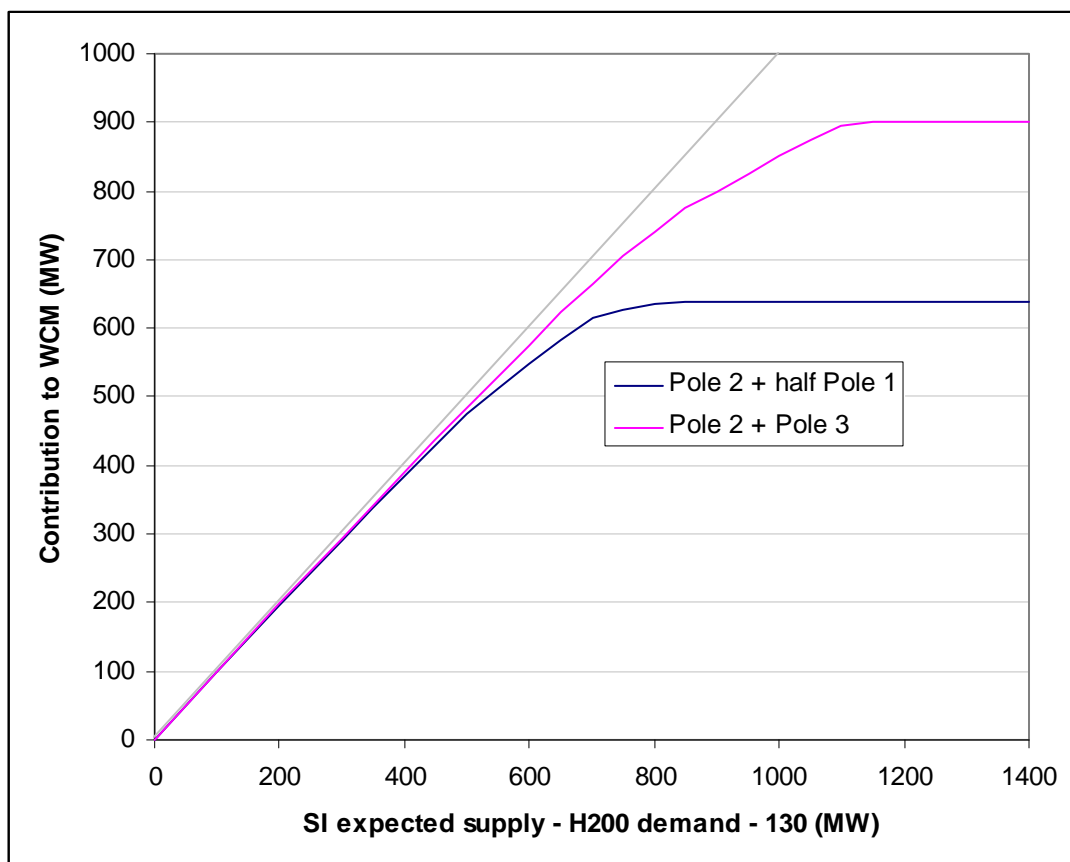
is used to convert South Island surplus to delivered North Island power at peak time. The curve was derived using simulation analysis, taking account of:

- (a) HVDC capacity;
- (b) transmission losses;
- (c) North Island instantaneous reserve requirements; and
- (d) the (low) probability of forced outages on the HVDC link.

2.8.7 It is expected that HVDC Pole 3 will become available in 2012. Accordingly, in this assessment, a new curve is used for winter 2012 onwards, reflecting increased ability to transfer power north at peak times. The curve was derived in the same way as the original, taking into account the benefits expected to stem from Pole 3 - including reduction in losses, increased ability to self-cover reserve risks, and reduction in forced outage rates.

2.8.8 The curves used are shown in Figure 18.

Figure 18: Curves used to convert South Island surplus to North Island capacity contribution (indicative)



- 2.8.9 This assessment does not explicitly model AC transmission constraints. The implicit assumption is that AC constraints will not systematically reduce inter-island transfers below the limits specified above.

2.9 Start storage assumptions

- 2.9.1 The energy margin calculations require an assessment of expected winter hydro capability, which is expressed as expected storage at the beginning of winter plus expected inflows.
- 2.9.2 As specified in the Security of Supply Policy and assumed in the 2008 assessment, expected storage levels at the beginning of winter (April 1) are defined as 2,750 GWh for New Zealand margin calculations and 2,400 GWh for South Island margin calculations. These are not a forecast of what actual storage will be in any given year, but, instead, reflect an estimate of the start storage across many years.

Appendix 3 Detailed demand forecast assumptions in the baseline scenario

3.1 Introduction

- 3.1.1 This Appendix sets out key demand assumptions used in the energy and capacity margin assessments.
- 3.1.2 Demand assumptions have not changed since the 2008 assessment, except where specifically noted.

3.2 Treatment of generation

- 3.2.1 Demand assumptions used in this assessment are consistent with the Commission's medium-term demand forecast carried out in late 2008.²⁵
- 3.2.2 This forecast predicts demand at GXP level, with most embedded generation netted off . However, several embedded generators are not netted off (and so are modelled on the supply side) and a few grid-connected generators are netted off (and so are *not* modelled on the supply side). Table 11 sets out the treatment of generation in this forecast.

Table 11: Summary of generation inclusions/exclusions in demand forecast

Generator	Netted off	Not netted off
Glenbrook – cogeneration at NZ Steel mill	<i>All</i> generation is netted off forecasts (whether embedded or grid-injected)	
Highbank – 'partly embedded' hydro generation Aniwhenua – 'partly embedded' hydro generation	<i>All</i> generation is netted off forecasts (whether embedded or grid-injected)	
Waipori – 'partly embedded' hydro generation	<i>All</i> generation, including Deep Stream, is netted off forecasts (whether embedded or grid-injected)	
Kawerau (Norske Skog), Karioi (Winstone Pulp and Paper), and Whirinaki (Pan Pac) – wood processing cogeneration	Cogeneration is netted off forecasts	
Rotokawa – embedded	Generation is netted off	

²⁵ <http://www.electricitycommission.govt.nz/opdev/modelling/demand/security/index.html>

Generator	Netted off	Not netted off
geothermal generation	forecasts	
Whareroa – dairy factory cogeneration		Generation is not netted off forecasts. <i>Net</i> injection should be modelled on the supply side
Te Rapa – dairy factory cogeneration		Generation is not netted off forecasts, even though it is embedded. <i>Net</i> injection should be modelled on the supply side
Kapuni – CHP cogeneration Kinleith - cogeneration Southdown - cogeneration		Generation is not netted off forecasts and should be modelled on the supply side
Tararua Wind Farm		Generation is not netted off forecasts, even though stages 1 and 2 are embedded, and should be modelled on the supply side
Te Apiti		Generation is not netted off forecasts and should be modelled on the supply side
White Hill		Generation is not netted off forecasts, even though embedded, and should be modelled on the supply side
New wind farms	Generation from new wind farms with capacity <i>under 30 MW</i> is assumed to be netted off forecasts	Generation from new wind farms with capacity <i>over 30 MW</i> should be modelled on the supply side
New geothermal development		Generation is not netted off forecasts and should be modelled on the supply side
Other embedded generators not listed above, whether existing or new	Generation is assumed to be netted off forecasts	
Other grid-connected generators not listed above, whether existing or new		Generation is not netted off forecasts and should be modelled on the supply side

3.3 Demand assumptions for energy margin assessments

3.3.1 The energy margin assessment for the baseline scenario is based on the 2008 medium-term forecast of energy demand. Based on information received from participants, the following changes have been made:

- (a) a reduction in South Island winter energy demand of 350 GWh in 2010; and
- (b) a reduction in North Island winter energy demand of 100 GWh in all future years.

3.3.2 The resulting forecast is shown in Table 12 below.

Table 12: Baseline forecast of annual energy demand at grid exit point

Calendar year	New Zealand (GWh)	North Island demand (GWh)	South Island demand (GWh)
2010	41,014	25,990	15,024
2011	42,300	26,448	15,852
2012	43,137	26,986	16,151
2013	43,975	27,533	16,441
2014	44,828	28,091	16,737
2015	45,699	28,660	17,039
2016	46,586	29,241	17,345
2017	47,490	29,833	17,657
2018	48,413	30,437	17,975
2019	49,352	31,054	18,299

3.3.3 For the margin calculations, this forecast is adjusted as follows:

- (a) winter demand forecasts are produced by scaling annual forecasts;
- (b) an allowance is made for voluntary demand reductions in the event of a dry year; and
- (c) transmission losses are added.

Estimating winter demand

3.3.4 As in the 2008 assessment:

- (a) New Zealand winter demand (April to September) is assumed to be 52% of annual New Zealand demand; and
- (b) South Island winter demand is assumed to be 51.5% of annual demand.

Demand response

3.3.5 As in the 2008 assessment, energy demand forecasts have been reduced by 2% to allow for voluntary demand response.

3.3.6 This includes voluntary demand response resulting from high spot prices or retailer pricing initiatives, but excludes reductions in demand as a result of savings campaigns or calls for conservation.

Losses

3.3.7 As in the 2008 assessment, energy demand forecasts have been increased to allow for average AC transmission losses of 3.5% (New Zealand) or 4.5% (South Island).

3.3.8 DC losses are incorporated in the assumptions about southward HVDC transfers, which reflect energy received in the South Island after losses.

3.4 Demand assumptions for capacity margin assessments

3.4.1 The capacity margin assessment for the baseline scenario is based on the 2008 medium-term forecast of "H200" (top 200 half-hours) demand. Based on information received from participants, the following changes have been made:

- (a) a reduction of South Island peak demand of 45 MW in 2010; and
- (b) a reduction in North Island peak demand of 25 MW in all future years.

3.4.2 The resulting forecast is shown in Table 13 below.

3.4.3 The H200 demand forecast is a measure used in the capacity margin calculation, and is defined as a prediction of average demand over the two hundred winter trading periods with highest demand. For reference, the H200 demand forecast for the North Island is approximately 200 MW less than the expected forecast of annual peak demand.

Table 13: Baseline forecast of annual H200 demand at grid exit point

Calendar year	North Island demand (MW)	South Island demand (MW)
2010	4,404	2,160
2011	4,487	2,257
2012	4,580	2,297
2013	4,663	2,333
2014	4,748	2,370
2015	4,834	2,408
2016	4,922	2,446
2017	5,012	2,484
2018	5,103	2,524
2019	5,196	2,563

3.4.4 For the margin calculations:

- (a) transmission losses are added; and
- (b) demand-side response is also considered.

Losses

3.4.5 As in the 2008 assessment, peak demand forecasts have been increased to allow for AC transmission losses of 2.88% (North Island) or 4.88% (South Island).

3.4.6 DC losses are incorporated in the assumptions about northward HVDC transfers, which reflect power received in the North Island after losses.

Demand-side response

3.4.7 As in the 2008 assessment, it is assumed that 176 MW of demand response and interruptible load are available in the North Island at peak. This represents the average of the distribution of historic interruptible load offers.

Appendix 4 Rationale for including the “poor unit commitment” sensitivity scenarios

4.1 Introduction

- 4.1.1 This assessment includes several scenarios labelled “Poor unit commitment”, in which capacity margins are reduced by 200 MW. This appendix describes the rationale for including those scenarios.
- 4.1.2 A key assumption of the capacity assessment is that all generation will be available to meet peak, except where plants are unavailable for various reasons set out in Appendix 2 (such as forced outages, provision of ancillary services, or planned outages notified well in advance).
- 4.1.3 However, in practice, slow-start thermal generation will only be able to run at peak times if it is already committed. These commitment decisions need to be made hours in advance; if a particular slow-start plant is not committed for a particular peak period, then it will not be able to support security of supply.
- 4.1.4 Unit commitment is a commercial decision for generators, based on their portfolio management, their cost structures and their expectations of market price. There is no intention to criticise generator decisions in this area. However, if unit commitment decisions will lead to the market delivering less capacity than is assumed in the baseline scenario, then the effect on assessment outcomes needs to be explored.

4.2 Unit commitment in 2009

- 4.2.1 Unit commitment is a long-standing issue. However, the effect on security of supply is increasing as capacity margins tighten and the proportion of wind generation on the system rises. Experience from the 2009 winter can help to highlight the current situation.
- 4.2.2 Capacity margins were generally tight over the winter, with a record number of Standby Reserve Shortfall notices issued by the System Operator. A key reason was that slow-start plants were often not fully committed (particularly in April, May, September and October).
- 4.2.3 Transpower commented, in a letter to the Commission on 28 October 2009, that “the number of notices is a commentary on the current inadequacy of the incentives that exist for generators and instantaneous reserve providers to offer adequate capacity to enable the power system to be operated in a secure state”.
- 4.2.4 On six occasions during 2009 it was impossible to maintain full North Island instantaneous reserve cover. The System Operator declared a Grid Emergency and

advised that Reserve Adjustment Factors (RAFs) were reduced – i.e. the amount of North Island instantaneous reserve to be procured was lower than normal, and in some cases was nil.

- 4.2.5 With reduced RAFs, the power system may not be able to manage a contingent event, such as the loss of an HVDC pole or single large generating unit, without triggering AUFLS (automatic under-frequency load shedding). This is an undesirable state of affairs and indicates a serious capacity shortfall.
- 4.2.6 During the Grid Emergencies when RAFs were reduced, some slow-start plants were not committed. Table 14 (next page) indicates the output of some key plants on these occasions.
- 4.2.7 The purpose of publishing these output statistics is not to criticise the commercial decisions of the generators involved, but to illustrate how unit commitment can affect security of supply at peak.

Table 14: Approximate output of some key slow-start generators during 2009 grid emergencies

Date	Times	RAFs set to	Approximate average output (MW)						Assumed combined contribution to capacity margin (MW)
			Huntly 1-4	Huntly e3p	Otahuhu B	Taranaki CC	Waikato hydro system	Total	
4 May	17:54 – 19:00	0.6	660	390	370	0	730	2,150	3,035
21 May	07:41 – 08:34	0.8	455	405	370	370	700	2,300	3,035
23 May	17:47 – 18:30	0.8	420	395	370	350	750	2,285	3,035
5 Oct	18:00 – 20:30	0	205	400	395	0	845	1,845	3,035
6 Oct	09:00 – 10:58	0	380	395	390	0	660	1,825	3,035
14 Oct	17:49 – 19:45	0	170	375	380	0	840	1,765	3,035

Note that Contact’s Taranaki CC was unavailable due to maintenance outages, rather than for unit commitment reasons.

May and October are not core winter, and it would normally be expected that *some* major generating units would be on planned outages, or uncommitted.

Nonetheless, the amount of generation not available during these periods of capacity shortage does cast doubt on the assumptions used in the baseline assessment.

4.3 Impact of commitment decisions on the capacity threshold

- 4.3.1 One way of estimating the impact of unit commitment on capacity margins is to rederive the capacity threshold using different commitment assumptions.
- 4.3.2 Two different modelling tools were originally used to derive the current capacity threshold of 780 MW²⁶:
- (a) a load duration curve (LDC) convolution model; and
 - (b) a chronological model.
- 4.3.3 Reassuringly, the two tools produced very similar results. In the end, the LDC convolution model was used to derive the standard.
- 4.3.4 Of the two tools, the chronological model is more suited to analyse unit commitment, and so it was used to investigate the effect of commitment decisions on the threshold.
- 4.3.5 It was found that:
- (a) unavailability of a single combined cycle gas turbine (CCGT) over the “off-winter” period of April, May and September has little effect on the threshold – as there is some surplus capacity at these times;
 - (b) but unavailability of a CCGT *and* a coal-fired Huntly unit over the above “off-winter” period increases the threshold by 210 MW;
 - (c) unavailability of a coal-fired Huntly unit over the “midwinter” period of June-August also increases the threshold by 210 MW; and
 - (d) the two effects above are roughly cumulative – in other words, unavailability of a CCGT over off-winter and a Huntly unit through the entire winter increases the threshold by over 400 MW.

4.4 Resulting assumptions

- 4.4.1 In the “poor commitment” sensitivity scenarios, capacity margins have been reduced by 200 MW. Given the outcomes observed in 2009 and the analysis in section 4.3 above, this seems a reasonable reflection of the effect that commitment decisions might have on peak security.
- 4.4.2 The effect on the capacity assessment is similar to that of removing a Huntly unit or derating a CCGT by 50%.

²⁶ <http://www.electricitycommission.govt.nz/pdfs/opdev/secsupply/policy/capacity-adequacy-standard.pdf>

4.4.3 The assessment of energy margins is unaffected. In an extended energy shortage, it would be expected that market prices would be high enough to justify slow-start generation operating.

4.5 Factors contributing to unit commitment issues

4.5.1 It may be useful to list some of the factors that can contribute to a lack of committed plant at peak times.

4.5.2 Issues relating to price signals may include:

- (a) the way in which energy and reserve price signals are depressed when RAFs are reduced;
- (b) the way in which energy price signals can be depressed when plants are constrained on for security purposes;
- (c) the non-commercial offer strategy of Whirinaki Power Station; and
- (d) the unpredictability of spot prices, due in part to variable demand and variable output from increasing quantities of intermittent generation.

4.5.3 Issues relating to market information may include:

- (a) the quality of price forecasts, including the extent to which they provide information about the possible effect of demand and intermittent generation on price; and
- (b) the quality and quantity of security notices.

4.5.4 Issues relating to the nature of thermal plant may include:

- (a) the time needed to start plant from cold;
- (b) the cost structure of thermal generation, with a significant cost attached to startups; and
- (c) the difficulty of scheduling maintenance outages;

4.5.5 The Commission is currently working with industry to improve joint understanding of these issues.