2008 Statement of Opportunities

Draft for consultation July 2008

Electricity Commission
Te Komihana Hiko

Disclaimer

This document is the draft 2008 Statement of Opportunities (SOO) prepared by the Commission pursuant to part F of the Electricity Governance Rules 2003 (Rules). It is published as a draft for the purpose of inviting submissions from interested parties as required by rule 9.5 of section III of part F of the Rules.

The purpose of the SOO is to enable the identification of potential opportunities for efficient management of the grid, including investment in upgrades and transmission alternatives. The SOO is also relevant to the Grid Investment Test (GIT) and the Grid Reliability Standards (GRS) under part F, each of which reference the possible future scenarios set out in the SOO. There are also links between the SOO and documents prepared by Transpower, as grid owner, pursuant to part F: the Grid Reliability Report (GRR), the Grid Economic Investment Report (GEIR), and Grid Upgrade Plans (GUPs).

Rule 9.3 of section III of part F of the Rules states that statements of opportunities are provided for information only. No liability will attach to the Commission, Transpower, or any other person, for the accuracy of Grid Planning Assumptions (GPA) or power systems analysis set out in statements of opportunities.

Chair’s foreword

As part of its role in overseeing aspects of transmission investment, the Electricity Commission (Commission) must prepare and publish a SOO. The purpose of the SOO is to enable the identification of potential opportunities for efficient management of the grid, including investment in upgrades and transmission alternatives.

The SOO is not a plan for the future development of the grid or of generation. However, it is a tool that will be used to test the appropriateness of transmission investments. It may also be used by other parties to identify investment opportunities.

The first SOO (Initial SOO) was published in 2005 when the Commission was still in its infancy. Since then, transmission issues have continued to be a dominant feature of the Commission’s work programme. The Commission has made decisions on a number of investment proposals from Transpower and progressed development of key aspects of the regulatory framework for transmission.

In early 2007 work on the preparation of the draft SOO was put on hold until the New Zealand Energy Strategy was finalised, as the Commission anticipated that the NZES would have a significant impact on the SOO. All the energy strategy documents have now been finalised, and the Commission has prepared a draft 2008 SOO which takes into account:

- the impacts of the energy strategy documents;
- stakeholders’ feedback on the Initial SOO; and
- submissions on draft Grid Planning Assumptions released for comment in 2007 and early 2008.

Since the Initial SOO was published, the Commission has been reviewing and progressively enhancing its models and analysis tools, its information databases, and its approach to developing and publishing a SOO.

The SOO is an important document for:

- Transpower in its role as grid planner, including in preparing reports on the forecast ability of the grid to meet the reliability standards, opportunities for economic investment, its formal proposals for investing in the grid, and managing and operating grid assets; and

- for investors in generation, in that it provides a central information source for investors in generation, other participants, end use customers and those interested in evaluating transmission alternatives.

The issues facing the electricity industry have changed in key areas since the Initial SOO was published. A prolonged period of low inflows into the hydro lakes, equipment failure at the Otahuhu substation in June 2006, an increase in resource consents sought for new generation (especially wind generation), and two proposals for new transmission lines into Auckland have all heightened awareness of security and reliability of supply of electricity.

In addition, the Government has signalled its commitment to a new vision for New Zealand's energy future, focussed on responding to climate change and tackling carbon emissions while delivering secure, clean energy at affordable prices. To this end the Government released the New Zealand Energy Strategy to 2050 (NZES) which forms the basis for stakeholder and public engagement on medium and long-term decisions that will shape New Zealand's energy future.

The content and conclusions in this publication, including forecasts, scenarios, and power systems analysis, are subject to various assumptions and limitations, and are prepared only for the purposes of this SOO. It is important that readers understand that the SOO is an information document presenting the results of analysis undertaken by the Commission. It is not a document in which the Commission is endorsing or rejecting any particular option or the implications of any particular option. That may be a part of a separate process, whereby the Commission will consider approving (or not approving) proposed investments submitted by Transpower in a GUP. Included within the GUP process is the requirement that the Commission consider alternatives to transmission.

The analysis presented in the 2008 SOO may inform the GUP process, but the Commission is required to, and will, approach the GUP process with an open mind. Accordingly, the inclusion or exclusion of analysis or discussion about any particular investment in generation, transmission, or alternatives in the 2008 SOO scenarios or power systems analysis should not be taken as the Commission expressing a settled view on any option.

Your feedback on this 2008 SOO is an important input to the Commission's processes.
I encourage you to consider this document and to provide the Commission with your views.

David Caygill
Chair

Glossary of abbreviations and terms

Act	Electricity Act 1992
ADMD	after diversity maximum demand
APR	Transpower's Annual Planning Report
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CDS	centralised dataset
Commission	Electricity Commission
e3p	energy efficiency enhancement project
ETS	Emission Trading Scheme
GAMS	General Algebraic Modelling System
GDP	gross domestic product
GEIR	Grid Economic Investment Report
GEM	Generation Expansion Model
GIP	Grid Injection Point
GIT	Grid Investment Test
GJ	gigajoule
GPA	Grid Planning Assumptions
GPS	Government Policy Statement on Electricity Governance
GRR	Grid Reliability Report
GRS	Grid Reliability Standards
GUIRP	Grid Upgrade Investment and Review Policy
GUP	Grid Upgrade Plan
GW	gigawatt

GWh	gigawatt-hour — the amount of energy as measured by a rate of 1 GW for a period of 1 hour
GXP	Grid Exit Point
HVDC	high-voltage direct-current
HVDC Upgrade	HVDC grid upgrade investment proposal
IL	interruptible load
Initial SOO	Initial Statement of Opportunities
kV	kilovolt, that is 1000 volts
kVa	kilovoltampere
LDC	load duration curve
LNG	Liquified Natural Gas
LPC	load probability curve
LRMC	long-run marginal cost
MDS	market development scenarios
MED	Ministry of Economic Development
Minister	Minister of Energy
MIP	mixed integer programming
MoT	Ministry of Transport
MVA	megavoltampere
MW	megawatt
NPV	net present value
NZAS	New Zealand Aluminium Smelters Limited
NZEECS	National Energy Efficiency and Conservation Strategy
NZES	New Zealand Energy Strategy
NZIER	New Zealand Institute of Economic Research

O and M	operating and maintenance
OCGT	open cycle gas turbine
PBA	Parsons Brinckerhoff Associates
PoE	probability of exceedance
PSA	power systems analysis
PSS/E	power system simulator for engineering
pu	per unit
PV	present value
Regulations	Electricity Governance Regulations 2003
Rules	Electricity Governance Rules 2003
SOI	Statement of Intent
SOO	Statement of Opportunities
SRMC	short-run marginal cost
SSG	System Studies Group
SVC	synchronous var condenser
TCC	Taranaki Combined Cycle
tCO2-e	tonne carbon dioxide emission
TPM	transmission pricing methodology
TTER	transmission to enable renewables
V2G	vehicle-to-grid
WEM_G	GEM winter energy margin
WGIP	wind generation investigation project

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1. Executive summary

1.1 Introduction

Electricity is a key component of the overall energy sector and has a critical part to play in the New Zealand economy. The key roles of the Electricity Commission (Commission) are to oversee the sector, promote efficient development of electricity infrastructure and market outcomes, and encourage good results for electricity consumers.

The Commission must give effect to the objectives and outcomes in the Government Policy Statement on Electricity Governance (GPS). In that Statement the Minister of Energy (Minister) sets objectives and outcomes that the Government wants the Commission to give effect to in relation to the governance of the electricity industry.[1]

The GPS includes the objective that a Statement of Opportunities (SOO) should be published at least every two years.[2] The purpose of the SOO is to enable the identification of potential opportunities for efficient management of the grid, including investment in upgrades and investment in transmission alternatives. The SOO is also relevant to the Grid Investment Test (GIT) and the Grid Reliability Standards (GRS) under part F of the Electricity Governance Rules 2003 (Rules), each of which refers to the possible future scenarios set out in the SOO.

In preparing the SOO, the Rules require the Commission to aim to meet the reasonable requirements of Transpower, investors in generation, other participants, end-use customers and those interested in evaluating transmission alternatives, and to reflect good electricity industry practice.

The Commission had expected to publish a new SOO in 2007, but decided to wait until the New Zealand Energy Strategy (NZES) was released so that the SOO could take into account the anticipated effects of the NZES. In late 2007, following finalisation of the NZES, the Commission resumed its work on the SOO. This included the Commission engaging with stakeholders at an early stage of developing the Grid Planning Assumptions (GPA) so that relevant comments were able to be incorporated.

Transpower plays a central role in the New Zealand electricity sector as it owns and operates the transmission grid. Over the last four years, Transpower has submitted to the Commission grid upgrade proposals exceeding $2.5 billion in total. Part F of the Electricity Governance Rules provides a process by which investment proposals are evaluated and, if the criteria set out in the Rules are met, approved by the Commission.

1 Section 172ZK.

2 Paragraph 89 of the GPS.

The SOO is important to the Commission's consideration of investment proposals submitted by Transpower. This is because the generation scenarios and demand forecasts in the SOO are default "market development" scenarios used to analyse an investment proposal in a GUP.

1.2 Electricity demand

A key component of the Grid Planning Assumptions (GPA) is the Commission's electricity demand forecast which sets out the Commission's view on demand forecasts for the New Zealand electricity market.

The Commission has an in-house specialist modelling team. It also draws on specialist external advice, academic literature and publications, and the insights gained by other parties involved in electricity demand forecasting. The Commission has developed for the purpose of this draft 2008 SOO a demand forecast covering the period to 2050.

The energy and peak demand forecasts presented in this draft document are significantly different from those presented as part of the Initial SOO. A complete review of the energy demand forecasting process has been carried out, and projections of long-term demand growth lowered as a result. The approach used for peak demand forecasting has also been substantially revised.

1.3 Generation scenarios

Another key component of the GPA are the generation scenarios. The GPA are required to contain (among other things) 'a reasonable range of credible future, high-level generation scenarios…'[3].

The scenario development process for the draft 2008 generation scenarios included three main steps:

- assembling input data;
- developing the scenario 'stories' identifying the key drivers and assumptions (for example fuel cost and availability, discount rates, carbon price) which guide the future development paths in the scenarios and determining that combination of drivers will apply in each scenario; and
- running the models to develop each generation scenario.

3 Rule 10.3.1.3 of section III of part F.

The five scenarios prepared, presented in Table 1, are intended to provide reasonably credible future possibilities, while encompassing most of the uncertainties.

Table 1 Scenarios outline

Scenario	Description
Sustainable Path	New Zealand embarks on a path of sustainable electricity development and sector emissions reduction. Major existing thermal power stations close down and are replaced by renewable generation, including hydro, wind and geothermal backed by thermal peakers for security of supply. Electric vehicle uptake is relatively rapid after 2020. New energy sources are brought on stream in the late 2020s and 2030s, including biomass, marine, and carbon capture and storage (CCS). Demand-side response helps to manage peak demand.
South Island Surplus	Renewable development proceeds at a slightly more moderate pace, with all existing gas-fired power stations remaining in operation until after 2030, though taking a more mid-order role as gas prices increase. The coal-fired units at Huntly Power Station are shifted into a reserve role and eventually removed from service. Wind and hydro generation increase considerably, particularly in the lower South Island. Relatively little geothermal energy is utilised. Thermal peakers supplement renewable development.
Medium Renewables	A 'middle-of-the-road' scenario. Renewables are developed in both islands, with North Island geothermal development playing an important role. The coal-fired units at Huntly transition through dry-year reserve to total closure. Thermal peakers and a new combined cycle gas turbine (CCGT) supplement renewable development. Tiwai smelter is assumed to decommission in the mid-2020s.
Demand-side Participation	Demand-side participation becomes a more important feature of the market, driven by a desire from consumers of all types to become more fully involved. Electric vehicle uptake is high, and vehicle-to-grid technology is used to manage peaks and provide ancillary services. On the generation side, new coal- and lignite-fired plants are constructed after 2020, and geothermal resources are developed. Little new hydro can be consented, however, and some existing hydro schemes have to reduce their output (due to difficulty in securing water rights). Huntly Power Station remains in full operation until 2030. Electricity-sector emissions rise, though transport-sector emissions would be lower than in other scenarios.
High Gas Discovery	Major new indigenous gas discoveries keep gas prices low to 2030 and beyond. Some existing thermal power stations are replaced by new, more efficient gas-fired plants. New CCGTs and gas-fired peakers are built to meet the country's power needs; the most cost-effective renewables are also developed. The demand-side remains relatively uninvolved.

These scenarios have been designed to encompass the range of uncertainty, rather than to provide a central forecast of investments. Although each scenario is intended to be a plausible view of the future, none represents the Commission’s view of a ‘most likely’ future scenario.

1.4 Power Systems Analysis

Rule 9.1.1 of section III of part F of the Rules requires the SOO to include an analysis of the performance of the power system against the GPA and the GRS[4].

The purpose of the SOO is to enable identification of potential opportunities for efficient management of the grid including investment in upgrades and transmission alternatives. The Rules also provide that in preparing the SOO the Commission must have regard to the principle of meeting the reasonable requirements of Transpower, investors in generation, other participants, end use consumers and those interested in evaluating transmission alternatives.

The PSA contributes to the purpose, and furthers the principle, by identifying when the grid, in any given scenario (that is, the GPA) will no longer meet the GRS.

The point at which the transmission grid is anticipated to no longer meet the GRS represents an opportunity for efficient management of the grid, including investment in upgrades and transmission alternatives. The opportunities signalled in the SOO are only transmission opportunities, but the Commission emphasises that, in some situations, opportunities for investment in transmission alternatives may arise at the same time.

1.5 Principal conclusions

1.5.1 South Island

The principal conclusions from the analysis of the power system for the South Island indicate opportunities for a number of upgrades to existing transmission lines and one new transmission line.

- 220 kV line Roxburgh-Twizel before 2032 for MDS 3 to handle increased power flow from south due to Tiwai smelter decommissioning (modelled project from Transpower 2008 APR).

1.5.2 Inter-Island transmission

The PSA assumes that in all scenarios, HVDC Pole 1 is replaced before 2017 increasing the bipole rating from 970 MW (270 MW on a Pole 1 Half-Pole and 700 MW on Pole 2) to 1200 MW (500 MW on Pole 1 and 700 MW on Pole 2). The opportunity to provide a fourth submarine cable to upgrade transfer capacity to 1400 MW to meet the assumed security criteria does not occur until after 2017.

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4 Rule 9.1.1.3 of section III of part F.

1.5.3 North Island

The principal conclusions from the power systems analysis for the North Island indicate a number of opportunities for upgrades to existing transmission lines and a limited number of new lines and cables. Significant new lines and cables are:

- 220 kV Auckland cross-harbour cable before 2017 (current GUP application) followed by second cable modelled before 2027 for MDS3;
- 220kV cable Pakuranga-Penrose after 2013 (current GUP application) followed by second cable modelled before 2032 for MDS2 and MDS3, and 2037 for MDS4 and MDS5;
- 110 kV cable Mangere-Otahuhu (SSG modelled project) before 2032 for MDS1, MDS2, and MDS3, and before 2037 for MDS4 and MDS5;
- 110 kV cable Otahuhu (modelled project from Transpower 2008 APR) before 2022 for MDS3 and MDS4, and before 2027 for MDS1, MDS2, and MDS5; and
- 220kV line Wairakei-Whakamaru (modelled project from Transpower 2008 APR) before 2022 for MDS1 and before 2037 for MDS3 and MDS4.

2. Regulatory and policy context

2.1 Introduction

To understand the role, purpose, and content of this SOO, it is important to be aware of the regulatory and policy context within which it has been prepared.

Accordingly, this chapter:

- summarises the role of the Commission, both generally in the context of the electricity industry and specifically in terms of publishing the SOO;
- discusses the impact of the NZES and the New Zealand Energy Efficiency and Conservation Strategy (NZEECS) in the Commission's preparation of this SOO; and
- discusses the impact of the GPS on the Commission's preparation of the SOO in light of the Commission's specific function to give effect to the objectives and outcomes in the GPS.

2.2 Overview of the regulatory framework

2.2.1 Introduction

The Commission is responsible for regulating the operation of the electricity industry and markets (wholesale and retail) in accordance with the Electricity Act 1992 (Act).

The Commission's principal objectives, as set out in the Act, are to ensure that electricity is produced and delivered to all classes of consumers in an efficient, fair, reliable, and environmentally sustainable manner, and to promote and facilitate the efficient use of electricity[5].

The Commission must have the objectives and the specific outcomes listed in section 172N of the Act in mind in exercising its powers.

The Act also sets out a number of specific functions of the Commission, including to:

- administer the electricity governance regulations and rules (section 172O(1)(b)); and
- give effect to GPS objectives and outcomes (section 172O(1)(j)).

[5] Section 172 N(1).

In relation to transmission, part F of the Rules sets out a series of processes that the Commission must follow to produce comprehensive transmission pricing, transmission contracting, transmission investment arrangements, and interconnection services.

Section III of part F[6] sets out rules relating to grid upgrades and investments. It is under section III that the Commission is required to prepare and publish the SOO.

Rule 2 sets out the purposes of the rules in section III of part F as being to:

2.1 facilitate **Transpower's** ability to develop and implement long-term plans (including timely securing of land access and resource consents) for investment in the **grid**;

2.2 assist **participants** to identify and evaluate investments in **transmission alternatives**;

2.3 facilitate efficient investment in generation;

2.4 facilitate any processes pursuant to Part 4A of the Commerce Act 1986; and

2.5 enable the cost of approved investments to be recovered through the **transmission pricing methodology** applied in **transmission agreements**.

In summary, the Rules seek to facilitate timely investment in transmission infrastructure in an efficient and cost-effective way.

2.2.2 Respective roles of the Commission and Transpower

It is important to acknowledge the different roles of the Commission and Transpower in relation to transmission planning and investment under section III of part F. These different roles are:

- The Commission is responsible for:
  - preparing and publishing key information, such as the SOO (including the GPA) and the centralised dataset (CDS);
  - determining the GRS that the grid must meet over time, and the GIT against which Transpower's investments will be assessed; and
  - considering and, if appropriate, approving investments proposed by Transpower in a Grid Upgrade Plan (GUP).

[6] Unless stated otherwise, each reference in this document to a rule is to a rule in section III of part F of the Rules.

- Transpower is responsible for:
  - developing and maintaining the transmission grid and operating grid assets;
  - reporting on the forecast ability of the grid to meet the GRS (the Grid Reliability Report (GRR)) and on economic investments that could be made to interconnection assets (the Grid Economic Investment Report (GEIR))[7]; and
  - grid planning to meet the GRS, including preparing GUPs for proposed investments in the grid.

In summary, the Commission's role is to provide information, and reviewing and approving investments in a GUP that meet the criteria set out in the Rules, rejecting investments that do not. Transpower is responsible for grid planning, development and operation.

Recognising the interface between their respective roles, the Commission and Transpower have jointly developed a Grid Upgrade Investment and Review Policy (GUIRP). Its purpose is to promote an effective process for the preparation of investment proposals by Transpower, as part of Transpower's wider grid planning process, and the review of those proposals by the Commission. It provides a framework within which the Commission and Transpower will interact during the grid upgrade and investment and review process, and provides guidance to interested parties in relation to how Transpower and the Commission will interact with them[8].

The Commission's intention is to publish the SOO by the first working day of October every second year. Publication at that time allows Transpower six-months to publish the GRR and GEIR. Accordingly, Transpower intends to publish an Annual Planning Report (APR) containing those reports by 31 March each year. The six-month period aligns with Transpower's obligations under the Rules in relation to publishing the GRR and GEIR.

As new information may come to light in the period after a SOO is published, it might be necessary for the Commission to consider, as provided for in clause 6.1 of the GIT, whether scenarios other than the scenarios set out in the SOO are more appropriate for the purposes of applying the GIT to a particular investment proposal. In addition, some proposals may require more specific scenarios than those provided in the SOO. If this is the case, Transpower, the Commission, or a proponent of a transmission alternative, may put forward such alternative scenarios[9].

7 The Commission notes that the GRR and GEIR only have to be published when a new SOO is published, however, Transpower has indicated that it intends to update these annually as part of its Annual Planning Report.

8 http://www.electricitycommission.govt.nz/opdev/transmis/gridupgradepolicy

9 Clause 6.1 of the GIT.

2.2.3 Purpose and content of the Statement of Opportunities rule requirements

Rule 9.1.2 states that the purpose of the SOO is to enable identification of potential opportunities for efficient management of the grid including investment in upgrades and investment in transmission alternatives.

In preparing the SOO, the Commission must have regard to two key principles. First, the SOO should aim to meet the reasonable requirements of Transpower, investors in generation, other participants, end-use customers and those interested in evaluating transmission alternatives[10]. Second, the SOO should reflect good electricity industry practice[11].

The Rules also stipulate specific items that the SOO must contain[12]:

- Grid Reliability Standards determined by the Commission in accordance with rule 4;
- Grid Planning Assumptions. Rule 10 states that the GPA are required to set out a reasonable range of credible forecasts and scenarios for the electricity system; and
- analysis of the performance of the power system against the GPA and the GRS (the power systems analysis).

By setting out these items, the SOO is intended to signal opportunities for investment and provide key information that may assist interested persons to evaluate those opportunities and identify possible solutions, including investment in transmission or transmission alternatives.

The SOO identifies, on a non-exhaustive basis, likely constraints in the transmission network, the possible timing of the emergence of those constraints, and some potential options for resolving them.

Because the SOO is published relatively infrequently, new information may arise subsequent to a SOO being published, and market conditions may change. This means that the SOO necessarily represents a snapshot of the Commission's views at the time the SOO is published. The SOO therefore sets out possible states of the electricity system based on the information available to the Commission at the time the SOO is published. The SOO does not describe a plan for investing in, or managing the electricity system. The inclusion or exclusion of analysis or discussion about any particular investment in generation, transmission or alternatives should not be taken as the Commission expressing a settled view on any options.

10 Rule 9.2.1 of section III of part F.

11 Rule 9.2.2 of section III of part F.

12 Rule 9.1.1 of section III of part F.

Reasonable requirements and good electricity industry practice

Having regard to the principles for the SOO, the Commission considers that preparing the SOO should involve:

- consideration, and a detailed description, of a range of credible future scenarios for the electricity sector, including variations in electricity demand and the location and type of new generation;
- expert analysis of the capability of the power system to provide an efficient system of connecting generation with demand while meeting the reliability standards;
- identification of likely constraints in the transmission network, the possible timing of the emergence of those constraints, and potential options for resolving them; and
- presentation of the results of the analysis in a manner that makes them accessible to the stakeholders identified in rule 9.2.2.

These elements are all present in this SOO.

2.3 The Statement of Opportunities in context

Information in the SOO is a basis for, or interfaces with, a number of other elements set out in the Rules. The relationship between the SOO and other elements of the Rules is summarised here to provide the wider context for the SOO document and the approach to its preparation.

2.3.1 Statement of Opportunities interface with the Grid Investment Test and the Grid Reliability Standards

The GIT is a schedule to the Rules in part F. It is essentially an economic test, with an expected net market benefits assessment at its heart. The GRS, also a schedule to part F, set out the reliability standards to which the grid must be planned.

The SOO is relevant to the GIT because the GIT requires the use of market development scenarios (MDS) based on the scenarios provided in the SOO.

In particular, the GIT sets out[13] the MDS used in applying the GIT to an investment proposal must be the possible future scenarios set out in the SOO unless the Commission has determined that others are more appropriate. The probability of occurrence of an MDS must be as set out in the SOO for that MDS. The number of scenarios must be the same as the number of MDS in the SOO.

13 Clause 6 of Schedule F4 of section III of part F (the GIT).

There is also a relationship between the GRS and the SOO:

- the purposes of the GRS[14] include providing a basis for the Commission to publish the SOO and Transpower to prepare a GUP;
- the SOO must set out the GRS[15];
- the power systems analysis set out in the SOO is an analysis of the performance of the system against the GPA and the GRS[16]; and
- the GRS require that the expected level of reliability must be assessed using the range of relevant operating conditions that could reasonably be expected, having regard to the possible future scenarios set out in the SOO[17].

The SOO is also relevant to Transpower when it prepares and submits a GUP under rule 12. A GUP must include reliability and economic investments that meet the requirements of the GIT.

Accordingly, the SOO, the GIT, the GRS, and a GUP are inter-related. Through these interrelationships, it is anticipated that the signalling of opportunities, in the SOO, and the assessment of proposed investments, proposed in the GUP, will generally start from a common reference point.

The Commission, in conjunction with Transpower, has prepared a Grid Upgrade and Investment Review Policy that is aimed at promoting an effective process for the preparation of investment proposals by Transpower, as part of Transpower's wider grid planning process, and the review and approval or rejection of those proposals by the Commission[18].

2.3.2 Grid reliability and economic investment reporting

There are also grid reporting obligations on Transpower under section III (grid upgrade and investments) and section VI (interconnection asset services) of part F that draw on aspects of the SOO, and are required to be produced shortly after a SOO is published. The grid reporting arrangements are briefly described here.

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14 Rule 4.2 of section III of part F.

15 Rule 9.1.1.1 of section III of part F.

16 Rule 9.1.1.3 of section III of part F.

17 Clause 6 of Schedule F3 of section III of part F (the GRS).

18 Details are available at http://www.electricitycommission.govt.nz/opdev/transmis/gridupgradepolicy

Grid reliability reporting

Transpower is required to publish, within six months of the publication of a SOO (or another date agreed by the Commission), Transpower is required to publish a GRR[19]. The purpose of the GRR is to set out Transpower's projection of the power system's ability to meet a defined level of grid security over the next ten years. Specifically, the GRR must set out:

- a forecast of supply and demand at each grid connection point over the next ten years, consistent with the SOO forecasts or explained by reference to them;
- whether the power system is reasonably expected to meet the N-1 criterion (also known as the 'N–1 safety net')[20] in the GRS at all times over the next ten years, having regard to the possible future scenarios set out in the SOO; and
- planning proposals for addressing any security matters that are identified in the assessment.

If a GRR identifies that the power system is not reasonably expected to meet the N-1 criterion at a Grid Exit Point (GXP) in the subsequent five-year period and that this is due to an interconnection asset[21], Transpower is required to assess that asset against the GRS. If the asset does not meet the GRS, Transpower is required to consider reasonably practicable options for addressing this and if necessary, submit a GUP to the Commission[22].

Grid economic investment reporting

Within six months of the publication of a SOO, or another date agreed by the Commission, Transpower must publish a GEIR on whether there are economic investments that it considers could be made in respect of interconnection assets. The GEIR must take into account the scenarios set out in the SOO and any other information that Transpower considers may be useful to the Commission in determining MDS under the GIT, if the GIT were applied to the economic investments set out in the GEIR. Where the GEIR identifies that there are economic investments that could be made, Transpower must publish within six months a report setting out a proposed timetable for Transpower to consider whether to submit a GUP to the Commission in respect of those possible economic investments.

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19 Rule 12A of section III of part F.

20 The N-1 criterion is defined as meaning that, with all assets that are reasonably expected to be in service, the power system would be in a secure state (that is able to sustain a credible contingency without unplanned loss of load, overloading, unacceptable voltage conditions or system instability).

21 Under part F, the grid is comprised of interconnection and connection assets. Connection assets are generally spur lines and customer specific assets for the connection of that customer at an injection or off-take point. Interconnection assets, broadly speaking, are those assets for which it is not possible to attribute services to a single party because of 'loop-flow' effects. They are defined to include the HVDC link.

22 Rule 6.1 of section VI of part F (the interconnection rules).

Transpower's Annual Planning Report

While Transpower is not required to publish its APR, Transpower's approach to meeting the grid reliability and economic investment reporting requirements under part F is to incorporate those reports into preparation of its APR. The APR sets out Transpower's view of how the grid could be developed over the next 10 years in order to provide both reliability of supply and a competitive electricity market. The APR draws on other publications, such as the System Operator's System Security Forecast and the Commission's SOO, to provide a comprehensive 10-year forecast of the issues impacting on the grid and Transpower's plans and possible future paths for development.

The APR considers demand forecasts and compares these with the transmission capacity in 13 regions across the country. The places where capacity is approaching its limit are highlighted, and possible transmission solutions listed. Thus it provides Transpower's view on future grid development needs and augmentation options, so that current and future market participants have a greater degree of information about Transpower's plans in order to confirm their own.

2.4 The Government Policy Statement and the energy policy and strategy development

2.4.1 The Government Policy Statement

The Minister of Energy must set the objectives and outcomes that the Government wants the Commission to give effect to in relation to the governance of the electricity industry.[23] Those objectives and outcomes are called the GPS objectives and outcomes. The Commission is required to give effect to GPS objectives and outcomes.[24]

The Commission must report against the GPS objectives and outcomes in its Statement of Intent (SOI) prepared in accordance with the Crown Entities Act 2004. The Commission publishes a Statement of Intent[25] by 1 July each year. The Statement of Intent is tabled in the House by the Minister of Energy.

The first GPS published after the Commission was established was published in October 2004. An updated GPS was published in October 2006. The current GPS—at the time of publishing this draft 2008 SOO—was published in May 2008.

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23 Section 172ZK.

24 Section 172O(1)(j)

25 http://www.electricitycommission.govt.nz/publications

Transmission-specific GPS objectives and outcomes

At the time the October 2006 GPS was published the Minister of Energy stated that changes to the previous GPS were to improve the quality and timeliness of decision-making on transmission, and to set out the Government's objectives regarding renewable generation.

The October 2006 GPS revisions set out substantially revised objectives and outcomes regarding transmission. They also strengthened expectations around grid reliability, sought to clarify the roles of the Commission and Transpower, and provided greater detail on the expected process for preparing and considering GUPs. The revisions also set out the Government's expectations for transmission as they relate to renewable generation. The May 2008 GPS is very similar to the October 2006 GPS with regard to the transmission-specific GPS outcomes.

Specifically, the Government's objectives and outcomes for the provision of transmission services are that[26]:

- the services are provided in a manner consistent with the Government's policy objectives for electricity, and in particular, that grid reliability should be maintained at a level required by residential, commercial, and industrial users and by the Government's economic development objectives;
- the transmission grid should be adequately resilient against the effects of low probability but high impact events having regard to the load that could be disrupted and the duration of any disruption;
- where practicable, the transmission grid should provide adequate supply diversity to larger load centres, having regard to the load that could otherwise be disrupted and the duration of any disruption;
- efficient competition in generation and retail is facilitated and transmission constraints are minimised;
- the national transmission grid should be planned and made available so as to facilitate the potential contribution of cost-effective renewables to the electricity system, and in a manner that is consistent with the Government's climate change and renewables policies;
- the efficiency of transmission services should be continuously reviewed and improved so as to produce the services that grid users and consumers want at least cost;
- the services are priced in a manner that:

26 Paragraph 83 of the GPS.

  - is transparent;
  - fully reflects their costs including risk;
  - facilitates nationally efficient supply, delivery and use of electricity;
  - promotes efficient investment in transmission or transmission alternatives;
  - promotes nationally efficient use of transmission services by grid users and consumers; and
- stakeholders and the public are kept well informed about how agreed minimum levels of grid reliability are to be maintained throughout the development and consideration of any GUP.

Paragraph 89 of the GPS relates specifically to the SOO. It states that the SOO should:

- incorporate electricity demand and supply forecasts;
- enable identification of potential opportunities for:
  - efficient management of Transpower's transmission network including investment in system expansions, replacements, and upgrades; and
  - transmission alternatives, notably investment in local generation, demand-side management, and distribution network augmentation;
- facilitate long-term planning for timely securing of easements and resource consents, including the connection of renewables; and
- be prepared at least every two years.

Finally, the May 2008 GPS also states that GUP should be consistent with (amongst other things) the forecasts in the SOO[27].

[27] Paragrah 92 of the GPS.

2.4.2 Energy policy and strategy development

Throughout the world, countries are grappling with the issues posed by dramatic electricity price increases, constraints on fuel supplies and the future impacts of climate change. New Zealand is no exception—the New Zealand Energy Outlook to 2030 predicts energy use in New Zealand will increase by 35 percent by 2030 and energy-related greenhouse gas emissions will rise by 30 percent if changes are not made to the way we produce and use energy.

Energy policy underpins government policies on economic development, climate change, transport, resource management and research and development. It also supports wider government objectives for sustainable development and economic transformation. Over recent years, the Government has been pursuing a number of development initiatives in the area of energy policy and strategy.

A significant milestone in this regard was reached in October 2007 with the publication by the Ministry of Economic Development (MED) of 'Powering our Future: Towards a Sustainable Low Emissions Energy System—New Zealand Energy Strategy to 2050' (NZES).

The NZES sets the strategic direction for the energy sector within the context of an over-arching vision of a sustainable, low emissions energy system. The NZES therefore provides key guidance for medium and long-term decisions that will shape New Zealand's energy future, and for the issues considered in the formulation of this SOO, such as the challenge to reduce energy-related greenhouse gas emissions while maintaining security of electricity supply at competitive prices relative to higher emission alternatives.

Energy efficiency and the use of renewable energy are significant elements of the approach proposed in the NZES. Specifically, the NZES is based on the principles that:

- investment should occur in energy efficiency measures where this is cheaper than the long-term costs of building extra generation capacity, including environmental costs; and
- for the foreseeable future, it is preferable that all new electricity generation be renewable, except to the extent necessary to maintain security of supply.

The policies and initiatives of the NZES will influence future demand and supply projections in the electricity sector, as well as transmission investment. Accordingly, the Commission has taken these into account when establishing the scenarios in this SOO.

2.5 Key components of this Statement of Opportunities

Table 2 sets out the key components of the SOO, and where they can be found in this SOO document.

Table 2 Components of the 2008 Statement of Opportunities

Component	Description	Location
Grid Reliability Standards (GRS)	The GRS are the primary reliability standards that enable the reliability of the grid to be maintained during credible contingency events.	Section 4
Grid Planning Assumptions (GPA)	The GPA are required to cover a reasonable range of credible forecasts and scenarios.	Sections 5 to 9
Power Systems Analysis (PSA)	This is an analysis of the performance of the power system against the GPA and GRS. It includes information to meet the Commission's view of the reasonable requirements of the SOO audience and to enable identification of potential opportunities for investment in upgrades and transmission alternatives.	Sections 10 and 11

The Commission is mindful that the sections of this document relating to the various aspects of the GPA contain background information, input and assumptions, and commentary, as well as the GPA themselves. For ease of reference, Table 3 sets out the various tables and figures in this document that collectively constitute the GPA prepared for publication in this SOO.

Table 3 The Grid Planning Assumptions

GPA component	Description	Location
Credible demand forecasts	Demand forecasts:	
	– national annual projections	Table 6
	– regional annual projections	Appendix 2
	– prudent and expected peak forecast	Appendix 3
	– After diversity maximum demand (ADMD) prudent and mean peak forecast	Appendix 4
Credible future high level generation scenarios	Existing generation:	
	– grid-connected generation	Table 10
	– significant existing embedded generation	Table 11
	Committed projects:	
	– committed generation projects	Table 12
	– committed transmission projects	Table 36
	Scenarios:	
	– Sustainable Path	Figure 28, Figure 29, Table 31
	– South Island Surplus	Figure 30, Figure 31, Table 32
	– Medium Renewables	Figure 32, Figure 33, Table 33
	– Demand-side Participation	Figure 34, Figure 35, Table 34
	– High Gas Discovery	Figure 36, Figure 37, Table 35

The scenarios set out in the SOO are also relevant to the application of the GIT and the GRS. In particular, the MDS referred to in the GIT are the scenarios set out in the SOO and discussed in section 9 of this document, together with the committed transmission projects set out in the tables in Appendix 6. For ease of reference, Table 4 sets out the key information the Commission considers relevant to the application of the GIT and the GRS. Further relevant information is set out in Appendix 1.

Table 4 Information on the location of the matters referred to in the GIT and the GRS in relation to the SOO

GIT/GRS component	Description	Location
Size, timing and location of demand growth (relevant to MDS—clause 28 of the GIT)	Demand projections:	
	– national annual projections	Table 6
	– regional annual projections	Appendix 2
	– prudent and expected peak forecast	Appendix 3
	– ADMD prudent and mean peak forecast	Appendix 4
Existing assets — clause 25 of the GIT	Existing generation:	
	– grid-connected generation	Table 10
	– significant existing embedded generation	Table 11
	Transmission assets:	
	– interconnection rules schedules	Commission's website
	– published transmission agreements	Commission's website
	– SOO case data (PSS/E raw data files)	Commission's website
	– operating and maintenance costs	Transpower information, through the GUP
Committed projects—clause 21 of the GIT	Generation projects:	
	– committed generation projects	Table 12
	Transmission projects:	
	– committed transmission projects	Appendix 6

GIT/GRS component	Description	Location
Opportunities	Scenarios:	
	– Sustainable Path	Figure 28, Figure 29, Table 31
	– South Island Surplus	Figure 30, Figure 31, Table 32
	– Medium Renewables	Figure 32, Figure 33, Table 33
	– Demand-side Participation	Figure 34, Figure 35, Table 34
	– High Gas Discovery	Figure 36, Figure 37, Table 35
	Transmission projects:	
	– modelled transmission opportunities	Appendix 6

The Commission has employed a number of models in the preparation of this document and the underlying analysis. These include spreadsheets, forecasting models, and market simulation tools. Where practicable, the Commission has made the key inputs and outputs of these models available through its website—and in some cases, the models themselves. In particular:

- where practicable, the information referenced in Table 3 are available in electronic form through the Commission's website;
- the SOO study cases used in the power systems analysis are Power System Simulator for Engineering (PSS/E) study cases, and are available as PSS/E raw data files[28] . The PSS/E raw data files contain key information[29] underpinning the preparation of this draft 2008 SOO;

[28] The Power System Simulator for Engineering (PSS/E) package is marketed and maintained by Siemens PTI. The version used for this analysis was PSS/E Version 31. The PSS/E raw data files are named in a logical sequence according to the scenario, year, and summer/winter cases. An explanation of the file-naming convention to allow interested parties to correctly assess each file is provided along with the files on the Commission's website. Study horizon extended from 2007-2037 in five- yearly blocks.

[29] These files contain only very limited information regarding future connection assets due to the simplifying assumptions made.

- where practicable, the information referenced in Table 4 is available in electronic form through the Commission's website; and
- the Commission's national demand forecasting models and regional demand allocation models[30] are also available.

In addition, there is substantial factual and historical information contained in the centralised dataset assembled and maintained by the Commission, pursuant to part F, to support efficient planning processes, analyses and decision-making in relation to transmission and transmission alternatives[31].

2.6 Related information

A number of other publications and information sources provide additional background material that may be of interest to readers of this document. Four reports in particular were used as key input to the generation scenario analysis work undertaken for this draft 2008 SOO.

- Parsons Brinckerhoff Associates—'Transmission to enable renewables—Potential NZ hydro schemes – December 2007—Final report'[32].
- The Commission final report—'Transmission to enable renewables—Existing and potential geothermal generation in New Zealand—March 2008'[33].
- Connell Wagner—'Transmission to enable renewables—Economic wind resource study'[34].
- System Studies Group (SSG)—'Transmission to enable renewables project, Transmission Network Reinforcement: Inputs for GEM – April 2008'. This report was a key input to the generation scenario analysis work undertaken for this draft 2008 SOO.

Other information sources potentially of interest.

- The Commission's consultation papers and explanatory documents prepared as part of the process to develop the draft 2008 GPA[35].

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30 See http://www.electricitycommission.govt.nz/

31 The CDS is not published on the Commission's website. Details of how copies can be requested are available at http://www.electricitycommission.govt.nz/opdev/modelling/centraliseddata/index.html

32 http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/pdfsconsultation/renewables/TTER percent20Appe ndix percent202.pdf

33 http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/pdfsconsultation/renewables/TTER percent20Appendix percent201.pdf

34 http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/pdfsconsultation/renewables/TTER percent20Appendix percent203.pdf

- SSG report—'Inter—Area Transmission Capacity—September 2006'[36].
- MED's Energy Data File[37].
- The GUIRP[38].
- Information on the methodology and data used to prepare the demand forecasts[39].
- Development of Marine Energy in New Zealand.

To the extent practicable, and where available in an appropriate form, these documents have been made available on the Commission's website.

35 http://www.electricitycommission.govt.nz/consultation/GPA

36 http://www.electricitycommission.govt.nz/pdfs/opdev/modelling/GPA/SSG-inter-regional-transmission-capacity.pdf

37 http://www.med.govt.nz/templates/StandardSummary____15169.aspx

38 http://www.electricitycommission.govt.nz/opdev/transmis/gridupgradepolicy

39 http://www.electricitycommission.govt.nz/opdev/modelling/GPA/Draft2008SOOdemand/index.html

3. Approach adopted for the 2008 Statement of Opportunities

3.1 Introduction

Since the Initial SOO was published, transmission has continued to be an important feature of the Commission's work programme. The areas of focus have included developing the various components of the regulatory framework for transmission, such as the transmission pricing methodology (TPM) and benchmark agreements, and considering transmission investment proposals put forward by Transpower. The Commission has also used this period to review and enhance its modelling and analysis tools, its information databases and its approach to undertaking its duties and obligations in the area of transmission. Stakeholder feedback on the draft Initial SOO and experience with considering the first investment proposals from Transpower have been key inputs to this.

3.2 Experience with the Initial Statement of Opportunities

At an early stage in its preparation of this SOO, the Commission reviewed its experience with the Initial SOO and the feedback received. In particular, the Commission noted feedback in the areas of:

- specific input data and assumptions;
- the approach to scenario development;
- the approach to demand forecasting, particularly regional and peak demand forecasting methodologies;
- content that should be added or removed;
- the approach to the power systems analysis, and presentation of the results; and
- the role of the Commission in preparing the SOO, and the relationship of the SOO with other roles and accountabilities, particularly those of Transpower.

This review helped shape the framework, content and development work plan for this SOO.

3.3 Overview of approach adopted for this Statement of Opportunities

3.3.1 Development work

The Commission has used the period since the Initial SOO to further develop its modelling and analytical capabilities, drawing on the feedback received and on experience with considering the first grid upgrade proposals. This development work has been particularly focused on:

- enhancing the regional and peak demand forecasting methodologies;
- the production of load probability curves;
- investigating demand scenarios to address possible future step changes in demand;
- identifying inter-regional transmission constraints; and
- the development of a Generation Expansion Model (GEM) to assist in the formulation of supply-side scenarios (including the co-optimisation of transmission and generation).

The use of GEM in developing and testing SOO scenarios is a significant development from that followed when preparing the Initial SOO. Combining all inputs and assumptions into a single capacity expansion model such as GEM provides a number of benefits.

- It forces the logic of how the various inputs relate to one another to be carefully considered and their impact to be evaluated consistently.
- It enables competing scenarios to be accurately and reliably compared.

The Commission has also:

- commissioned independent reviews and reports from technical and specialist advisers on aspects of supply and demand forecasting, and on the performance of its GEM; and
- reviewed aspects of its databases and key input assumptions, particularly in the areas of modelled generation projects, fuel availability and price, transmission assumptions, cost of capital, and energy strategy/climate change policy assumptions.

3.3.2 Grid Planning Assumptions preparation and consultation

Experience from preparing the Initial SOO suggested that providing stakeholders with an early opportunity to comment on the GPA and other key input assumptions would be beneficial to stakeholders and to the Commission. In particular, it would:

- enable feedback to be incorporated early in the SOO preparation process; and
- provide a more accurate information base for preparing the MDS.

The rules in part F prescribe a defined timeframe for publishing the draft and final versions of the SOO. The rules allow a maximum of only 20 business days following the submission expiry date for the Commission to complete its consideration of submissions, revise the SOO and publish the final version. Although the Commission can seek the Minister's approval for a longer period, in practical terms the extension would need to be of the order of several months if submissions on input data were to be fully reflected through the forecasting, scenario development and power systems analysis processes.

Accordingly, for this SOO, the Commission decided to seek participants' input to the development of the GPA and other key assumptions, before embarking on the detailed analysis work. The purpose was to enable feedback to be incorporated early in the SOO preparation process, thereby providing a more accurate information base for scenario development and undertaking the power systems analysis.

The preparation of the GPA, in particular the demand forecasts and the generation scenarios, involves assembling a diverse range of data inputs, making a number of key assumptions, and designing modelling methodologies. One key input to the draft 2008 generation scenario was the information gathered through the Transmission to Enable Renewables (TTER) project[40], which provided a more up-to-date map of existing and potential renewables (hydro, wind and geothermal) in New Zealand.

In February 2008, the Commission prepared a package for consultation regarding the work-in-progress GPA, and sought stakeholder feedback.

The material was published and the process to develop the GPA and key input assumptions for the SOO continued in parallel with the feedback period. In particular the scenario development tools were refined and the information-gathering process continued.

[40] http://www.electricitycommission.govt.nz/opdev/transmis/renewables

The Commission also held a workshop for stakeholders. This provided stakeholders with an opportunity to hear from the Commission and to ask questions about various aspects of the GPA and key assumptions.

Stakeholders responded positively to the open consultative approach to the GPA development adopted by the Commission for this SOO, and welcomed the opportunity for early input. Nine submissions were received, representing all the major stakeholder groups.

The submissions are available in full from the Commission website[41]. A summary of the submissions received and the Commission's response to them are also available on the Commission's website[42]. In general terms, the key issues that emerged from the feedback tended to be grouped into two main categories.

- High level issues of principle regarding the purpose of the GPA with respect to the SOO.
- More specific comments on either the links between the current GPA process and other Commission workstreams or the modelling assumptions used.

3.3.3 Grid Reliability Standards

The GRS set the standards against which the performance of the power system is analysed. The Rules define the standards. The GRS have two limbs.

- An economic limb, which applies to the entire grid.
- A single contingency (N-1) reliability limb, which applies only to the core grid.

The Commission's approach to the GRS is outlined in detail in section 4.

3.3.4 Power systems analysis

The SOO is required by the Rules to include a PSA. The PSA tests the capability and reliability of the existing transmission system to supply forecast demand, over a range of assumed generation scenarios. In practice the PSA involves a two-stage analysis intended to:

- assist with the development of the generation scenarios; and
- verify the operational credibility of the generation scenarios.

The Commission's approach to the PSA is outlined in detail in section 10.

41 http://www.electricitycommission.govt.nz/submissions/SubmissionsGPA08

42 See http://www.electricitycommission.govt.nz/

3.4 On-going development

The Commission's development work generally, and in particular the preparation of the SOO, is an ongoing process. Consideration has already been given to the work programme for the next cycle. As part of its continuing development of GPA for use in future SOOs, the Commission intends to undertake the following activities.

- Collection of additional information, within the TTER project, of potential renewable generation projects, and the identification of firm renewable generation projects such as pumped hydro.
- Consideration of how any key developments from the TTER project might be factored into the analysis for the next SOO.
- Further analysis and co-optimisation modelling to enable transmission costs and capacities to be factored into the multi-regional GEM.
- Exploration of scenarios in which existing thermal plant is expected to be decommissioned.
- Incorporation of price projections and price elasticity analysis from Transpower.
- Consideration of analysis from Transpower of the economics of distributed generation.
- Consideration of the results of Transpower's strategic grid development project.
- Consideration of improved modelling of transmission expansion and losses within the GEM.
- Further exploration of the degree to which market-based generation expansion will provide adequate dry-year reserve margin.
- Consideration of improvements to the modelling approach to handle end-effects.
- Investigation of system costs resulting from peak capacity and scheduling issues in respect of wind generation.
- Investigation of alternative peak and firm generation options, such as diesel, geothermal and pumped hydro, and biofuelled peaking.
- Participation in a cross-government project to improve data collection in the energy sector, to enable improved demand forecasts.

- Continued development of load probability curve (LPC) forecasts, sector modelling in the energy forecast, and participation in cross-government energy sector modelling initiatives.

Stakeholder feedback on the 2008 SOO will assist in the augmentation and refinement of this development work programme in the lead-up to the third SOO. It is also anticipated that the programmes of activities associated with the NZES, NZEECS and related climate change initiatives will be advanced significantly over the next year or so, and these developments will also be reflected within the next SOO cycle. Finally, it is important to note that Transpower's planning and development of the grid is a continuous process: a number of key transmission investigations, investment proposals and projects can be expected to be progressing in the time between now and the third SOO, with associated implications to be incorporated into the development of GPA and power systems analysis for that SOO.

4. Grid Reliability Standards

4.1 Introduction

The GRS set out the standards against which the performance of the power system is analysed under each scenario contained in the GPA.

The GRS came into force in April 2005[43] and have since been used by the Commission to consider reliability investments submitted by Transpower.

4.2 The economic and reliability limbs of the Grid Reliability Standards

The GRS are defined in schedule F3 of section III of part F of the Rules. The purpose of the GRS is to provide a basis for the Commission to publish the SOO, for Transpower to prepare GUPs, and for other parties to approve opportunities for transmission investments and transmission alternatives (rule 4.2).

The essence of the GRS is contained in clause 4 of Schedule F3, which states:

> For the purpose of clause 3, the **grid** satisfies the **grid reliability standards** if:
>
> 4.1. the power system is reasonably expected to achieve a level of reliability at or above the level that would be achieved if all **economic reliability investments** were to be implemented; and
>
> 4.2 with all **assets** that are reasonably expected to be in service, the power system would remain in a **satisfactory state** during and following any **single credible contingency event** occurring on the **core grid**.

Therefore, the GRS can be viewed as having two limbs;

- an 'economic limb' applicable to the entire grid; and
- a single contingency (*N – 1*) 'reliability limb' applicable only to the core grid[44].

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43 The GRS can be found at http://www.electricitycommission.govt.nz/pdfs/rulesandregs/rules/rulespdf/PartFSectionIIIScheduleF3-gridreliabilitystandards-17Jan08.pdf

44 Where 'N' refers to a number of transmission facilities and '-1' refers to a 'single credible contingency event', as defined in Part A of the Rules.

The economic limb expresses the generic reliability standard. The reliability limb is considered to be a 'safety net' that ensures a classical minimum deterministic reliability standard for the core grid[45].

Clause 6 of Schedule F3 provides that:

> For the purpose of clause 4.1 and 4.2, the expected level of reliability, and state, of the power system must be assessed using the range of relevant operating conditions that could reasonably be expected, having regard to the possible future scenarios set out in the **statement of opportunities**.

4.2.1 Role of the probabilistic analysis in the Grid Reliability Standards

The economic limb of the GRS requires a 'probabilistic' approach when deciding whether to upgrade the grid beyond the N-1 safety net. The GRS also require a probabilistic approach when assessing the expected net market costs of investments that are necessary to comply with the N-1 safety net.

The probabilistic planning approach involves estimating the probability of network and generator contingencies (based on historically observed failure rates or international benchmarks), calculating the overall capacity and reliability of the interconnected system containing these assets, and then using the 'value of unserved energy' to calculate the likely costs associated with numerous outage combinations. These costs are regarded as the 'reliability benefits' and are used:

- to trade off the costs and timing of providing additional transmission investments and transmission alternatives compared with the economic benefit of increased reliability;
- to decide on an economic basis whether proposed transmission or alternative investments should be made earlier than otherwise, or whether additional investments are required to yield a security standard at levels greater than the N-1 safety net minimum; and
- to assist in selecting investments or alternatives that minimise the expected net market cost of achieving the N-1 safety net.

This approach allows direct numerical consideration of generation and network elements that are reasonably likely to be in service, rather than consideration on a simple discretionary deterministic basis. It has a number of significant benefits when compared with the deterministic approach.

[45] For the non-Core Grid, there is no minimum N–1 standard, and there is also the possibility of a higher than N-1 standard if the economic assessment supports this.

- Alternatives to transmission that have lower reliability can be considered on an equal footing with transmission investments, instead of being dismissed due to their apparent lower reliability when considered in isolation from the expected performance of other elements of the power system.

- Innovative transmission investments can be considered, including investments in secondary assets, which do not affect deterministic security, but which nevertheless deliver reliability benefits.

- Demand-side and intermittent resources, which make a contribution to reliability, can be considered.

- The numerical evaluation of reliability gives an assurance that reliability will be maintained at adequate levels at a reasonable cost — this cannot be assumed from application of a deterministic 'rule of thumb' or 'good electricity industry practice'.

4.2.2 Role of deterministic analysis in the Grid Reliability Standards

The reliability limb of the GRS requires a 'deterministic' approach when deciding whether the core grid meets the N-1 safety net.

The deterministic planning approach involves modelling the power system to test that single contingencies will leave the system operating in a satisfactory state. This is regarded as a 'classical' approach, which was applied before the recent development of more sophisticated probabilistic analysis.

The advantage of the classical deterministic approach to planning is that it is generally simpler to apply than the probabilistic approach and it can be easier for non-experts to understand. The drawback of the deterministic approach is that its application requires a number of subjective judgments, such as:

- which options are reliable enough to qualify as alternatives—in practice few investments are as reliable as transmission options; and

- what system operating state should be considered — in other words, generation plant dispatch and demand levels.

There is a significant risk that when transmission options are expensive (relative to other options, including non-transmission alternatives) this approach will require an expensive N-1 security standard for loads that do not economically justify this standard of supply or, alternatively, provide a less than efficient supply to major loads even when it is economic to provide higher reliability level.

In developing the N-1 safety net, the Commission sought to mitigate these disadvantages as far as possible. For example, reliability benefits were included in comparing costs, and the use of modelled projects allowed, so that the cost implications of investment options could be considered over the longer term.

The single (that is "N-1") credible contingency events considered in the reliability limb are defined in Part A of the Rules as any one of the following:

(a) a single transmission circuit interruption;

(b) the failure or removal from operational service of a single **generating unit**;

(c) an **HVDC link** single pole interruption;

(d) the failure or removal from service of a single bus section;

(e) a single interconnecting transformer interruption;

(f) the failure or removal from service of a single shunt connected reactive component.

The GRS requires that the power system be in a 'satisfactory state' during and following the occurrence of any single credible contingency event. Part A of the Rules defines 'satisfactory state' as meaning that none of the following occur on the power system:

(a) insufficient **supply** of **electricity** to satisfy **demand** for **electricity** at any **grid exit point**;

(b) **unacceptable overloading** of any **primary transmission equipment**;

(c) **unacceptable voltage conditions**; and

(d) **system instability**.

4.3 Application of the Grid Reliability Standards in the Power systems analysis for the 2008 Statement of Opportunities

The SOO is required to include an analysis of the power system against the GRS. In practice, this means that the Commission:

- models inter-regional transmission against the GRS to determine when transmission constraints (based on the GRS) may occur; and
- analyses the power system for each generation scenario in the GPA, and identifies transmission opportunities that may exist when the modelling above determines that a constraint may occur.

The application of the GRS in the PSA is further explained below.

4.3.1 Analysing inter-regional transmission against the Grid Reliability Standards

The first stage of the PSA involved analysing the constraints on power flow between regions using a load flow, and listing measures to relieve the constraints in a rough hierarchy based on the cost of the measures[46]. This inter-regional analysis was used to assist with the initial development of the generation scenarios with respect to the interplay between demand, transmission, and generation at a regional level.

The inter-regional constraints were determined by an N-1 security analysis that considered the following subset of single credible contingency events:

- a single inter-regional transmission circuit interruption; and
- an HVDC link single pole interruption.

The PSA uses a simplified approach to the consideration of the GRS similar to that used in the Initial SOO, namely the use of a deterministic reliability standard. This is likely in most cases to have a similar outcome as the use of both limbs of the GRS. Detailed application of the GRS would have involved a substantially greater amount of analysis. Therefore, the Commission applied an N-1 deterministic standard in carrying out its PSA.

The Commission prefers this style of analysis to assist with considering co-optimising new generation and new transmission, when developing internally consistent generation scenarios. This enables the likely costs of transmission investment to be taken into account without requiring overly complex analysis.

4.3.2 Verifying generation scenarios

The second stage of the PSA was a more detailed analysis that was primarily intended to verify the operational credibility of the finalised generation scenarios, by modelling the power system for each scenario over a 30-year horizon 2007—2037.

The analysis was based on load flow simulations to verify that the power system would meet the deterministic limb of the GRS, and to determine the type of transmission augmentation opportunities that may achieve this. As this is only a high level analysis, there was no attempt to apply the economic limb of the GRS to the second stage of the PSA. Consequently, it should

[46] 'Inter-Area Transmission Capacity', System Studies Group NZ Limited, S013-02 Draft Revision 9, 21 September 2006.

be recognised that the transmission augmentation opportunities in the PSA have not been optimised and that alternative transmission augmentations, or transmission alternatives, may well be justified under the economic limb of the GRS.

As the demand for energy grows, the supply transformer capacity will need to be augmented to provide a secure supply to the load on low voltage buses. Modelling these supply transformer augmentations is likely to involve a considerable amount of work. Customer specific issues need to be taken into account and there is a large uncertainty in the nature of the augmentation because individual GXP demand growth is harder to forecast than national demand growth. On the other hand, not modelling the augmentations will result in an unrealistically high reactive consumption in the supply transformers. Instead of augmenting supply transformers, the analysis took the approach of maintaining a constant load power factor as viewed from the high voltage side of GXP supply transformers and eliminating the supply transformers.

The Commission holds the view that this simplified approach to the application of the GRS, as was also used in the Initial SOO, is appropriate for the purpose of the SOO. For the Commission to investigate whether at each connection point the GRS was met would involve a substantial amount of power systems analysis. The Commission notes that Transpower is required to do this as part of the GRR reporting and it would not be efficient for the Commission to duplicate this activity.

Further details on the approach adopted for the PSA, including the list of assumptions used in the analysis, is detailed in section 10 of this paper.

5. Electricity demand forecasts

5.1 Introduction

Electricity demand forecasts[47] are a key component of the GPA. This section sets out the Commission's view on demand forecasts for the New Zealand electricity market.

The Commission has an in-house specialist modelling team. It also draws on specialist external advice, academic literature and publications, and the insights gained by other parties involved in electricity demand forecasting.

The energy and peak demand forecasts presented in this document are significantly different from those presented as part of the Initial SOO. A complete review of the energy demand forecasting process has been carried out, and projections of long-term demand growth lowered as a result. The approach used for peak demand forecasting has also been substantially revised.

Throughout this section, the term 'energy demand' is used to refer to total electrical energy demand over a period of time, as opposed to peak demand, which is the highest rate at which energy is consumed[48] over the relevant time period.

The following sections set out the review process and the methodologies used for the preparation of the updated forecasts.

5.2 Forecasting national energy demand

The GPA, and the demand projections they contain, are required to have a length of outlook commensurate with consideration of future investment in long-life transmission assets. Accordingly, the Commission has prepared demand forecasts out to 2050.

The national and regional energy demand forecasts are based on annual periods from 1 April to 31 March. This is primarily driven by the availability of key input data that is published on a year-ending March basis.

The forecasts presented here are of electricity taken off the national transmission grid at the GXPs.

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47 The term 'forecast' is often used to describe a prediction of future outcomes. In the context of the Statement of Opportunities, the term 'forecast' is used to describe projections or extrapolations made by the Commission using a number of models and assumed inputs.

48 National energy forecasts are usually measured in gigawatt hours (GWh) whereas the rate of energy consumption is measured in gigawatts (GW).

Electricity is lost in transporting it across the national grid from the injection points (generation) to the GXPs. Therefore the total amount of generation is higher than total GXP off-take. The difference between grid injection and grid off-take is referred to as transmission losses.

Similarly, some electricity is lost in transporting it across the local distribution network from the GXP to the customer's meter. This is referred to as local losses. Additionally, some distribution networks have locally connected generation known as embedded generation. The total demand measured at customers' meters is different from that measured at the GXPs due to the combined effect of local losses and demand met by embedded generation**.**

The forecasts presented in this section do not include reductions or increases in demand that may occur as a result of highly uncertain influences such as the introduction of significant new demand-side management measures, or the uptake of plug-in hybrid or fully electric vehicles. Similarly, while the impact of ongoing energy efficiency improvements on demand is implicitly included in the forecasts, step changes in demand that may result from the introduction of significant new policies are not. The impact of such events is explored through demand-side scenarios, discussed in section 5.6.

5.2.1 Forecasting approach

The Commission uses econometric models for the development of its long-term national energy forecasts. The econometric models use the historical relationship between electricity demand and key drivers, such as gross domestic product (GDP), to produce future demand projections based on forecasts of those key drivers.

The Commission splits demand into three main sectors for the purpose of preparing the forecasts:

- residential;
- commercial and industrial; and
- heavy industrial (Tiwai Aluminium Smelter).

Splitting the sectors in this way is a small departure from the previous split used for modelling for the 2005 Initial SOO, where the heavy industrial group included the other industrial customers directly connected to the grid. The reason for this change is discussed below in section 5.2.4.

Each of the above sectors has different characteristics. Accordingly, different econometric models and assumptions are used for each, tailored to the particular characteristics.

5.2.2 Key drivers

The Commission tested the relationships between a number of key economic variables — or drivers (historical population, GDP, electricity prices and household figures) —and historical electricity demand for each sector.

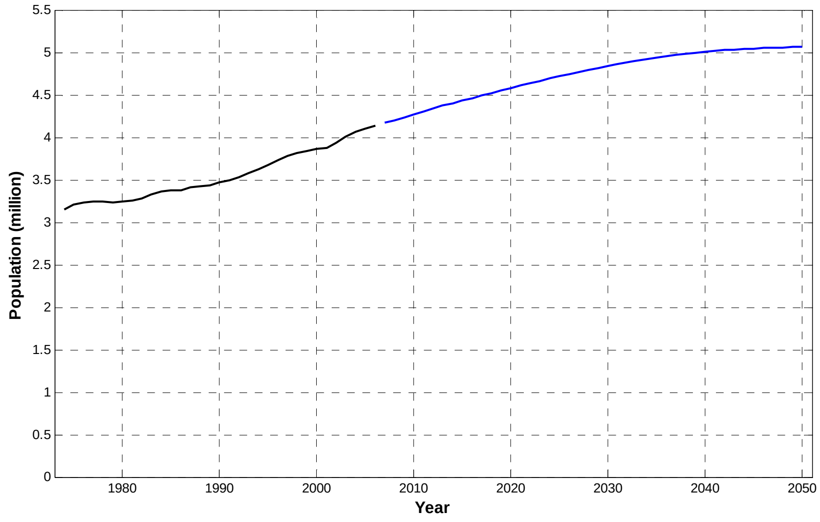
Historical economic data is readily available. However it is subject to changes in measurement techniques and definitions over time, so obtaining a reasonably consistent long-term series often requires some adjustments to historical data to be made. Long-term forecasts of economic variables are more difficult to source and their availability has some bearing on the selection of variables used in the econometric models.

Population

Historical population data is available from Statistics New Zealand. There have been some changes in the definitions used for measuring total population. Adjustments were made to the earlier population data to produce a consistent series.

Statistics New Zealand also publishes long-term projections of population based on different scenario assumptions around birth, death and immigration rates. The Commission has used the mid-level growth scenario as a baseline for forecasting. This scenario assumes medium fertility, medium mortality, and long-term net migration of 10,000 people per year. Figure 1 shows historical and forecast total New Zealand population out to 2050. In this and similar graphs in this section, historical data is shown with a black line, and the forecast with a blue line.

Figure 1 Total New Zealand Population — mean forecast



Gross domestic product

Historical real GDP statistics are published by Statistics New Zealand. Older GDP values are expressed in different base year values compared to more recent figures, so the various series have been converted to a single comparable group.

Long-term forecasts of GDP were obtained from the New Zealand Institute of Economic Research (NZIER). The NZIER forecasts are based on Statistics New Zealand population and workforce projections, and assumed changes in productivity.

Figure 2 and Figure 3 show historical and forecast GDP in absolute and percentage growth terms.

Figure 2 Total New Zealand real GDP ($1995/1996) — mean forecast

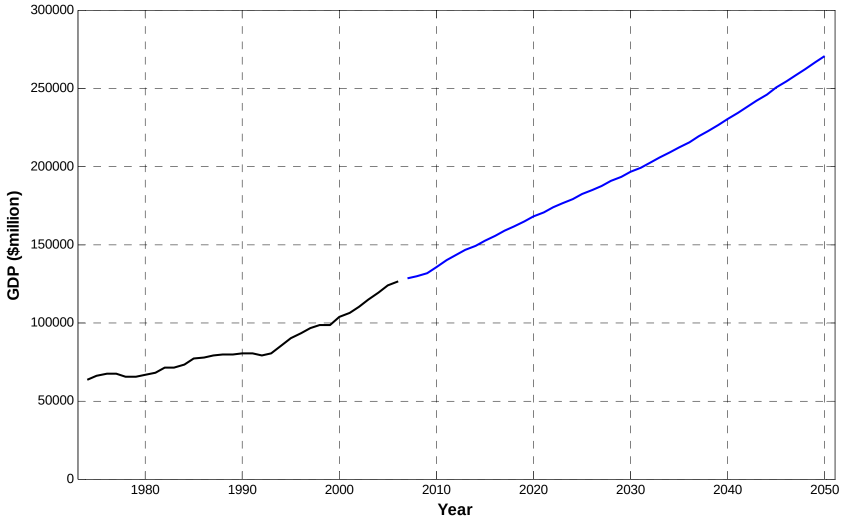
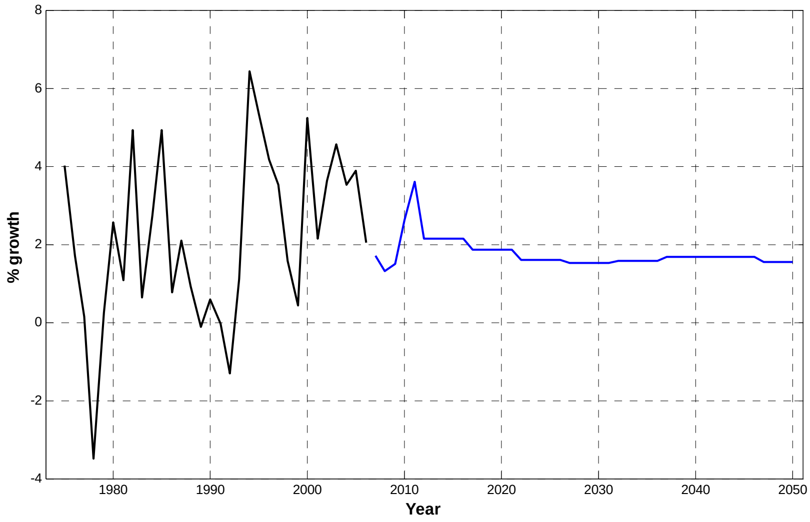


Figure 3 Total New Zealand real GDP ($1995/1996) — percentage growth

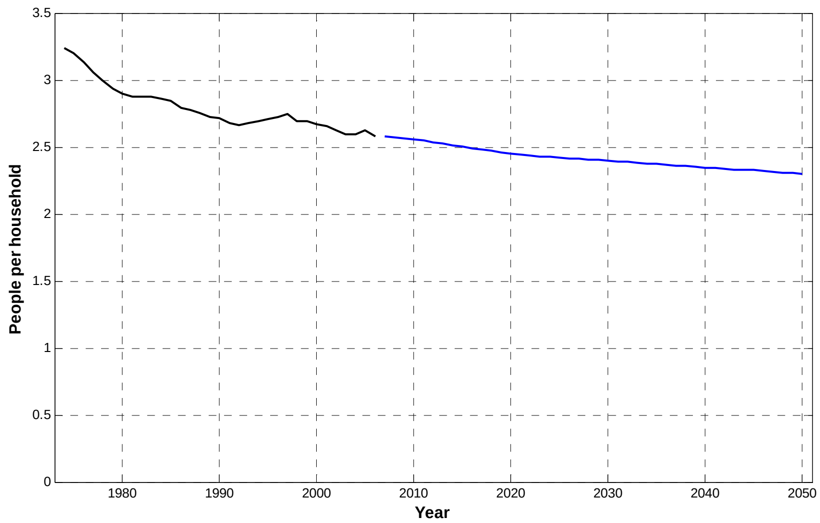


Households

Historical data on the number of residential consumers is published in the Ministry of Economic Development Energy Data File. Statistics New Zealand produces a number of projections of future household numbers based on different scenario assumptions around population and household composition. The definition of the 'consumers' data contained in the MED Energy Data File differs slightly from the household definition used by Statistics New Zealand. The Statistics New Zealand projections were therefore adjusted to retain comparability with the MED Energy Data File series.

The household projections are combined with the population projections to derive a forecast of the projected change in household size. Figure 4 shows historical and forecast average household size.

Figure 4 Average New Zealand household size



5.2.3 Demand Data

Historical demand data for the residential, commercial and industrial sectors is published in the MED Energy Data File.

The definition used to split the modelling into different consumer sectors has been changed by the Commission as better consumption information became available. The Initial SOO forecasts were based on a commercial and industrial series that had been constructed from a number of different sources over an extended period of time. The Commission used data from the newly established centralised dataset to revise the various historical demand series. This produced an updated series that could be tracked back to a combination of the Energy Data File series and checked half-hourly historical meter data.

5.2.4 Model selection

A number of different models for each sector were assessed, using different data fitting techniques and different combinations of key drivers, in order to determine which combination yielded the best predictor of demand for each sector. These included changing the sector definitions in order to test the impact of excluding additional heavy industrial loads from the commercial and industrial sector. Table 5 summarises the key drivers used in the residential, commercial and industrial and heavy industrial models.

Residential model

The residential model is unchanged from that used for the Initial SOO. It is a log-based model that relates demand per capita to GDP per capita, households per capita, and real residential electricity prices.

Commercial and industrial model

The commercial and industrial model has been revised as a result of the changes in the input series used. The change in model and series has resulted in a significant reduction in the demand forecast for this sector.

The revised model relates total commercial and industrial demand to GDP, with an adjustment for years where there was a perceived electricity supply shortage.

The key decision affecting the commercial and industrial forecasts revolves around the modelling period used for assessing the historical relationship between demand and GDP. Reasonably robust electricity consumption data exists back to 1972.

There is, however, evidence of significant structural changes in the economy in the mid-late 1970s and early 1980s, supported by a statistically significant breakpoint in the relationship between GDP and electricity demand before and after the late 1980s. Based on this, and on the feedback received during consultation carried out on the draft GPA, the Commission has taken the view that the data from the late 1980s onwards is likely to be a better predictor of future demand growth than data prior to this period.

Heavy industrial model

The Initial SOO forecasts grouped together a number of heavy industrial loads together, including the Tiwai Aluminium Smelter, for projecting future demand.

The Commission tested the impact of both excluding and including the large grid-connected industrial loads on the commercial and industrial model. There was little impact on the final national forecast, so to keep the modelling process as simple as possible only the aluminium smelter was separated out into the heavy industrial category.

The growth assumption for the heavy industrial sector has changed as a result. In the Initial SOO forecasts, the heavy industrial group was assumed to grow at the same rate as it had since the late 1980s. The revised forecast for the aluminium smelter is that it will maintain its existing levels of demand.

Table 5 Drivers used in the residential, commercial and industrial and heavy industrial model

Sector	Population	GDP	Number of households	Electricity prices	Model structure
Residential	✓	✓	✓	✓	Log based model using data from 1974 onwards.
Commercial and industrial		✓			Linear model using data from 1986 onwards.
Heavy industrial (Tiwai Point smelter)					Fixed forecast based on maximum annual historical demand.

5.2.5 Uncertainty

A key problem with forecasting demand over long time periods is the high level of uncertainty that arises due to potential changes in the underlying drivers. The nature of opportunities for investment in transmission or transmission alternatives can be sensitive to uncertainty in demand forecasts. Therefore it is important that this uncertainty is understood and incorporated into the modelling process.

The Commission has used a Monte Carlo simulation technique to model uncertainty in the key drivers. This technique involves estimating distributions for key drivers used in the model. The model is then re-run many times, replacing the actual input data with data randomly drawn from the estimated distributions. This provides a range of forecasts that confidence limits can be based on.

Population

Uncertainty in the population forecasts has been addressed by applying a scale factor to the forecasts. The scale factors are sampled from a distribution created from the various Statistics New Zealand population scenarios.

The population uncertainty in each individual run of the model is used as an input to both GDP and the number of households in that same model run. This is done to maintain consistency between the various drivers within each run.

Gross domestic product

Uncertainty in the GDP forecasts is based around three different sources of variation. The population component of GDP is kept consistent with the population scaling within each model run, as discussed above. The productivity component is varied based on an estimated range. Finally, a random component is included to introduce shocks from changes in the international environment, such as overseas market conditions. The shock component is based on historical variation against the underlying trend.

Households

Uncertainty in forecast household sizes uses two sources of variation. The population change component of household numbers is kept consistent with the population scaling above within each model run. Household size is varied based on the Statistics New Zealand household scenarios.

Electricity Prices

Residential electricity price uncertainty is dealt with by applying a simple normal distribution with a standard deviation of 10 percent to the base case price forecast. The relatively low price elasticity in the model means that there is only a small impact associated with varying electricity prices.

Embedded generation

Embedded generation is incorporated as a fixed factor in the baseline forecast. The volume of embedded generation used for assessing forecast sensitivity is held as a constant proportion of total national demand across the various model runs.

5.2.6 National demand forecasts

This section outlines the Commission's national electricity demand forecasts, produced through the modelling approach described above.

The following table shows 80 percent confidence limits and the sectoral breakdown for national demand forecast out to 2036.

Table 6 National Energy Demand Projections—March Years (GWh)

Year	Baseline	80 percent confidence limits		Sectoral breakdown			
		High	Low	Residential	Commercial & industrial[49]	Local lines losses	Embedded generation excluded
2007	37,820	38,015	37,564	12,674	25,388	1,702	1,944
2008	38,182	38,645	37,652	12,790	25,634	1,721	1,963
2009	38,616	39,303	37,862	12,936	25,921	1,743	1,985
2010	39,288	40,180	38,346	13,102	26,427	1,778	2,019
2011	40,234	41,326	39,077	13,329	27,146	1,827	2,068
2012	40,882	42,155	39,532	13,532	27,590	1,861	2,101
2013	41,523	42,975	39,971	13,719	28,044	1,894	2,134
2014	42,192	43,806	40,453	13,924	28,508	1,929	2,169

[49] This includes the Tiwai smelter.

Year	Baseline	80 percent confidence limits		Sectoral breakdown			
		High	Low	Residential	Commercial & industrial[49]	Local lines losses	Embedded generation excluded
2015	42,884	44,690	40,935	14,141	28,982	1,964	2,204
2016	43,578	45,579	41,420	14,351	29,466	2,000	2,240
2017	44,202	46,401	41,879	14,551	29,890	2,033	2,272
2018	44,839	47,227	42,322	14,754	30,323	2,066	2,305
2019	45,484	48,039	42,783	14,960	30,763	2,099	2,338
2020	46,140	48,861	43,221	15,167	31,212	2,133	2,372
2021	46,798	49,745	43,661	15,367	31,669	2,167	2,405
2022	47,368	50,492	44,067	15,534	32,072	2,197	2,435
2023	47,946	51,265	44,481	15,701	32,482	2,227	2,464
2024	48,530	52,081	44,844	15,869	32,898	2,257	2,494
2025	49,121	52,866	45,190	16,037	33,321	2,287	2,525
2026	49,718	53,673	45,639	16,204	33,751	2,318	2,555
2027	50,295	54,425	45,986	16,368	34,164	2,348	2,585
2028	50,878	55,180	46,353	16,530	34,584	2,378	2,615
2029	51,466	55,995	46,751	16,692	35,011	2,409	2,645
2030	52,059	56,813	47,138	16,852	35,444	2,440	2,676
2031	52,658	57,651	47,556	17,011	35,883	2,471	2,707
2032	53,280	58,568	47,910	17,172	36,344	2,503	2,739
2033	53,907	59,412	48,295	17,330	36,812	2,535	2,771
2034	54,540	60,327	48,706	17,488	37,287	2,568	2,803
2035	55,179	61,230	49,088	17,644	37,770	2,601	2,836
2036	55,823	62,107	49,518	17,798	38,260	2,635	2,869

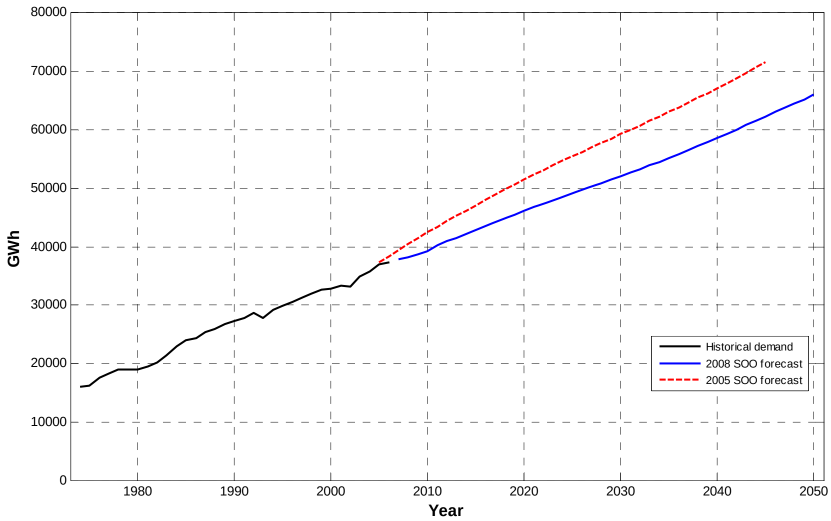
Figures in GWh

80 percent confidence limits: High = 90th percentile, Low = 10th percentile

Total demand = Residential demand + Commercial/Industrial Demand + Local lines losses - Embedded generation

Figure 5 shows historical total national demand, the 2005 Initial SOO forecasts, and the revised 2008 SOO forecasts.

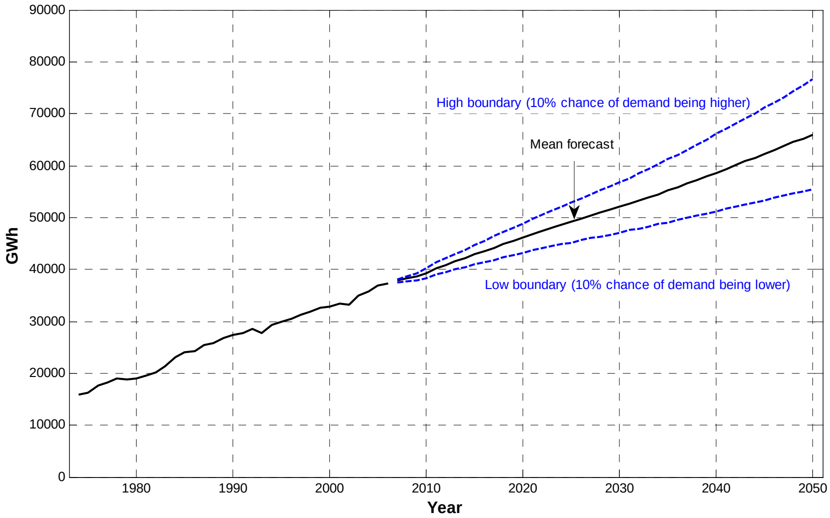
Figure 5 Historical and forecast total national energy demand



The demand growth rate is initially low due to forecast GDP growth being lower than average until 2009. At that point growth rates increase over the medium term, and then ultimately taper off as economic growth and population growth gradually drop away.

Figure 6 shows the 80 percent confidence limits in a graphical form to demonstrate the sensitivity of demand to uncertainty in the key drivers.

Figure 6 National energy forecast 80 percent confidence limits



5.3 Forecasting regional energy demand

The limited availability of regional sectoral demand and key driver information severely restricts the options available for forecasting regional level demand.

The approach adopted to date has been to allocate forecast national electricity demand to regions based on the key drivers that are available at a regional level. It would be preferable in the long-term to more accurately model demand within the regions. However, this will only be possible once suitable data collation processes have been established and in place for some time.

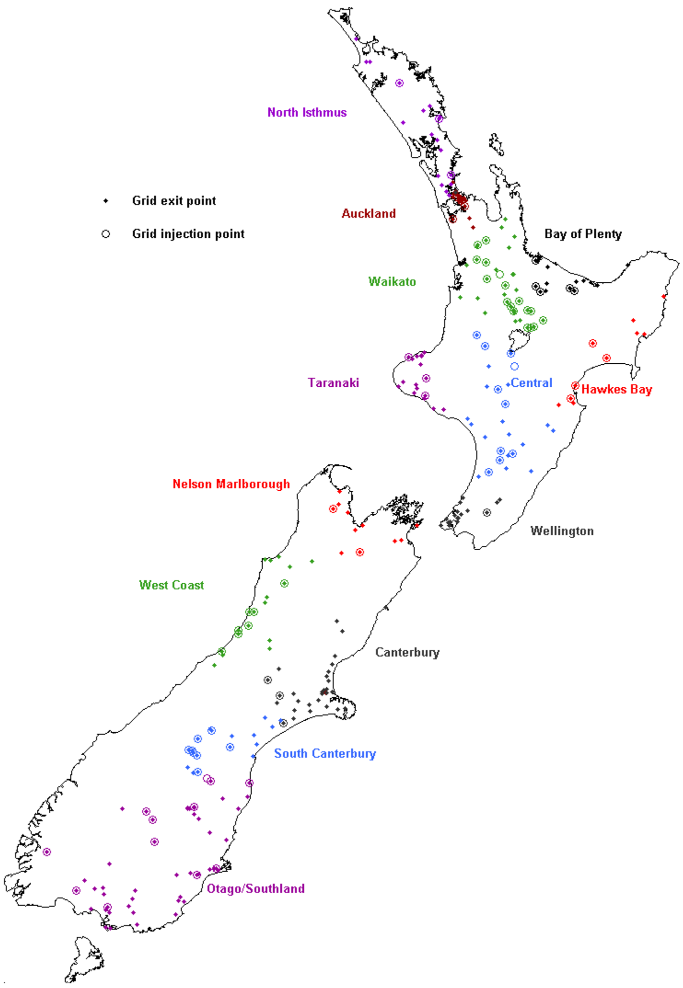
In the Initial SOO, the Commission adopted the approach used by Transpower. This approach, in general terms, allocates total forecast demand to regions, with the allocation based on population projections obtained from Statistics New Zealand.

The revised approach adopted by the Commission in preparing the 2008 SOO is to continue allocating residential demand based on regional population projections, but to allocate commercial and industrial demand based on regional GDP projections.

The regions used by the Commission are determined by the configuration of the transmission grid rather than by regional council boundaries. In most areas there is no difference in this definition, but there are a small number of exceptions where GXPs are defined as being in regions different from those they are normally associated with.

Figure 7 shows the GXPs and Grid Injection Points (GIP) graphically. A list of GXPs contained within each region is included as Appendix 1.

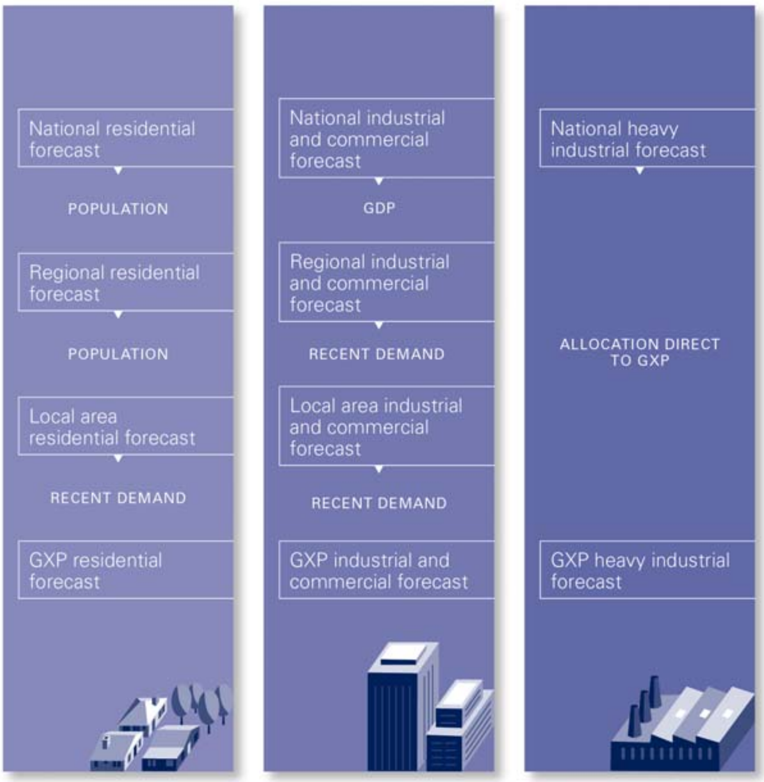
Figure 7 Grid Exit Points and Grid Injection Points



A breakdown of the current split of residential demand versus commercial and industrial demand at a regional level was obtained from electricity retailers by the Commission. This was used as a starting point for projecting the industry sectors forward based on changes in projected population and GDP.

GXP level forecasts were calculated by allocating the various regional totals to the relevant GXPs. Population forecasts were available from Statistics New Zealand at the old Electric Power Board level. The Electric Power Board areas are a useful level of aggregation as they provide an approximate grouping of demand that is supplied through each local area network. Residential demand was initially allocated to the Electric Power Board level based on forecast population for each area. This was then further allocated to individual GXPs based on recent demand. Commercial and industrial demand was allocated from the regional forecasts straight to GXP level based on recent demand.

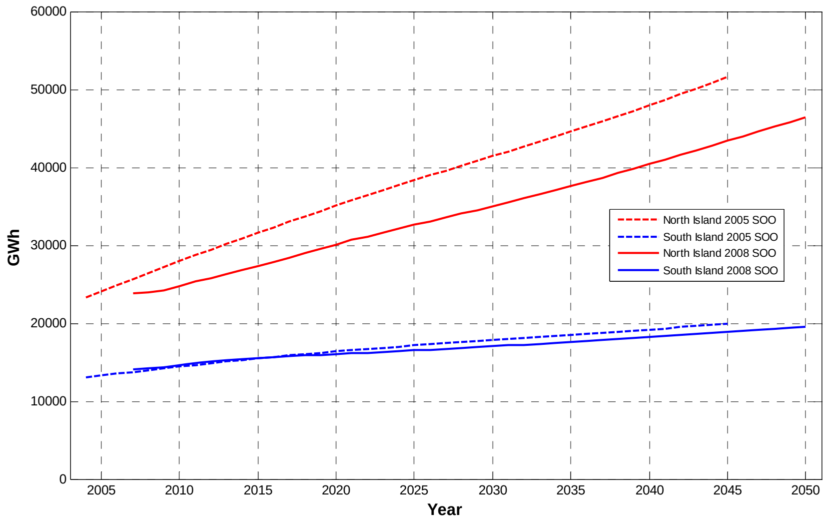
Figure 8 Allocation process—from national to regional GXP by sector



Some regions have experienced significant recent growth as a result of short-term changes in energy intensity in some industries. These changes would not necessarily be reflected in a simple allocation based on GDP or population. To capture the impact of the short-term trends, recent demand in each region has been extrapolated and used to allocate higher demand to those areas that have seen recent fast growth (and as a consequence, lower demand to the lower growth areas). The impact of the extrapolated growth in each region is weighted relative to the impact of the underlying GDP/population allocation, with the weighting reducing over time following a logistic curve[50]. The Tiwai aluminium smelter has been excluded from the calculation of the recent Otago/Southland trend, consistent with the assumption of no future demand growth at the smelter.

The impact of the combined reduction in the national level forecasts and the change in regional allocation is illustrated in Figure 9. It shows the relative balance of demand in the North Island and South Island in the new forecasts, compared with the allocation used in the Initial SOO.

Figure 9 Island energy demand forecast



Regional GWh figures have been included in Appendix 2.

50 Logistics curves are often used to describe the transition from one 'state' to another. The initial rate of change is approximately exponential, then as saturation begins, the rate of change slows and gradually stops.

5.3.1 Regional uncertainty

Like the national demand forecasts, the regional forecasts are subject to uncertainty arising from a number of sources, including modelling error and input uncertainty.

The range of national demand forecasts generated as part of the assessment of national level demand uncertainty has been allocated through to a regional level using the regional allocation methodology outlined above. The Commission has adjusted the approach used in the Initial SOO by including additional uncertainty in inter-regional population changes relative to the Statistics New Zealand base Electric Power Board level forecasts. The resulting distribution of regional demand forecasts is used to calculate confidence limits for each region.

5.4 Forecasting peak demand

The GPA include forecasts of peak demand as well as the energy demand forecasts described above. Peak forecasts are important for transmission planning and investment decision-making.

Peak demand is defined for this purpose as the maximum of the average demand levels in all the half-hours ('trading periods') in a calendar year (as opposed to the highest instantaneous demand). Typically, demand peaks occur on weekdays in winter; they can occur either in the morning (often around 8am) or in the early evening. They are generally associated with cold weather events during which domestic heating demand is high.

The methodology used for calculating the peak demand forecasts is substantially different from that used for the Initial SOO. The goals driving the changes are:

- incorporate information on recent trends in peak demand, ensuring that if a region has experienced rapid increase in peak demand over the last few years, the peak forecast continues to increase at a similar rate for the next few years; and
- provide a range of scenarios, from an 'expected' growth scenario with average demand growth, to a more conservative 'prudent' scenario with much higher, but still plausible, peak demand growth.

Two distinct sets of peak demand forecasts are included in this document:

- prudent and expected peak forecasts; and
- after diversity maximum demand peak forecasts.

The prudent and expected forecasts are designed to show the range of plausible demand growth rates, from the 'expected' forecast (an average growth scenario) to the 'prudent' forecast (a high growth scenario).

- The generation scenarios described in section 9 of this document were developed using the 'expected' peak forecasts.
- The ADMD forecasts were developed using both the 'expected' and 'prudent' peak forecasts. The ADMD forecasts use the growth rate of the 'prudent' forecast for the first five projected years, reflecting the need to plan transmission to serve high but plausible levels of demand growth in the near future. After the first five years, the ADMD forecast growth rate declines towards the growth rate of the 'expected' peak forecast, reflecting the reduced requirement for conservatism in the long-term (since transmission plans can be adjusted in the future if demand growth is higher than expected).
- The LPC forecasts presented in section 5.5 are based on the full range of possible growth rates, encompassing both the expected and prudent peak projections.

Like the energy forecasts in section 5.3, these forecasts are expressed at GXP level (including distribution but not transmission losses). They are net of embedded generation, that is they represent total electricity demand minus the output of New Zealand's embedded generators.

Note that these forecasts make no explicit allowance for the possible impacts of increased demand-side response. In particular, the forecast has not been revised downwards to model the probable benefits of increased load management or demand-side price response. The Commission considers that these demand-side measures will be among the options for dealing with the demand peaks that are forecast, and should be modelled alongside supply-side measures.

These forecasts also make no explicit allowances for the impact of improved energy efficiency on energy consumption or peak demand. Energy efficiency has steadily improved during the historical period on which the forecasts are based, and is therefore captured in the forecast. It is expected that this trend will continue, but can provide the forecast does not assume that the rate of improvement in energy efficiency will increase over the long-term.

Recent changes to the transmission pricing methodology may have implications for the incentives for electricity lines businesses to use their load management assets to reduce peak demand. At this stage, the impact of these changes on coincident peak demand is unknown and has not been modelled.

5.4.1 Prudent and expected peak forecasts

The prudent[51] and expected peak forecasts cover a range of possible growth projections[52]. The expected forecasts represent an 'average growth' scenario; the prudent forecast incorporates higher growth rates and also considers year-to-year variation in peak demand.

The prudent and expected peak forecasts are included in the GPA because of their role in indicating the Commission's views on possible peak demand growth. They are also key inputs to the processes of producing LPC forecasts, ADMD forecasts, and generation scenarios, which, in turn, are important inputs to the GIT analysis.

Prudent and expected peak forecasts are produced at the regional, island, and national levels, and also on the 'half-island' level (Upper and Lower South Island, Upper and Lower North Island). While the energy forecasts presented in section 5.3 are additive over regions, the same does not apply to these peak forecasts. Due to diversity of load, the joint peak forecast for each island will be slightly less than the sum of the regional peaks within that island, and the peak forecast for New Zealand will be less than the sum of the North and South Island peaks.

The peak forecasts are annual (representing the highest projected half-hourly demand occurring in a given calendar year), and cover the period from 2007 to 2049.

The expected forecasts are calculated as projections of historical peak demand series. Predicted growth rates are driven in the short term (up to five years in the future) by projecting historical peak demand growth forward. In the longer term, peak demand growth is projected to proceed at the same rate as energy demand growth.

Demand growth in some regions is adjusted for known 'step changes' at specific sites. For example, it is assumed that the electricity demand of the aluminium smelter at Tiwai will plateau at 605 MW (demand at coincident peak), rather than continuing to grow as it has in recent years.

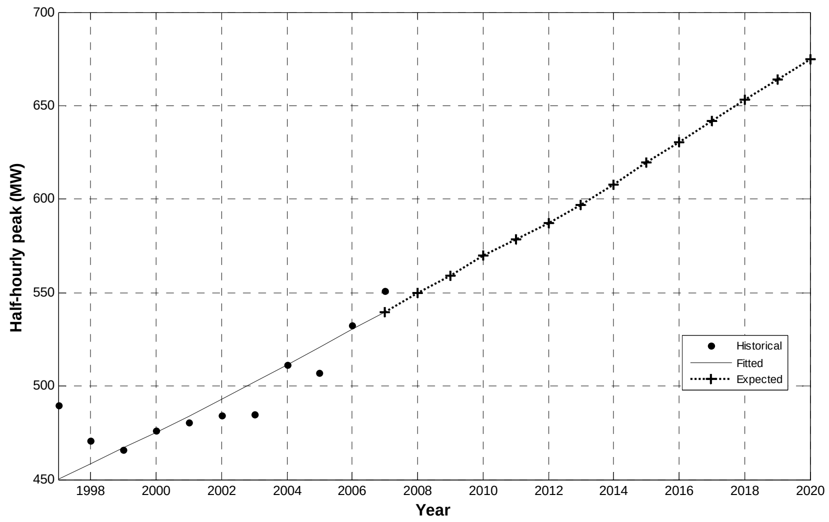
The prudent forecasts are based on a 10 percent probability of exceedance (PoE) criterion. In other words, they are calculated as the 10th percentile of the probability distribution of future peak demand, allowing for various unpredictable factors that may influence demand growth. These factors include weather (high-demand peaks are closely correlated with cold temperatures), uncertainty about energy growth rates, and uncertainty about the relationship between peak and energy growth.

51 Prudent demand forecasts are used to assess compliance with the N-1 safety net.

52 A document presenting the regional, island and national forecast of peak electricity is available at http://www.electricitycommission.govt.nz/pdfs/opdev/modelling/GPA/Expected-and-prudent-peak-forecast.pdf

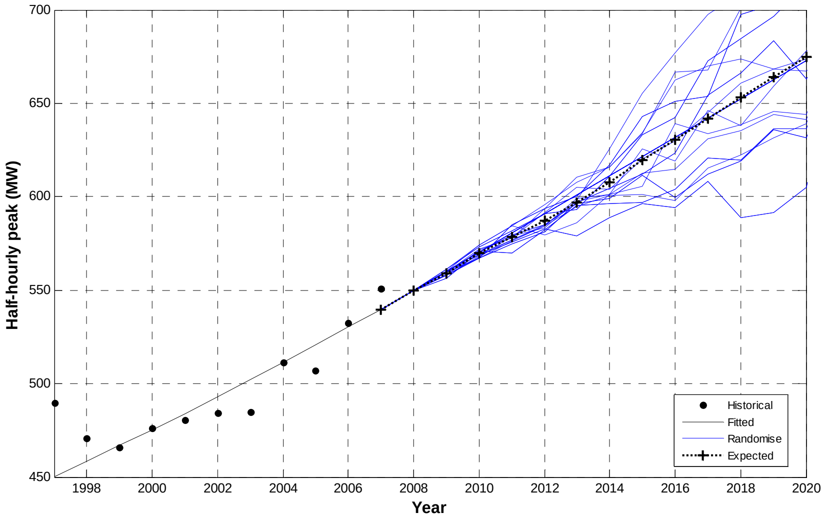
The following diagrams demonstrate the combination of the various sources of uncertainty used to produce the prudent peak forecasts, for an example region. The first step is to produce an expected peak forecast.

Figure 10 Example: 'expected' peak forecast derived from historical trends and from the expected forecast of energy growth



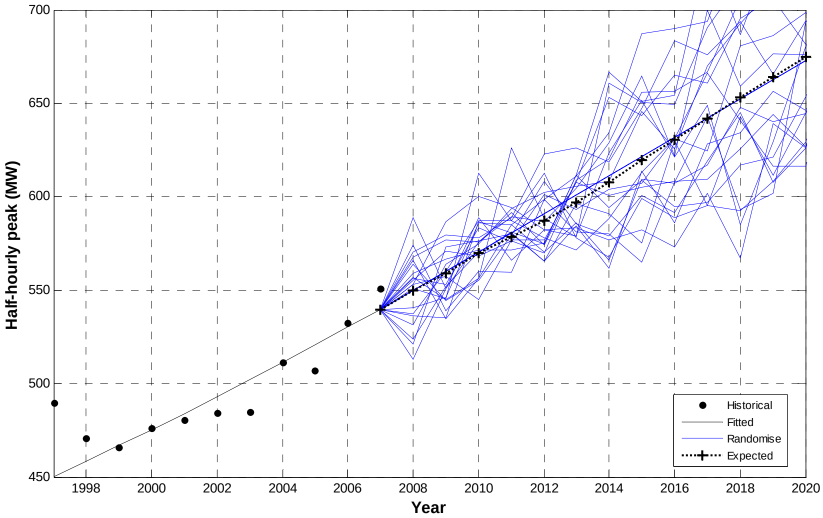
Many randomised trajectories of energy demand growth have been produced; each leads to a different trajectory of peak demand growth. A few of these trajectories are shown in Figure 11.

Figure 11 Example continued: with energy demand growth variation



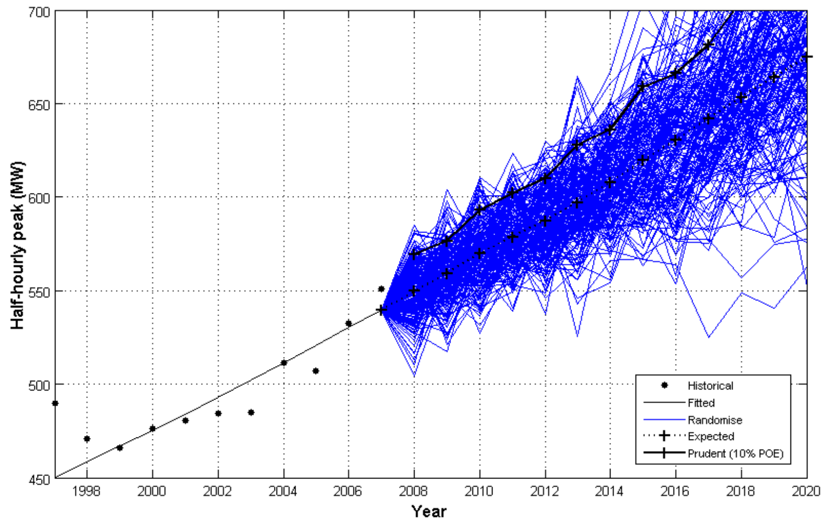
Next, in 20 percent of these randomisations, it is assumed that peak demand growth is faster than energy demand growth over a period of up to five years. Then, between-year variation in peak demand is added to each trajectory.

Figure 12 Example continued: with peak variability



The 90th percentile of the values in each year is the prudent forecast.

Figure 13 Example continued: the prudent peak forecast is the 90th percentile



Note that the gap between 'expected' and 'prudent' forecasts is considerably larger than the likely variation from year to year. In the longer term, it would not be expected that peak demand would jump from the current 'expected' forecast to the 'prudent' forecast from one year to the next. Rather, it would be expected that the level of the prudent forecast would be reached only after several years of growth above the 'expected' projection.

The prudent and expected peak forecasts (National, North Island and South Island) are included in Appendix 3 of this document[53].

The expected forecast predicts approximately 1.9 percent annual growth in national peak from 2007 to 2012, 1.5 percent growth from 2012 to 2020, and 1.2 percent from 2020 to 2030.

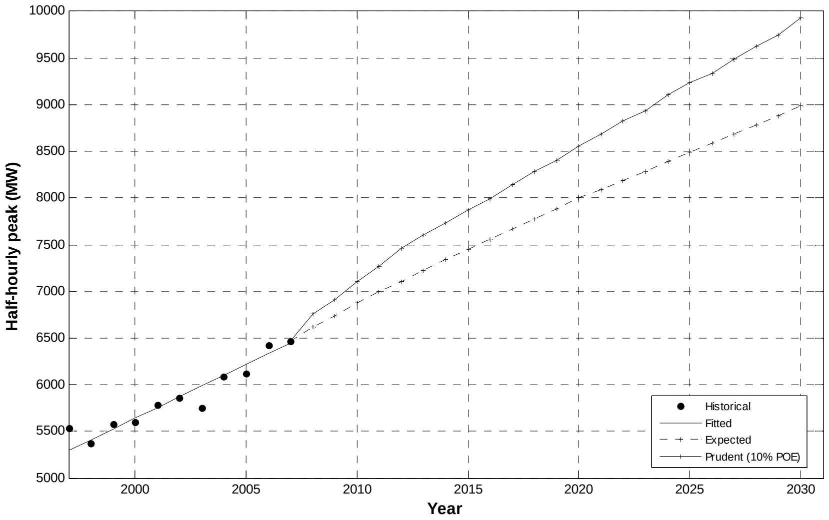
The prudent (P10)[54] forecast of national peak is initially 140 MW higher than the expected forecast (about 2 percent higher) and grows at a faster rate from that point onwards: 2.5 percent from 2008 to 2012, 1.7 percent from 2012 to 2020, and 1.5 percent from 2020 to 2030.

[53] The regional prudent and expected forecast are available at http://www.electricitycommission.govt.nz/

[54] P10 is shorthand for 10 percent probability of exceedence. That is, there is a 10 percent probability that the observed demand will be more than the forecast.

The national expected and prudent peak forecasts are shown in Figure 14. These forecasts have also been produced separately for each island, and these are shown in Figure 15 and Figure 16 respectively.

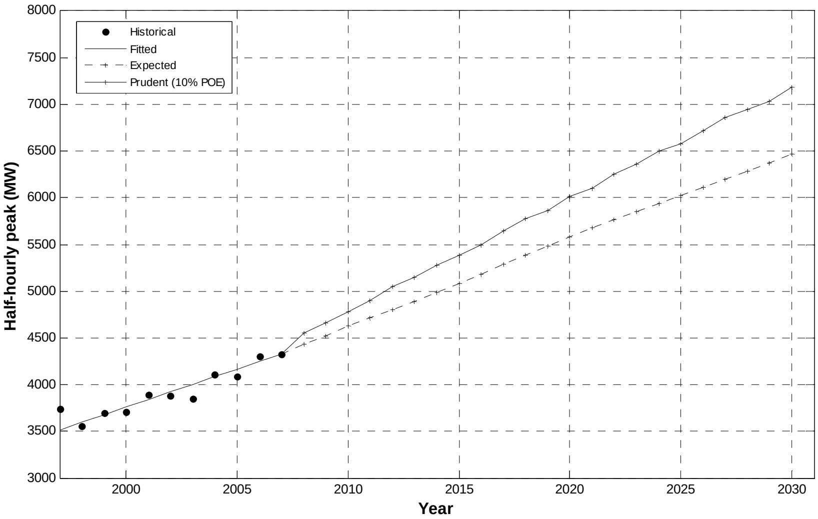
Figure 14 National peak demand forecast



For the North Island, the expected forecast predicts approximately 2.0 percent annual growth from 2007 to 2012, continuing at 1.9 percent until 2020, and 1.5 percent from 2020 to 2030.

The prudent (P10) forecast of North Island peak is initially 120 MW higher than the expected forecast (or 2.8 percent higher) and grows at a faster rate from that point on: 2.6 percent from 2007 to 2012, then 2.2 percent until 2020, and 1.8 percent from 2020 to 2030.

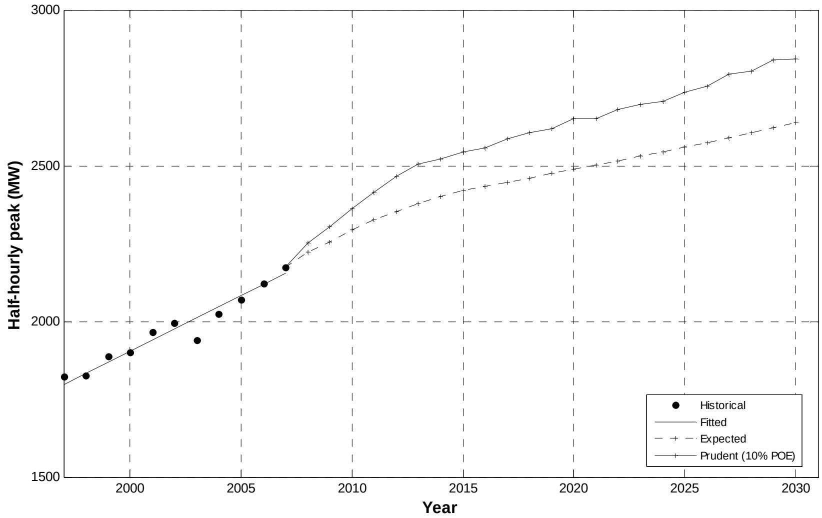
Figure 15 North Island peak demand forecast



For the South Island, the expected forecast predicts approximately 1.6 percent annual growth from 2007 to 2012, down to 0.7 percent from 2012 until 2020, and continuing at 0.6 percent from 2020 to 2030.

The prudent (P10) forecast of South Island peak is initially just 30 MW higher than the expected forecast (or 1.3 percent higher) and grows at a faster rate from that point on: 2.3 percent from 2007 to 2012, down to 0.9 percent from 2012 until 2020, and continuing at 0.7 percent from 2020 to 2030.

Figure 16 South Island peak demand forecast



5.4.2 After diversity maximum demand peak forecasts

The ADMD peak forecasts are a key part of the GPA; they are the peak forecasts that are used in constructing consistent power-flow cases. An ADMD forecast can be viewed as representing a snapshot of a future high-demand state on the grid. The snapshot accounts for the fact that the peak demands forecast for each GXP or region do not all occur simultaneously. Whereas a GXP or regional peak forecast may be useful for analysing connection assets, the ADMD forecast is more useful for analysing core grid loading. The ADMD forecasts are intended to incorporate an allowance for possible high peak growth over the next five years, while following an expected growth path beyond that timeframe. They are constructed using the regional prudent and expected peak forecasts, with a number of additional adjustments applied. The process used to produce the ADMD peak forecasts is described below.

The mean 2007 peak for each GXP is assessed using half-hourly meter data from 1997 to 2006. Starting peaks are based either on the GXP's peak trend over that period, or on a mean value if there is significant disruption or variation in the peaks at the GXP.

Diversity factors, which relate the peak load at each GXP to the peak of the region containing the GXP, are calculated using 2006 calendar year data. The peak load for each GXP is projected forward using the regional energy forecasts—for the raw peak forecasts it is assumed that peak growth increases at the same rate as total energy growth. Projected raw region peaks are then calculated by applying the diversity factors to the GXP projections.

The individual mean GXP forecasts are then scaled so that the regional total peaks for the first five years of the forecasts (after adjustment for the diversity factors) match back to the 10 percent PoE region forecasts calculated above. For the sixth and subsequent years the forecasts are scaled by the same proportion used in year five. This ensures that shorter term variation in peaks is included within the timeframe required for committing new transmission build, without over-inflating the peak projections used for long-term planning due to uncertainty in the GDP and population forecasts.

Two minor additional adjustments are then made to the resulting peak projections to produce the ADMD forecasts:

- to allow for the impact of generating plant embedded in the local line company networks, the peak forecasts are increased slightly to incorporate potential growth in demand 'hidden' behind GXPs by embedded generation; and
- additional peak load adjustments are also made in regions where identified 'committed' new load represents a significant proportion of the existing regional load. A total of 22 MW of committed new load has been identified in the West Coast region and 10 MW additional load at the new Black Point GXP in the Waitaki area. 12 MW of new load has been included in the Taranaki region. The new loads are expected to come online between 2008 and 2009 and have been added directly to the peak forecasts.

The ADMD peak forecasts presented in this paper (see Appendix 4) are the regional loads at the time of island peak as used in the power systems analysis. The individual peaks projected for each region are slightly higher.

5.5 Load probability curve forecasts

Load probability curve (LPC) forecasts[55] are not GPA as such, but are provided for the information of participants. It may sometimes be appropriate for them to be used in applying the GIT. The LPC conveys additional information about the likelihood of demand beyond say the 90th percentile.

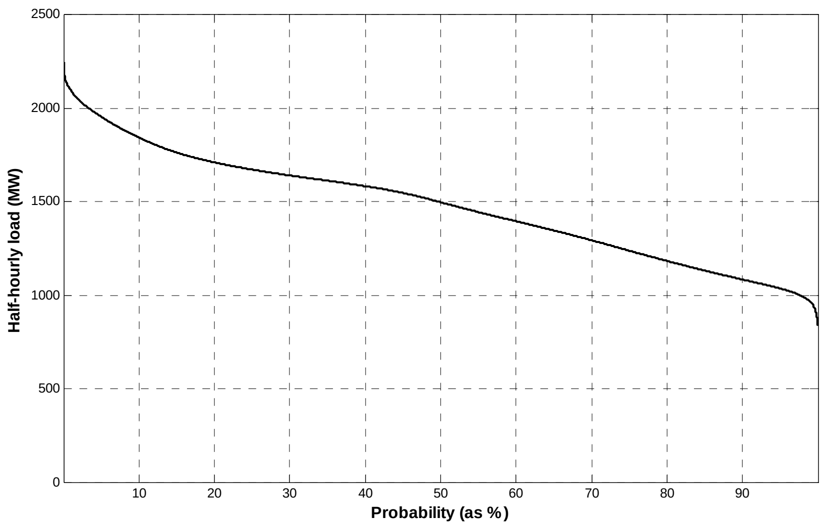
A half-hourly LPC is a curve that indicates the probability that any given load level will be exceeded in a trading period drawn randomly from a specified future year. The spread of this

[55] A document presenting the regional, island and national LPC forecast together with the methodology used is available at http://www.electricitycommission.govt.nz/pdfs/opdev/modelling/GPA/Regional-LPC-forecast.pdf

distribution is a combination of the variation of load levels within a reference year and the uncertainty in peak and energy growth forecasts.

An example LPC is shown in Figure 17 below.

Figure 17 Example load probability curve

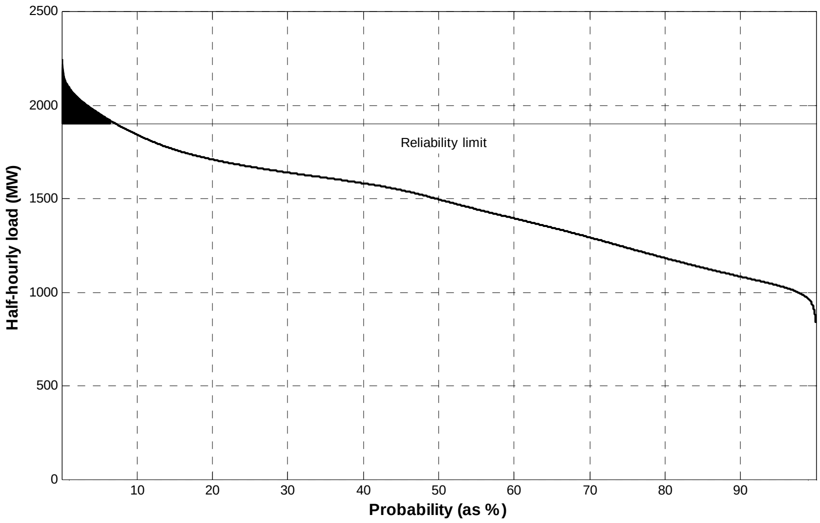


The LPC should not be confused with the load duration curve (LDC), which is a plot that shows the number of trading periods exceeding each given load level in a time period. The two curves have the same form, but the LPC is a probabilistic forecast that incorporates uncertainty in demand growth, whereas the LDC is deterministic.

It is important to note that the LPCs relate to half-hourly rather than instantaneous demand. If a given load level of *x* MW occurs at the 0.1 percent mark on the curve, then this indicates that there is an 0.1 percent chance that a randomly chosen half-hour will have an average load of at least *x* MW — not, for example, that instantaneous load is expected to exceed *x* 0.1 percent of the time. Since instantaneous peak is always higher than half-hourly peak, it would not be surprising if the instantaneous peak in a given future year was higher than the top of the half-hourly LPC.

A key application of the LPC is in stochastic reliability studies. The LPC is used to model variation in demand, including forecast uncertainty. In a simple case, a given load level is defined as the maximum that can be supplied, with all load over this level being unserved. The expected unserved energy over a given time period is then calculated as the area of the portion of the load probability curve over the maximum served load level (shaded area in plot below), multiplied by the duration of the period.

Figure 18 Load probability curve—unserved energy



In more complex studies, the load level that can be supplied is also stochastic (depending on generation and transmission availability), and the calculation of expected unserved energy involves convolving the distributions of supply and demand.

It may be noted that the LPC forecasts are not appropriate for use when high or low-demand sensitivities are required. In those cases, it would be better to use LDC forecasts based on high or low growth rates. The Commission can develop such LDC forecasts as required.

Plots of the LPC forecasts are included in Appendix 5 of this document. Those forecasts are expressed on the same scale as the peak and energy forecasts (demand at GXP level, net of embedded generation) and cover the same timeframe and geographical regions.

Seasonal LPC forecasts have also been prepared but are not presented here. The Commission can provide these forecasts on request.

5.6 Demand scenarios

5.6.1 Plug-in hybrid electric vehicles demand forecast

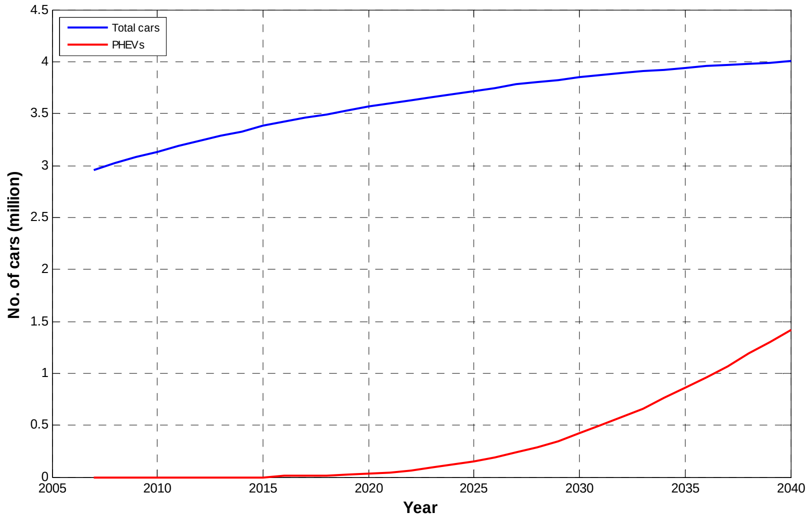
The Commission considers it reasonable to assess the impact electric vehicles and plug-in hybrid electric vehicles may have on electricity demand and on generation and transmission development. Support for electric vehicle development has recently been signalled through the NZES, and internationally there is clearly a great deal of research and development directed toward commercial availability of these vehicles.

Due to the typically short daily commute distance in New Zealand, the electricity demand of either plug-in hybrid electric vehicles or electric vehicles would be very similar (that is, even for plug-in hybrid electric vehicles, most trips would be fully electric). Consequently the term 'electric vehicle' is used loosely to refer to full electric vehicles, plug-in hybrid electric vehicles or fuel cell vehicles.

The electric vehicle demand has been modelled as an additional component of demand, added to the base forecast in two of the five scenarios, the Sustainable Path and Demand-side Participation[56]. The electric vehicle demand forecast is based substantially on an electric vehicle penetration scenario developed by the Ministry of Transport (MoT), using their vehicle fleet emissions model. The vehicle fleet emissions model produces a projection of total number of vehicles of different types (Figure 19), and total vehicle kilometres travelled.

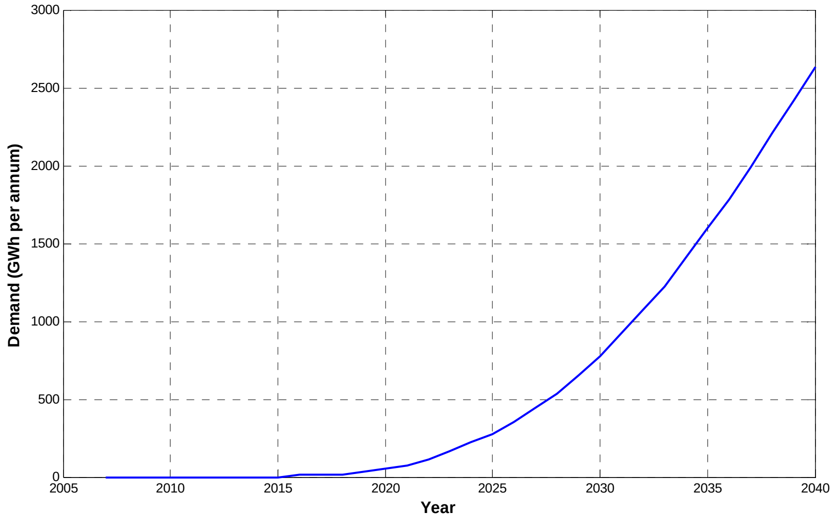
[56] Refer to section 9 for discussion of these and the other scenarios developed for the 2008 SOO.

Figure 19 Fleet composition



Additionally, MoT provided the Commission with trip distance data from the Household Travel Survey. Assuming a pro-rata allocation of vehicle kilometres travelled to the total electric vehicle fleet, an assumed electric vehicle daily range, and energy consumption per vehicle kilometres travelled, a simple calculation yields the electric vehicle energy demand, in GWh per annum. Data from the Household Travel Survey also enables an allocation of electric vehicle demand on a regional basis. The resulting electric vehicle energy demand forecast is illustrated in Figure 20.

Figure 20 Plug-in hybrid demand forecast

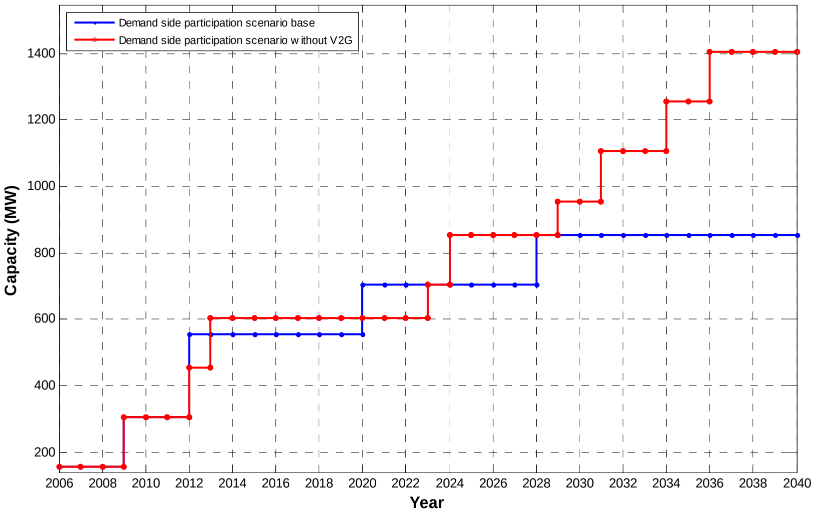


There are a number of options for recharging these vehicles. For instance, they can be charged overnight ('off-peak'), or the load can be spread over the entire 24 hours of the day ('anytime'). The Commission considers that ultimately electric vehicles are likely to be charged off-peak, with some ability to shift the charging time in response to price or other supply-side constraints. It is possible that electric vehicles will participate in balancing intermittent generation (through smart metering and vehicle-to-grid or vehicle-to-house technology), and may enable a greater penetration of wind generation into the electricity system. These issues are still under investigation by the Commission, and will be incorporated in the GEM model at a later date.

For now, the Commission has assumed a charging profile for the demand that is mostly off-peak, with some small contribution during peak demand periods. In the 'demand-side participation' scenario, the electric vehicles were also modelled as a price-responsive curtailment, to mimic the vehicle-to-grid technology. In this scenario the presence of electric vehicles caused a reduction in peaking plant requirement from 1400 MW to 850 MW in 2040, illustrated by the expected peaking plant installed capacity in Figure 21.

Future investigation of these issues will require representation of demand-side response, wind variability, pumped hydro, and wind balancing, and other reserve types in GEM.

Figure 21 Installed capacity of diesel and gas peakers with and without the plug-in electric vehicles to grid technology



6. Overview of the scenarios and the development approach

This section describes the Commission's approach to scenario development for this SOO and provides a brief description of the five generation scenarios. This section also includes a discussion of how the scenario approach within the SOO will have a bearing on scenario evaluation under the GIT, plus a brief discussion of GEM, the Commission's purpose-built scenario development tool.

6.1 Approach to scenario development

6.1.1 Overview

The GPA are required to contain, among other things, 'committed projects for additional generation…'[57] and 'a reasonable range of credible future, high-level generation scenarios…'[58].

The committed generation projects and future generation scenarios inform the market and support industry transmission planning processes.

- They form part of the GPA that feed into the scenarios set out in the SOO and are the default MDS used in applying the GIT to grid investment proposals put forward by Transpower (in a GUP) (See section 2.3.1 and section 6.3 for further discussion on the relationship between the SOO scenarios and the GIT process).
- They provide stakeholders who may wish to undertake their own analyses with a reasonable range of credible future scenarios.

Scenario techniques are typically adopted where the range of plausible future uncertainties is sufficiently wide that decision-making or planning outcomes would be markedly different under different states. Projecting transmission requirements over the economic lifetime of generation and transmission assets would appear to be such a situation. The approach generally involves developing a set of scenarios intended to encompass a credible range of future uncertainties.

[57] Rule 10.3.1.1 of section III of part F.

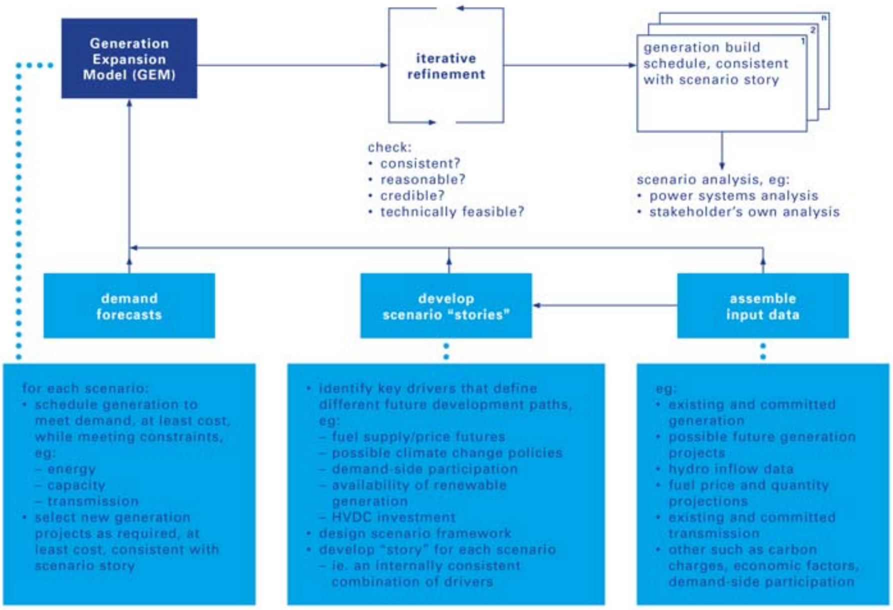
[58] Rule 10.3.1.3 of section III of part F.

The scenario development process has three main steps.

- Assembling input data, including information on existing, committed and future generation, and also on fuel price projections, carbon charges, economic factors, aspects of the transmission system, demand-side participation, etc.
- Developing the scenario 'stories'—that is, identifying the key drivers and assumptions (for example fuel cost and availability, discount rates, carbon price) which guide the future development paths in the scenarios, and determining which internally consistent combination of drivers will apply in each scenario.
- Running the models to develop each generation scenario.

This process is illustrated in Figure 22.

Figure 22 Generation Expansion Model diagram



It should be noted that the modelling approach is not output-driven. That is, the input assumptions have not been chosen to deliver a pre-determined outcome (such as a certain quantity of generation build at a particular time and location). Rather, the Commission has used an internally consistent model that dynamically schedules generation build based on underlying input drivers that have been constructed on an internally consistent basis.

Input assumptions have been chosen to cover a reasonable range of possible values, with regard to the level of uncertainty involved, rather than to yield specific outcomes.

These steps are repeated, in a process of iterative refinement, until the scenarios are reasonable, credible, technically feasible, suitable for power systems analysis, and accurately reflect the stories that they are intended to depict.

Stakeholders can reproduce the scenarios by downloading the GEM model[59] and running it to generate build schedules. This allows interested parties to investigate the effects of varying any assumption on the end result. The Commission sees this as a step forward from the Initial SOO, where the scenario development could not easily be reproduced.

This new approach also provides greater flexibility to Transpower to modify the scenarios, as a result of its own consultation during the process of preparing investment proposals, and to do so in a way that is transparent and able to be replicated by the Commission or other stakeholders.

6.1.2 Reviewing inputs, assumptions, and scenario framework

The Commission prepared and published a set of information on committed and possible future generation projects in 2007 and early 2008 in the lead up to its preparation of the 2008 SOO. The information was compiled following discussions with stakeholders and consideration of specialist reports commissioned from generation experts.

In particular, the Commission:

- updated input data in response to announcements by participants and reviewed a number of industry publications such as annual reports and energy outlook papers;
- updated its centralised dataset which contains factual and historical information on the transmission system, nodal prices, bids and offers, demand and generation information;

59 The GEM model can be downloaded at http://www.electricitycommission.govt.nz/opdev/modelling/gem/index.html

- held discussions with stakeholders to explore possible future generating projects, fuel supply and cost projections, major maintenance programmes and other relevant information;
- drew on data from reports commissioned for the TTER project including hydro, wind and geothermal; and
- engaged a consultant to provide information on the potential marine (wave and tidal) generation worldwide and more specifically in New Zealand.

6.1.3 Developing the scenario 'stories'

In preparing to develop a set of scenario stories, the Commission:

- reviewed experience from the Initial SOO and from recent consideration of investment proposals put forward by Transpower;
- reviewed the approach adopted by other parties in developing a scenario framework and/or development methodology (for instance, MED, Solid Energy);
- explored possible modelling methodologies and scenario development techniques;
- considered the energy policy context, likely drivers of future supply and demand and key uncertainties; and
- engaged with a representative set of stakeholders to seek input into identifying key uncertainties and designing the scenario framework.

The output from these reviews formed the basis for the Commission's preparation for the 2008 SOO scenario development process.

The Commission settled upon a scenario framework based around fuel supply/price futures coupled with possible climate change policies. The key drivers adopted were carbon price, renewables preference, availability of renewable generation, fate of existing thermal stations, fuel availability and cost, state of the HVDC link, penetration of the plug-in hybrid electric vehicle into the vehicle fleet, status of the Tiwai smelter, and the extent of demand-side participation.

These drivers were chosen on the basis that they were:

- uncertain;
- very material to generation and transmission development; and

- quantifiable.

The drivers were varied across scenarios. Where possible, the combinations of drivers within each scenario remain consistent (that is, thermal stations are more likely to be displaced by renewables if fuel prices and carbon prices are high). However, in many cases the association of the two factors within a scenario is simply the result of a need to include many factors in just five scenarios, rather than an assertion that the two factors are causally connected.

6.1.4 Generation Expansion Model overview

The Commission's Generation Expansion Model is a long-term capacity planning model. The key purpose of GEM is to systematically sift through a large amount of information and produce internally consistent, least-cost `build schedules' for new generation plant. A build schedule is simply a chronological list of new plant that the model anticipates will be installed. One such build schedule is generated for each of the scenarios considered.

GEM was purpose-built for the Commission, with the development work initiated in 2006. Generation scenarios were defined by economic drivers, and an analytical tool was required to capture the effect of these drivers on plant mix, while also capturing hydrological variation and security of supply over long and short time frames. Since then, GEM has been further developed in a number of areas related to model implementation and system representation. A number of possible further developments have been identified, and the Commission intends progressively working through these over time[60].

Technically speaking, the heart of GEM is the canonical capacity expansion problem formulated as a mixed integer programming (MIP) problem. The computer code is written using the GAMS[61] optimisation software and the model is solved with CPLEX, a commercial MIP solver accessed via the GAMS CPLEX[62] interface. The model's input data is compiled as a series of thematic worksheets in an Excel spreadsheet. Model outputs are written to spreadsheet-compatible files, allowing further processing and/or plotting using software such as Matlab.

In determining the least-cost build schedule, GEM is required to satisfy certain conditions, or constraints. The constraints relate to economic, physical, and technical features of the New Zealand electricity system. While GEM has been constructed as a flexible modelling tool, the specific configuration used to produce the build schedules for the GPA includes the following key features.

60 The GEM computer codes, as used for this 2008 SOO, together with the input data files, and associated documentation, are available for download from the Commission's website at: http://www.electricitycommission.govt.nz/opdev/modelling/gem/index.html

61 General Algebraic Modelling System (GAMS).

62 CPLEX is a commercial solver.

- The costs the model seeks to minimise include capital expenditure on new generation plant and transmission investments, fixed and variable operating costs for all generation plant, and HVDC charges (where variable costs include operating and maintenance costs, carbon charges, fuel costs, and, where applicable, carbon sequestration costs).
- All load and generation is aggregated up to a two-node representation of the network, the North and South Islands.
- Inter-island transfers over the HVDC linked are modelled explicitly, as are transmission losses on the HVDC link.
- Annual energy demand is modelled using nine-block quarterly LDCs.
- Peak demand in each island is modelled by a single 'capacity constraint' requirement in each year, which must be satisfied by committed and new projects given their assumed availability at peak.
- The variability of hydro inflows is modelled by GEM scheduling quarterly hydro generation quantities over the relevant load blocks subject to minimum and maximum capacity factors (to reflect, for example, must-run releases in off-peak periods).
- Capacity expansion plans (build schedules) are determined according to the weighted average system operation costs over five hydro inflow sequences.
- Upgrades to the HVDC link are assumed to occur in 2012 and 2018.
- Perfect competition in the wholesale electricity market is assumed (that is possible wholesale or retail market competition benefits from transmission investments are not currently considered).
- Ancillary services are not completely represented in GEM at the present time. While some of these services are currently modelled within the context of the capacity constraints, the energy side of the model ignores ancillary services. A comprehensive treatment of a range of ancillary services in GEM is currently being developed.

6.2 Scenario outline and weightings

6.2.1 Scenario outline

A brief description of each of the scenarios is included in Table 7. These form the core of the supply-side of the GPA.

Table 7 Scenario outlines

Scenario	Description
Sustainable Path	New Zealand embarks on a path of sustainable electricity development and sector emissions reduction. Major existing thermal power stations close down and are replaced by renewable generation, including hydro, wind and geothermal backed by thermal peakers for security of supply. Electric vehicle uptake is relatively rapid after 2020. New energy sources are brought on stream in the late 2020s and 2030s, including biomass, marine, and carbon capture and storage. Demand-side response helps to manage peak demand.
South Island Surplus	Renewable development proceeds at a slightly more moderate pace, with all existing gas-fired power stations remaining in operation until after 2030, though taking a more mid-order role as gas prices increase. The coal-fired units at Huntly Power Station are shifted into a reserve role and eventually removed from service. Wind and hydro generation increase considerably, particularly in the lower South Island. Relatively little geothermal energy is utilised. Thermal peakers supplement renewable development.
Medium Renewables	A 'middle-of-the-road' scenario. Renewables are developed in both islands, with North Island geothermal development playing an important role. The coal-fired units at Huntly transition through dry-year reserve to total closure. Thermal peakers and a new CCGT supplement renewable development. Tiwai smelter is assumed to decommission in the mid-2020s.
Demand-side Participation	Demand-side participation becomes a more important feature of the market, driven by a desire from consumers of all types to become more involved. Electric vehicle uptake is high, and vehicle-to-grid technology is used to manage peaks and provide ancillary services. On the generation side, new coal- and lignite-fired plants are constructed after 2020, and geothermal resources are developed. Little new hydro can be consented, however, and some existing hydro schemes have to reduce their output (due to difficulty in securing water rights). Huntly Power Station remains in full operation until 2030. Electricity-sector emissions rise, though transport-sector emissions would be lower than in other scenarios.
High Gas Discovery	Major new indigenous gas discoveries keep gas prices low to 2030 and beyond. Some existing thermal power stations are replaced by new, more efficient gas-fired plants. New CCGTs and gas-fired peakers are built to meet the country's power needs; the most cost-effective renewables are also developed. The demand-side remains relatively uninvolved.

6.2.2 'Renewableness'

In the context of the NZES, a key output statistic is the projected proportion of electricity that would be produced by renewable generation. Renewable generation fuels are deemed to include hydro, geothermal, wind, biomass, and marine, but not gas, coal or diesel. The exception is that coal with carbon sequestration is considered to be renewable (because the greenhouse emissions would be relatively low). The five new scenarios vary in the extent of renewable generation assumed the following.

- Sustainable Path is 89 percent renewable by 2025.
- South Island Surplus is about 82 percent renewable by 2025, with a bias towards South Island wind and hydro.
- Medium Renewables is about 77 percent renewable by 2025, with more generation located in the North Island.
- Demand-side Participation is about 69 percent renewable by 2025, with extensive demand-side involvement and high electric vehicle uptake.
- High Gas Discovery is approximately 69 percent renewable by 2025, with low gas prices due to indigenous gas finds.

6.2.3 Scenario weighting

With regard to the relative weightings accorded to the scenarios, it is essentially academic, as their use within the SOO is solely to help stakeholders understand the range of possible futures. However, as set out in section 6.3 below, their use within the GIT is material.

Accordingly, the Commission has given careful consideration to the weightings of the scenarios for this second SOO. It has considered experience from the Initial SOO, feedback from submitters in the earlier GPA consultation, and further development work. The Commission has also been mindful of recent policy announcements from Government, particularly the NZES. At this stage, the Commission's view is that the five scenarios could all be assigned equal weight.

Table 8 Scenario weightings

Scenario name	Weighting
Sustainable Path	20%
South Island Surplus	20%
Medium Renewables	20%
Demand-side Participation	20%
High Gas Discovery	20%

6.3 Scenario linkages with the Grid Investment Test

With respect to the use of the SOO scenarios in the application of the GIT, it is the Commission's view that an *a priori* scenario approach will not always be the best means of evaluating a transmission investment.

In constructing scenarios for the SOO, there are many 'degrees of freedom' in selecting assumptions and modelled plant. In particular there are many different possible combinations of internally consistent input assumptions. Using a limited set of scenarios is an appropriate approach for the SOO in terms of helping inform stakeholders of the broad range of possible futures and the general impact of key drivers.

However, for the GIT analysis of a major transmission investment, the outcome of an economic analysis of the transmission proposal using the SOO scenarios could be materially different to one which considered a more tailored set of possible futures having regard to the particular investment proposal.

Therefore, in accordance with clause 6.1 of the GIT, the Commission may determine that market development scenarios proposed by Transpower, the proponent of a transmission alternative, or the Commission are more appropriate. This enables the Commission to adopt alternative scenarios that more reasonably reflect new knowledge, or then-current uncertainty about the future in light of the investment proposal in front of it.

The Rules also permit a real options analysis of benefits to be adopted, as an alternative to a standard net present value analysis[63]. Current practice for evaluating real options value for transmission investments using a standard net present value analysis is to employ a Monte Carlo simulation of many possible futures (many thousands to millions). To make this problem numerically feasible, many simplifications must be made to modelled interactions (for example to avoid the need for power flow analysis within each Monte Carlo draw). A hybrid approach, utilising both scenarios and Monte Carlo real options analysis was developed for the analysis and decision on Transpower's North Island Grid Upgrade Proposal.[64]

There is considerable flexibility within the Rules to vary scenarios and use state of the art analysis techniques, where there is merit. This would principally be for large investments. In other cases, a simple application of the existing scenarios will be appropriate. It is the Commission's view that establishing the default scenarios in the SOO, but allowing the Commission to adopt other scenarios if it considers appropriate, best balances the need to provide a flexible environment within which Transpower can undertake the cost benefit

63 Clause 13 of the GIT.

64 http://www.electricitycommission.govt.nz/opdev/transmis/auckgridinvest/Decision

analysis required by the GIT, with the need for a transparent framework for transmission investment decision-making.

7. Electricity generation

7.1 Approach to information gathering

A key component of the GPA is the Commission's view of the reasonable range of credible future generation scenarios[65].

The Commission adopted a two-stage approach to developing these projections. Firstly, it collated a list of existing, committed, and potential future generation projects. It then produced the generation scenarios by selecting projects from this list, using GEM (the Generation Expansion Model, described in the previous section).

This section describes the list of generation projects. For consistency with the broad approach adopted in the design of the GIT, generation is broken into three categories:

- existing generation;
- committed projects; and
- other possible future projects (these are called generation opportunities, but may eventually become "modelled projects" in the analysis of a particular investment proposal).

The last of these is further broken down into 'near-future generation' consisting of projects that are highly likely in the first few years of the scenarios, and 'prospective projects' that vary widely in terms of their nature, timing and status.

All the projects listed have a capacity of at least 10 MW, apart from some small hydro schemes. Distributed generation, which is the collective term for relatively small generators, in the sub-10 MW range, sourced close to load, is not included in the generation lists. The Commission recognises the importance of distributed generation as part of New Zealand's generation portfolio, but has decided not to include it explicitly in the GPA. The reason is that distributed generation imposes relatively few additional transmission requirements, because it is sited close to load. Progressive increases in the amount of available distributed generation are effectively built into the Commission's demand forecasts, which implicitly assume that the amount of available distributed generation will continue to grow at historical rates.

65 Rule 10.3.1.3 of section III of part F.

7.2 Types of generation

The types of large-scale electricity generation relevant to the New Zealand market are summarised in Table 9. The table also includes some demand-side measures, which can supply services to the power system in a similar way to generation.

Table 9 Types of generation

Generation type	Fuel	Comment
Non-fossil-fuelled	Geothermal	Geothermal generation is focused on the geothermal steam fields in the central North Island, although there are smaller fields elsewhere such as in Northland. Currently it contributes around eight percent of total generation, but this is expected to increase in the next decade.
	Wind	Wind energy currently provides only about three percent of total supply. However, many new wind farms are at various stages of the planning and construction processes, and this technology is expected to make an important contribution to supply over the next few years.
	Hydro	Hydro generation currently accounts for approximately 55 percent of total generation, though this percentage varies considerably from year to year with inflows into hydro catchments. There are major hydro systems in both the North and South Islands, together with a number of smaller systems and individual stations scattered around the country.
	Other renewables	Other renewable forms of generation include (but are not limited to) pumped hydro, wave generation, tidal generation, landfill gas, biogas, photovoltaic (solar), and biomass-fired generation. Their current contribution to national electricity supply is relatively small, but some of them may play a more important role in future.
Fossil-fuelled	Gas	Gas-fuelled plant currently provides about 25 percent of total supply. Major gas-fired generators are located in Taranaki, the Waikato and Auckland, following the route of the gas transmission system.
	Coal	Coal-fuelled plant currently provides about 10 percent of total supply, though this varies from year to year (driven by various factors including hydro inflows). Currently the main coal-fired generation is at Huntly Power Station. While Huntly burns 'black coal'[66], sourced both from local supplies and imports; the South Island's vast lignite resources provide a potential alternative source of fuel.

66 Black coal is defined as a higher grade coal with low sulphur and ash.

Generation type	Fuel	Comment
	Diesel	The Whirinaki power station is a gas station but is currently being operated on diesel. It plays an important role in national security of supply. More diesel-fired generation may be constructed in future.
	CCS	In future, it may be possible to construct coal- or gas-fired plant with 'carbon capture and storage'. This technology could be used to store the greenhouse gases produced, rather than releasing them into the atmosphere.
Demand-side[67]	Interruptible load (IL)	Interruptible load is demand that can be quickly disconnected by a central agency, for example, ripple controlled hot water heating. Participation in IL provision is voluntary and is compensated for. Interruptible load already plays an important part in system security, and this role is expected to increase. Other Commission work programmes are currently working on promoting load management and removing barriers to its development.
	Demand-side management	Demand-side management refers to voluntary load reductions in response to price, and will be supported by a range of initiatives including demand-side bidding, smart metering, time-of-use pricing, and/or demand-side aggregation. The role of demand-side management in promoting system security is expected to increase over the years to come.

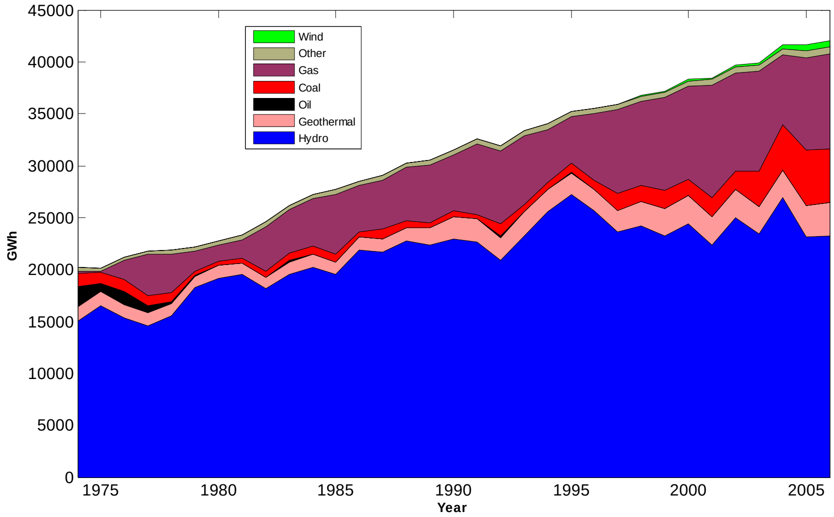
7.3 Existing generation

New Zealand's electricity consumption is primarily met through a mix of hydro, thermal, geothermal and wind generation. Approximately 95 percent of electricity generated is produced by plant directly connected to the transmission grid. The remainder is either embedded with the local lines networks—either associated with a load or operating independently— or serves load that is not connected to the national electricity network.

Hydro remains the predominant source of generation, contributing around 55 percent of the total in a typical year. Thermal is around 34 percent of total generation and geothermal eight percent. Wind currently contributes around three percent but is expanding quickly compared with the existing installed base, with significant new capacity recently commissioned or under construction.

[67] Demand-side response is treated as a potential 'generator' and is part of the list of modelled projects. Its features refer to options for reducing electricity demand. Some demand-side measures are included here because they can potentially be used to reduce the need for new generation.

Figure 23 Generation by fuel type from 1974 to 2006[68]



Data on existing plant was obtained from a number of sources including asset capability statements, generating company corporate reports, market data, and security of supply generator returns.

The type, location and size of existing generation connected to the transmission grid are shown in the following table.

Table 10 Existing grid-connected generation

Name	Type	MW	Region
Arapuni	Hydro	197	Waikato
Aratiatia	Hydro	78	Waikato
Argyle	Hydro	4	Nelson
Atiamuri	Hydro	84	Bay Of Plenty
Aviemore	Hydro	220	South Canterbury
Benmore	Hydro	540	South Canterbury
Clyde	Hydro	432	Otago/Southland

68 Source: June 2007 Energy Data File

Name	Type	MW	Region
Cobb	Hydro	32	Nelson
Coleridge	Hydro	45	Canterbury
Huntly	Thermal	1,000	Waikato
Huntly e3p	Thermal	385	Waikato
Huntly p40	Thermal	50	Waikato
Kaitawa	Hydro	36	Hawke's Bay
Karapiro	Hydro	90	Waikato
Manapouri	Hydro	710	Otago/Southland
Mangahao	Hydro	42	Central
Maraetai	Hydro	360	Waikato
Matahina	Hydro	72	Bay of Plenty
Mokai I and II	Geothermal	112	Waikato
Mokai III	Geothermal	17	Waikato
Ohaaki	Geothermal	40	Waikato
Ohakuri	Hydro	112	Waikato
Ohau A	Hydro	264	South Canterbury
Ohau B	Hydro	212	South Canterbury
Ohau C	Hydro	212	South Canterbury
Otahuhu B	Thermal	380	Auckland
Patea	Hydro	31	Taranaki
Piripaua	Hydro	42	Hawke's Bay
Poihipi Rd	Geothermal	55	Waikato
Rangipo	Hydro	120	Central
Roxburgh	Hydro	320	Otago/Southland
Southdown	Thermal	170	Auckland
Tararua Stage 3	Wind	93	Central
Taranaki Combined Cycle (TCC)	Thermal	385	Taranaki
Te Apiti	Wind	90	Central

Name	Type	MW	Region
Tekapo A	Hydro	25	South Canterbury
Tekapo B	Hydro	160	South Canterbury
Tokaanu	Hydro	240	Central
Tuai	Hydro	60	Hawke's Bay
Waipapa	Hydro	51	Waikato
Waipori*	Hydro	84	Otago/Southland
Wairakei	Geothermal	161	Waikato
Wairau	Hydro	7	Nelson
Waitaki	Hydro	105	Otago/Southland
Whakamaru	Hydro	100	Waikato
Wheao and Flaxy Scheme	Hydro	24	Bay of Plenty
Whirinaki	Thermal	155	Hawke's Bay
Glenbrook	Co-generation	112	Auckland
Kapuni	Co-generation	25	Taranaki
Kawerau pulp and paper	Co-generation	37	Bay of Plenty
Kinleith	Co-generation	40	Waikato
Whareroa (Kiwi Dairy)	Co-generation	70	Taranaki
Total		**8,488**	

* Some generating units at Waipouri are grid-connected, others are embedded within the local lines network, and some can be switched between both.

Generation over 10 MW embedded within local lines networks is shown below.

Table 11 Significant existing embedded generation

Name	Type	MW	Region
Aniwhenua	Hydro	25	Bay of Plenty
Bay Milk Edgecumbe	Co-generation	10	Bay of Plenty
Highbank	Hydro	25	Canterbury
Kaimai scheme	Hydro	42	Bay of Plenty
Ngawha	Geothermal	10	North Isthmus
Paerau Gorge scheme	Hydro	12	Otago/Southland
Rotokawa	Geothermal	33	Waikato
Tararua Stages 1 + 2	Wind	68	Central
Te Rapa	Co-generation	44	Waikato
Teviot scheme	Hydro	15	Otago/Southland
White Hill	Wind	58	Otago/Southland
Total		**342**	

7.4 Committed generation projects

A generation project will be a 'committed project' if it is reasonably likely to proceed and where all of the following are satisfied.[69]

- All necessary resource and construction consents have been obtained and any other regulatory requirements have been obtained.
- Construction has commenced or a firm commencement date set.
- Arrangements for securing the required land are in place.
- Supply and construction contracts for plant and equipment have been executed.
- Financing arrangements are in place.

The committed generation projects are set out in Table 12.

[69] See clause 21 of the GIT.

Table 12 Committed generation projects

Year	Name	Type	Owner	Island	Nameplate MW
2008	Deep Stream	Hydro	Trustpower	South	6
2009	Ngawha 2	Geothermal	Top Energy	North	15
2009	Kawerau	Geothermal	Mighty River Power	North	90
2009-10	West Wind	Wind	Meridian Energy	North	143

There is also a range of committed transmission projects that have been included in all scenarios and assumed in the PSA. They are listed in Appendix 13**.**

7.5 Other possible generation projects

In addition to the committed projects identified, the GPA include a long list of nearly two hundred other potential generation projects. These cover a wide range of technologies — wind, geothermal, hydro, gas, coal, diesel, marine, and demand-side.

The list of projects has been prepared by the Commission using information from:

- the 'Electricity Generation Database' report prepared by Parsons Brinckerhoff Associates (PBA);
- the draft Annual Security and Reserve Energy Needs Assessment prepared by Concept Consulting for the Commission;
- the TTER project, for new hydro and geothermal generation ;
- other commissioned reports on possible future generation projects;
- publicly available information such as newspaper articles and generator websites;
- industry publications such as annual reports; and
- discussion with stakeholders.

These projects are divided into two groups—the 'near future' projects that are not yet committed but are likely to be constructed in the next few years, and the 'prospective projects' that might be built from 2011 on.

Near-future generation

Some generation projects have been designated as not yet committed but 'highly likely' to be constructed in the first few years of the generation scenarios. The Commission has scheduled each of these projects in the scenarios, and assigned them probabilities and commissioning years that reflect uncertainty about whether and when they will be built. The assignment of these 'highly likely' projects to scenarios is intended to be credible and consistent with the scenario 'stories', but, within these constraints, is somewhat arbitrary.

Table 13 presents the projects that the Commission views as highly likely in the next few years and the scenarios with which they are associated. The name and location of one project have been omitted to preserve confidentiality.

Table 13 'Highly likely' projects in the generation scenarios

	Description	Sustainable Path	South Island Surplus	Medium Renewables	Demand-side Participation	High Gas Discovery
Anonymous gas-fired peaker	150 MW peaking plant in the North Island	2009			2009	
Taranaki gas-fired peaker	Contact Energy's proposed 200 MW gas-fired peaking station in Taranaki		2010		2010	2010
Rotokawa 2	Mighty River Power's proposed 130 MW geothermal plant	2010	2011	2010	2010	2011

	Description	Sustainable Path	South Island Surplus	Medium Renewables	Demand-side Participation	High Gas Discovery
Te Mihi	Contact Energy's proposed new geothermal plant – 220 MW, but replacing the 163 MW Wairakei station	2011	2011	2011	2011	2011
Hawea Control Gates	Contact Energy's 17 MW retrofit hydro project	2011	2011	2010	2012	
Wairau	Trustpower's 73 MW hydro project	2011		2011	2011	2013
Te Rere Hau	NZ Windfarms' 49 MW expansion	2009	2010	2009	2009	2011
Te Waka	Unison's 102 MW wind farm	2010	2010		2012	
Titiokura	Unison's 45 MW wind farm	2010	2012	2010		

Prospective projects

From 2011, the generation scenarios draw from a list of 'prospective' projects. These projects vary widely in terms of their current status.

- Some are consented or going through the consenting process.
- Others have been proposed by generators, but are not yet in the consenting process.

- Some have been suggested, but are not currently known to be being investigated by generators, because, for instance, they are not yet technically possible, or would not be economic under current market conditions.

Some of the projects are represented as generic plants (that is, no specific project name or developer indicated). In some instances this is for reasons of confidentiality. In other cases it is a useful means of incorporating possible new technologies into the scenario mix.

The list of projects includes[70]:

- over thirty possible wind projects, ranging from 15 to 300 MW[71], located throughout New Zealand—although with the majority in the North Island — and totalling to nearly 4,000 MW;
- up to 150 MW of new interruptible load, up to 400 MW of demand-side response available at peak, and up to 1000 MW of vehicle-to-grid support from plug-in electric vehicles;
- nine geothermal projects, located in the central North Island and totalling about 800 MW (in addition to committed and 'highly likely' geothermal projects);
- fifty-five possible hydro projects ranging in size from 10 to 300 MW, located throughout New Zealand and totalling about 3000 MW;
- six generic wave projects of 50 MW;
- ten assorted co-generation projects totalling to about 400 MW;
- five gas-fired CCGTs totalling about 2000 MW (Otahuhu C, Rodney, and Taranaki CC 2, plus two generic 400 MW plants in Auckland and Taranaki);
- up to five 200 MW peaking gas-fired open cycle gas turbines (OCGTs)s, located in Taranaki or the Waikato;
- up to ten 150 MW diesel-fired thermal peakers, located as needed;
- seven black coal plants (generic projects in the 300-400 MW range, nominally located at Glenbrook, Taranaki, Christchurch, Tauranga, Northland, and in the Waikato);
- two lignite plants (400 MW generic projects located in Southland and Otago); and

70 The complete list of projects is included as Appendix 6.

71 Project Hayes is even larger, at around 600 MW, but is modelled as four separate stages.

- seven coal or gas plants with carbon sequestration.

The Commission acknowledges that these projects vary widely in consentability and economic viability. For example, some of the modelled hydro schemes may face considerable barriers to obtaining consents. The selection of projects is merely intended to be indicative of the types of possible opportunities, and does not constitute an endorsement of the selected schemes by the Commission.

In some scenarios, some projects are not offered to the model because they would not be constructed due to assumed consenting difficulties, etc. The treatment of these limitations is described in section 8.

7.6 Generation costs

A key aspect of the generation input data is the relative economics of the various types of generation. The following tables describe the costs of the modelled generation technologies, in terms of long-run marginal cost (LRMC) and short-run marginal cost (SRMC).

SRMC is defined as the marginal cost, at the relevant GIP, of producing the next unit of electricity (in this context, including carbon costs, fuel costs and variable operation and maintenance (O and M), but excluding capex, fixed O and M, transmission charges and network losses).

LRMC is defined as the mean price (at the relevant GIP) that is sufficient to cover all plant costs (in this context, including capital financing costs, carbon costs, fuel costs, O and M and transmission charges but excluding network losses). A real pre-tax discount rate of eight percent has been assumed in the calculation of LRMC. Assumed depreciation rates vary between technologies. LRMCs depend on load factor and have been calculated for several different load factors, where applicable.

Connection costs[72] have not been included in the LRMCs shown here (but are modelled in GEM).

Readers should be cautious in comparing the LRMCs shown here with those published in other documents. Differences in assumed project life, depreciation rate, treatment of tax, discount rate, load factor and/or types of cost considered can make a very substantial difference to calculated LRMCs (easily $20/MWh or more). If cost assumptions are to be compared, the comparison is best carried out on raw cost components (capital cost per kW, variable O and M cost per MWh, etc).

[72] Connection costs in this context represent the costs of connecting the generator to the interconnected grid.

The Commission's assumptions about LRMCs for thermal technologies are shown in Table 14. Prices depend on carbon costs, and, for gas-fired plant, on gas prices. Three sets of prices are shown, to indicate the range of values: an LRMC with cheap gas ($7/GJ) and no carbon charge, an LRMC with more expensive gas ($10/GJ) and a moderate carbon charge of $30/t CO2-equiv, and an LRMC with very expensive gas ($13/GJ) and a high carbon charge of $50/t CO2-equiv. All prices shown are for North Island plant.

It can be seen that thermal LRMCs depend strongly on the assumed load factor. A plant operating as mid-order (load factor in the ballpark of 50 percent) faces a higher LRMC per unit output than a similar plant operating as baseload. On the other hand, the mid-order plant has the flexibility to run when prices are higher, so will earn more revenue per unit output. Plants running in a peaking capacity have extremely high LRMCs (much higher than their SRMCs). GEM will determine the load factor of each plant in each simulated year on a least-cost basis, within the limits imposed by the technology.

Carbon prices and fuel prices also have a very significant impact on thermal SRMCs and LRMCs.

Table 14 Assumed LRMCs of thermal generation.

Category	Assumed load factor	LRMC ($/MWh) – gas at $7/GJ, no carbon charge	LRMC ($/MWh) – gas at $10/GJ, carbon at $30/t	LRMC ($/MWh) – gas at $13/GJ, carbon at $50/t
Combined cycle gas turbine	50%	92	125	153
	70%	81	113	142
	90%	75	107	136
Diesel-fired peaker	5%	620	640	656
Gas-fired peaker	5%	545	591	632
	20%	215	261	302
Conventional coal plant	30%	161	187	205
	50%	115	141	158
	70%	96	122	139
	90%	85	111	128
IGCC coal plant with CCS	70%	137	140	143
	90%	119	123	125

Assumed SRMCs for thermal technologies are shown in Table 15.

Table 15 Assumed SRMCs of thermal generation

Plant (example)	SRMC ($/MWh) – gas at $7/GJ, no carbon charge	SRMC ($/MWh) – gas at $10/GJ, carbon at $30/t	SRMC ($/MWh) – gas at $13/GJ, carbon at $50/t
Taranaki CC	56	90	119
Whirinaki	280	304	320
Huntly units 1-4 on coal	52	81	100

Assumed LRMCs for renewable technologies are shown in Table 16. Each technology is divided into three tranches — the most economic resources, the next most economic projects, and finally the least economic (that are unlikely to be built in most scenarios). For each tranche, the table shows a range of LRMCs and the amount of capacity available at that price.

These assumptions indicate that the best available resources of wind, hydro and geothermal are each around the $80/MWh level.

Geothermal generation has a relatively low LRMC, in part because geothermal has no fuel cost and a high capacity factor, and in part because of the moderate capital costs assumed for geothermal projects. LRMCs of near-future geothermal generation options typically range from $70 to $90/MWh, based on a capital cost of $3000 to $4000/KW[73]. Wind and hydro have lower capacity factors, but can still be economic where capital costs are low enough.

South Island generation projects would also incur HVDC cost recovery charges. These would be a redistribution of an existing cost, rather than a new cost imposed on the economy, but would still need to be taken into account by the developer. The effective cost would depend on:

- who builds the generation (due to portfolio effects the effective marginal charge is highest on a new entrant, lower on Contact and Trustpower, and much lower on Meridian); and
- what HVDC refurbishment option is selected (more expensive options will lead to higher HVDC charges).

[73] NZES and Parsons Brinckerhoff Associates, 'Draft Electricity Generation Database, Statement of opportunities 2006, September 2006'.

If a full Pole 1 replacement was commissioned in 2012, the effective marginal cost faced by developers could be in the range of $1.70 – $8.00/MWh for new wind generation, or $1.40 – $6.00/MWh for hydro. (Other forms of generation in the South Island would also be exposed to the charge, with the effect varying depending on load factor.)

Table 16 Assumed LRMCs of renewable generation

Category	Island	Assumed load factor	Best resources – LRMC ($/MWh)	Capacity at this price (MW)	Next resources – LRMC ($/MWh)	Capacity at this price (MW)	Lower-grade resources – LRMC ($/MWh)
Wind (*)	NI	(intermittent) 35–45%	80–85	approx. 500	approx. 95	over 2,000	over 100
	SI	(intermittent) 35–45%	80–85	approx. 300	95	over 1,000	over 100
Geothermal (**) (+)	NI	90%	80	250–300	approx. 85	approx. 400	as much as 100
Hydro backed by storage (+)	SI	50%	85	approx. 200	90–115	approx. 600	N/A
Run-of-river hydro	NI	(intermittent)	85–100	approx. 100	100–120	approx. 200	very high
	SI	(intermittent)	85–100	approx. 100	100–120	approx. 200	very high
Biomass co-generation	mostly NI	70%	130	150			
Marine	both	(intermittent)	125	400			

These LRMCs are calculated based on GEM data inputs. See the explanation in the main text.

(*) Wind costs are increased in MDS 5, indicating new sources of cost (either technical or regulatory)

(**) Carbon costs could increase geothermal LRMCs but are not included

(+) Some of the best hydro and geothermal resources are assumed to be unavailable in some scenarios

7.7 Locational signals sent by the Transmission Pricing Methodology and the Grid Investment Test

When developing generation scenarios the Commission needs to take into account the likely location of new generation. The future location of generation will have a significant impact on the overall level of transmission investment and a tangible effect on end consumers' electricity bills. However decisions regarding the location of new generation investment and decommissioning of existing plant are made by market participants in response to the strategic and commercial drivers they face. Generation investment is not regulated by the Commission (except to the extent that the Commission has a role in securing reserve energy requirements as dry year insurance).

Consequently an important part of the part F rule framework has been to provide, to the extent practicable, market signals to encourage efficient generation location decisions. This has been manifest in two aspects of the transmission pricing methodology (TPM) and a consequence of the application of the GIT.

The transmission pricing guidelines published by the Commission required that a definition of deep connection be developed and applied consistently and transparently. This ensures that when generators choose to locate far from the existing grid they take into account the full costs of connection to the grid.

The transmission pricing guidelines also required that the costs of existing and new HVDC link assets be allocated to grid-connected generators located in the South Island. This ensured that where generation is located in areas of current surplus and far from increasing demand centres then some recognition was made of the substantial costs likely over time to allow that generation to meet demand.

Ideally locational signals provided by the TPM would be more precise and finely structured than those provided by these two aspects. However, at this stage the Commission considers that the substantial additional investigation and analysis required to develop such an arrangement is not a high priority. The Commission has taken into account the effect of the HVDC charge in developing the GPA in this SOO.

The application of the GIT can provide strong locational signals to investors in generation. The nature of the signals is inherent in the cost assumptions in the GPA. Specifically, if the Commission identifies that a region has a substantial resource of low-cost generation, and this is reflected in generation projects in the GPA, proposed transmission investments within and connecting to the specific region may be more likely to pass the GIT than if the converse was true.

For example, if renewable generation resources with equivalent economic characteristics existed both in unconstrained and potentially constrained parts of the network then it would be economically rational to expect that the generation should locate in the unconstrained areas as this would avoid the cost of transmission investments otherwise needed to relieve the constrained regions.

The efficacy of this signal to investors is currently being tested by Transpower as it develops proposals for investment in the Lower South Island and Wairakei area. For this signal to be effective, the Commission expects that investors should take a view on whether investment in the interconnected grid is likely to be required; and if so, if it is likely to pass the GIT.

8. Key inputs and assumptions

This section sets out the key assumptions made in relation to the development of the generation scenarios.

The assumptions described are confined to those considered to be primarily generation-related. They do not include the key assumptions regarding the following (as these are described elsewhere in this SOO).

- Electricity demand (section 5).
- Uptake of electric vehicles (section 5).
- Generation projects (section 7).
- Power systems analysis (section 10).

For the 2008 SOO, two kinds of generation assumptions were made: assumptions that differed between scenarios (scenario-specific assumptions), and those that were common to all of the scenarios (common assumptions).

Assumptions that differed between scenarios were the 'key drivers' which differentiated one scenario from another. The scenario-specific assumptions had the following characteristics.

- They were key drivers that, in order to appropriately reflect uncertainty, covered a range of outcomes.
- They were influential in terms of generation (and hence transmission) build.
- They were consistent with the current policy context and expected technological change.

Assumptions that were common to all scenarios were those that were:

- inherent in the GEM model itself; and
- considered to be reasonable for use across all scenarios.

The remainder of this section sets out the key drivers and some of the more important common assumptions. It cannot, however, describe every single assumption made in the scenario development. The most comprehensive source is the GEM model itself and its associated datafiles[74].

[74] These can be downloaded at http://www.electricitycommission.govt.nz/opdev/modelling/gem/index.html

The Commission has an ongoing work programme to review assumptions used in the development of the GPA. It is the intention that these assumptions will be periodically reviewed in the light of new information and feedback from participants.

8.1 Key drivers of the generation scenarios

The key drivers of the five generation scenarios are summarised in Table 17. These factors are the primary causes of the differences between the scenarios.

It should be noted that the values of the key drivers were chosen so as to represent a credible range of possibilities, given the uncertainties faced by the sector. The results (build plans, emissions, renewable percentages, etc) are then determined from the input assumptions through the use of the GEM model. This can be contrasted with an 'output-driven' approach where the inputs are chosen to produce a predetermined set of results.

Table 17 Key drivers of the generation scenarios

Scenario	Eventual carbon price ($/t CO_2e)	Renewables preference	Availability of gas	Renewables available	Fate of coal-fired Huntly units	Fate of other thermal power stations	Fate of HVDC Pole 1	Demand-side
Sustainable Path	$60 (rising to this level by 2018)	Restriction on baseload thermal continues indefinitely	High price path; no imported Liquified Natural Gas (LNG)	Extensive hydro, wind and geothermal available; biomass and marine available later	Closed by 2020	TCC, Huntly p40 and Southdown decommissioned by 2025	Half pole on standby until replacement in 2012	Baseline participation; high electric vehicles uptake
South Island Surplus	$50	Restriction continues until 2019; coal-fired plant without CCS can never be built	High price path; no imported LNG	Extensive hydro and wind available, especially in lower SI; some restrictions on geothermal development	By 2020, two units out and two in dry-year reserve mode	TCC in reduced operation from 2023	Half pole on standby until replacement in 2012	Baseline participation
Medium Renewables	$30	Restriction continues until 2019; coal-fired plant without CCS can never be built	Moderate price path; imported LNG from 2020	Extensive wind and geothermal, and some hydro available	By 2020, all four units in dry-year reserve mode		Half pole fully available until replacement in 2012	Baseline participation; Tiwai smelter phases out of operation around 2025
Demand-side Participation	$20	Restriction continues until 2019	Moderate price path; imported LNG from 2020	Extensive wind and geothermal available; little new hydro can be consented; some existing hydro must reduce output from 2020	Coal-fired units remain in operation until 2030		Pole 1 removed from service in 2009 and replaced in 2012	Extensive participation; high electric vehicles uptake, with vehicle-to-grid

Scenario	Eventual carbon price ($/t CO_2e)	Renewables preference	Availability of gas	Renewables available	Fate of coal-fired Huntly units	Fate of other thermal power stations	Fate of HVDC Pole 1	Demand-side
High Gas Discovery	$40	Restriction continues until 2019, though CCGTs can be built to replace coal in the 2010s	Low price path	Moderate amounts of wind, geothermal and hydro available	Two units replaced by a new CCGT in 2015; the remaining units run until 2030	TCC in reduced operation from 2023 (displaced by more efficient new plant)	Half pole on standby until replacement in 2012	Minimal participation

8.2 Cost of carbon

It seems very likely that, in the future, generators will have to pay for the greenhouse gases that their plant emits. All five of the generation scenarios assume that there will be 'a price on carbon' (that is, a requirement to pay for greenhouse gas emissions).

The effect of the price of carbon in the model is to disincentivise baseload and mid-order thermal generation — especially coal-fired, but also gas-fired — and to encourage renewable development.

The framework of carbon charging may change over time. The Government's proposed Emission Trading Scheme (ETS)[75] is a broad-based, economy-wide cap-and-trade scheme that is neutral between domestic and international emission reductions. Future measures to curb greenhouse emissions may or may not use the same framework. In the GPA, the Commission has modelled the cost of carbon as a flat rate applied to all electricity-sector emissions, denominated in real NZ$/t CO_2-equivalent. The Commission considers this to be a reasonable approximation for modelling purposes.

The future price of carbon in the New Zealand electricity sector is unknown and difficult to predict. Many different estimates have been published, based on a number of methodologies[76]. These have included modelling simulations and comparative analyses, and have typically produced estimates with large standard errors, reflecting the uncertainty associated with the factors being considered. Nevertheless, expectations seem to be that the price of carbon will rise over time, with indicated price estimates in the range of $20/t to $60/t over the next ten years, and potentially significantly higher after that.

In the GPA, the Commission has used a range of carbon prices, to indicate the uncertainty about the price path. The assumed long-run price of carbon varies from $20/t (Demand-side Participation) to $60/t (Sustainable Path).

Some sources suggest that the long-run price of carbon may be well over $60/t, perhaps over $100/t. At these prices, the economics of existing baseload thermal generation, and maybe even new peaking thermal generation, could become very marginal. The Commission acknowledges that this is a plausible outcome, but has not attempted to model it to date. More work will be needed on the economics of renewable generation, especially peaking renewables, before the effects of such high carbon prices can be modelled with confidence.

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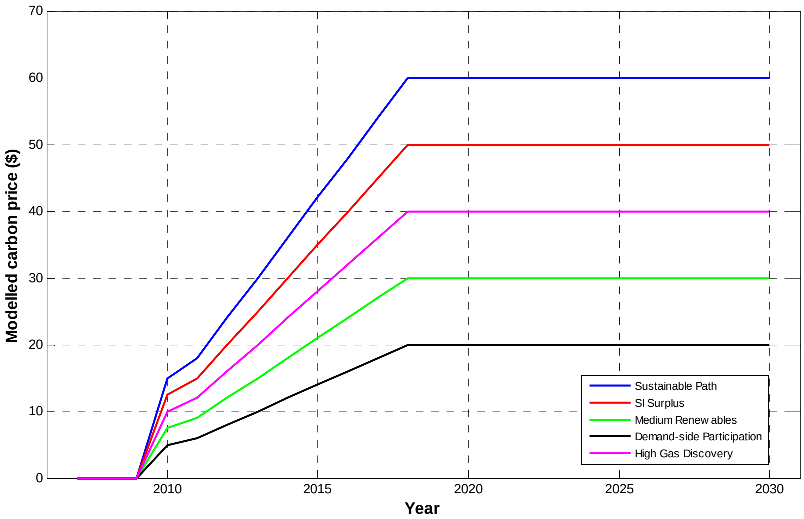
75 http://www.parliament.nz/NR/rdonlyres/C2BE5C1F-9228-4B0A-8F88-DB64487A5BFB/82174/DBHOH_BILL_8368_562994.pdf

76 Page 30 of the New Zealand Energy Strategy to 2050 http://www.med.govt.nz/upload/52164/nzes.pdf

In all the GPA scenarios, the Commission assumes the price of carbon applies from 2010, when the electricity sector comes under the ETS. The price starts low due to free allocation of some units, but increases until it reaches its long-term level in 2018; it remains constant thereafter. The resulting price paths are shown in Figure 24.

Figure 24 Modelled carbon prices for the five scenarios



In practice, carbon prices might fluctuate widely from year to year. Many sources also suggest that prices could continue to rise after 2020. As yet, the Commission has not attempted to model these effects.

8.3 Renewables preference

The Government has expressed a preference for new baseload generation in New Zealand to be renewable. To this end, it has proposed a restriction on new baseload thermal generation as part of the Climate Change (Emissions Trading and Renewable Preference) Bill. The Bill supports the target within the NZES for 90 percent renewable electricity generation by 2025, and the preference for all new electricity generation to be renewable, except to the extent necessary to maintain security of supply.

If passed the Bill would implement a 10-year moratorium on new (non-exempt) fossil-fuelled thermal generation greater than 10 MW capacity, and the introduction of an emissions trading scheme to apply price signals to activities that contribute to climate change.

In all five of the generation scenarios, baseload and mid-order thermal generation is restricted before 2019. A new CCGT (nominally at Rodney) is built in 2015 in the High Gas Discovery scenario, on the assumption that such a project might be approved if it was displacing coal-fired generation with higher greenhouse emissions. In the other four scenarios, no baseload or mid-order thermal plant is built before 2019, although diesel and gas-fired peaking generation is constructed.

The preference for renewable generation may continue beyond 2018. It might take effect through an ongoing restriction on baseload thermal generation, through resource management channels, or simply through societal attitudes. Without taking a position on which of these might be the case, the Commission assumes that:

- in the Sustainable Path scenario, no baseload or mid-order thermal generation is built even after 2019, unless it has carbon capture and storage;
- in the South Island Surplus and Medium Renewables scenarios, no new coal generation is built even after 2019, unless it has carbon capture and storage. Gas is allowed if economic; and
- in the Demand-side Participation and High Gas Discovery scenarios, any type of thermal generation can be built after 2019, if economic.

8.4 Availability of thermal fuels

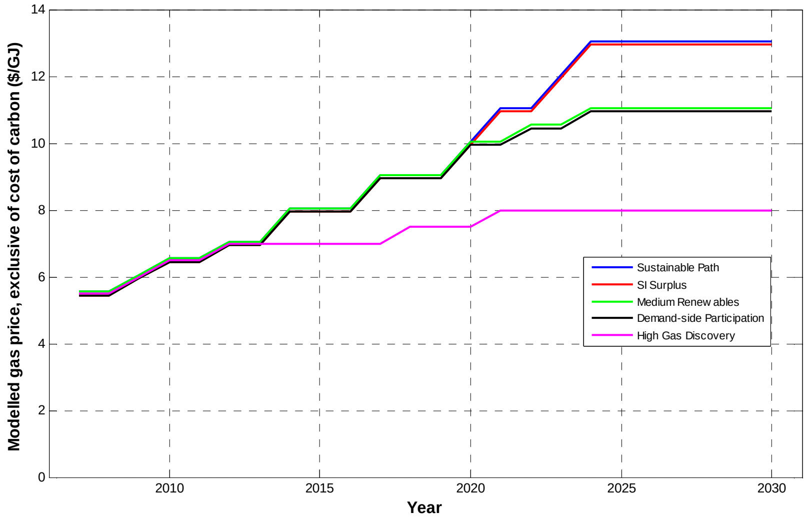
The three main fossil fuels currently used for electricity generation in New Zealand are natural gas, coal and oil. New Zealand has a plentiful supply of coal which could supply our needs in the long run—although we may choose not to use it. However, it seems unlikely that natural gas will continue to be available in large quantities, at current prices, in the long-term.

The availability and price of natural gas and, to a lesser extent, oil, are important drivers of the scenarios.

The future price of natural gas is unknown and difficult to predict. Among other things, the price will depend on the price of carbon, the extent of new gas discoveries around New Zealand, and whether an LNG terminal is constructed for the importation of liquefied gas. In the absence of new gas discoveries, the amount of gas available would decline and the price would increase, eventually to very high levels. New gas discoveries will tend to increase the amount of gas available and reduce its price, unless the gas is exported. The availability of imported LNG would tie the price of gas to the international LNG price and potentially allow large volumes of gas to be imported.

The gas price paths assumed in the scenarios are shown in Figure 25. In that Figure and throughout this section, gas prices are denominated in $/GJ, paid as baseload electricity generation at (or south of) Huntly. They do not include charges for flexible gas supply (section 8.13), the cost of carbon (section 8.2), or charges for gas transmission to points north of Huntly.

Figure 25 Modelled gas prices for the five scenarios (exclusive of cost of carbon)



Each scenario follows one of three outcomes for the gas market.

- In the Sustainable Path and South Island Surplus scenarios, it is assumed that no LNG terminal is constructed (perhaps because high international carbon prices cause worldwide fuel substitution from coal to gas, increasing the international demand for gas and making it difficult for New Zealand to secure a supply). Gas prices rise to $13/GJ by 2024, and less than 60 PJ per year is used in the electricity sector. At this price, renewables tend to displace gas-fired generation.
- In the Medium Renewables and Demand-side Participation scenarios, it is assumed that an LNG terminal is commissioned in 2020. Based on advice from MED and consistent with estimates in the Energy Strategy[77], it is assumed that gas prices rise to $11/GJ by 2024 and remain steady at that level indefinitely, and that unlimited amounts of gas can be obtained at that price.

77 Page 30 of NZES states: "assuming medium-term gas prices of $9/gigajoule".

- In the High Gas Discovery scenario, it is assumed that new gas finds provide an ongoing supply of gas at relatively affordable prices. Up to 120 PJ per year is available at a price of $8/GJ.

It should be noted that the assumed gas price is highest in scenarios where the assumed carbon price is highest. Some might argue that high carbon prices would lead to reduced use of gas and hence lower gas prices. The counter argument would be that high carbon prices would lead to reduced gas exploration and/or substitution of gas for coal, both of which would result in higher gas prices.

There is also uncertainty about the future price and availability of oil for electricity generation. However, the sensitivity to these parameters is relatively low, since the scenarios only use oil in small quantities to fuel peaking generation. All scenarios assume that up to 25 PJ per year of diesel can be used for electricity generation; this constraint is never approached. Following advice from MED, the future price of oil for electricity generation is assumed to be $25/GJ in all scenarios except the Sustainable Path scenario, where it assumed to rise to $35/GJ by 2020, following a 'peak oil' scenario.

Future prices of $4/GJ for black coal and $1.80/GJ for lignite are assumed.

8.5 Access to renewables

There is uncertainty about the extent to which renewable resources will be able to be exploited to produce electricity in the next few decades. It may be difficult to obtain resource consent (or resource consent on acceptable conditions) for some renewable developments, especially hydro. Long-term geothermal development is dependent on the progress of steamfield exploration. Integration of wind generation into the power system raises various technical challenges and uncertain system costs. Each of these difficulties can potentially be overcome, but it is not certain that all of them will be.

The Commission has incorporated uncertainty about the feasibility of renewable development in the scenarios as follows.

Generation from geothermal sources appears to be highly economic and is expected to expand rapidly in the next few years. However, it is possible that resource management issues may restrict development. This is modelled by creating three separate growth paths.

- In the Sustainable Path, Medium Renewables and Demand-side Participation scenarios, geothermal capacity can be expanded by up to 1050 MW, if economic.

- In the High Gas Discovery scenario, geothermal capacity can increase by less than 800 MW, and some projects are delayed.

- In the South Island Surplus scenario, geothermal capacity can increase by less than 600 MW, and again some projects are delayed.

Wind development is also proceeding rapidly at present. It is possible, however, that wind generation costs may be higher than expected, perhaps as a result of international market trends, or because of the increased system operation requirements imposed by operators of intermittent generation (assumed to be reflected as 'causer pays' ancillary service costs). This is modelled by increasing the capital cost of wind generation by 10 percent in one scenario (High Gas Discovery).

Large-scale hydro generation has been found to be difficult to consent in recent years. It may be impossible to consent new schemes, especially those on rivers that are of high environmental or recreational value or where there are other significant uses for water. This is modelled by dividing hydro schemes into three groups — those that may be relatively consentable, those that might be very difficult to consent, and those in the middle (based in part on the PBA report — Potential NZ hydro schemes — final report – December 2007[78]). Given the uncertainties associated with consenting hydro schemes, the Commission considers that this categorisation is consistent with the requirement for the GPA to include a reasonable range of credible future high-level generation scenarios. Therefore:

- in the Sustainable Path scenario, all three groups can be built if economic;
- in the Medium Renewables and High Gas Discovery scenarios, the most consentable and moderately consentable groups can be built if economic;
- in the South Island Surplus scenario, the most consentable group can be built, and South Island schemes in the moderately consentable group can be built; and
- in the Demand-side Participation scenario, only the most consentable schemes can be built.

The Demand-side Participation scenario models a future where it is difficult to obtain resource consent for hydro generation. It could be problematic not only to construct new hydro schemes, but also to maintain consents and water rights for existing hydro plants. Accordingly, the output and peaking capacity of existing hydro generation in this scenario is reduced by five percent in 2020, and by a further five percent in 2030. (In practice there might be a significant reduction in output from a few schemes rather than a smaller across-the-board reduction.)

78 http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/pdfsconsultation/renewables/TTER percent20Appendix percent202.pdf

8.6 Lifespan of existing thermal generators

No power plant will last forever. Ageing plant will eventually be shifted to limited operation or decommissioned entirely. The fate of existing thermal generation is a key source of uncertainty in the power system generally, and the scenarios in particular. When ageing thermal generators are decommissioned, new generation is needed and transmission augmentations may also be required.

The choice to retire a thermal generator is an economic decision driven by the value of electricity and the costs of keeping the plant in service. As the plant gets older, maintenance costs tend to increase. Rising fuel and carbon costs would tend to make the economics of ageing thermal plant more difficult, as would the introduction of new, more efficient thermal plant.

Determining when generators will be decommissioned is difficult. New Plymouth Power Station and the co-generation at the Te Awamutu dairy factory have recently been decommissioned and are not expected to return to service – but otherwise, the Commission has not been made aware of any planned decommissioning.[79]

In theory, GEM could be modified to make plant closure decisions endogenous, but it is not clear that there is sufficient data to predict these decisions within the model (for instance, more information on maintenance and refurbishment costs would be needed). Currently, decommissioning assumptions are exogenous to the model, and are made on the basis of fuel and carbon prices.

In the scenarios, the assumptions about decommissioning of generation are as follows.

- The dual-fuelled (coal- and gas-burning) units 1—4 at Huntly Power Station may close down or shift to dry-year reserve mode. In the latter case, they would cease operation except when low lake levels pushed up wholesale electricity prices to a high enough point. If carbon prices were high, this mode of operation could be more economic than normal service.
    - In the Sustainable Path, these units are phased out of service between 2015 and 2020.
    - In South Island Surplus, two are closed between 2013 and 2020 and the other two are used for dry-year reserve until 2030.
    - In Medium Renewables, all four are shifted into dry-year reserve mode between 2013 and 2020.
    - In Demand-side Participation, all remain in normal operation until 2030.

[79] Although Contact has recently indicated that part of the New Plymouth Station may soon be returned to service.

– In High Gas Discovery, two are closed in 2015 (replaced by a CCGT) and the other two remain in normal operation.

The Commission stresses that, although these assumptions probably cover the range of possible outcomes, it is not at all clear what will transpire in practice. One clear point is that it would be difficult to achieve the Government's target of 90 percent renewable electricity generation by 2025 with Huntly Power Station in full service. Further:

- several scenarios assume that one CCGT (nominally TCC) will move to restricted operation (winter only) in the early 2020s, or close entirely. The Sustainable Path scenario assumes TCC will be decommissioned by 2025, in response to very high delivered gas prices; South Island Surplus and High Gas Discovery assume it will shift to winter-only operation around 2022, due to high gas prices or displacement by new, more efficient gas generation respectively;
- some of the less efficient open-cycle gas-fired generators are assumed to close down in the Sustainable Path scenario in the early 2020s, since delivered gas prices would be high enough that renewables could undercut gas plant; and
- in all scenarios TCC is assumed to close in 2033, and Otahuhu B in 2038, if they have not closed already, but they can potentially be replaced by new plant at the same site if this is economic (in practice a process of refurbishment might take place instead).

8.7 HVDC assumptions

The fate of Pole 1 of the Benmore—Haywards HVDC link is a key parameter in the scenarios. It affects the balance of new generation between the North and South Island.

In September 2007, Transpower decided to stand down Pole 1 of the HVDC link in response to operational risk concerns. Although Pole 1 has since been returned to standby operation (March 2008), Transpower is understood to have planned to eventually decommission Pole 1.

Accordingly, Transpower has included in the 2007 GUP an investment proposal to replace Pole 1[80]. At present, it is unclear how long the remaining Pole 1 will stay in standby mode. One half-pole was permanently decommissioned in December 2007.

All the generation scenarios assume, without prejudice to the Board's decision-making on Transpower's HVDC investment proposal, that an HVDC upgrade to 1200 MW of northwards operation will occur in 2012, followed by a further upgrade to 1400 MW in 2018. It is also assumed that HVDC charges will continue to be paid by South Island generation.

80 http://www.electricitycommission.govt.nz/opdev/transmis/hvdc/index.html

The status of Pole 1 before 2012 is uncertain. Transpower has advised that it intends to keep half Pole 1 in standby operation until 2012. It will be available for service at times of peak demand during winter should it be needed and will only run in a northwards direction. Its operation will be limited to grid emergencies and subject to the following conditions.

- A minimum run time of 4 hours following a start.
- A maximum run time of 240 hours in a calendar year and/or a maximum of twenty starts in a calendar year, whichever is reached first.
- Time between load changes of 4 hours.
- Minimum/maximum transfer of 130/200 MW in current control mode only.

Of the scenarios, three assume that this regime holds. The Medium Renewables scenario instead assumes that half Pole 1 will be returned to full operation by 2009 and the Demand-side Participation scenario assumes that Pole 1 will be decommissioned entirely and not replaced until 2012.

On average, this set of scenarios is consistent with Transpower's position, but it allows for the possibility that new information about the serviceability of the remaining Pole 1 equipment may become available in future.

8.8 Demand-side assumptions

Much of the detail in the generation scenario modelling relates to the supply side. However, the demand-side is also important.

The scenarios presented are based on the medium growth forecasts described in section 5.4, but also include the following 'demand-side scenarios'.

- The Sustainable Path and Demand-side Participation scenarios assume high uptake of consumer electric vehicles.
- The Medium Renewables scenario assumes closure of the New Zealand Aluminium Smelters Limited (NZAS) at Tiwai in the 2020s.
- The scenarios assume varying amounts of demand-side response at peak.

The demand-side can contribute to managing peak demand through a variety of means.

- Providing interruptible load for instantaneous reserves.

- Use of interruptible load to reduce peak demand (in response to transmission pricing signals or with the intention of reducing electricity prices).
- Increased price-responsive demand from major consumers exposed to spot prices.
- Wholesale market improvements that facilitate the demand-side to predict and react to price signals effectively.
- Price-responsive demand from residential and commercial consumers, if time-of-use pricing becomes widespread.
- 'Anytime' demand reduction through energy efficiency or fuel substitution.

These types of measures are included in the GEM modelling as 'demand-side response' and 'interruptible load', on the same basis as generation projects. However, it is not yet clear how effective demand-side response will be in helping to manage peak demand. The scenarios, therefore, have a range of assumptions about the amount of demand-side response that is available.

- The Demand-side Participation scenario allows up to 200 MW by 2016, and up to a further 400 MW by 2030.
- The High Gas Discovery scenario allows only 50 MW by 2016, and a further 200 MW by 2030.
- The other three scenarios allow 150 MW by 2016, and a further 250 MW by 2030.

The Demand-side Participation scenario also includes vehicle-to-grid technology, which could potentially make a very substantial contribution to managing peak demand, from 2030 onwards.

8.9 Status of New Zealand aluminium smelter at Tiwai

The Tiwai smelter represents the single biggest demand in New Zealand, peaking just over 600 MW. The closure of the smelter would greatly change the supply/demand balance and have a major impact on transmission flows.

The owner of the Tiwai smelter, NZAS, has not expressed any intention to close down, and has recently contracted to purchase electricity from Meridian Energy until 2030. However, it is still possible that the smelter could be closed before 2030, depending on the price of aluminium, the price of imported bauxite, and the electricity prices in New Zealand compared with those in other aluminium-producing countries.

Despite comments from submitters that the smelter decommissioning should not be modelled, the Commission considers it is appropriate to include one scenario where the plant closes before 2030. Since there is no indication that the plant will close in the near future, the GPA assumes that the smelter is phased out over the period from 2022 to 2027.[81]

The smelter closure takes place in the Medium Renewables scenario. In theory it could occur in any scenario, since it would depend largely on the exogenous factors listed above[82]. However to include early closure in more than one scenario would give too much significance to this uncertainty.

8.10 Assumptions common to all generation scenarios

A number of assumptions applied to the GEM model are common to all scenarios tested. The most important of these, in terms of materiality to the model's output, are described below. All assumptions used in the model are encapsulated and available in the GEM code and associated input datafile.

8.11 Energy constraints

The energy constraints in the GEM model state that total electricity generation must be sufficient to meet demand. In years with high hydrological inflows ('wet years'), there should be enough generation, except, perhaps, at peak times. In dry years it may be necessary to use expensive forms of generation such as thermal peakers to meet demand. If the amount of available generation is still insufficient, electricity consumption must be scaled down (at an assumed shortage cost of $500/MWh).

The generation scenarios are optimised over a range of inflow sequences from very dry (inflows equivalent to those experienced in 1992), through dry (2003), medium (2002), wet (2000), and very wet (1998). The build schedule in each scenario is chosen to have the lowest weighted average cost over this set of inflow sequences, with the extreme cases having less weight (eight percent each) than the three intermediate cases (28 percent each). This approach is intended to mimic the real situation experienced by generators — that is, there is an incentive to build generation so that it is available for dry years, but plant owners must consider that the plant may not be needed in wet years.

81 This is later than the assumption included in the 2007 draft GPA.

82 In earlier drafts of GPA, the smelter closure was included in the Sustainable Path scenario. Some submitters considered that this assumption indicated a view that a sustainable future could only be achieved if the smelter was closed down. The Commission had not intended to imply this, and therefore shifted the smelter closure to the Medium Renewables scenario to avoid confusion.

Typically, in dry years, the following effects would be seen in the GEM generation dispatch for the winter periods.

- Coal- and gas-fired generation increase output.
- If dual-fired units at Huntly are operating in dry-year reserve mode, they produce output if inflows are low enough.
- Diesel-fired peakers generate if inflows are very low.
- Demand reduction can occur if necessary.

In wet years we see:

- coal and gas generation operating at the minimum level allowed in the model;
- peakers operating only at times of peak demand and/or low wind output; and
- renewable energy being spilled.

8.12 Capacity constraints

The 'capacity' constraints in the GEM model state that electricity generation capacity must be able to meet cold-year winter peak demand in each island, with enough reserve to cover a single contingent event. The contingencies considered are the loss of the single largest generating unit, or a single HVDC pole. The constraints take account of higher transmission losses at peak times, and of the need for some generation to be assigned to frequency keeping.

These are 'hard' constraints — they must be satisfied in all years. They have a significant effect on the build schedule, tending to lead to:

- the development of demand-side options;
- the construction of thermal peaking plant;
- later in the scenarios, the construction of renewable peaking plant (such as pumped hydro); and
- a preference for mid-order generation over baseload.

The GEM peak demand forecasts used in the capacity constraint are derived from the GPA' prudent and expected regional peak forecasts. The GEM forecast starts at the level of the GPA prudent peak forecast for 2008, and then increases at the growth rate of the GPA' expected peak forecast. This approach is intended to predict cold-year demands under a scenario of average underlying demand growth (as opposed to using the prudent forecast throughout, which would model a scenario of high underlying demand growth).

In the capacity constraint, each form of generation is assigned a 'peak contribution factor' that quantifies its ability to contribute to meeting peak. A factor of 1 would indicate that the plant was guaranteed to be fully available at peak time; a factor of 0.1 or below would indicate that its availability at peak was extremely limited. Some of the peak contribution factors used are shown in Table 18.

Table 18 Peak contribution factors in GEM

Technology	Peak contribution factor
Thermal (various)	0.95
Coal generation in dry-year mode	0.50
Co-generation	0.60
Geothermal	0.90
New hydro backed by storage	0.95
New run-of-river hydro	0.65
Wind	0.20
Marine	0.30

Existing hydro is omitted from the table because its contribution to peak is handled differently in the model.

The factors assumed for thermal, co-generation, geothermal, and existing hydro generation reflect typical levels of availability of existing plant during peak periods.

The factors of 0.65 for run-of-river hydro and 0.2 for wind are based on exploratory analysis carried out by the Commission (which involves convolving the output of simulated hydro and/or wind generators with the availability curve of the rest of the generation stack).

There is a lively debate about the impact of increased wind penetration on the New Zealand power system, and, recognising the limited extent to which the effect of more intermittent generation on system security can be reduced to a single number, on the appropriate peak contribution factor for wind. Some parties have suggested that the correct peak contribution of wind in the New Zealand power system may be as high as 40 percent for small amounts of additional wind; others suggests that the correct figure is zero. Analysis performed by the

Commission and others suggest that this should at least be 30 percent for moderate levels of wind penetration, however this depends on the mix of other generation sources assumed. The Commission has chosen to adopt the 20 percent figure as a conservative approach at this stage.

8.13 Flexibility of fuel supply

The generation sector must be flexible in its output to meet variations in demand on various time scales. In the past, much of this flexibility has been provided by hydroelectric generation, but it appears that in the future thermal generation may take a larger role. In short time scales, thermal generators can ramp up over a period of minutes to hours to meet peak demand. On longer time scales, thermal generators can produce more power in dry and/or calm years, to make up for the lower contribution of renewables. This is referred to as 'dry-year swing'.

In the short term, the difference in hydro production between a 1-in-20-year wet year and a 1-in-20-year dry year is of the order of 6000 GWh, or about 15 percent of total electricity supply. This gap must be made up somehow. Currently the main source of dry-year swing is increased generation at Huntly Power Station; the other options are increased production from gas generators, oil-fired generation at Whirinaki, reduced spill from renewable generators, and/or demand reduction.

In some scenarios, the coal-fired units at Huntly Power Station are shifted to a limited operation mode or closed entirely. With Huntly less able to provide dry-year swing, a different source must be found. The options in the model are:

- using oil-fired peaking thermal generators;
- demand reduction;
- building surplus renewable baseload and spilling energy in wet years; and
- using gas for dry-year swing.

Since natural gas is cheaper than oil, it would seem economic to use gas-fired rather than oil-fired generators to provide dry-year swing and to help to meet peak demand. However, the ability of gas generators to produce flexible output is dependent on their ability to obtain a flexible supply of fuel.

Generally gas is sold to generators on a 'take or pay' basis, which limits flexibility. This, in turn, is driven by the lack of physical flexibility in the gas production sector. Increased flexibility in gas supply is possible in theory, but would come at a significant cost. It could be achieved by measures including the following.

- Continued overbuild in gas production facilities (unlikely).
- Gas storage (that is in depleted gas reservoirs, such as Contact's proposed facility at Ahuroa[83]).
- LNG deliveries, if an LNG terminal were in place.
- Gas demand response (for example, reduced production in dry years at plants such as Methanex's methanol plants and Petrochem's ammonia and urea plants).

The cost of flexible gas supply is modelled in the scenarios by:

- requiring CCGTs to operate as baseload, with load factors varying between 70 percent and 100 percent, less outages. This means that CCGTs are limited in their ability to provide dry-year swing, and cannot operate as peaking plant; and
- allowing new OCGT 'gas-fired peakers' to be built. These fast-start plants can operate at a wide range of load factors, and can provide dry-year reserve and peaking capacity. However, their gas supply is subject to a 'flexibility charge' of as much as $5/GJ.

8.14 Treatment of intermittent generation

In some scenarios, the proportion of wind generation rises significantly over time. Integrating increased amounts of wind into the power system will lead to various challenges. The Commission has carried out the wind generation investigation project[84] (WGIP) to investigate some of these potential problems and the options to mitigate them.

Wind generation integration issues are modelled in the scenarios in several ways.

- Wind is assigned a peak capacity factor of just 20 percent in the capacity constraints.
- There is an additional 'calm day' capacity constraint that requires the power system to be able to meet winter peak demand with no output from any wind generators, but with reserves dispatched.
- There is an overall restriction of 20 percent on the proportion of New Zealand's total annual electricity supply that can be produced by wind (reflecting general uncertainty about the problems that may arise at very high levels of wind penetration in an islanded system).

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83 http://www.originenergy.com.au/files/080402PresentationContactInvestorsQueenstown.pdf

84 http://www.electricitycommission.govt.nz/opdev/comqual/windgen/wgip

- Modelling of the need for peaking generation in GEM to balance wind output.

Clearly, the output of wind generators will vary over time. At some times, the aggregate output from all New Zealand's wind farms will be substantially less than their average output. The difference will need to be made up by other forms of generation, including hydro and thermals. The ability of thermal generation to increase output to balance wind will be limited, depending on the amount of advance warning. Thermal peakers are able to start relatively quickly from cold, but the ability of mid-order thermal plant to ramp up in time may be limited. The implication is that with increased amounts of wind generation, variability may require relatively expensive peaking generation to be dispatched, which could increase system costs. Further, if wind output is low when demand is near annual peak, then some form of peaking generation will certainly be required.

GEM attempts to model these dynamics by splitting some blocks of the LDC into 'low-wind' and 'high-wind' sub-blocks. There are six main blocks in the LDC, of which the smallest is a 'peak block' of just nine hours per quarter; the top three load blocks are subdivided. Based on exploratory analysis, wind output is assumed to be half the mean level during the 'low-wind' sub-blocks, which take up one quarter of the total time, and is increased during the 'high-wind' sub-blocks to compensate.

Figure 26 An example of the GEM load duration curve, including low-wind (red), high-wind (green) and medium-wind (blue) sub-blocks, showing demand by load block

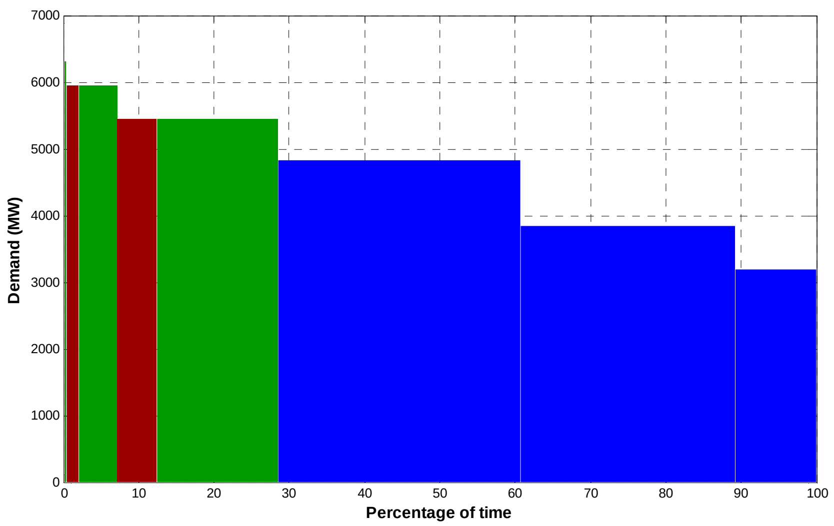
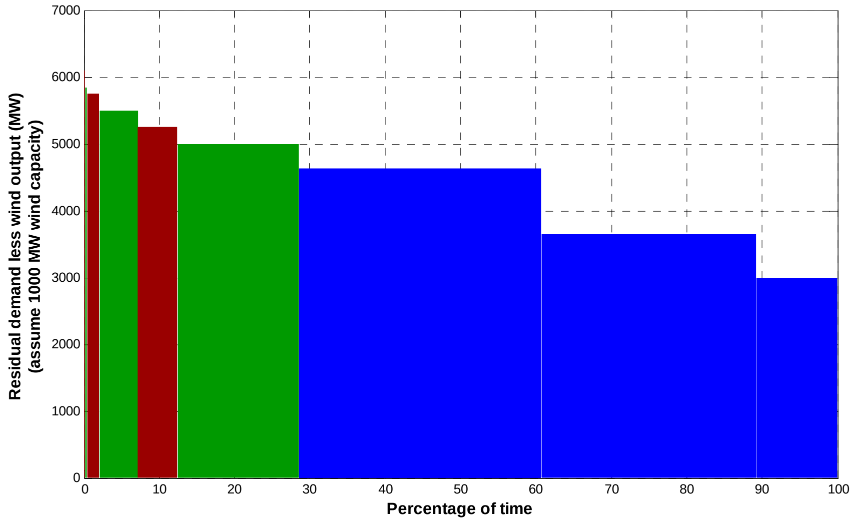


Figure 27 An example of the GEM load duration curve, including low-wind (red), high-wind (green) and medium wind (blue) sub-blocks, showing the residual demand after wind output is subtracted



Generally, some expensive peaking generation will run during these peak and low-wind blocks. If there is still insufficient generation to meet demand, then demand-side response at peak must activate, at a cost of $1000/MWh or higher. The cheaper dry-year demand response cannot be used, nor can coal in dry-year reserve mode. Further, in the low-wind blocks where demand is relatively low, even baseload and mid-order thermals have a limited ability to contribute (since they might not be running before the wind drops, and if not, might not be able to ramp up in time).

The effect of these model features is to better model the need for peaking generation to be built and dispatched in scenarios with high levels of wind penetration.

8.15 Siting of generation

In GEM, each potential generation project is assigned to a specific location.

- For renewable generation, these locations are based on the distribution of renewable resources.
- For baseload and mid-order thermal generators, several possible locations are provided for plant of each type. These locations are consistent with the availability of fuel (for gas and lignite generation), and are otherwise somewhat arbitrary.
- Diesel-fired peaking generators are assumed to be located in either Auckland or Christchurch for modelling purposes, but in fact could be almost anywhere. Different sites for these generators could be explored as part of a GIT application.

The version of GEM used to produce the generation scenarios is a 'two-node model'—it is spatially aggregated to the island level. Project locations (within each island) are important for power systems analysis, but are not so important to the GEM modelling results in the case of a two-node variant of the model. HVDC inter-island transfers are modelled, but transmission constraints on the AC parts of the grid are not considered (although losses on the AC part of the grid are accounted for by adjusting load in each island). Transmission charges other than the HVDC charge are not modelled.

However, project locations do affect the model in one respect. The variable operating and maintenance costs at each plant are adjusted by regionally specific location factors in order to reflect the observed differences in nodal prices attributable to transmission losses. A total of 18 location factors are specified, ranging in value from 0.98 to 1.13. The location factors generally increase in value the further north a region is located. For example, Southland has the lowest value of 0.98, Wellington has a value of 1.00 and Northland has a value of 1.12. The West Coast and northern parts of the South Island have the highest value of 1.13.

8.16 Capital cost uncertainty

There is considerable uncertainty around the capital costs and potential benefits of the modelled wind and hydro generation projects. However, this uncertainty is not reflected in the baseline project cost/benefit estimates. The baseline cost curve for wind is very flat, with relatively little variation in LRMC between projects. In reality this curve should be more sloping, because some potential projects would have higher output than predicted, or would have a lower capital cost.

This issue is reflected in the generation scenarios using a 'capital cost uncertainty' model. Modelled wind and hydro projects (excluding committed and 'highly likely') are divided into five mutually exclusive subsets of roughly equal size on an arbitrary basis. In each scenario, one of these subsets is selected, and it is assumed that projects in this subset possess unexpected advantages (for example, can be constructed more cheaply, or can produce more energy, than the baseline predictions indicate). These advantages are modelled by reducing the capital costs of the selected projects by 10 percent in that scenario. The effect is to shift the selected projects higher up the merit order. This increases the slope of the cost curves for wind and hydro, with the affected projects becoming more competitive with other forms of generation.

Another useful effect of this feature is to increase the diversity between scenarios. Each scenario has a different merit order for renewables, and hence a different built order. This indicates the uncertainty around which projects will be built first, and hence about which transmission upgrades may be required.

9. The generation scenarios

This section describes the five generation scenarios developed by the Commission resulting from the application of the assumptions described in earlier sections. Each scenario is defined by a schedule of new generation projects on a timeline from 2008 to 2040. The schedule has been developed using the GEM model, with the demand forecast to be met, and the key inputs and assumptions as described in the preceding sections. The new generation projects for the scenario are listed, and information is also provided about the consequences in terms of generating technology mix, security of supply, capital and operating costs, fuel use and greenhouse gas emissions.

Although the results and commentary in this section extend to 2040, it should be recognised that predicting generation over such a long timeframe is fraught with difficulties. Readers should view the Commission’s predictions with a degree of scepticism proportional to the gap between now and the year of the predicted event. Even predictions to 2015 are affected by many uncertainties around policy settings, fuel prices, resource availability, and technological costs; but projections beyond 2030 are attempting to describe a world in which our economy, society, environment, and technological options might be very different.

9.1 Introduction and overview

The scenarios are expressed as build schedules — that is lists of projects to be constructed, by commissioning year including generator decommissioning[85].

It is important to emphasise that the generation projects included in each scenario should be regarded as a representative mix, consistent with the 'story' of that scenario. The inclusion of one project rather than another should not be considered as indicative of a Commission view that the first project is more technically feasible, more likely to obtain a resource consent, or more economic. Projects are simply included as instances of the types of plant that might be constructed and the locations in which they might be located.

Table 19 describes the scenarios in an informal timeline format, showing some of the major events projected to occur in each five-year period until 2030.

[85] These schedules are reproduced in full in Appendix 6 for each of the scenarios.

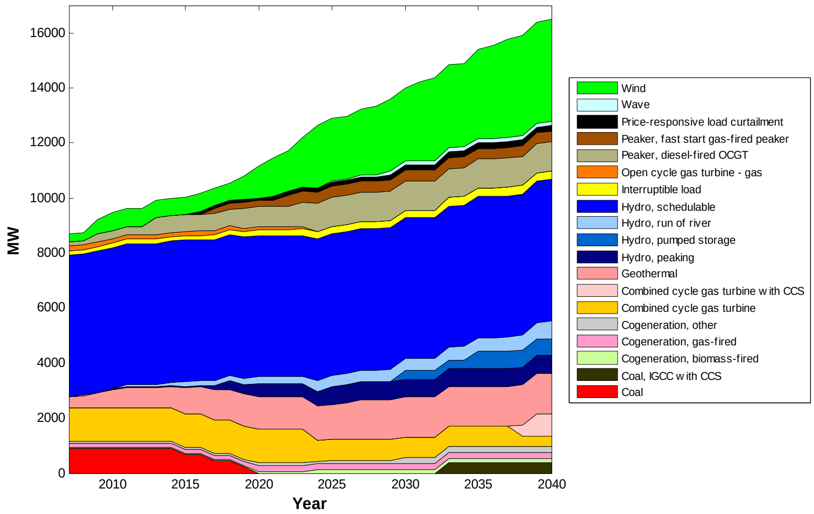
Table 19 Timelines to 2030 for the draft scenarios (based on summarised GEM output)

Scenario	2008 - 2010	2011 - 2015	2016 - 2020	2021 - 2025	2026 - 2030
Sustainable Path	New wind and geothermal developments, with thermal peakers to provide security of supply at North Island peak. Some uncertainty about status of HVDC Pole 1.	New HVDC Pole 1. Hydro and geothermal development backed by thermal peakers.	Coal-fired units at Huntly close down. Hydro, geothermal and wind development backed by demand-side response.	Taranaki Combined Cycle (TCC) and some less efficient gas generators decommission. Hydro, wind and biomass development backed by thermal peakers and demand-side response.	Consumer electric vehicles becoming widespread. Renewable development continues. Pumped hydro and marine energy developed.
South Island Surplus		New HVDC Pole 1, major South Island wind developments, backed by thermal peakers, and some geothermal.	Coal-fired units at Huntly shift to dry-year reserve status. Major South Island hydro developments, plus wind and some geothermal.	Wind development backed by more thermal peakers and demand-side response.	More hydro and wind development. Coal-fired units at Huntly closing down, but coal with carbon storage on the horizon.
Medium Renewables		New HVDC Pole 1. Mixed renewable development backed by thermal peakers.	Coal-fired units at Huntly shift to dry-year reserve. New CCGT built when moratorium lapses. Demand-side backs renewables.	Tiwai smelter begins to close down. Little generation development.	Tiwai smelter closed. Coal-fired units at Huntly closing down and being replaced by thermal peakers.
Demand-side Participation		New HVDC Pole 1. Mixed renewable development backed by thermal peakers.	Geothermal and hydro development. Demand-side takes an important role with advanced metering widespread.	New coal plant built after thermal moratorium lapses. Demand-side continues to develop.	Coal-fired units at Huntly close, but are replaced by new, more efficient coal and lignite plant. Consumer electric vehicles widespread. Vehicle-to-grid technology in place.
High Gas Discovery		New HVDC Pole 1. Two Huntly units replaced by Rodney CCGT. Demand-side has little involvement; thermal peakers used instead.	Some, relatively minor, renewable development.	Another CCGT built, operating in a semi-baseload role.	Remaining coal-fired units at Huntly close down. Some geothermal development. Gas continues to provide a high proportion of supply.

9.2 Sustainable Path scenario

Figure 28 and Figure 29 show the installed capacity and the energy stackplot by technology and by year for the Sustainable Path scenario. The capacity and energy stackplots by fuel are shown in Appendix 7 Figure 50 and Appendix 9 Figure 66 respectively.

Figure 28 Installed capacity stackplot by technology by year of the Sustainable Path scenario



The major features of the Sustainable Path scenario are as follows.

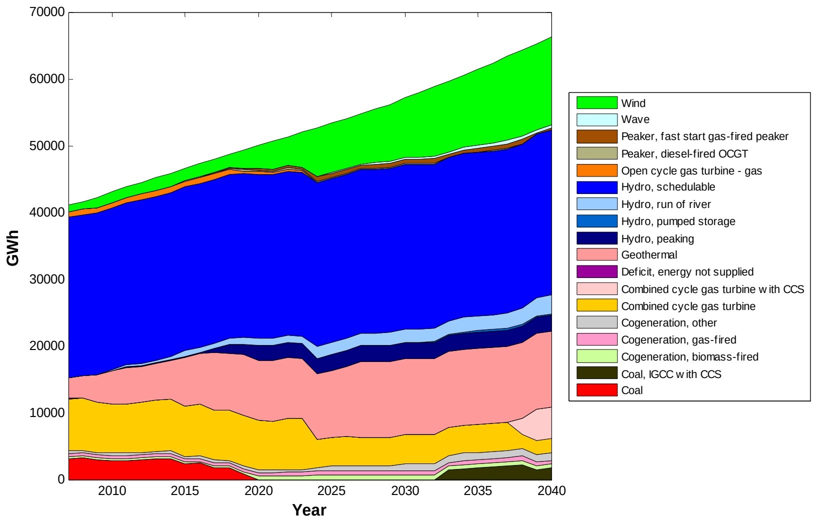
- The combination of high carbon charges and high gas prices leads to renewable projects being very cost-effective relative to thermal generation, and displacing generation from existing thermal plant (with Huntly units 1—4, TCC and various other gas-fired plant closing by 2025).
- Major development of renewable generation takes place in both islands. Wind generation is developed extensively with over 2500 MW of installed capacity by 2030 (see Figure 28), geothermal capacity reaches 1500 MW as early as 2026, and 1400 MW of new hydro is constructed by 2030 (including run-of-river, storage-backed, and pumped modes).
- Biomass (Figure 56) and marine (Figure 65) generation enter after 2020.

- Coal and gas plant with carbon capture and storage follow after 2030, to help meet increased consumption from electric vehicle charging.

- Thermal peaking plants are required in order to balance intermittent generation, provide dry-year swing, and supply reliable capacity to meet peak demand. These are built periodically over the years— by 2030 the scenario includes 1000 MW of diesel-fired peakers (see Figure 61) and 1400 MW of flexible gas-fired generation (Figure 57).

- Demand-side response also assists in meeting peak demand.

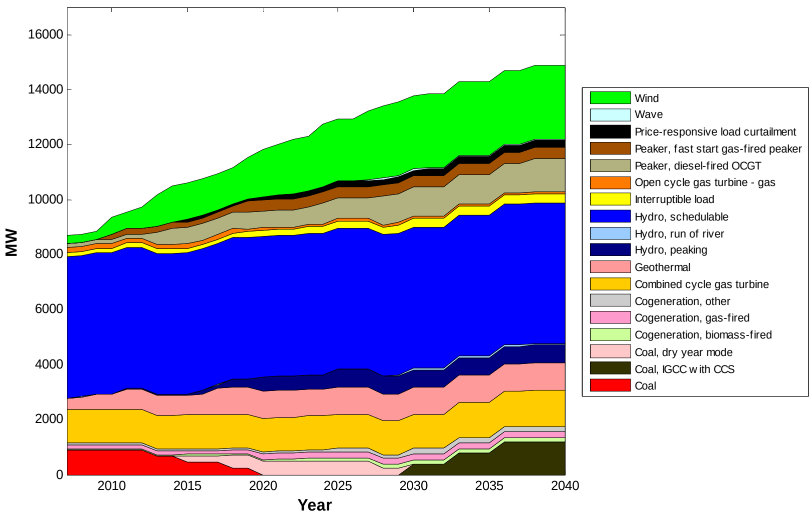
Figure 29 Energy stackplot by technology by year of the Sustainable Path scenario



9.3 South Island Surplus scenario

Figure 30 illustrates the installed capacity by technology and by year for the South Island Surplus scenario. The installed capacity by fuel is shown in Appendix 7 Figure 51.

Figure 30 Installed capacity stackplot by technology by year of the South Island Surplus scenario



The key features of the South Island Surplus scenario are as follows.

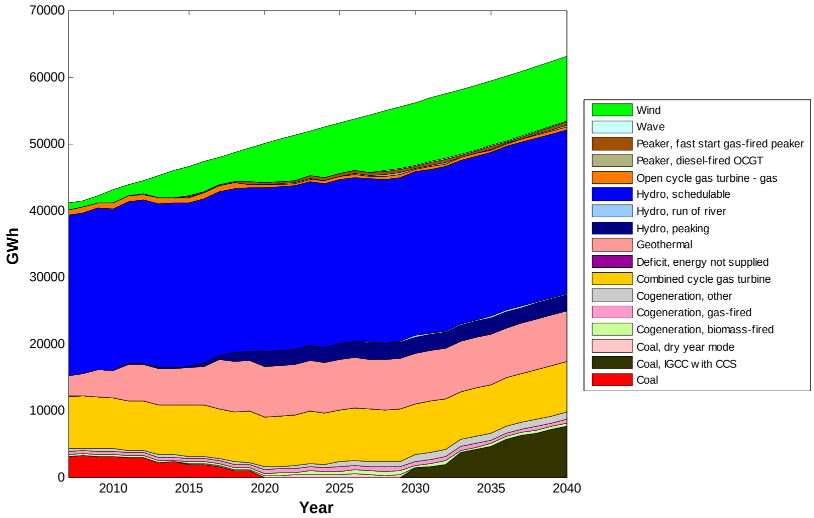
- As in the Sustainable Path scenario, the combination of a high carbon price and a high gas price results in renewable projects being cost effective relative to thermal generation.
- Coal generation is used for dry-year reserve only until carbon capture and storage becomes available.
- As in the Sustainable Path, we see extensive new wind generation, with over 2500 MW installed by 2030 (Figure 55).
- There is also significant amounts of new hydro generation, with about 700 MW of new capacity by 2030, mostly in the lower South Island.
- Geothermal development is slower than in sustainable path, with less than 1000 MW installed by 2030 (see Figure 58).

- As in Sustainable Path, nearly 1000 MW of diesel-fired peakers and 2000 MW of flexible gas plants are constructed by 2030, to balance intermittent generation, provide dry-year swing, and supply reliable capacity at peak.

- Demand-side response also assists in meeting peak demand.

The energy (GWh) by technology and by year for the South Island Surplus scenario is shown in Figure 31 while the energy by fuel is presented in Appendix 9 Figure 67.

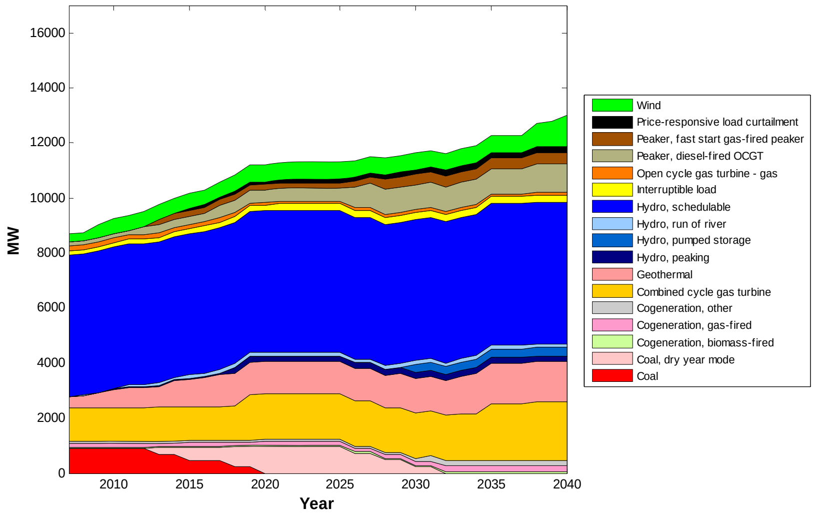
Figure 31 Energy stackplot by technology by year of the South Island Surplus scenario



9.4 Medium Renewables scenario

Figure 32 and Figure 33 illustrate the installed capacity and the energy stackplot by technology and by year for the Medium Renewables scenario. Again the capacity and energy stackplots by fuel are shown in Appendix 7 Figure 52 and Appendix 9 Figure 68.

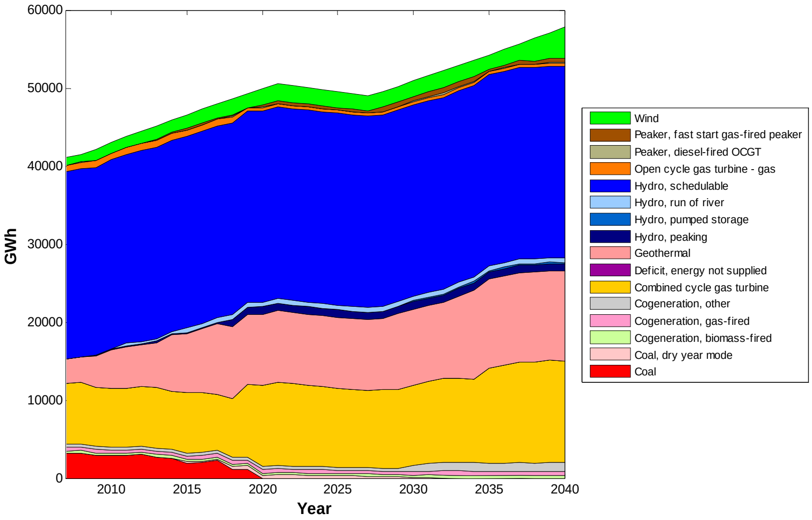
Figure 32 Installed capacity stackplot by technology by year of the Medium Renewables scenario



The key outputs of the Medium Renewables scenario are as follows.

- Due to the phasing out of the Tiwai aluminium smelter around 2025, the medium renewables scenario has the lowest cumulative installed capacity (see Figure 76).
- Importation of LNG provides substantial gas supply from 2020 (Figure 33) – though with fuel costs higher than in the High Gas Discovery scenario — and gas generation remains a major component of electricity supply.
- There is some renewable development, but not as much as in the Sustainable Path and South Island Surplus scenarios—mainly geothermal, with small amounts of hydro and wind.
- There is a requirement for peaking thermal generation, mainly after 2025, when the removal of the very flat Tiwai load leads to a peakier LDC.

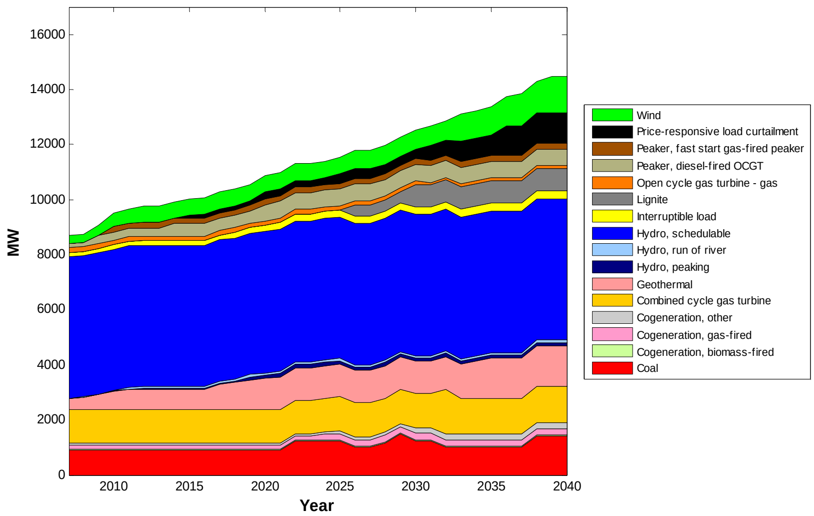
Figure 33 Energy stackplot by technology by year of the Medium Renewables scenario



9.5 Demand-side Participation scenario

Figure 34 and Figure 35 present the installed capacity (MW) and the energy (GWh) by technology and by year for the Demand-side Participation scenario. Similar plots for the fuel are shown in Appendix 7 Figure 53 and Appendix 9 Figure 69.

Figure 34 Installed capacity stackplot by technology by year of the Demand-side Participation scenario

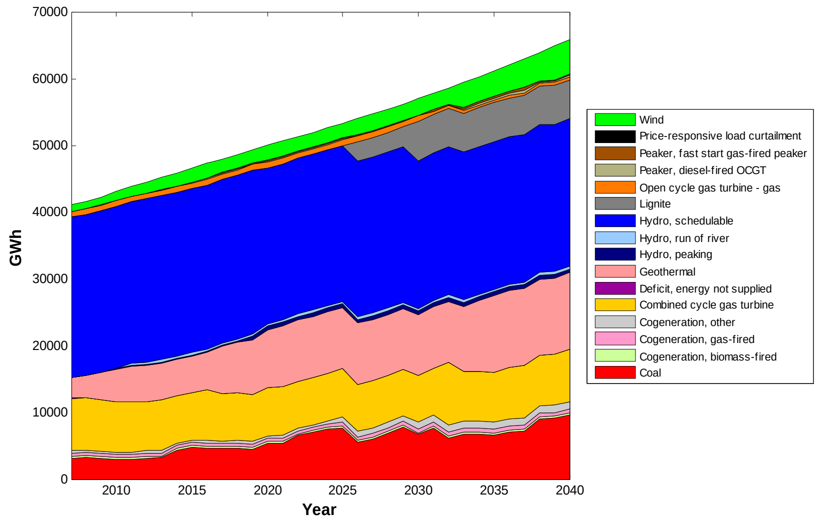


The principal outcomes of the Demand-side Participation scenario are as follow.

- Interruptible load and price-responsive demand (driven by advanced metering, time-of-use tariffs and other initiatives) have an important role to play in balancing intermittent generation and meeting peak demand.
- Electric vehicles increase electricity demand significantly after 2025, but also have an important role to play in supporting the grid via vehicle-to-grid technology.

- Coal- and lignite- fired generation have major roles to play in this scenario. The coal-fired units at Huntly remain in operation until they are replaced by more efficient new plant, with 1800 MW of coal plant (in the North Island) and lignite plant (in the South Island) installed by 2030. As a consequence, sectoral greenhouse emissions are very high.
- There is extensive geothermal development, but little new wind or hydro.
- The output of existing hydro generation is severely curtailed due to difficulties in obtaining water rights.
- Use of thermal peakers is relatively light.

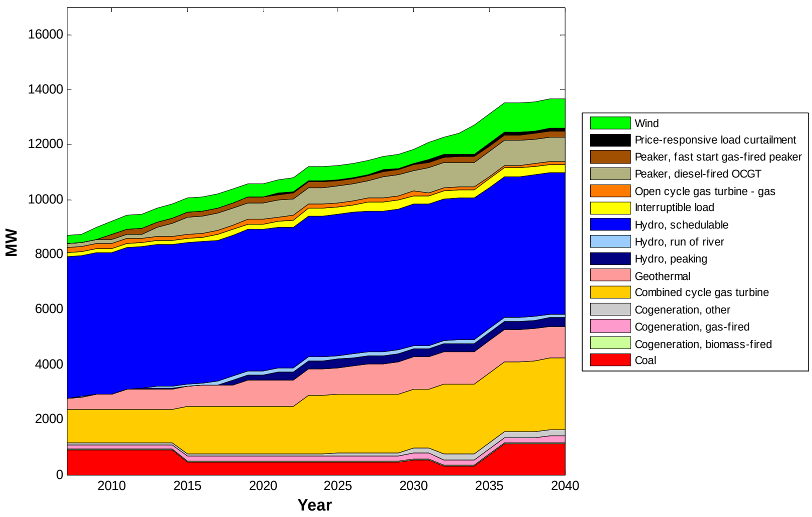
Figure 35 Energy stackplot by technology by year of the Demand-side Participation scenario



9.6 High Gas Discovery scenario

Figure 36 presents the installed capacity by technology for the High Gas Discovery scenario. Capacity by fuel is shown in Appendix 7 Figure 54.

Figure 36 Installed capacity stackplot by technology by year of the High Gas Discovery scenario



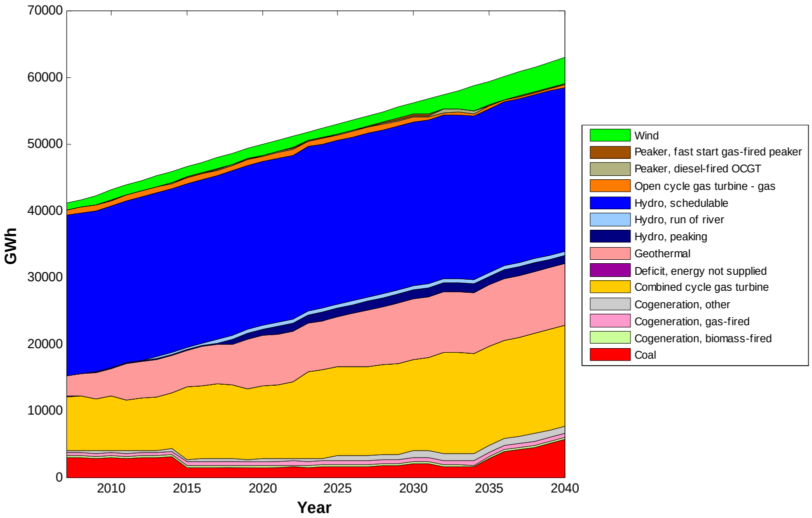
The main outputs of the High Gas Discovery scenario are as follows.

- With a low gas price of $8/GJ and a moderate carbon charge of $40/t, gas generation is favourable. Two new CCGTs are installed by 2030, with gas forming a major component of electricity supply.
- Coal-fired generation is expensive due to the $40/t carbon charge. Two Huntly units are closed and replaced with a CCGT by 2015; the others remain in operation until 2030, but no new coal-fired generation is constructed until at least 2035.
- There is extensive geothermal development, plus some wind and hydro.
- There is a requirement for peaking thermal generation.
- Demand-side participation also contributes to meeting peak.

- The great majority of new plants are scheduled for construction in the North Island, so relatively little energy is transmitted northwards over the HVDC link (Figure 40).

Figure 37 shows the energy by technology for the High Gas Discovery scenario and Figure 70 in Appendix 9 presents the energy by fuel for the same scenario.

Figure 37 Energy stackplot by technology by year of the High Gas Discovery scenario



9.7 Further discussion

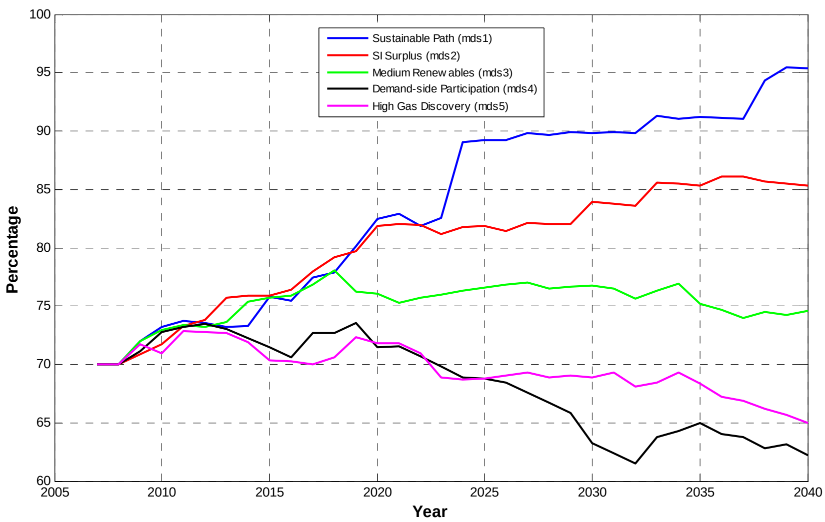
This section compares and contrasts several other key aspects of the scenarios:

- the projected proportion of electricity produced by renewables;
- projected greenhouse gas emissions; and
- implications for HVDC transfers.

9.7.1 Renewable percentage

A key statistic is the projected proportion of electricity that would be produced by renewable generation. Renewable generation fuels are deemed to include hydro, geothermal, wind, biomass, and marine, but not gas, coal or diesel. The exception is that thermal generation with carbon sequestration is considered to be renewable, because the greenhouse emissions would be relatively low. The renewable generation percentage is plotted in Figure 38. It should be noted that these renewable generation percentages represent averages over inflow sequences. The actual percentage would be lower in a dry year, but higher in a wet year.

Figure 38 Renewable energy percentage for each of the five scenarios



The most renewable scenario is Sustainable Path, reaching approximately 90 percent renewable generation by 2025. The South Island Surplus is over 80 percent renewable from 2020 onwards. The Medium Renewables scenario is over 75 percent after 2015, though never as high as 80 percent renewable.

The Demand-side Participation and High Gas Discovery scenarios have relatively high contributions from thermal generation, with renewable percentages dropping to the 60-70 percent range after 2020.

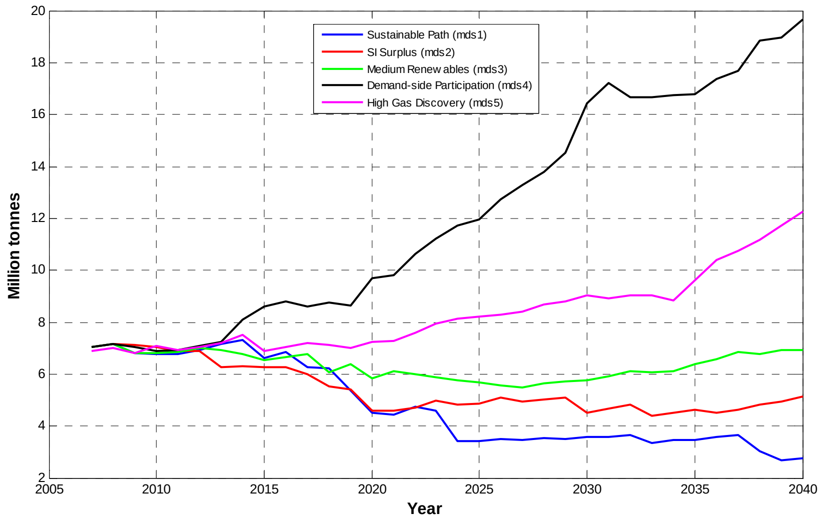
9.7.2 Electricity-sector greenhouse gas emissions

Projections of sectoral greenhouse gas emissions are plotted in Figure 39. Again, these are averages over inflow sequences. Details of the greenhouse gas emissions by technology are shown in Appendix 10 .

The Sustainable Path and South Island Surplus scenarios predict major reductions in sectoral greenhouse emissions by 2020.

The Medium Renewables scenario projects sectoral emissions remaining roughly constant at or slightly below 2008 levels.

Figure 39 Electricity-sector greenhouse gas emissions for the five scenarios



The High Gas Discovery scenario shows an increase in sectoral emissions, by about 32 percent of 2008 levels by 2030. This is driven by increased use of gas for electricity generation. A new coal plant towards the end of the scenario causes a final 'uptick' in emissions after 2035, though this could be avoided by developing renewables instead.

The Demand-side Participation scenario shows a dramatic increase in sectoral emissions after 2020, as new coal and lignite generation comes online. It should be noted that this is not *caused by* demand-side participation; it is a coincidental effect, driven by the high electric vehicle demand and the low carbon price. If, post-2030, New Zealand had a target for total onshore greenhouse gas emissions, then increases in electricity-sector emissions could also be countered by decreases in other sectors (agriculture, or industry).

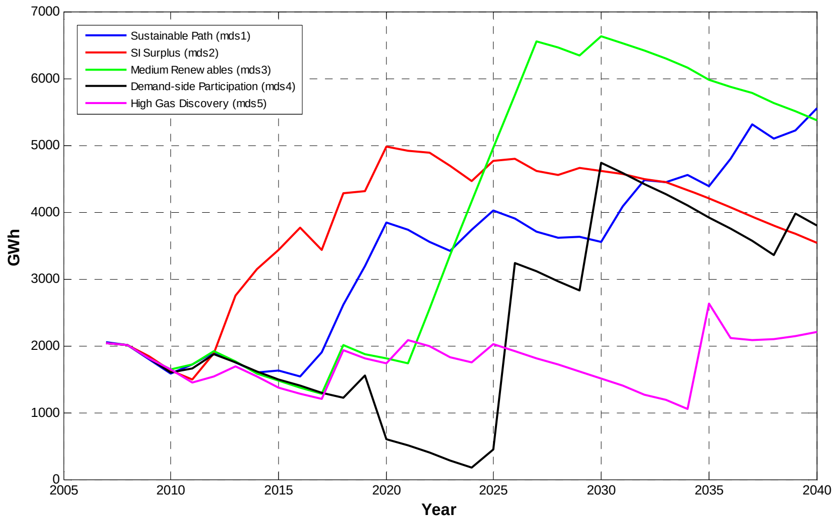
For example the CO_2-e emission from motor vehicles could be reduced through the penetration of electric vehicles. Based on an electric vehicle and biofuel penetration of 35 percent each in 2040 and assuming that an electric vehicle will produce 0.42 tCO_2-e compared to 2.94 tCO_2-e[86] each year for an average light vehicle, a reduction of around 4 million tonnes of CO_2-e could be achieved. This should be seen as a ballpark number and further work will be done to determine a more precise CO_2-e reduction from the electric vehicle penetration.

9.7.3 HVDC transfers

Figure 40 presents the net annual inter-island HVDC transfers in GWh for the five scenarios. Appendix 12 provides the northward and southward transmission and losses by year for the five scenarios.

86 Pers. Comm.. with MoT 4 June 2008.

Figure 40 Net annual inter-island HVDC transfers



In all scenarios the average net transfer (over inflow sequences) is northwards, though in dry years a much larger southwards transfer would be expected.

The South Island Surplus scenario has the highest northwards flow over the 2010s, with new renewable generation constructed in the lower South Island. After 2020 the new generation mix is more evenly distributed across the two islands.

The Sustainable Path scenario has increasing northwards transfer from 2018 onwards, as South Island renewable resources are developed.

In Medium Renewables scenario, northwards flow increases drastically in the 2020s, caused by the phasing out of the Tiwai smelter.

The Demand-side Participation scenario has very low northwards flow in the early 2020s, due to reduced output from South Island hydro schemes. However, lignite generation in Southland/Otago after 2025 increases northward transfer.

High Gas Discovery has relatively low northwards flow throughout, with a high proportion of new generation being North Island gas or geothermal plant.

9.7.4 Peak security and balancing intermittent generation

The GEM model includes capacity constraints (Section 8.12) that require that there must be sufficient generation to meet peak demand. The effect of these constraints on the model results is to:

- prefer mid-order generation over baseload, and baseload over intermittent generation, all else being equal;
- bring in peaking generation (diesel- and gas-fired peakers, pumped hydro and augmentations to increase the capacity of existing hydro schemes); and
- lead to increased demand-side response at peak times.

Firm capacity by scenario is shown in Figure 77. Firm capacity is defined in GEM as the product of nameplate capacity and a technology-specific peak contribution factor. The capacity constraints (North Island and national) result in firm capacity tracking upwards with increases in peak demand.

In the generation scenarios, peaking generation is an increasingly important component of firm capacity going forwards. GEM currently divides peaking generation into diesel- and gas-fired OCGTs, in 'chunks' of 150 MW and 200 MW respectively (though in practice some peaking plant might be dual-fuelled and/or come in smaller sizes). The gas-fired plants have lower SRMC and are typically dispatched first in the model.

All five scenarios include one or two 200 MW gas-fired peakers and from three to six 150 MW diesel-fired peakers. The combined capacity ranges from 350 to 500 MW by 2013, from 500 to 850 MW by 2020, and from 650 to 1300 MW by 2030 (cumulative, not including Whirinaki).

It is not clear whether this estimate of thermal peaking capacity is high or low. Future development will depend on many factors, including but not limited to:

- what security standard New Zealand will require;
- how this will be achieved (through the energy-only market or by some other means);
- how much the demand-side will contribute to meeting peak;
- how easy it will be to integrate wind generation into the system; and
- to what extent these peakers will be needed for dry-year security.

The introduction of extensive thermal peaking generation would be a major change from the recent past, in which relatively little has been available. However, for the last few years, peaking capacity has been supplied in large part by New Zealand's hydro generation assets, with the majority of the remainder coming from thermal generation.

It seems highly unlikely that future demand increases will be matched by growth in hydro generation. In the absence of substantial new baseload and mid-order thermal generation, most new electricity must be sourced from geothermal and wind generation. But wind and geothermal cannot be relied on to ramp up to meet peak, as hydro and thermal generators do. If peak demand growth is to be met in an environment where most new construction is wind and/or geothermal, then either peakers must be added, or the generation system must be overbuilt (that is, the total amount of generation built must be more than is necessary to supply average demand).

Scenarios where existing generation is decommissioned also require more peaking generation to replace the lost assets. All scenarios include the closure of New Plymouth Power Station in 2008. All scenarios also include the eventual closure of the dual-fuelled units at Huntly Power Station and of the Otahuhu B and TCC generators (though the modelled closure dates vary widely). The lost capacity (over 2000 MW) must be replaced by new plant. In scenarios where the dual-fuelled units at Huntly are shifted to dry-year operation, most of their capacity must still be replaced, since they would not reliably be able to contribute to meeting winter peak.

It should be noted that, although the model includes a significant amount of thermal peaking generation in all scenarios, the modelled output of these peakers is relatively low. This might seem to imply that it would not be possible to recover the construction costs of these peakers through their wholesale market revenues, that is, that those plant would not be 'revenue-adequate'. (The corollary would be that the use of the peaking capacity constraint had resulted in the scheduling of plant that would not be built under a free market). However, the Commission considers that there are other explanations for the low load factors of peakers in the model. GEM does not describe the operation of peakers correctly, in some respects.

- GEM does not yet model reserve requirements (other than in the capacity constraint). In the GEM dispatch, all baseload and mid-order generation can potentially contribute towards meeting peak, which reduces the need for peakers to run —but in reality, some of this plant would be providing instantaneous reserves instead.
- The GEM LDC only has nine blocks, which means the resolution is limited at the top end of the curve where peakers operate.
- Transmission losses in GEM do not vary from block to block – in reality, losses increase with transmission flows, increasing the need for generation at peak time.

- Situations where wind output drops below half its average level are not modelled in GEM.
- Cold winters are not modelled in the GEM LDC (the top load block represents peak in an average winter).
- Regional transmission constraints that could provide opportunities for peaking generation are not modelled.

It therefore remains to be determined whether the build schedules produced by the model are revenue-adequate (see section 9.7.6) but it appears that the low modelled utilisation rates of thermal peakers should not be relied on when carrying out this analysis.

9.7.5 Generation costs

This section presents cost data for the generation scenarios.

The GEM model projects various types of costs, for each scenario, in each year, and over a range of inflow sequences.

- Generation capital expenditure (including connection costs).
- Fuel costs.
- Generation operation and maintenance, for new projects only.
- Costs of carbon to the generation sector.
- Costs of carbon storage where applicable.
- HVDC charges.

GEM seeks the build schedule that minimises these costs, on a post-tax basis and discounted at eight percent real. Generation capex enters the model as an annualised cost stream.

Modelled costs by scenario are shown in Figure 41 to Figure 45. For ease of interpretation, these plots show pre-tax costs, with generation capex represented on a lump-sum basis. All costs are expressed in real undiscounted dollars. The figures shown are averages over inflow sequences (in dry years, fuel and carbon costs would be higher than average).

It should be noted that some types of supply-side costs are not modelled in GEM and so not included in these figures — including transmission upgrade costs, ancillary service costs, consenting costs, generator overheads, etc. HVDC charges are modelled in GEM but not shown in the figures.

Figure 41 Annual costs (mean, undiscounted, pre-tax) in the Sustainable Path scenario

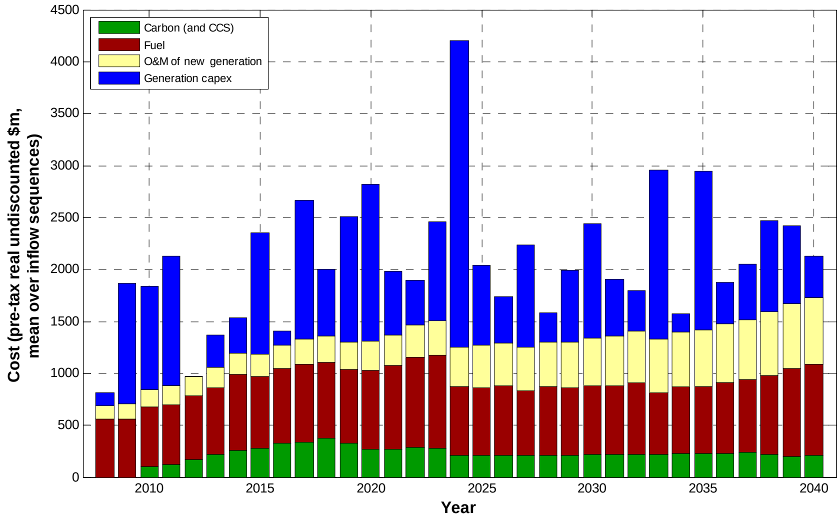


Figure 42 Annual costs (mean, undiscounted, pre-tax) in the South Island Surplus scenario

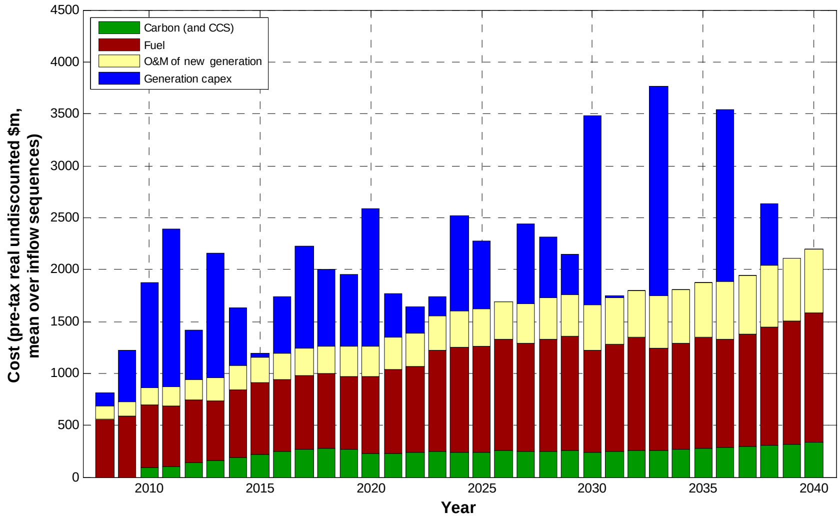


Figure 43 Annual costs (mean, undiscounted, pre-tax) in the Medium Renewables scenario

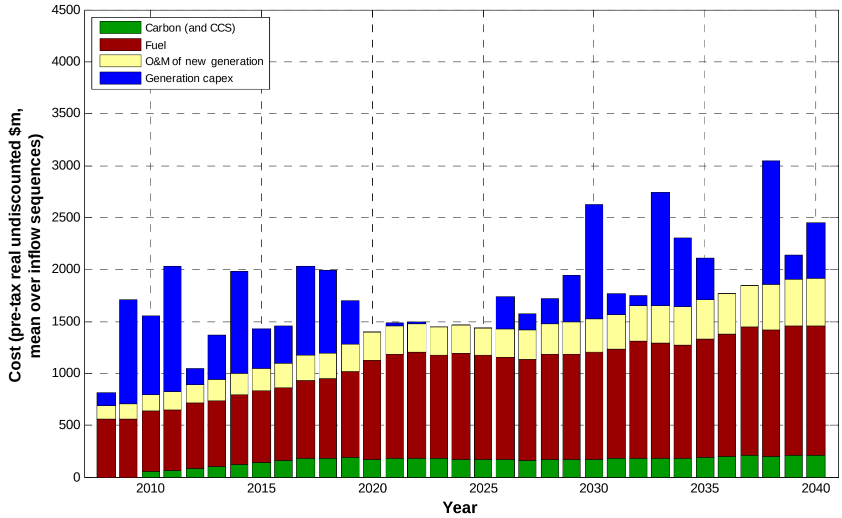


Figure 44 Annual costs (mean, undiscounted, pre-tax) in the Demand-side Participation scenario

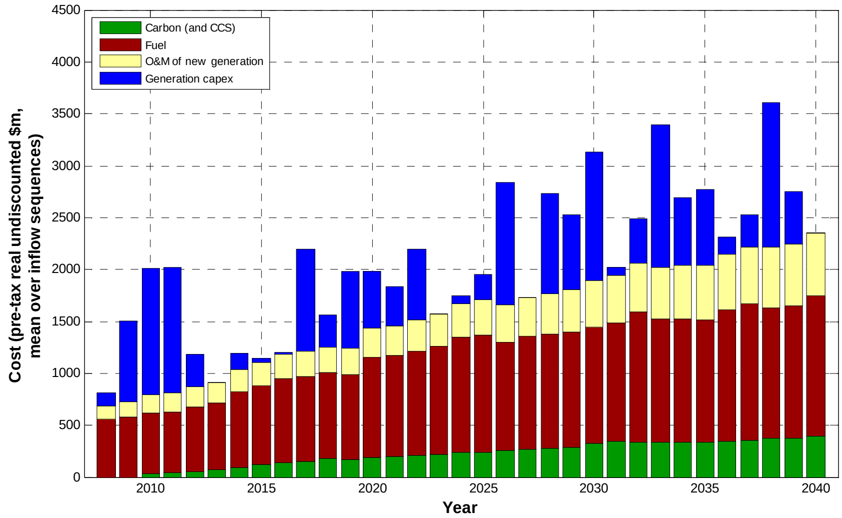
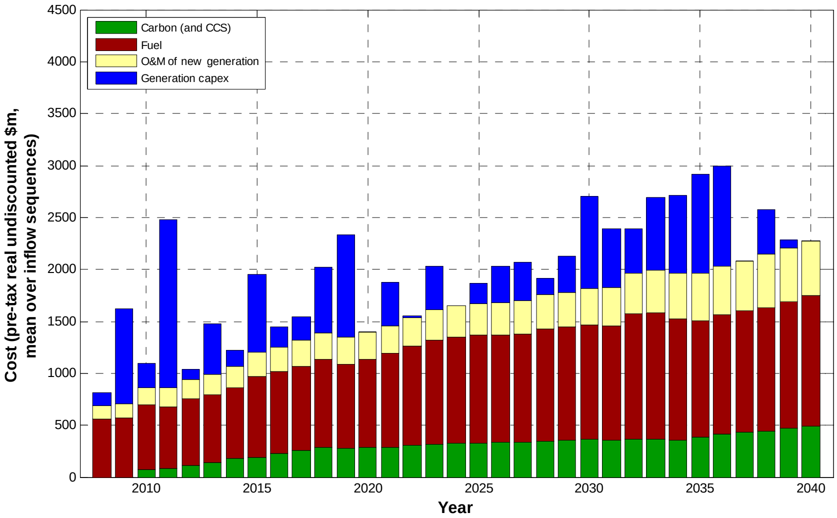


Figure 45 Annual costs (mean, undiscounted, pre-tax) in the High Gas Discovery scenario



Net present values (NPVs) of supply-side costs are shown in Table 20. A central discount rate of seven percent is used, with five percent and 10 percent as sensitivities. These are pre-tax costs. They include annualised generation capex, connection costs, O and M of new generation, fuel, electricity-sector carbon costs, and carbon storage costs where applicable. As before, HVDC charges are excluded, as are cost elements not modelled in GEM, such as transmission upgrade costs, ancillary service costs, consenting costs, generator overheads, etc (see section 12).

Table 20 NPVs of pre-tax costs (mean over inflow sequences) in the generation scenarios

Discount rate (real, post-tax)	Scenario	PV ($m)
5%	Sustainable Path	36,129
	South Island Surplus	35,743
	Medium Renewables	30,763
	Demand-side Participation	33,093
	High Gas Discovery	32,554
7%	Sustainable Path	27,016
	South Island Surplus	26,711
	Medium Renewables	23,314
	Demand-side Participation	24,705
	High Gas Discovery	24,487
10%	Sustainable Path	18,602
	South Island Surplus	18,372
	Medium Renewables	16,359
	Demand-side Participation	17,001
	High Gas Discovery	17,013

Care should be taken in comparing costs between scenarios. In large part, the cost differences are driven by exogenous assumptions. For example:

- the high costs in the Sustainable Path and South Island Surplus scenarios are the result of high fuel and carbon prices;
- the low costs in the High Gas Discovery scenario are the result of low carbon prices;
- the costs in the Sustainable Path and Demand-side Participation scenarios are partly the result of fuel switching from liquid fuels to electricity in the transport sector, and could be partly offset by reductions in liquid fuel costs; and
- the low costs in the Medium Renewables scenario are partly due to the closure of the Tiwai smelter, which significantly reduces national electricity consumption.

In each scenario, the generation build plan presented is the least-cost response to the exogenous assumptions (given the GEM modelling framework). For instance, the extensive use of renewables in the Sustainable Path and South Island Surplus scenarios is the most economic way of producing electricity in an environment where carbon emissions are expensive and fossil fuels are scarce. So, rather than concluding that 'renewable generation is expensive', the Commission concludes that 'renewable generation is the best way of reducing supply-side costs in some scenarios'.

9.7.6 Revenue adequacy

The Commission is currently developing tools to help understand possible future trends in wholesale electricity market prices. The aim of this work is to assess whether the generation scenarios are revenue-adequate — that is, to determine whether they would lead to wholesale prices that would be high enough for generators to recoup their investments. Achieving revenue adequacy is not a requirement for the GPA to be considered credible, but if it can be demonstrated, this will support the credibility of the scenarios.

It should be noted that long-term wholesale market prices are notoriously hard to predict. Any analysis based on long-term price predictions must be considered highly speculative.

Three different approaches are under consideration.

- A calculation of the 'revenue-adequate price path', which seeks to determine the price levels that would be necessary to achieve revenue adequacy in the scenarios.
- A 'statistical projection' of wholesale price, based on observed relationships between the wholesale price, the New Zealand winter energy margin (WEM_G), and the short-run marginal cost (SRMC) of thermal generation.
- Reading off the 'shadow price' of energy from GEM solutions for each future modelled year.

Revenue-adequate price paths have been calculated and are presented in this document.

The other two approaches are still in early development.

Ideally, the 'revenue-adequate' and 'statistical' price projections would be roughly equal (indeed, they would be identical if they were each ‘right’). This would indicate that the scenario build plans would give rise to wholesale prices that were only just high enough for generators to recoup their capital cost and earn a reasonable return on their investment while doing so. In theory, this would be the natural outcome of a competitive market.

Revenue-adequate price paths

The revenue-adequate price path approach seeks to determine how high prices would have to be in each future year to allow generators to recoup the costs of their investments (plus a reasonable margin of profit).

There are two approaches that could be taken.

- To determine a price path that would allow the costs of existing and new generation to be recovered from generator revenues.
- To determine a price path that would allow the costs of new generation plants (only) to be recovered from the revenues of those plants.

In this work, the second approach has been taken, largely in response to uncertainty about the amount of costs still to be recovered from existing generation projects. However, note that Huntly e3p (Huntly unit 5) is considered to be a 'new' plant for this purpose, so from 2008 onwards, the adequate price level must be high enough to recover the assumed costs of building and operating Huntly unit 5.

Revenue adequacy should hold not only for the overall portfolio of new plant, but also for each category of plant. Thus, it is asserted that, under revenue adequacy:

- the costs of baseload plant should be recoverable from average prices;
- the costs of mid-order plant should be recoverable from prices during peak and shoulder periods; and
- some portion of the costs of peaking plant should be recoverable from prices during peak periods — however, peaking plant could also earn revenue from providing ancillary services, exploiting inter-regional wholesale price differences, and/or being paid to act as transmission alternatives.

There are infinitely many price paths satisfying these requirements. One extreme example could be for all plants to earn *no* revenue until 2040 and then to earn a very large amount of revenue in the 2040 year. To narrow down the options, additional constraints are added, requiring revenue adequacy in each year and putting some conditions on the shape of the price duration curve.

On this basis, a revenue-adequate price path has been defined as a set of prices (for each year, time period, load block, and inflow sequence) that satisfies the following constraints in each year.

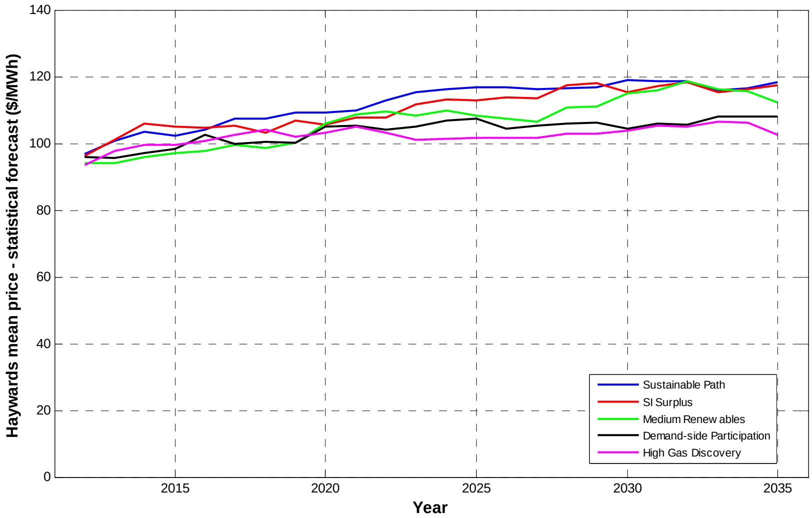
- The wholesale revenue (sum of output multiplied by Haywards price, less tax) obtained from new plant must exceed the total operating cost (post-tax, including that year's portion of the annualised capital costs) by at least a 10 percent profit margin.
- The wholesale revenue obtained from new baseload plant must exceed their operating cost by at least a 10 percent profit margin.
- The wholesale revenue obtained from new mid-order plant must exceed their operating cost by at least a 10 percent profit margin.
- The wholesale revenue obtained from new peaking plant must exceed *half* their operating cost by at least a 10 percent profit margin.

The resultant revenue-adequate price paths for the generation scenarios are shown in Figure 46. (Note that the mean is time-weighted rather than demand-weighted: a demand-weighted mean would be higher.)

Prices before 2012 have not been predicted, because the projected amount of new generation in that period is not yet enough to provide a clear picture of new entrant costs.

In some scenarios, the peaking plant adequacy constraint is not satisfied between 2012 and 2014. This may reflect unrealistically low utilisation of peakers in GEM.

Figure 46 Revenue-adequate price paths for the generation scenarios



All five scenarios show mean prices rising gradually from approximately $95/MWh in 2012[87] . After 2025, prices range from just over $100/MWh in the High Gas Discovery scenario (where low fuel prices allow for relatively cheap new thermal generation) to nearly $120/MWh in the Sustainable Path and South Island Surplus scenarios (where fuel and carbon costs are much higher and new generation consists mainly of renewables backed by thermal peakers).

The most renewable scenarios have the highest revenue-adequate price paths. This is not because renewables are an expensive option, but because those scenarios have high gas and carbon prices. Renewable development is the least-cost response to those conditions; with more thermal generation, costs and prices would be even higher.

In a competitive market, it could be expected that actual mean prices would not exceed these projections over an extended period (multiple years), since new entrant generators would be able to offer in at the revenue-adequate price level and still make a profit.

Actual mean prices might fall below the projected level. In this case, generators would not be able to recover the costs of their new plant. Owing to portfolio effects, however, it might still be optimal for them to continue to build new generation. The possibility of prices being less than the revenue-adequate level for extended periods of time can therefore not be ruled out.

[87] By comparison, the mean Haywards price between 2001 and 2007 was only about $50/MWh (in large part because of the availability of cheap fuel).

10. Approach to the power systems analysis

10.1 Rule requirements and purpose of the power systems analysis

Rule 9.1.1 of section III of part F of the Rules requires the SOO to include an analysis of the performance of the power system against the GPA and the GRS.

The purpose of the SOO is to enable identification of potential opportunities for efficient management of the grid including investment in upgrades and transmission alternatives. The Rules also provide that in preparing the SOO the Commission must have regard to the principle of meeting the reasonable requirements of Transpower, investors in generation, other participants, end-use consumers and those interested in evaluating transmission alternatives.

The PSA contributes to the purpose, and furthers the principle, by identifying when the grid, in any given scenario (that is, the GPA) will no longer meet the GRS.

The point at which the transmission grid is anticipated to no longer meet the GRS represents an opportunity for efficient management of the grid, including investment in upgrades and transmission alternatives. The opportunities signalled in the SOO are only transmission opportunities, but the Commission emphasises that, in some situations, opportunities for investment in transmission alternatives may arise at the same time.

Therefore, in summary, the PSA:

- identifies the characteristics and capabilities of the existing transmission network;
- assesses the ability of the existing transmission network to meet the GRS under each generation scenario over the relevant period of the GPA (30 years);
- identifies transmission limitations and constraints within regions that may require investment in order to continue to meet the GRS. This analysis focuses on forecasting supply and demand within regions, and on when constraints are likely to become binding; and
- identifies rudimentary, long-term, least-cost transmission opportunities for each scenario.

The PSA is presented in section 11 by region, for each scenario.

10.2 Approach to the power systems analysis

The PSA uses a simplified approach to the consideration of the GRS, namely the use of a deterministic reliability standard. This is likely in most cases to have a similar outcome as the use of the full GRS. Detailed application of the GRS would have involved a substantially greater amount of analysis.

This more detailed GRS analysis is the responsibility of Transpower as the grid planner. It is expected that in future years when Transpower has complied with the grid planning requirements specified in the new Benchmark Agreement (section II of part F of the Rules) and interconnection rules (schedule F6 of section VI of part F of the Rules) that this more comprehensive information will be available to the Commission to assist with this work.

10.3 Market Development Scenarios

The generation build sequences provided as GEM outputs create market development scenarios that are based on providing sufficient capacity to meet the forecast national winter peak demand, and sufficient energy to meet the national annual energy demand. The GEM generation build sequences do not consider any transmission augmentations that may be required to deliver the power to the demand.

10.4 Key information and assumptions

10.4.1 Planning horizon

The PSA considers a 30-year planning horizon from 2007 to 2037. In the analysis the planning horizon is broken into five-year intervals with 2007 being the benchmark year.

10.4.2 Generation scenarios

The PSA uses the 2008 generation scenarios that correspond to an N–G–1[88] system peak generation security criteria, allowing for a 'realistic maximum generation capacity'. For example, the grid is assumed to be capable of meeting demand and losses with Otahuhu B (360 MW)) out as well as limitations to the generation dispatch as outlined below.

It was assumed that in the event of a large generator tripping or HVDC pole tripping, reserves might be made up from a combination of interruptible load and HVDC overload capacity.

[88] N-G-1 security means that the system is in a secure state with all transmission facilities in service, and in a satisfactory state following a generator outage and a credible single contingency event.

10.4.3 Generation dispatch

For the 2008 SOO a power-flow model has been developed for all of New Zealand[89]. To initialise this generation was dispatched as follows[90]

Peak Winter Generation Dispatch

For peak winter demand, all North Island generation plant is set to its maximum output, with the following exceptions.

- Wind generation was dispatched at 20 percent active power output and 100 percent reactive power capacity.
- Otahuhu B (1 x 360 MW) was disconnected to represent the effect of an unplanned outage of a large unit on both Auckland and the rest of the country.
- In the Bay of Plenty, Wheao (1 x 24 MW) was disconnected to represent the effect of the loss of a large unit in that region.
- In Hawke's Bay, one Piripaua unit was disconnected to represent the effect of low hydro generation in the region. The reserve generation at Whirinaki (3 x 52 MW) was also disconnected unless required in the event of a generation shortfall.

With the above North Island generation dispatch, the HVDC link was set to maintain the North Island slack bus within its generating limits.

With the HVDC set, the South Island peaking hydro (and/or gas/coal) generators were then set to maintain the South Island slack within its generating limits, with the following exceptions.

- In the Upper South Island, Cobb generation was restricted to 50 percent output (17.1 MW) to represent the effect of low hydro generation in the region.
- On the West Coast, Arnold (1 x 3 MW) was disconnected and the Kumara/Dillmans scheme (11 MW) was restricted to 4.5MW.

Manapouri generation was limited to 721 MW unless a generation scenario declares that a higher output is reliably available.

[89] Previously the North and South Islands were represented as separate power flow models.
[90] This generation dispatch was automated to give consistency across all scenarios and years.

Peak Summer Generation Dispatch

For peak summer demand, all North Island generation plant is reduced from its maximum output. This gives some leeway when resolving summer transmission issues by altering generation dispatch. The same exceptions apply as for winter, however in summer, one Huntly coal unit (1 x 250 MW) was disconnected to represent a scheduled maintenance outage.

With the above summer North Island generation dispatch, the HVDC link was set to maintain the North Island slack bus within its generating limits.

With the HVDC set, the South Island peaking hydro (and/or gas/coal) generators were then set to maintain the South Island slack within its generating limits, with the same exceptions as used in the winter generation dispatch above.

Wind generation sensitivity

When studying a region, all wind generation in that region was disconnected to represent a windless day. All other wind generation will be dispatched at 20 percent active power output and 100 percent reactive power capacity.

As a sensitivity case all wind generation in the country was disconnected to represent a windless day throughout the country.

10.4.4 Dry-year dispatch not explicitly studied in the power systems analysis

The PSA does not explicitly study the network's capacity to transfer energy south during off-peak periods such as dry years because the generation scenarios already take into account the capacity of the network to do this transfer.

The Commission did not study of dry-year dispatch as it is expected that market participants would effectively manage hydro storage using the capability of the grid to transfer power from North to South during periods of low demand.

10.4.5 HVDC upgrade

When analysing energy loads for 2007 and 2012 the Commission assumed that the HVDC Link operates with only Pole 2 (700 MW) and one Pole 1 Half Pole (270 MW) giving a 970 MW capacity.

When analysing energy loads for 2017, the Commission assumed that an upgraded Pole 1 was added before this date with a 500 MW capacity, bringing the total HVDC bipole capacity to 1200 MW. This was consistent with Transpower's current preferred option.

From 2022 onward, the Commission assumed a fourth submarine cable has been installed to further upgrade Pole 1 to 700 MW, bringing the total HVDC bipole capacity to 1400 MW. This is not inconsistent with Transpower's assumptions in the HVDC GIT consultation material which assumed commissioning of this capacity before this date.

10.4.6 Demand forecast

The ADMD prudent peak forecasts discussed in section 5.4.2 were used in the PSA.

These demand forecasts were used in the PSA. The forecasts are the same across the different scenarios, apart from the following exceptions.

- In MDS 3 the Medium Renewables Scenario, the Tiwai Aluminium Smelter is decommissioned by 2027.
- In MDS 4 Demand-side Participation, there is significant price-responsive load curtailment (1100 MW by 2037). In the PSA analysis we have modelled this at negative demand on the Otahuhu (Auckland), Central Park (Wellington) or Islington (Christchurch) busbars.

No explicit allowance was made for fluctuations due to extreme weather conditions. This was because the demand forecasts used already allow for extreme weather conditions in the early years where timing of new investments is more critical than the later years in the horizon.

It was assumed that both the winter peak and summer peak will have national diversity factors applied to the GXP peak loads. It should be noted that the use of national diversity factors will result in slightly lower regional loads than the use of regional diversity factors. However, this was not considered to be significant in the context of a 30-year horizon.

From 2017 onward it was assumed that the demand power factor has improved to unity on the low voltage side of GXP supply transformers in the Upper North Island and Upper South Island.

As the demand for energy grows the supply transformer capacity will need to be augmented to provide a secure supply to the load on the low voltage supply buses. Modelling these supply transformer augmentations is likely to involve a considerable amount of work and there is a large uncertainty in the nature of the augmentation because individual GXP demand growth is harder to forecast than national demand growth. On the other hand, not modelling the augmentations will result in an unrealistically high reactive consumption in the supply transformers.

Instead of augmenting supply transformers the analysis took the approach of maintaining a constant load power factor as viewed from the high voltage side of GXP supply transformers and eliminating the supply transformers.

For the Upper North Island and Upper South Island the analysis maintained a 0.99 lagging power factor as viewed from the high voltage side. This was consistent with the new connection code which requires a unity power factor so that off-take customers in these regions do not draw reactive power from the grid at peak times.

For other loads the analysis maintained a 0.96 lagging power factor as viewed from the HV side. (The value for power factor was determined by averaging all of the high voltage side power factors at peak load. The average winter peak power factor and summer peak power factor were both found to be about 0.96 lagging).

Note that 220/110kV inter-connecting transformers were still added or upgraded explicitly where there was a need for such upgrades. Also where there was a mix of generation and load on the low voltage side the analysis will not eliminate the transformers.

10.4.7 Performance criteria

The security criteria that were assumed for this study were generally based on the N – 1 single contingency criteria described in Transpower's 'Main Transmission System Planning Criteria'[91], allowing for the generation outages described in paragraph 16.

However, supply to Auckland is based on N-G-1 which is the security level that will be achieved when Transpower's North Island Grid Upgrade proposal is limited. That proposal was approved by the Commission in July 2007.

The credible single contingency events that were considered in the PSA are those defined in the Rules.

The PSA assumes that the following system performance criteria would be maintained for normal operation and following a single contingency.

- Transmission circuits can be loaded up to 100 percent of winter or summer rating.
- Interconnector transformers can be loaded up to 120 percent of rating (except where overload ratings for specific transformers are known).

[91] Main Transmission System Planning Criteria', Transpower New Zealand Limited, March 2005.

- Voltages are maintained in the range 0.90 – 1.10 pu at all buses (after capacitor switching and tap changing).
- Five percent margin to the nose of the PV curve for Upper North Island, Upper South Island, and the Bay of Plenty.
- Fault levels at selected bus bars will be recorded for information purposes only. The analysis is not intended to specifically study augmentations to limit fault levels.

The PSA did not consider dynamic analysis because this was intended to be an overview rather than a detailed design study.

10.4.8 Selection of transmission augmentation

As outlined above, the PSA identifies possible transmission augmentations as required to maintain the system. Performance criteria in each of the study years were selected in the following order.

- Committed transmission projects discussed in Transpower's 2008 Annual Planning Report.
- Transmission opportunities, namely:
  - other possible transmission projects discussed in Transpower's 2008 APR that are transmission opportunities;
  - transmission opportunities chosen from the 'building blocks' described in the previous report on inter – area capacity[92]; and
  - Transpower's projects that have been modelled in the GIT for the HVDC Upgrade.

When selecting transmission opportunities, the PSA favours lower cost upgrades in preference to new lines where possible.

The PSA assumed that the existing 220kV grid will continue to be augmented with new 220kV lines. (The committed 220/400kV line from Whakamaru to Pakuranga will be upgraded from 220kV to 400kV when required).

Supply to the Upper South Island is currently constrained by voltage stability rather than thermal limits. Modelled augmentations will include a second Synchronous Var Condenser (SVC) at Islington and Ashburton, followed by a new 220kV transmission line.

92 http://www.electricitycommission.govt.nz/pdfs/opdev/modelling/GPA/SSG-inter-regional-transmission-capacity.pdf

10.4.9 Cost of transmission opportunities

The PSA included an approximate cost of modelled transmission augmentations. These costs were based on:

- SSG's report on 'Inter-Area Transmission Capacity';
- Transpower's 2008 APR;
- Transpower's modelling for the HVDC Upgrade proposal;
- Transpower's North Island Grid Upgrade Proposal; and
- Transpower's North Auckland and Northland proposals.

11. The power systems analysis

11.1 Introduction

This section describes the results of the power systems analysis.

Only those regions with significant committed projects or transmission opportunities are discussed here. Relatively minor augmentations, such as supply transformer upgrades, are not discussed. Appendix 13 sets out a detailed list of all augmentations (that is, committed projects as well as opportunities for transmission investment modelled in the power systems analysis).

The need dates that are stated here imply a possible five-year window because the analysis is carried out in five-year steps. For example if a transmission opportunity is identified as existing 'before 2017' then the actual need date could be anywhere between 2013 and 2017.

11.2 North Island transmission analysis

11.2.1 Northland

The Northland regional demand is forecast to increase from around 800 MW in 2007 to over 1500 MW by 2037.

The region is currently supplied from the south by a 220kV double circuit Henderson- Marsden transmission line and a 110kV double circuit Henderson-Maungatapere line. From Maungatapere there is a 110kV double circuit line to Kensington and a 110kV double circuit line to Kaikohe with a single circuit line continuing to Kaitaia. These circuits provide an adequate supply into the region for the near future with little transmission augmentation planned or committed.

The region has a small amount of generation in the form of the Ngawha geothermal power station. In all scenarios this station is modelled to increase output by 15 MW by 2009 (15 MW is assumed to be decommissioned in 2020 in the Sustainable Path scenario). A medium-sized (85 MW) gas-fired generating unit is modelled at Marsden, post 2020, in all scenarios except the High Gas Discovery scenario, and a large (300-400 MW) coal-fired generating plant is modelled, post 2022, in the South Island Surplus, Demand-side Participation and the High Gas Discovery scenarios. In the High Gas Discovery scenario a large (480 MW) CCGT plant is modelled at Rodney in 2015. Up to 570 MW of wind generation is modelled in the region for the Sustainable Path, South Island Surplus and High Gas Discovery scenarios. Overall, the Medium Renewables scenario offers the least new generation (100 MW, none of which is wind generation), while the High Gas Discovery scenario offers the most generation (875 MW, of which 300 MW is wind).

In spite of the differences in the generation scenarios, few future transmission opportunities are identified. Reactive support is committed at Kaitaia before 2012. There is also a transmission opportunity to supply Dargaville before 2012, modelled as an upgrade to the 110/50 kV interconnecting transformer at Maungatapere. Between 2017 and 2037 additional inter-connecting capacity may be required at Marsden, dependent on future generation on the 110kV network. Likewise, between 2022 and 2037, there is a transmission opportunity to supply Kaikohe. This is modelled as an upgrade to the 110kV double circuit Maungatapere–Kaikohe line.

Up to 570 MW of wind generation is built in the Sustainable Path and South Island Surplus scenarios. Export of this power at high wind speeds is likely to be handled adequately, even during low demand periods. However, during no wind and high demand periods there may be a transmission opportunity to bring forward 220/110kV interconnection capacity at Marsden.

11.2.2 North Auckland

The North Auckland transmission region feeds Northland as well as parts of Auckland. As discussed in the previous section, the Northland demand is forecast to increase from around 800 MW in 2007 to over 1500 MW by 2037. In addition to this, Auckland demand is forecast to increase from around 1300 MW in 2007 to over 2000 MW by 2037.

The existing transmission in this region is currently supplied, through North Western Auckland from Otahuhu substation by a 220 kV Henderson – Otahuhu double circuit line. In addition to this there are two double circuit 110kV transmission lines from Otahuhu to Mount Roskill, one through Mangere to Mount Roskill and another passing through (but not connected to) Penrose. These 110kV lines are of relatively low capacity and sections of them are nearly fully utilised. Transpower notes that these lines are not presently configured to carry power to the North Auckland and Northland regions (Mt Roskill-Hepburn Rd 110 kV circuits are currently split at Mount Roskill).

The future generation scenarios are the same as those described for the Northland region.

Substantial transmission augmentation is planned for this region. Transpower has committed significant augmentation to the existing transmission network before 2012. Current projects include:

- +/- 100 MVAr SVC at Albany (committed project);
- 50 MVAr capacitor at Hepburn Rd (committed project);

- closure of Mt Roskill-Hepburn Rd 110 kV split (committed project); and
- resource consent to operate Otahuhu-Henderson 220 kV line at design capacity during forced outage (transmission opportunity identified in Transpower's 2008 APR).

A transmission opportunity exists for a new cross-harbour interconnection through Auckland before 2017. This new interconnection is modelled as a 220 kV cable from Penrose substation to Hobson Street substation, across the Auckland Harbour Bridge to the Wairau Rd substation and then onto Albany substation (current GUP application). Depending on future North Auckland and Northland generation, a transmission opportunity may exist for a further cross harbour interconnection, modelled as a second cable, before 2037 (this occurs in the Medium Renewables scenario which has a relatively low amount of additional generation north of Auckland compared with other generation scenarios).

Other transmission opportunities may include an increase in the interconnecting 220/110 kV capacity (likely at Henderson substation) and the supply into Hepburn Road from Henderson.

11.2.3 Auckland

Auckland demand is forecast to increase from around 1300 MW in 2007 to over 2000 MW by 2037.

Auckland is currently supplied from the south by 220 kV and 110 kV transmission lines with interconnecting transformers at Otahuhu and Penrose substations. Reactive voltage support is supplied by capacitor banks at Otahuhu and Penrose as well as dynamic reactive support from condensors at Otahuhu.

In all scenarios a significant amount of peaking thermal generation is assumed to be built in the Auckland region (generally near or at Otahuhu). This varies from 450 MW in the Demand-side Participation scenario to 500 and 900 MW in the Sustainable Path and South Island Surplus scenarios. In addition the South Island Surplus, Medium Renewables, Demand-side Participation and High Gas Discovery scenarios all have at least one 400 MW CCGT built by 2033 and the Demand-side Participation and High Gas Discovery scenarios have an additional 400 MW coal-fired plant. The Demand-side Participation scenario has up to 550 MW of price-responsive load curtailment occurring by 2037. Southdown is decommissioned in the Sustainable Path scenario by 2024. Overall, the High Gas Discovery scenario assumes the most generation built in the Auckland/Northland region (over 3000MW), while the Sustainable Path assumes the least amount of new generation (around 1400 MW).

Substantial transmission augmentation is planned for this region including a new 400 kV capable transmission line, operated at 220 kV, to be built from Whakamaru to Auckland by

2012. In all generation scenarios this line continues to be operated at 220 kV and is not upgraded to 400 kV before 2037.

Current projects likely to be completed by 2012 include:

- contracts for fourth and fifth synchronous compensators at Otahuhu (existing assets) providing a total of 195 MVAr of dynamic reactive support on the Otahuhu 110 kV system);
- 200 MVAr capacitor bank at Otahuhu (committed project);
- 100 MVAr capacitor bank at Penrose (committed project);
- the conversion of Pakuranga from 110 kV to 220 kV and the operation of the Otahuhu-Pakuranga line at 220 kV and removal of the Pakuranga-Penrose 110 kV line (committed project);
- thermally upgrade Otahuhu-Whakamaru 220 kV Line A and B (committed project);
- thermally upgrade Otahuhu-Whakamaru 220 kV Line C (committed project);
- 220 kV switching station at Ohinewai to bus Otahuhu-Whakamaru 220 kV Line C east of Huntly (committed project);
- 220 kV switching station at Drury to bus Huntly-Glenbrook-Otahuhu Line (committed project);
- remove Arapuni-Pakuranga 110 kV line to make way for 400 kV line (committed project); and
- 400 kV line (operated at 220 kV) Whakamaru-Brown Hill and 2x220 kV cables Brown Hill-Pakuranga (committed project).

There is a transmission opportunity for a new 220 kV Pakuranga to Penrose circuit after 2013 (most likely in the form of a cable, as in the Transpower's North Auckland and Northland investment proposal)[93]. There is also a transmission opportunity for a new cross-harbour inter-connection through Auckland before 2017. Depending on the generation scenario, there is a transmission opportunity for further augmentation between Pakuranga and Penrose, modelled as a second cable, before 2032, (South Island Surplus and Medium Renewables scenarios) or before 2037 (Sustainable Path, Demand-side Partipation and High Gas Discovery scenarios).

[93] http://www.electricitycommission.govt.nz/opdev/transmis/gup/naan

Further 220/110 kV interconnection capacity (at Otahuhu) may also be required post-2022 and the 110 kV network will likely require further investment post-2022 in all scenarios. Additional transmission capacity, possibly in the form of 110 kV cables could be required between Otahuhu and Wiri before 2022 and between Otahuhu and Mangere before 2032.

11.2.4 Waikato

The Waikato regional demand is forecast to increase from around 540 MW in 2007 to over 850 MW by 2037.

The transmission network consists of 220 kV and 110 kV transmission lines with interconnecting transformers located at Hamilton. Substantial transmission from Whakamaru to Auckland passes through the region (upgrades to these circuits are described in the previous section). The 110 kV network supplies demand in the region, branching out from both Hamilton and Arapuni.

The region offers substantial generation with the Huntly gas and coal-fired power station north of Hamilton. South of Hamilton, Karapiro and Arapuni provide generation on the 110 kV network and further south the Waipapa, Maraetai and Whakamaru hydro schemes provide generation on the 220 kV network.

In all generation scenarios, the existing Huntly power station is anticipated to be fully decommissioned by 2032, and as early as 2020 in the Sustainable Path scenario. Much of Huntly's generation capacity is modelled to be replaced by peaking plant in Auckland with significant amounts of geothermal generation built in the Wairakei region, between 600 MW to 1000 MW modelled in all scenarios.

Aside from the transmission into Auckland, which passes through the Waikato region, there appear to be few additional transmission opportunities. There exists a transmission opportunity on the Hamilton–Waihou 110kV transmission line in all scenarios by 2032, and the Sustainable Path scenario may require additional 110 kV transmission augmentation (between Arapuni and Bombay.

The Hamilton – Arapuni 110 kV transmission line may require augmentation some time beyond 2017, dependent on the generation scenario and the use of a runback scheme at Arapuni (currently being investigated by Transpower, TP APR 2008 section 10.6.2).

11.2.5 Wairakei

In terms of the North Island transmission system, the central Wairakei region is essentially a generating region with substantial peaking hydro and base load geothermal generation modelled in all scenarios. Power is exported to Hawke's Bay, the Bay of Plenty, Auckland and sometimes southward towards Bunnythorpe under certain generation/demand dispatch combinations.

The PSA carried out for the SOO work establishes the loading on the Wairakei ring transmission circuits during peak demand periods, under contingent conditions. The opportunities for transmission upgrades in this region are very dependent on the generation dispatch and are therefore likely to be economic, rather than reliability driven investments.

Nevertheless, there is a transmission opportunity to augment the Wairakei 220 kV ring (defined as the two parallel 220 kV circuits Wairakei-Poihipi-Whakamaru and Wairakei-Ohakuri-Atiamuri-Whakamaru) before 2017 to meet security criteria in all scenarios. This was modelled as a reconductoring on the basis of the information in Transpower's 2008 APR.

The combination of Huntly decommissioning and the significant amounts of geothermal generation that are assumed to be built (up to 1000 MW built in the Sustainable Path scenario, Medium Renewables and the Demand-side Participation scenarios by 2037 and over 600 MW built in the South Island Surplus and High Gas Discovery scenarios by 2029) further increase the northward loading on the Wairakei ring circuits. Further transmission opportunities are therefore likely and have been modelled as a new Wairakei-Whakamaru transmission line for scenarios with high geothermal development and low Auckland/Northland generation (as in the Sustainable Path, Medium Renewables and Demand-side Participation scenarios).

It is possible that an economic application of the GIT for the upgrade of these circuits or construction of a new line could bring forward the timing of these investments.

11.2.6 Bay of Plenty

The Bay of Plenty regional peak demand is forecast to increase from around 400 MW in 2007 to over 650 MW by 2037. Although the average demand growth is not high, the existing system is near its operating limits and hence the region may require relatively extensive transmission augmentation in order to meet the GRS over the period covered by the GPA.

The Bay of Plenty is supplied predominantly from the northern side of the Wairakei ring by the 220 kV Whakamaru-Atiamuri and Ohakuri-Wairakei circuits. 220 kV transmission lines extend from Atiamuri hydro power station to Tarukenga and Ohakuri hydro power station to Kawerau and Edgecumbe where 220/110 kV interconnecting transformers feed the 110 kV network. A 110 kV connection from Tarukenga also exists through Kinleith to Arapuni hydro power station in the Waikato region.

A new substation, named Kaitimako, near Hairini in the Tauranga area has recently been commissioned. This substation busses the double circuit 110 kV line from Tarukenga with the 110 kV single circuit transmission line through Te Matai from Okere.

There is over 260 MW of existing generation in the region, much of it embedded within the lower voltage network. Common to all scenarios is a 90 MW geothermal power station at Kawerau currently under construction and due for completion during 2008. The Sustainable Path, Medium Renewables and Demand-side Participation scenarios each assume that a further 142 MW of geothermal is built by 2033 (the High Gas Discovery scenario has a further 67 MW by 2026 while the South Island Surplus has no additional geothermal built). The Demand-side Participation scenario has the greatest amount of additional generation with over 500 MW added, 400 MW of this from a large coal fired plant connected to Kaitimako in 2029. The South Island Surplus scenario has the lowest additional generation with only 30 MW.

Substantial transmission augmentation is planned for this region, the major augmentation being an upgrade of the 110 kV Tarukenga-Kaitimako double circuit transmission line to 220 kV and 220/110 kV interconnecting transformers at Kaitimako substation near Tauranga.

Current projects likely to be completed by 2012 include:

- 25 MVAr Capacitors at Tauranga (committed project); and
- a thermal upgrade Kaitimako – Tauranga 110 kV circuits to supply Tauranga demand (committed project).

The PSA has identified a transmission opportunity to increase the capacity from Tarukenga to Kaitimako. This has been modelled as an increase in the operating voltage on the Kaitimako-Tarukenga circuits from 110 kV to 220 kV before 2017 with the addition of two 220/110 kV interconnecting transformers at Kaitimako.

There are opportunities for increased transmission capacity of the 110 kV lines into both Rotorua from Tarukenga, and into Tauranga and Mt Maunganui from Kaitimako (modelled as thermal upgrades). There are also opportunities in the Sustainable Path and Demand-side Participation scenarios, which include the largest increase in Bay of Plenty generation, for augmentation of the Kinleith-Lichfield-Tarukenga 110 kV circuits.

11.2.7 Hawke's Bay

The Hawke's Bay regional demand is forecast to increase from around 275 MW in 2007 to 330 MW by 2037. As a consequence of this small demand increase, no transmission opportunities were identified over the duration of the analysis for any of the generation scenarios.

Hawke's Bay is supplied by a double circuit 220 kV transmission line, following the Napier – Taupo road from Wairakei. Two 110 kV circuits also connect Hawke's Bay from Bunnythorpe through Woodville-Dannevirke-Waipawa to Fernhill but these are usually open at Waipawa.

The region has over 140 MW of generation capacity (excluding the 155 MW Whirinaki generation station used for dry years or as otherwise determined by the Commission). The majority of this generation is from the Waikaremoana hydro scheme which consists of three stations, Tuai, Kaitawa and Piripaua.

Although no transmission opportunities have been identified, the Sustainable Path and South Island Surplus scenarios assume up to 140 MW of wind generation (the proposed Titiokura and Te Waka wind farms) is completed by 2012. Over 200 MW of additional wind generation is assumed to be built by 2032 in the Sustainable Path scenario. The remaining scenarios share up to 100 MW of additional wind generation with the High Gas Discovery scenario having no new generation at all.

11.2.8 Central North Island

The Central North Island regional demand is forecast to increase from around 320 MW in 2007 to 440 MW by 2037.

The region comprises 220 kV and 110 kV transmission lines with interconnecting transformers at Bunnythorpe. Two double circuit 220 kV transmission lines connect Bunnythorpe to Haywards. The loading on these circuits depends on demand in Wellington and HVDC transfer. Transmission north of Bunnythorpe consists of three single circuit 220 kV transmission lines, two connecting to Whakamaru via Tokaanu. The third connects Bunnythorpe to Wairakei via Tangiwai and Rangipo. A double circuit 220 kV line connects Stratford with Bunnythorpe via Brunswick.

The Manawatu has plentiful wind possibilities; some of this is existing and embedded in the low voltage network. Te Apiti and Tararua 3 wind farms have recently been built and the Sustainable Path, South Island Surplus, Demand-side Participation and High Gas Discovery scenarios all assume a further 200 to 400 MW of additional wind generation is installed by 2033. The Sustainable Path, Medium Renewables and High Gas Discovery scenarios assume up to 95 MW of additional run-of-river hydro built by 2024. In total, the Sustainable Path scenario offers over 470 MW of additional generation capacity by 2029 while the Medium Renewables scenario offers only a 48 MW wind farm commissioned in 2009.

Although not all HVDC and demand/generation dispatch conditions have been modelled, no transmission opportunities have been identified to meet the GRS, at least during peak demand periods. However, with increased levels of wind generation connected at 110 kV, there may be requirement for additional 220/110 kV interconnection capacity at Bunnythorpe.

11.2.9 Taranaki

Taranaki is characterised as a thermal generation region with relatively low demand. The SOO demand forecast for this region is for an increase from 125 MW in 2007 to only 150 MW in 2037.

The generation in the area is dominated by the 360 MW TCC plant. Other significant generation within the region is a 70 MW co-generation plant at Whareroa and a 30 MW hydro scheme at Patea.

In all scenarios the Taranaki 360 MW CCGT at Stratford is assumed to be decommissioned by 2033 (2024 for the Sustainable Path scenario). In the Sustainable Path, South Island Surplus and High Gas Discovery scenarios the turbine is assumed to be operated as a peaking unit only during winter for several years before being fully decommissioned. An additional 200 MW peaking gas turbine is modelled between 2010 and 2017 in every scenario, and in the High Gas Discovery scenario a 50 MW co-generation plant is assumed to be constructed in 2015 with a replacement 380 MW CCGT built by 2033. The Sustainable Path scenario assumes 110 MW of wind generation is built by 2028. With the decommissioning of the Taranaki 360 MW CCGT in the Sustainable Path, South Island Surplus, Medium Renewables and Demand-side Participation, those scenarios have a net deficit in future generation. In the High Gas Discovery scenario, it is assumed that the Taranaki CCGT is replaced with an extra 260 MW of generation added to the region.

The low-demand forecast, combined with low future generation scenarios means that the PSA did not identify any transmission opportunities in any scenario for the duration of the analysis.

11.2.10 Wellington

The Wellington regional demand is forecast to increase from around 630 MW in 2007 to 960 MW by 2037.

The transmission network comprises 220 kV transmission lines connecting Haywards to Bunnythorpe in the north and a 110 kV transmission line through the Wairarapa. Interconnecting transformers are located at Haywards and Wilton. The HVDC link terminates at Haywards substation from Benmore Power station in the South Island.

In December 2007 Transpower announced it would decommission half of Pole 1 after standing down the full Pole 1 in September 2007. Pole 1 is located on the 110 kV network and helps support the local Wellington demand. Prior to the stand-down, Transpower up-rated some of the 110 kV transmission lines and helps provide additional security. However, opportunities for further interconnecting capacity are likely.

The region is essentially a major demand area with very little local generation. However, with good wind potential there is a high likelihood of future increased wind generation. This has been initiated with the current commissioning of a 143 MW wind farm, west of Wellington City – Meridian's West Wind project. The Sustainable Path and Demand-side Participation scenarios assume over 400 MW of additional wind generation is installed by 2029, while the Medium Renewables scenario assumes 70 MW is installed by 2018, and the High Gas Discovery scenario assumes 120 MW is installed by 2033. The Demand-side Participation includes 320 MW of wind generation with 400 MW of price responsive load curtailment.

As discussed, there are opportunities for augmenting the inter-connection capacity between the 220 kV and 110 kV networks. The replacement of the Wilton 220/110 kV interconnecting transformer is modelled before 2012 and an additional 220/110 kV interconnecting transformer is modelled at Haywards before 2022. With increased demand growth in the region there are opportunities for 110 kV network augmentation. By 2012 upgrades were modelled to the transmission capacity between Haywards and Melling (reconductoring) and by 2017 upgrades were modelled to the transmission between Takapu Road and Pauatahanui to supply the regional demand north of Wellington.

11.3 Inter-island transmission analysis

In December 2007 Transpower announced it would decommission half of Pole 1 after standing down the full Pole 1 in September 2007.

The following transmission augmentations were assumed to be common to all scenarios.

- Before 2017: upgrade Pole 1 with new thyristor converters, providing a 1200 MW bipole (500 MW on Pole 1 and 700 MW on Pole 2) connecting the Benmore 220 kV bus to the Haywards 220 kV bus (this is consistent with current GUP application for 1000 MW by 2012 and 1200 MW by 2014).
- Before 2022: add a fourth submarine cable to increase the bipole rating to 1400 MW (700 MW on Pole 1 and 700 MW on Pole 2).

Table 21 shows the HVDC northward transfer at peak winter demand for each year studied. The table suggests that the fourth cable may be required to meet North Island peak demand when the HVDC transfer increases above 700 MW. The HVDC risk at this point is 200 MW, which could be met by interruptible load of 200 MW or from improved demand-side technology. This analysis supports the need for a fourth cable to meet security criteria before

2022 (Sustainable Path, South Island Surplus, High Gas Discovery scenarios), before 2027 (Demand-side Participation scenario), and before 2032 (Medium Renewables scenario). The later need-dates for the Medium Renewables and the Demand-side Participation scenarios are due to the relatively high North Island generation or demand-side management associated with these scenarios.

Table 21 HVDC transfer northward at peak winter demand

Year	Sustainable Path	South Island Surplus	Medium Renewables	Demand-side Participation	High Gas Discovery
2012	649 MW	611 MW	673 MW	444 MW	622 MW
2017	664 MW	494 MW	176 MW	560 MW	512 MW
2022	990 MW	758 MW	205 MW	281 MW	942 MW
2027	972 MW	777 MW	479 MW	839 MW	872 MW
2032	1078 MW	914 MW	988 MW	695 MW	536 MW
2037	850 MW	539 MW	874 MW	668 MW	572 MW

11.4 South Island transmission analysis

11.4.1 Nelson/Marlborough

The Nelson/Marlborough demand is forecast to increase from around 200 MW in 2007 to 300 MW in 2037.

The top of the South Island consists of the Nelson/Marlborough and West Coast regions and is supplied from Islington in Christchurch to Kikiwa substation by three 220 kV circuits on two transmission lines. The recent addition of the third 220 kV circuit in 2006 has upgraded the transmission capacity into the top of the South Island. The Nelson/Marlborough transmission network consists of a parallel network of 220 kV and 110 kV transmission lines between Kikiwa and Stoke with a 66 kV spur supplying the Golden Bay area. There are also 220/110 kV interconnecting transformers at Kikiwa and Stoke, both which have recently been upgraded with 150 MVA units.

The main generators in the region are the 32 MW Cobb power station in Golden Bay, and the 11 MW Branch River scheme in the Wairau valley. The only future generation modelled in the region is a new 70 MW Wairau scheme which is built in the Sustainable Path, Medium Renewables, Demand-side Participation and High Gas Discovery scenarios. The South Island Surplus scenario models no additional generation in this region.

The relatively low demand growth, coupled with the recent transmission upgrades in the region mean the only transmission project is a +/- 40 MVAr SVC located at Kikiwa substation committed by Transpower. No other additional transmission opportunities were identified in any of the generation scenarios throughout the duration of the analysis.

11.4.2 West Coast

The West Coast regional demand is forecast to increase from around 47 MW in 2007 to 83 MW by 2037. The Lower West Coast demand is forecast to increase reasonably significantly in the next few years, driven mainly by the mining sector.

The West Coast is predominantly supplied from Kikiwa substation through a 220/110 kV interconnecting transformer and two 66 kV circuits from Lake Coleridge. From the 110 kV Inangahua substation, two transmission lines supply the Northern West Coast/Buller region with another two 110 kV lines supplying Reefton. From Reefton a single circuit line, recently upgraded from 66 kV to 110 kV, supplies Dobson with a new GXP added for the Pike River Coal mine near Atarau. An investment proposal for the addition of a second transmission line from Reefton to Dobson with a second 110/66 kV interconnecting transformer at Dobson and capacitors at Hokitika has recently been approved and this will provide additional security to the new Atarau GXP and the Lower West Coast.

The Northern West Coast has very little generation. However, the Lower West Coast south of Dobson has quite significant embedded generation in the form of a number of small hydro plant, the largest being the Kumara/Dillmans scheme of around 10 MW.

All generation scenarios assume a 50 MW coal seam gas plant is commissioned by 2030. Only the Sustainable Path scenario has increased hydro generation with 25 MW and 17 MW schemes at Toaroha and Kakapotahi built by 2015.

There is also an opportunity to augment the 66 kV circuits around the Lower West Coast. These circuits are low capacity and the need for investment is dependent on future generation development and demand. Augmentation opportunities are generally related to the export of power from the Lower West Coast and could include the reconductoring of the Dobson–Greymouth–Kumara–Hokitika–Otira circuits, before 2027.

In the Sustainable Path scenario there is significant new generation on the Lower West Coast and a transmission opportunity to alleviate overloading on the 66 kV Coleridge-Hororata circuits, with power being exported from Coleridge to Hororata. This was modelled by reconductoring these circuits before 2027. Alternatively this situation could be handled with a system split over Arthur’s Pass or runbacks on Lower West Coast/ Coleridge generation.

11.4.3 Canterbury

The Canterbury regional demand is forecast to increase from around 740 MW in 2007 to over 1150 MW by 2037.

The region is supplied from the Waitaki valley by four main 220 kV transmission circuits, three from Twizel and one from Livingstone. These circuits supply the Upper South Island (USI) consisting of the Nelson/Marlborough region, the West Coast, and Canterbury regions. The transmission network within Canterbury comprises 220 kV and 66 kV transmission circuits, with 220/66 kV interconnecting transformers at Islington, Bromley, Ashburton, Culverden and Waipara. As demand increases in the USI voltage stability limits constrain the transmission into Christchurch and the USI. Several committed projects, helping relieve the voltage stability limits into Christchurch, will be completed by 2012, these include:

- bussing the 220 kV Islington-Twizel circuits at Ashburton (committed project);
- 75 MVAr capacitor at Islington (committed project); and
- -75/+100 MVAr SVC at Islington (committed project).

The analysis assumes that loads are shifted to share the loading between the 220/66 kV interconnecting transformers at Islington and Bromley. The analysis also identifies an opportunity for 220/66 kV interconnecting capacity at Bromley will be before 2012.

An opportunity exists for further 220/66 kV interconnecting capacity at Islington before 2022. This may also require a 66 kV bus split or current limiting reactors to limit fault levels. An opportunity also exists for further reactive support at Ashburton and Islington out to 2037.

11.4.4 South Canterbury

The South Canterbury regional demand is forecast to increase from around 80 MW in 2007 to 120 MW by 2037.

This region contributes a major portion of the generation in the South Island through the Tekapo, Ohau and Waitaki Valley generation stations. The main transmission system is designed to export power to the major demand areas such as the upper South Island and the North Island, through the HVDC link. The region supplies its small demand through 220/110 kV interconnecting transformers at Timaru and Waitaki. The 110 kV network is normally split at Studholme creating two radial feeds supplying Temuka, Albury and Tekapo from the Timaru interconnection, and Studholme, Black Point and Oamaru from the Waitaki interconnection.

There is no new generation in this region in any of the scenarios.

Aside from the transmission upgrades out of the region to Christchurch and the North Island (the HVDC link upgrade) the PSA has identified few other transmission opportunities. Some transmission capacity upgrades will be required on the 110 kV radial feed from Waitaki to Oamaru, through Blackpoint and Glenavy before 2012. This will likely be the result of the continued increase in the dairy sector and the associated high summer loading resulting from increased farm irrigation.

High HVDC northward transfer, as occurs in the Sustainable Path scenario, results in the opportunity to increase transmission capacity in the Waitaki Valley. Thermal upgrades are modelled on the Aviemore-Benmore 220 kV circuits helping enable full northward HVDC flow.

11.4.5 Otago/Southland

The Otago/Southland regional demand is forecast to increase from around 1100 MW in 2007 to around 1280 MW by 2037 in the Sustainable Path, South Island Surplus, Demand-side Participation and High Gas Discovery scenarios. In the Medium Renewables scenario the Tiwai Point aluminium smelter is assumed to be decommissioned in stages between 2021 and 2027. This causes the demand in the region to halve from around 1220 MW in 2021 to 650 MW in 2027.

The transmission network consists of 220 kV and 110 kV transmission lines with interconnecting transformers at Cromwell, Halfway Bush, Roxburgh and Invercargill. Transmission out of the region, during low-demand, high-generation dispatch is limited by the transmission capacity north of Roxburgh. This inter-regional constraint may become binding if high levels of generation are built in the Southland region and/or the Tiwai Point Aluminium smelter is decommissioned.

Along with the existing large hydro stations at Manapouri, Clyde, and Roxburgh, high levels of generation are modelled in the Sustainable Path, South Island Surplus and Demand-side Participation scenarios. The Sustainable Path and South Island Surplus scenarios share significant amounts of new wind generation—over 900 MW by 2037 in the Sustainable Path scenario and over 650 MW by 2014 in the South Island Surplus scenario. Both scenarios include over 500 MW of hydro generation on the Clutha by around 2020. The Medium Renewables and High Gas Discovery scenarios offer the least new generation, but Tiwai is decommissioned by 2027 in the Medium Renewables scenario. The Demand-side Partipation scenario includes two large 400 MW lignite fired coal plants in 2026 and 2030.

The PSA identified high transfers on the Lower South Island transmission circuits during peak demand periods under contingent conditions. Transmission upgrades in this region are dependent on the generation dispatch and are therefore likely to be economic, rather than reliability driven investments.

There are transmission opportunities for increasing the capacity from Roxburgh to the Waitaki Valley. This was modelled by reconductoring the Roxburgh-Naseby-Livingstone 220 kV circuit and the thermal up-rating of the Cromwell-Twizel 220 kV circuits. Low Southland generation scenarios such as the High Gas Discovery scenario offer opportunities later (2027-2037), while the higher generation scenarios of the Sustainable Path and South Island Surplus scenario offer opportunities prior to this. In the Medium Renewables scenario, a new 220 kV Roxburgh-Twizel transmission line was modelled before 2032.

It is likely that an economic application of the GIT with revised generation dispatch assumptions (including wind) could significantly bring forward the timing of these investments.

11.5 Generation capacity on a windless day

The PSA also identified possible generation capacity shortfalls associated with a windless day throughout the country, coincident with peak winter demand.

Three conditions were tested.

- Ability to meet peak demand with no wind generation.
- Ability to meet peak demand with no wind generation, but with Otahuhu B (360MW) running.
- Not able to meet peak demand without wind generation.

In all generation scenarios there appears adequate generation to cover peak winter demand on a nationwide windless day. However, the Sustainable Path scenario required the operation of Otahuhu B power station post 2022.

12. Net present value analysis

12.1 Generation and transmission costs in the scenarios

This section summarises the costs that are expected to arise in the five market development scenarios, using an NPV approach.

As in section 9.7.5, generation costs include annualised capital expenditure, connection costs, and O and M costs (for all new projects, whether committed or assumed in the relevant scenario) and fuel and carbon costs (for both existing and new projects). Variable costs are averages over inflow sequences.

In terms of transmission costs, the estimated costs of transmission opportunities common to all scenarios (identified in Table 37) and scenario-specific transmission opportunities (Table 38 to Table 42) are included, but the costs of existing assets and committed projects (Table 36) and assorted maintenance costs are *not* included. Costs are annualised and the terminal portion of the cost is excluded.

All NPVs shown are 2007 present values of pre-tax costs. A central discount rate of seven percent is used, with five percent and 10 percent as sensitivities.

Table 22 NPVs of pre-tax costs in the market development scenarios (committed transmission projects are excluded)

Discount rate (real, pre-tax)	Scenario	Generation NPV (2007 $m)	Transmission NPV (2007 $m)	Total NPV (2007 $m)
Five percent	Sustainable Path	36,129	1,093	37,222
	South Island Surplus	35,743	1,055	36,798
	Medium Renewables	30,763	1,114	31,877
	Demand-side Participation	33,093	1,059	34,152
	High Gas Discovery	32,554	1,044	33,598
Seven percent	Sustainable Path	27,016	779	27,795
	South Island Surplus	26,711	754	27,465
	Medium Renewables	23,314	787	24,101
	Demand-side Participation	24,705	757	25,462
	High Gas Discovery	24,487	747	25,234

Discount rate (real, pre-tax)	Scenario	Generation NPV (2007 $m)	Transmission NPV (2007 $m)	Total NPV (2007 $m)
10 percent	Sustainable Path	18,602	482	19,084
	South Island Surplus	18,372	469	18,841
	Medium Renewables	16,359	483	16,842
	Demand-side Participation	17,001	471	17,472
	High Gas Discovery	17,013	465	17,478

As noted in section 9.7.5, care should be taken in comparing costs between scenarios. In large part, the cost differences are driven by exogenous assumptions—for example, fuel costs, renewable resource availability, and the level of carbon charges.

13. Concluding comments

The purpose of the SOO is to enable the identification of potential opportunities for efficient management of the grid, including investment in upgrades and transmission alternatives.

The Initial SOO was published in 2005 and a second SOO was due to be published in 2007. The Commission decided to delay the publication of what was to be the 2007 SOO to take into account the Government's future energy vision which was published in late 2007.

The release of the NZES and changes to the GPS gave rise to a direction shift in New Zealand's energy future. The NZES and the GPS both have a strong emphasis on renewables, energy efficiency and reduction of carbon emissions which in turn impacted the scenarios and the demand forecast presented in this document.

In preparing the draft 2008 SOO, the Commission sought participants' input early during the development of the GPA and other key assumptions, before embarking on the detailed analysis work.

Following consultation on this draft SOO, a final SOO will be prepared and published.

The PSA indicates that no major investments are needed for reliability reasons, but economic investments may be needed to release constraints for remote renewable generation. However, this is beyond the scope of the SOO and will be separately considered by Transpower and the Commission.

The PSA indicates that the scenarios in the SOO are feasible provided that the transmission system is augmented to maintain a secure supply.

The need dates for the augmentations are based on a deterministic reliability analysis and could be advanced or deferred for economic reasons.

13.1 South Island

The analysis indicates a number of upgrades to existing transmission lines and a limited number of new lines and cables.

- Second 110 kV line Dobson-Reefton before 2012 (current GUP application).
- 220 kV line Roxburgh-Twizel before 2032 for the Medium Renewables scenario to handle increased power flow from south due to decommissioning Tiwai smelter (modelled project from Transpower 2008 APR).

13.2 Inter-island transmission

The PSA assumes that in all scenarios, HVDC Pole 1 is replaced before 2017 increasing the bipole rating from 970 MW (270 MW on a Pole 1 Half-Pole and 700 MW on Pole 2) to 1200 MW (500 MW on Pole 1 and 700 MW on Pole 2).

The PSA also assumes that in all scenarios a fourth submarine cable is added before 2022, increasing the bipole rating to 1400 MW (700 MW on Pole 1 and 700 MW on Pole 2). The results of the analysis verify that the fourth cable may be needed to meet security criteria before 2022 (MDS 1, MDS 2, MDS 5), before 2027 (MDS 4), and before 2032 (MDS3). The later need-dates for MDS 3 and MDS 4 are due to the relatively high North Island generation associated with these scenarios.

13.3 North Island

The analysis indicates a number of upgrades to existing transmission lines and a limited number of new lines and cables.

- 400 kV line and cables Whakamaru – Auckland by 2012 (committed).
- 220 kV Auckland cross-harbour cable before 2017 (current GUP application) followed by second cable modelled before 2027 for MDS3.
- 220 kV cable Pakuranga-Penrose after 2013 (current GUP application) followed by second cable modelled before 2032 for MDS2 and MDS3, and 2037 for MDS4 and MDS5.
- 110 kV cable Mangere-Otahuhu (SSG modelled project) before 2032 for MDS1, MDS2, and MDS3, and before 2037 for MDS4 and MDS5.
- 110 kV cable Otahuhu-(a modelled project from Transpower 2008 APR) occurring before 2022 for MDS3 and MDS4, and before 2027 for MDS1, MDS2, and MDS5.
- 220 kV line Wairakei-Whakamaru (modelled project from Transpower 2008 APR) before 2022 for MDS1 and before 2037 for MDS3 and MDS4.

Appendices

Appendix 1 Transmission regions and Grid Exit Points

North Island regions

North Isthmus
Albany (ALB)
Bream Bay (BRB)
Dargaville (DAR)
Henderson (HEN)
Hepburn Rd (HEP)
Kensington (KEN)
Kaikohe (KOE)
Kaitaia (KTA)
Maungatapere (MPE)
Maungaturoto (MTO)
Silverdale (SVL)
Wellsford WEL)
Wairau Road (WRU)

Auckland
Bombay (BOB)
Meremere (MER)
Glenbrook (GLN)
Liverpool St (LST)
Mangere (MNG)
Otahuhu (OTA)
Pakuranga (PAK)
Penrose (PEN)
Mt Roskill (ROS)
Takanini (TAK)
Wiri (WIR)

Bay of Plenty
Aniwhenua (ANI)
Edgecumbe (EDG)
Kawerau (KAW)
Mt Maunganui (MTM)
Owhata (OWH)
Rotorua (ROT)
Tauranga (TGA)
Te Kaha (TKH)
Te Matai (TMI)
Tarukenga (TRK)
Waiotahi (WAI)

Central
Bunnythorpe (BPE)
Brunswick (BRK)
Dannevirke (DVK)
Linton (LTN)
Mangamaire (MGM)
Mangahao (MHO)
Marton (MTN)
Mataroa (MTR)
National Park (NPK)
Ohakune (OKN)
Ongarue (ONG)
Tokaanu (TKU)
Tangiwai (TNG)
Woodville (WDV)
Wanganui (WGN)
Waipawa (WPW)

Taranaki
Carrington St (CST)
Huirangi (HUI)
Hawera (HWA)
Motunui (MNI)
New Plymouth (NPL)
Opunake (OPK)
TCC (SFD)
Taumarunui (TMN)
Whareroa (WAA)
Waverley (WVY)

Wellington
Central Park (CPK)
Gracefield (GDF)
Greytown (GYT)
Haywards (HAY)
Kaiwharawhara (KWA)
Melling (MLG)
Masterton (MST)
Pauatahanui (PNI)
Paraparaumu (PRM)
Takapu Road (TKR)
Upper Hutt (UHT)
Wilton (WIL)

Waikato
Cambridge (CBG)
Hamilton (HAM)
Hinuera (HIN)
Huntly (HLY)[94]
Hangatiki (HTI)
Kinleith (KIN)
Kopu (KPU)
Lichfield (LFD)
Ohaaki (OKI)
Te Awamutu (TMU)
Te Kowhai (TWH)
Western Road (WES)
Waihou (WHU)
Whakamaru (WKM)
Waikino (WKO)
Wairakei (WRK)

Hawke's Bay
Fernhill (FHL)
Gisborne (GIS)
Redclyffe (RDF)
Tuai (TUI)
Whirinaki (WHI)
Wairoa (WRA)
Whakatu (WTU)

[94] Huntly GXP will be commissioned in September 2008. Demand at this GXP has not been separated out from existing load.

South Island regions

Otago/Southland
Balclutha (BAL)
Brydone (BDE)
Blackpoint (BPT)
Cromwell (CML)
Clyde (CYD)
Edendale (EDN)
Frankton (FKN)
Gore (GOR)
Halfway Bush (HWB)
Invercargill (INV)
North Makarewa (NMA)
Naseby (NSY)
Oamaru (OAM)
Palmerston (PAL)
South Dunedin (SDN)
Studholme (STU)
Tiwai (TWI)
Waitaki (WTK)

West Coast
Arthurs' Pass (APS)
Atarau (ATU)
Castle Hill (CLH)
Dobson 33kV (DOB)
Greymouth (GYM)
Hokitika (HKK)
Murchison (MCH)
Orowaiti (ROB)
Otira (OTI)
Reefton (RFT)
Westport (WPT)

Canterbury
Addington (ADD)
Ashburton (ASB)
Ashley (ASY)
Bromley (BRY)
Coleridge (COL)
Culverden (CUL)
Hororata (HOR)
Islington (ISL)
Kaiapoi (KAI)
Kaikoura (KKA)
Papanui (PAP)
Southbrook (SBK)
Springston (SPN)[95]
Waipara (WPR)
Middleton (MLN)[96]

South Canterbury
Albury (ABY)
Timaru (TIM)
Tekapo (TKA)
Temuka (TMK)
Twizel (TWZ)

Nelson/Marlborough
Blenheim (BLN)
Kikiwa (KIK)
Motueka (MOT)
Motupipi (MPI)
Stoke (STK)

95 This GXP has been recently commissioned. Demand at this GXP has not been separated out from the existing load.
96 This GXP has been recently commissioned. Demand at this GXP has not been separated out from the existing load.

Appendix 2 Regional energy demand projections

Table 23 Regional demand projections North Island (GWh)[97] (March years)

Year	North Isthmus	Auckland	Waikato	Bay of Plenty	Hawkes Bay	Central	Taranaki	Wellington	Total North Island
2007	3,899	6,936	2,954	2,823	1,737	1,624	797	3,020	23,789
2008	3,944	7,007	2,949	2,829	1,731	1,609	873	3,029	23,972
2009	4,014	7,124	2,964	2,854	1,735	1,608	875	3,057	24,230
2010	4,115	7,298	3,003	2,899	1,753	1,631	882	3,110	24,691
2011	4,244	7,526	3,063	2,964	1,782	1,676	895	3,184	25,335
2012	4,344	7,708	3,104	3,005	1,797	1,697	901	3,236	25,793
2013	4,444	7,899	3,149	3,045	1,810	1,718	907	3,288	26,259
2014	4,547	8,112	3,200	3,085	1,822	1,740	912	3,343	26,762
2015	4,655	8,349	3,259	3,127	1,833	1,764	917	3,400	27,304
2016	4,764	8,608	3,324	3,169	1,842	1,786	921	3,458	27,872
2017	4,866	8,866	3,386	3,209	1,848	1,804	922	3,509	28,411
2018	4,971	9,133	3,450	3,253	1,854	1,822	924	3,561	28,967
2019	5,077	9,402	3,513	3,301	1,862	1,840	925	3,611	29,530
2020	5,184	9,670	3,572	3,352	1,871	1,858	927	3,660	30,094
2021	5,291	9,933	3,629	3,406	1,882	1,876	929	3,709	30,654
2022	5,387	10,168	3,675	3,454	1,890	1,889	929	3,748	31,140
2023	5,484	10,402	3,720	3,504	1,898	1,902	930	3,787	31,628
2024	5,581	10,636	3,764	3,556	1,907	1,915	931	3,825	32,114
2025	5,681	10,870	3,807	3,607	1,916	1,928	932	3,865	32,605
2026	5,781	11,107	3,849	3,660	1,925	1,941	932	3,904	33,100
2027	5,878	11,330	3,890	3,710	1,935	1,955	934	3,942	33,574
2028	5,974	11,555	3,932	3,760	1,946	1,968	937	3,980	34,052

97 In Table 23 and Table 24, the figures represent the aggregate electricity demand at GXPs.

Year	North Isthmus	Auckland	Waikato	Bay of Plenty	Hawkes Bay	Central	Taranaki	Wellington	Total North Island
2029	6,072	11,781	3,973	3,811	1,956	1,982	939	4,019	34,534
2030	6,171	12,010	4,015	3,863	1,967	1,996	941	4,058	35,020
2031	6,270	12,241	4,057	3,915	1,977	2,009	944	4,097	35,510
2032	6,372	12,480	4,101	3,969	1,988	2,024	946	4,138	36,018
2033	6,475	12,721	4,145	4,023	2,000	2,039	949	4,179	36,531
2034	6,579	12,966	4,189	4,078	2,011	2,053	952	4,221	37,049
2035	6,684	13,213	4,234	4,133	2,022	2,068	955	4,263	37,572
2036	6,790	13,463	4,279	4,189	2,034	2,083	958	4,305	38,100

Table 24 Regional energy demand projections South Island (GWh) (March years)

Year	Nelson/ Marlborough	West Coast	Canterbury	South Canterbury	Otago/ Southland	Total South Island
2007	1,112	273	4,165	599	7,881	14,031
2008	1,125	389	4,210	610	7,877	14,210
2009	1,145	453	4,281	624	7,882	14,385
2010	1,173	458	4,384	643	7,939	14,597
2011	1,208	466	4,515	665	8,045	14,898
2012	1,233	471	4,609	682	8,093	15,089
2013	1,255	477	4,698	696	8,139	15,264
2014	1,274	482	4,781	709	8,184	15,430
2015	1,290	488	4,857	718	8,227	15,580
2016	1,302	494	4,924	723	8,263	15,706
2017	1,307	498	4,976	725	8,284	15,791
2018	1,313	502	5,026	726	8,304	15,872
2019	1,318	506	5,080	728	8,322	15,954
2020	1,327	510	5,138	730	8,341	16,046
2021	1,335	514	5,200	735	8,361	16,143

Year	Nelson/ Marlborough	West Coast	Canterbury	South Canterbury	Otago/ Southland	Total South Island
2022	1,344	516	5,255	738	8,375	16,228
2023	1,353	519	5,314	743	8,389	16,318
2024	1,364	522	5,374	749	8,406	16,415
2025	1,375	524	5,438	755	8,423	16,515
2026	1,386	527	5,504	762	8,440	16,618
2027	1,397	530	5,567	768	8,458	16,721
2028	1,409	532	5,632	775	8,477	16,826
2029	1,421	535	5,697	782	8,496	16,932
2030	1,434	538	5,763	790	8,516	17,040
2031	1,446	541	5,829	797	8,535	17,148
2032	1,459	544	5,898	805	8,556	17,262
2033	1,472	547	5,967	813	8,577	17,376
2034	1,485	550	6,036	821	8,599	17,491
2035	1,498	553	6,106	829	8,620	17,606
2036	1,511	556	6,177	837	8,642	17,723

Appendix 3 Prudent and expected peak forecasts

Table 25 National forecast

Year	Observed peak (MW)	Expected peak (MW)	Prudent peak (MW)
1998	5,376	-	-
1999	5,579	-	-
2000	5,606	-	-
2001	5,786	-	-
2002	5,859	-	-
2003	5,749	-	-
2004	6,089	-	-
2005	6,119	-	-
2006	6,421	-	-
2007	6,466	-	-
2008	-	6,620	6,763
2009	-	6,742	6,908
2010	-	6,881	7,100
2011	-	6,998	7,271
2012	-	7,110	7,457
2013	-	7,224	7,602
2014	-	7,339	7,729
2015	-	7,456	7,878
2016	-	7,561	7,995
2017	-	7,669	8,148

Year	Observed peak (MW)	Expected peak (MW)	Prudent peak (MW)
2018	-	7,777	8,284
2019	-	7,887	8,403
2020	-	7,998	8,556
2021	-	8,094	8,688
2022	-	8,191	8,825
2023	-	8,290	8,934
2024	-	8,389	9,103
2025	-	8,489	9,238
2026	-	8,587	9,335
2027	-	8,686	9,491
2028	-	8,785	9,624
2029	-	8,884	9,746
2030	-	8,988	9,928
2031	-	9,094	10,054
2032	-	9,200	10,201
2033	-	9,307	10,342
2034	-	9,414	10,527
2035	-	9,523	10,698
2036	-	9,639	10,835
2037	-	9,756	10,959

Year	Observed peak (MW)	Expected peak (MW)	Prudent peak (MW)
2038	-	9,876	11,128
2039	-	9,996	11,347
2040	-	10,118	11,540
2041	-	10,240	11,690
2042	-	10,364	11,909

Year	Observed peak (MW)	Expected peak (MW)	Prudent peak (MW)
2043	-	10,491	12,093
2044	-	10,612	12,240
2045	-	10,743	12,384
2046	-	10,866	12,628
2047	-	10,990	12,821

Table 26 Island forecast – North Island and South Island

Year	NI Observed peak (MW)	NI Expected peak (MW)	NI Prudent peak (MW)	SI Observed peak (MW)	SI Expected peak (MW)	SI Prudent peak (MW)
1998	3,557	-	-	1,826	-	-
1999	3,699	-	-	1,888	-	-
2000	3,705	-	-	1,901	-	-
2001	3,894	-	-	1,967	-	-
2002	3,885	-	-	1,994	-	-
2003	3,851	-	-	1,941	-	-
2004	4,110	-	-	2,026	-	-
2005	4,087	-	-	2,071	-	-
2006	4,307	-	-	2,121	-	-
2007	4,328	-	-	2,173	-	-
2008	-	4,431	4,555	-	2,221	2,251
2009	-	4,521	4,660	-	2,255	2,303
2010	-	4,623	4,778	-	2,295	2,361
2011	-	4,711	4,896	-	2,326	2,413

Year	NI Observed peak (MW)	NI Expected peak (MW)	NI Prudent peak (MW)	SI Observed peak (MW)	SI Expected peak (MW)	SI Prudent peak (MW)
2012	-	4,797	5,048	-	2,354	2,465
2013	-	4,889	5,145	-	2,379	2,504
2014	-	4,986	5,282	-	2,401	2,520
2015	-	5,088	5,390	-	2,420	2,542
2016	-	5,185	5,496	-	2,434	2,557
2017	-	5,284	5,646	-	2,447	2,586
2018	-	5,383	5,771	-	2,461	2,605
2019	-	5,485	5,866	-	2,475	2,619
2020	-	5,586	6,017	-	2,489	2,650
2021	-	5,673	6,104	-	2,502	2,652
2022	-	5,762	6,256	-	2,515	2,680
2023	-	5,850	6,360	-	2,529	2,696
2024	-	5,939	6,504	-	2,544	2,705
2025	-	6,028	6,577	-	2,559	2,736
2026	-	6,115	6,715	-	2,574	2,754
2027	-	6,201	6,856	-	2,590	2,793
2028	-	6,289	6,943	-	2,606	2,804
2029	-	6,376	7,031	-	2,622	2,839
2030	-	6,467	7,178	-	2,639	2,844
2031	-	6,560	7,304	-	2,656	2,880
2032	-	6,652	7,441	-	2,673	2,891
2033	-	6,746	7,571	-	2,690	2,914
2034	-	6,840	7,659	-	2,708	2,952
2035	-	6,936	7,811	-	2,725	2,964

Year	NI Observed peak (MW)	NI Expected peak (MW)	NI Prudent peak (MW)	SI Observed peak (MW)	SI Expected peak (MW)	SI Prudent peak (MW)
2036	-	7,038	7,901	-	2,744	2,992
2037	-	7,140	8,058	-	2,763	3,017
2038	-	7,245	8,218	-	2,783	3,042
2039	-	7,350	8,389	-	2,802	3,093
2040	-	7,457	8,547	-	2,822	3,121
2041	-	7,564	8,685	-	2,841	3,144
2042	-	7,673	8,873	-	2,861	3,176
2043	-	7,785	9,021	-	2,882	3,220
2044	-	7,892	9,180	-	2,900	3,233
2045	-	8,006	9,294	-	2,921	3,258
2046	-	8,115	9,471	-	2,941	3,316
2047	-	8,225	9,625	-	2,961	3,317

Appendix 4 After diversity maximum demand peak forecasts

Table 27 Region total at Island peak (prudent) – North Island (MW)

Year	North Isthmus	Auckland	Waikato	Bay of Plenty	Hawkes Bay	Central	Taranaki	Wellington	North Island Total
2007	783	1,276	542	398	272	323	125	633	4,352
2008	841	1,377	562	441	277	334	137	655	4,624
2009	870	1,419	576	450	279	339	139	670	4,742
2010	900	1,468	586	459	284	347	140	686	4,871
2011	931	1,516	600	469	289	354	141	703	5,004
2012	962	1,562	614	478	293	361	143	720	5,133
2013	984	1,605	624	484	295	366	144	732	5,233
2014	1,007	1,651	635	490	296	370	145	744	5,339
2015	1,030	1,701	648	497	298	375	145	757	5,451
2016	1,052	1,750	659	504	299	379	146	768	5,556
2017	1,074	1,802	671	510	300	382	146	779	5,665
2018	1,097	1,853	683	518	301	386	146	789	5,773
2019	1,119	1,905	694	526	303	390	146	800	5,884
2020	1,142	1,957	705	534	305	393	147	810	5,994
2021	1,163	2,003	714	542	306	396	147	819	6,089
2022	1,184	2,049	723	550	307	399	147	827	6,186
2023	1,204	2,096	732	558	308	401	147	836	6,282
2024	1,225	2,142	740	566	310	404	147	844	6,378
2025	1,247	2,188	749	574	311	407	147	852	6,475
2026	1,268	2,233	757	582	313	409	147	861	6,569
2027	1,288	2,277	765	590	314	412	148	869	6,663
2028	1,309	2,321	773	598	316	415	148	877	6,758
2029	1,330	2,366	781	606	318	418	148	886	6,852
2030	1,352	2,412	789	614	319	421	149	894	6,951

Year	North Isthmus	Auckland	Waikato	Bay of Plenty	Hawkes Bay	Central	Taranaki	Wellington	North Island Total
2031	1,374	2,460	798	623	321	424	149	903	7,052
2032	1,396	2,507	807	631	323	427	150	912	7,152
2033	1,418	2,555	815	640	325	430	150	921	7,254
2034	1,440	2,603	824	649	326	433	150	930	7,356
2035	1,463	2,652	833	658	328	436	151	939	7,460
2036	1,487	2,704	842	667	330	439	151	949	7,570

Table 28 Region total at Island peak (prudent) – South Island (MW)

Year	Nelson/ Marlborough	West Coast	Canterbury	South Canterbury	Otago/ Southland	South Island Total
2007	210	46	740	84	1,100	2,180
2008	216	69	781	92	1,118	2,276
2009	223	70	800	95	1,138	2,326
2010	232	72	823	99	1,161	2,387
2011	239	73	844	102	1,179	2,436
2012	247	74	865	105	1,199	2,490
2013	250	75	880	107	1,206	2,518
2014	253	75	894	108	1,212	2,543
2015	256	76	906	109	1,217	2,564
2016	257	76	916	110	1,221	2,580
2017	258	77	926	110	1,224	2,595
2018	260	77	936	110	1,227	2,610
2019	261	77	947	111	1,230	2,626
2020	263	78	958	111	1,233	2,642
2021	264	78	968	112	1,235	2,656
2022	266	78	978	112	1,237	2,672
2023	268	78	989	113	1,240	2,688
2024	270	79	1,000	114	1,242	2,705

Year	Nelson/ Marlborough	West Coast	Canterbury	South Canterbury	Otago/ Southland	South Island Total
2025	272	79	1,012	115	1,244	2,722
2026	274	79	1,023	116	1,247	2,740
2027	277	80	1,035	117	1,250	2,758
2028	279	80	1,047	118	1,253	2,776
2029	281	80	1,059	119	1,256	2,794
2030	284	80	1,071	120	1,259	2,814
2031	286	81	1,084	121	1,262	2,834
2032	289	81	1,096	122	1,265	2,853
2033	291	81	1,109	123	1,268	2,873
2034	294	82	1,121	124	1,272	2,893
2035	296	82	1,134	126	1,275	2,913
2036	299	82	1,148	127	1,279	2,935

Table 29 Region total at Island peak (mean) – North Island (MW)

Year	North Isthmus	Auckland	Waikato	Bay of Plenty	Hawkes Bay	Central	Taranaki	Wellington	North Island Total
2007	783	1,276	542	398	272	323	125	633	4,352
2008	817	1,314	541	424	270	324	133	635	4,458
2009	841	1,350	551	430	272	327	133	647	4,552
2010	868	1,390	561	437	275	333	134	660	4,658
2011	891	1,426	570	443	277	337	135	672	4,750
2012	912	1,462	579	449	278	341	136	683	4,839
2013	934	1,501	588	455	280	345	136	694	4,934
2014	955	1,545	599	461	282	350	137	706	5,034
2015	977	1,592	610	467	283	354	137	717	5,139
2016	998	1,638	621	473	284	358	138	728	5,238
2017	1,019	1,686	633	480	285	361	138	738	5,340
2018	1,040	1,733	644	487	287	365	138	748	5,442

Year	North Isthmus	Auckland	Waikato	Bay of Plenty	Hawkes Bay	Central	Taranaki	Wellington	North Island Total
2019	1,062	1,782	654	494	288	368	138	758	5,546
2020	1,084	1,831	665	502	290	372	139	768	5,650
2021	1,103	1,874	673	509	291	374	139	776	5,740
2022	1,123	1,917	682	517	292	377	139	784	5,830
2023	1,143	1,961	690	524	293	379	139	792	5,921
2024	1,163	2,004	698	532	295	382	139	800	6,011
2025	1,183	2,047	706	539	296	384	139	808	6,103
2026	1,203	2,089	713	547	297	387	139	816	6,191
2027	1,222	2,130	721	554	299	389	140	824	6,279
2028	1,242	2,172	728	562	300	392	140	832	6,369
2029	1,262	2,214	736	569	302	395	140	840	6,458
2030	1,283	2,257	744	577	304	398	141	848	6,550
2031	1,303	2,301	752	585	305	400	141	856	6,645
2032	1,324	2,345	760	593	307	403	141	865	6,739
2033	1,345	2,390	768	601	309	406	142	873	6,835
2034	1,367	2,435	776	610	310	409	142	882	6,931
2035	1,388	2,481	785	618	312	412	143	890	7,029
2036	1,411	2,530	794	627	314	415	143	900	7,133

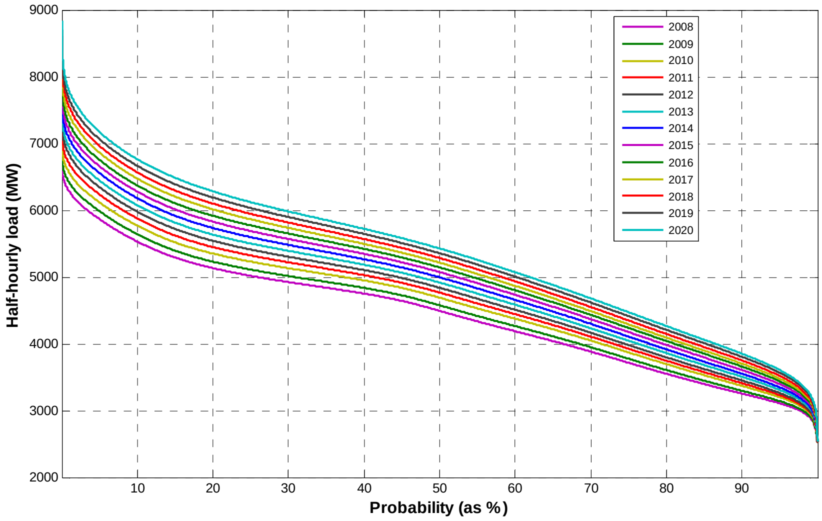
Table 30 Region total at Island peak (mean) – South Island (MW)

Year	Nelson/ Marlborough	West Coast	Canterbury	South Canterbury	Otago/ Southland	South Island Total
2007	210	46	740	84	1,100	2,180
2008	211	67	759	89	1,102	2,229
2009	217	69	775	92	1,113	2,265
2010	224	69	793	95	1,125	2,306
2011	230	70	809	97	1,133	2,339
2012	234	71	824	100	1,140	2,368

Year	Nelson/ Marlborough	West Coast	Canterbury	South Canterbury	Otago/ Southland	South Island Total
2013	238	71	838	101	1,146	2,395
2014	241	72	851	103	1,152	2,418
2015	243	72	863	103	1,157	2,438
2016	244	72	873	104	1,160	2,453
2017	245	73	882	104	1,163	2,467
2018	247	73	892	104	1,165	2,481
2019	248	74	902	105	1,168	2,496
2020	250	74	912	105	1,171	2,512
2021	251	74	922	106	1,173	2,525
2022	253	74	932	106	1,175	2,540
2023	255	75	942	107	1,177	2,555
2024	257	75	953	108	1,179	2,571
2025	259	75	964	109	1,181	2,587
2026	261	75	975	109	1,184	2,604
2027	263	76	986	110	1,186	2,621
2028	265	76	997	111	1,189	2,638
2029	267	76	1,008	112	1,191	2,656
2030	270	76	1,020	113	1,194	2,674
2031	272	77	1,032	115	1,197	2,693
2032	274	77	1,044	116	1,200	2,711
2033	277	77	1,056	117	1,203	2,730
2034	279	78	1,068	118	1,206	2,749
2035	282	78	1,080	119	1,209	2,768
2036	284	78	1,093	120	1,212	2,788

Appendix 5 Load probability curve forecasts

Figure 47 National load probability curve forecast



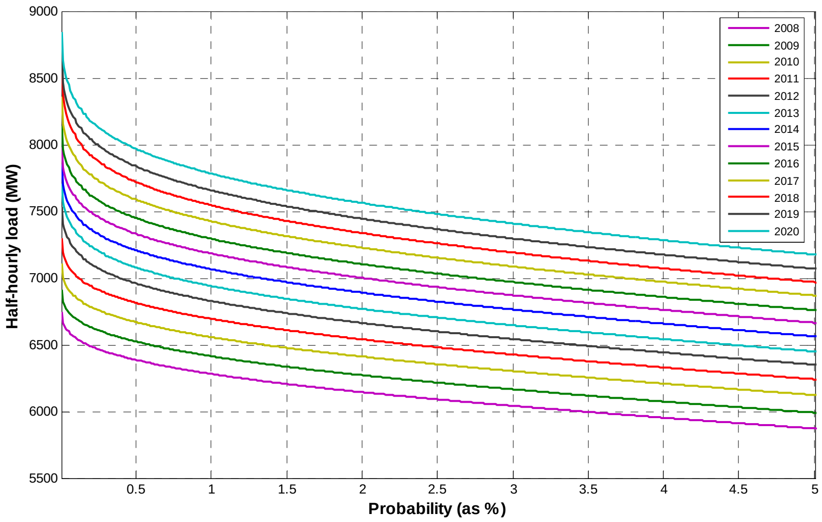
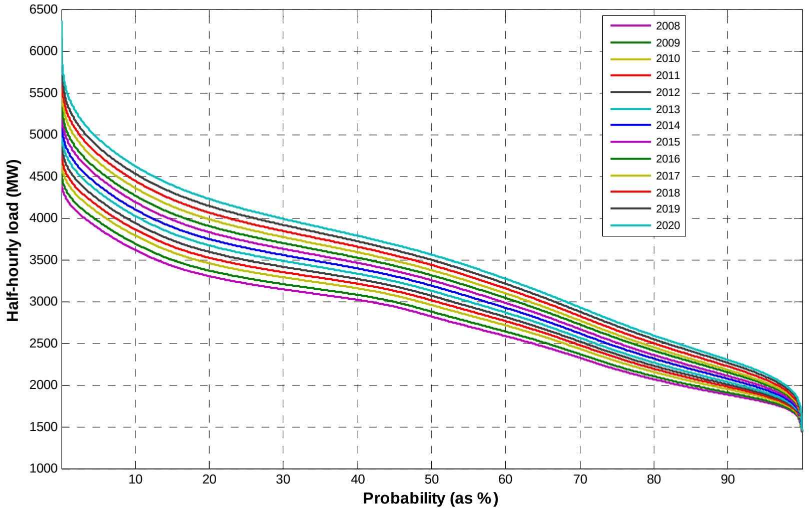


Figure 48 North Island load probability curve forecast



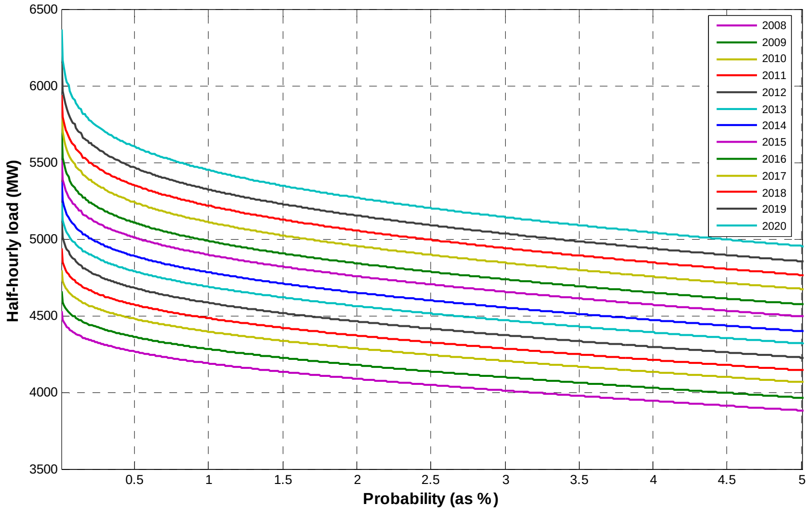
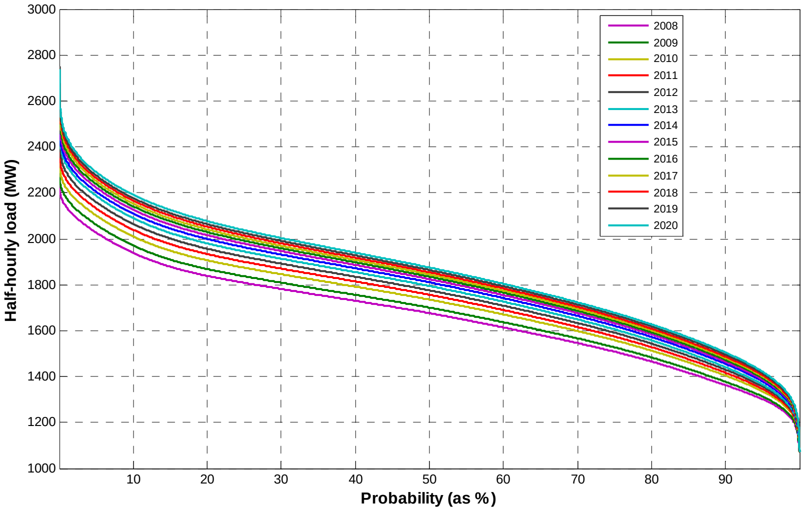
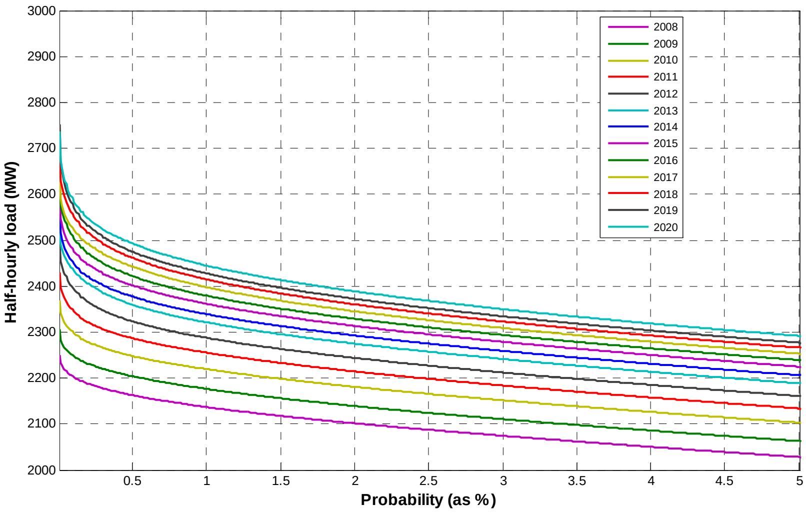


Figure 49 South Island load probability curve forecast





Appendix 6 Build schedules for the five scenarios

Table 31 Sustainable Path (mds1) build schedules

Year	Plant description	Technology description	MW
2008	Deep Stream	Hydro, run of river	6
2009	Generic OCGT NI 1	Peaker, diesel-fired OCGT	150
	Ngawha 2	Geothermal	15
	Kawerau stage 1	Geothermal	90
	Te Rere Hau	Wind	49
	West Wind	Wind	143
2010	Rotokawa 2	Geothermal	130
	Te Waka	Wind	102
	Titiokura	Wind	45
2011	Wairakei	Geothermal	-163
	Te Mihi	Geothermal	220
	Hawea Control Gate Retrofit	Hydro, peaking	17
	Wairau	Hydro, run of river	73
2013	Generic OCGT NI 4	Peaker, diesel-fired OCGT	150
	Generic OCGT NI 5	Peaker, diesel-fired OCGT	150
2014	Mokai 4	Geothermal	40
	Mohaka	Hydro, run of river	44
2015	Huntly coal unit 1	Coal	-226
	Tauhara stage 2	Geothermal	200
	Kakapotahi	Hydro, run of river	17
	Toaroha	Hydro, run of river	25
	Otoi Waiau	Hydro, run of river	17
2016	Tauhara stage 1	Geothermal	20
	Demand-side response 1 NI	Price-responsive load curtailment	100
2017	Huntly coal unit 2	Coal	-226

Year	Plant description	Technology description	MW
	Gas fired OCGT 1	Peaker, fast start gas-fired peaker	200
	Kawerau stage 2	Geothermal	67
	Rotokawa 3	Geothermal	67
	Clutha River Luggate	Hydro, peaking	100
2018	Clutha River Queensberry	Hydro, peaking	180
2019	Huntly coal unit 3	Coal	-226
	Huntly gas	Open cycle gas turbine - gas	-66
	Generic OCGT NI 2	Peaker, diesel-fired OCGT	150
	Ngatamariki	Geothermal	67
	Mangawhero to Wanganui Div	Hydro, run of river	60
	Lake Mahinerangi	Wind	200
	New IL 1	Interruptible load	50
2020	Huntly coal unit 4	Coal	-226
	Marsden Point Refinery	Co-generation, gas-fired	85
	Ngawha 2	Geothermal	-15
	Biomass Cogen, Kawerau	Co-generation, biomass-fired	30
	Clutha River Beaumont	Hydro, peaking	190
	Rototuna Forest	Wind	250
	Ohariu Valley	Wind	70
2021	Motorimu	Wind	80
	Turitea	Wind	150
	Demand-side response 2 NI	Price-responsive load curtailment	50
2022	Taranaki CC	Combined cycle gas turbine	-360
	TCC - in limited operation	Combined cycle gas turbine	360
	Gas fired OCGT 2	Peaker, fast start gas-fired peaker	200
	Long Gully	Wind	70
2023	Huntly P40	Open cycle gas turbine - gas	-50
	Generic OCGT NI 3	Peaker, diesel-fired OCGT	150
	Generic wind Waikato 2	Wind	200

Year	Plant description	Technology description	MW
	Puketiro	Wind	120
	New IL 2	Interruptible load	50
2024	Southdown	Combined cycle gas turbine	-122
	TCC - in limited operation	Combined cycle gas turbine	-360
	Southdown E105	Open cycle gas turbine - gas	-45
	Generic OCGT NI 6	Peaker, diesel-fired OCGT	150
	Generic geo 2	Geothermal	110
	Biomass Cogen, Central	Co-generation, biomass-fired	30
	Biomass Cogen, Whirinaki	Co-generation, biomass-fired	30
	Whakapapanui Papamanuka	Hydro, run of river	16
	Whangaehu	Hydro, run of river	20
	Clarence to Waiau Diversions	Hydro, run of river	70
	Waitangi Falls Ruakiteri	Hydro, run of river	16
	Kaituna Low Level	Hydro, run of river	38
	Tarawera at Lake Outlet	Hydro, run of river	14
	Mokairau	Wind	16
	Generic wind Wairarapa 1	Wind	100
	Pouto	Wind	300
	Belmont Hills	Wind	80
2025	Coal seam gas plant	Co-generation, other	50
	Waikato upgrade	Hydro, peaking	150
	Generic wave 1	Wave	50
2026	Generic geo 1	Geothermal	75
2027	Generic geo 3	Geothermal	110
	Te Uku	Wind	84
	Generic wave 2	Wave	50
2028	Tenergy NZ Wind Farm	Wind	10
	Waverley	Wind	100
2029	Lower Clarence River	Hydro, run of river	35

Year	Plant description	Technology description	MW
	Wainui Hills	Wind	30
	Red Hill	Wind	20
	Generic wind Wairarapa 2	Wind	100
	Generic wave 3	Wave	50
	Demand-side response 2 SI	Price-responsive load curtailment	50
2030	Glenbrook upgrade	Co-generation, other	80
	Generic pumped hydro	Hydro, pumped storage	300
2031	Project Hayes stage 1	Wind	150
	Tiwai Peninsula	Wind	80
2032	Project Hayes stage 2	Wind	160
2033	IGCC coal plant with CCS	Coal, IGCC with CCS	400
	New IL 3	Interruptible load	50
2034	Nevis River	Hydro, run of river	45
2035	Generic pumped hydro 2	Hydro, pumped storage	300
	Hawkes Bay Wind Farm	Wind	225
2036	Project Hayes stage 3	Wind	160
2037	Taipo	Hydro, run of river	33
	Project Hayes stage 4	Wind	160
2038	Otahuhu B	Combined cycle gas turbine	-365
	CCGT with CCS 2	Combined cycle gas turbine with CCS	410
	Arahura	Hydro, run of river	18
	Generic wind Taranaki	Wind	100
2039	CCGT with CCS	Combined cycle gas turbine with CCS	410
	Butler River	Hydro, run of river	23
	Upper Grey	Hydro, run of river	35
2040	Arawata River	Hydro, run of river	62
	Mt Cass	Wind	50

Table 32 South Island Surplus (mds2) build schedules

Year	Plant description	Technology description	MW
2008	Deep Stream	Hydro, run of river	6
2009	Ngawha 2	Geothermal	15
	Kawerau stage 1	Geothermal	90
2010	Gas fired OCGT 1	Peaker, fast start gas-fired peaker	200
	Te Rere Hau	Wind	49
	Te Waka	Wind	102
	West Wind	Wind	143
2011	Wairakei	Geothermal	-163
	Rotokawa 2	Geothermal	130
	Te Mihi	Geothermal	220
	Hawea Control Gate Retrofit	Hydro, peaking	17
2012	Project Hayes stage 1	Wind	150
	Titiokura	Wind	45
2013	Huntly coal unit 1	Coal	-226
	Generic OCGT NI 1	Peaker, diesel-fired OCGT	150
	Generic OCGT NI 3	Peaker, diesel-fired OCGT	150
	Lake Mahinerangi	Wind	200
	Project Hayes stage 2	Wind	160
2014	Generic OCGT NI 2	Peaker, diesel-fired OCGT	150
	Project Hayes stage 3	Wind	160
2015	Huntly coal unit 2	Coal	-226
	Huntly coal - reserve unit 2	Coal, dry year mode	245
	Demand-side response 1 NI	Price-responsive load curtailment	100
2016	Mokai 4	Geothermal	40
	Clutha River Luggate	Hydro, peaking	100
2017	Tauhara stage 2	Geothermal	200
2018	Huntly coal unit 3	Coal	-226
	Huntly coal - reserve unit 3	Coal, dry year mode	245

Year	Plant description	Technology description	MW
	Tauhara stage 1	Geothermal	20
	Clutha River Queensberry	Hydro, peaking	180
2019	Huntly gas	Open cycle gas turbine - gas	-66
	Gas fired OCGT 2	Peaker, fast start gas-fired peaker	200
	Mokairau	Wind	16
	Motorimu	Wind	80
	Belmont Hills	Wind	80
	New IL 1	Interruptible load	50
2020	Huntly coal unit 4	Coal	-226
	Marsden Point Refinery	Co-generation, gas-fired	85
	Clutha River Beaumont	Hydro, peaking	190
	Long Gully	Wind	70
	Turitea	Wind	150
	Red Hill	Wind	20
	Tenergy NZ Wind Farm	Wind	10
2021	Biomass Cogen, Kawerau	Co-generation, biomass-fired	30
	Puketiro	Wind	120
	Demand-side response 2 NI	Price-responsive load curtailment	50
2022	Generic wind Central	Wind	100
	Demand-side response 2 SI	Price-responsive load curtailment	50
2023	Taranaki CC	Combined cycle gas turbine	-360
	TCC - in limited operation	Combined cycle gas turbine	360
	Biomass Cogen, Central	Co-generation, biomass-fired	30
	Biomass Cogen, Whirinaki	Co-generation, biomass-fired	30
	New IL 2	Interruptible load	50
2024	Generic OCGT NI 4	Peaker, diesel-fired OCGT	150
	Pouto	Wind	300
2025	Coal seam gas plant	Co-generation, other	50
	Waikato upgrade	Hydro, peaking	150

Year	Plant description	Technology description	MW
2027	Rototuna Forest	Wind	250
	Generic wave 1	Wave	50
2028	Huntly coal - reserve unit 2	Coal, dry year mode	-245
	Generic OCGT NI 5	Peaker, diesel-fired OCGT	150
	Generic OCGT NI 6	Peaker, diesel-fired OCGT	150
	Generic wind Wairarapa 1	Wind	100
2029	Nevis River	Hydro, run of river	45
	Ohariu Valley	Wind	70
	New IL 3	Interruptible load	50
2030	Huntly coal - reserve unit 3	Coal, dry year mode	-245
	IGCC coal plant with CCS 2	Coal, IGCC with CCS	400
	Glenbrook upgrade	Co-generation, other	80
2031	Demand-side response 4 NI	Price-responsive load curtailment	50
2033	IGCC coal plant with CCS	Coal, IGCC with CCS	400
	Otahuhu C	Combined cycle gas turbine	407
	TCC - in limited operation	Combined cycle gas turbine	-360
2036	IGCC coal plant with CCS 4	Coal, IGCC with CCS	400
2038	Otahuhu B	Combined cycle gas turbine	-365
	Generic gas 1 Auckland	Combined cycle gas turbine	410
	Generic OCGT NI 7	Peaker, diesel-fired OCGT	150

Table 33 Medium Renewables (mds3) build schedules

Year	Plant description	Technology description	MW
2008	Deep Stream	Hydro, run of river	6
2009	Ngawha 2	Geothermal	15
	Kawerau stage 1	Geothermal	90
	Te Rere Hau	Wind	49
	West Wind	Wind	143
2010	Rotokawa 2	Geothermal	130
	Hawea Control Gate Retrofit	Hydro, peaking	17
	Titiokura	Wind	45
2011	Wairakei	Geothermal	-163
	Te Mihi	Geothermal	220
	Wairau	Hydro, run of river	73
2012	Generic OCGT NI 1	Peaker, diesel-fired OCGT	150
2013	Huntly coal unit 1	Coal	-226
	Huntly coal - reserve unit 1	Coal, dry year mode	245
	Gas fired OCGT 1	Peaker, fast start gas-fired peaker	200
	Mokai 4	Geothermal	40
2014	Tauhara stage 2	Geothermal	200
2015	Huntly coal unit 2	Coal	-226
	Huntly coal - reserve unit 2	Coal, dry year mode	245
	Tauhara stage 1	Geothermal	20
	Mangawhero to Wanganui Div	Hydro, run of river	60
	Demand-side response 1 NI	Price-responsive load curtailment	100
2016	Kawerau stage 2	Geothermal	67
	New IL 1	Interruptible load	50
2017	Generic OCGT NI 6	Peaker, diesel-fired OCGT	150
	Ngatamariki	Geothermal	67
	Rotokawa 3	Geothermal	67
2018	Huntly coal unit 3	Coal	-226

Year	Plant description	Technology description	MW
	Huntly coal - reserve unit 3	Coal, dry year mode	245
	Clutha River Queensberry	Hydro, peaking	180
	Long Gully	Wind	70
2019	Otahuhu C	Combined cycle gas turbine	407
	Huntly gas	Open cycle gas turbine - gas	-66
2020	Huntly coal unit 4	Coal	-226
	Huntly coal - reserve unit 4	Coal, dry year mode	245
2021	New IL 2	Interruptible load	50
2022	Demand-side response 2 NI	Price-responsive load curtailment	50
2026	Huntly coal - reserve unit 1	Coal, dry year mode	-245
	Generic OCGT NI 2	Peaker, diesel-fired OCGT	150
	Generic OCGT NI 3	Peaker, diesel-fired OCGT	150
2027	Generic OCGT NI 4	Peaker, diesel-fired OCGT	150
2028	Huntly coal - reserve unit 2	Coal, dry year mode	-245
	Gas fired OCGT 2	Peaker, fast start gas-fired peaker	200
2029	Generic geo 1	Geothermal	75
2030	Huntly coal - reserve unit 3	Coal, dry year mode	-245
	Coal seam gas plant	Co-generation, other	50
	Generic pumped hydro	Hydro, pumped storage	300
2031	Glenbrook upgrade	Co-generation, other	80
2032	Huntly coal - reserve unit 4	Coal, dry year mode	-245
	Marsden Point Refinery	Co-generation, gas-fired	85
	Demand-side response 4 NI	Price-responsive load curtailment	50
2033	Generic gas 1 Auckland	Combined cycle gas turbine	410
	Taranaki CC	Combined cycle gas turbine	-360
	Generic geo 2	Geothermal	110
2034	Generic geo 3	Geothermal	110
2035	Taranaki CC 2	Combined cycle gas turbine	380
2038	Otahuhu B	Combined cycle gas turbine	-365

Year	Plant description	Technology description	MW
	Generic gas 2 Taranaki	Combined cycle gas turbine	410
	Generic OCGT NI 5	Peaker, diesel-fired OCGT	150
	Motorimu	Wind	80
	Turitea	Wind	150
2039	Waverley	Wind	100
2040	Hawkes Bay Wind Farm	Wind	225

Table 34 Demand-side Participation (mds4) build schedules

Year	Plant description	Technology description	MW
2008	Deep Stream	Hydro, run of river	6
2009	Generic OCGT NI 1	Peaker, diesel-fired OCGT	150
	Ngawha 2	Geothermal	15
	Kawerau stage 1	Geothermal	90
	Te Rere Hau	Wind	49
2010	Gas fired OCGT 1	Peaker, fast start gas-fired peaker	200
	Rotokawa 2	Geothermal	130
	West Wind	Wind	143
2011	Wairakei	Geothermal	-163
	Te Mihi	Geothermal	220
	Wairau	Hydro, run of river	73
2012	Hawea Control Gate Retrofit	Hydro, peaking	17
	Te Waka	Wind	102
2014	Generic OCGT NI 3	Peaker, diesel-fired OCGT	150
2015	Demand-side response 1 NI	Price-responsive load curtailment	100
2016	Demand-side response 1 SI	Price-responsive load curtailment	50
2017	Tauhara stage 2	Geothermal	200
2018	Tauhara stage 1	Geothermal	20
	Mokai 4	Geothermal	40
	New IL 1	Interruptible load	50
2019	Kawerau stage 2	Geothermal	67
	Clutha River Luggate	Hydro, peaking	100
2020	Generic OCGT NI 2	Peaker, diesel-fired OCGT	150
	Rotokawa 3	Geothermal	67
	Demand-side response 2 SI	Price-responsive load curtailment	50
	Demand-side response 2 NI	Price-responsive load curtailment	50
2021	Ngatamariki	Geothermal	67
	New IL 2	Interruptible load	50

Year	Plant description	Technology description	MW
2022	Marsden Coal	Coal	320
2024	Marsden Point Refinery	Co-generation, gas-fired	85
2025	Coal seam gas plant	Co-generation, other	50
	Demand-side response 3 NI	Price-responsive load curtailment	100
2026	Huntly coal unit 1	Coal	-226
	Generic lignite 1 Southland	Lignite	400
	Motorimu	Wind	80
2028	Generic coal 1 Glenbrook	Coal	400
	Huntly coal unit 2	Coal	-226
2029	Generic coal 4 Tauranga	Coal	300
2030	Huntly coal unit 3	Coal	-226
	Generic lignite 2 Otago	Lignite	400
	Glenbrook upgrade	Co-generation, other	80
2031	Huntly gas	Open cycle gas turbine - gas	-66
	Vehicle-to-grid at peak time 1	Price-responsive load curtailment	100
	Demand-side response 3 SI	Price-responsive load curtailment	50
	Demand-side response 4 NI	Price-responsive load curtailment	50
2032	Huntly coal unit 4	Coal	-226
	Otahuhu C	Combined cycle gas turbine	407
2033	Taranaki CC	Combined cycle gas turbine	-360
	Generic geo 1	Geothermal	75
	Long Gully	Wind	70
	Generic wind Wairarapa 1	Wind	100
	Turitea	Wind	150
	Vehicle-to-grid at peak time 2	Price-responsive load curtailment	200
	New IL 3	Interruptible load	50
2034	Generic geo 2	Geothermal	110
2035	Generic geo 3	Geothermal	110
	Wainui Hills	Wind	30

Year	Plant description	Technology description	MW
2036	Vehicle-to-grid at peak time 3	Price-responsive load curtailment	300
	Demand-side response 5 NI	Price-responsive load curtailment	50
2037	Puketiro	Wind	120
2038	Generic coal 5 Huntly stage 1	Coal	400
	Otahuhu B	Combined cycle gas turbine	-365
	Generic gas 1 Auckland	Combined cycle gas turbine	410
2039	Lake Mahinerangi	Wind	200

Table 35 High Gas Discovery (mds5) build schedules

Year	Plant description	Technology description	MW
2008	Deep Stream	Hydro, run of river	6
2009	Ngawha 2	Geothermal	15
	Kawerau stage 1	Geothermal	90
	West Wind	Wind	143
2010	Gas fired OCGT 1	Peaker, fast start gas-fired peaker	200
2011	Wairakei	Geothermal	-163
	Rotokawa 2	Geothermal	130
	Te Mihi	Geothermal	220
	Te Rere Hau	Wind	49
2012	Tauhara stage 1	Geothermal	20
2013	Generic OCGT NI 5	Peaker, diesel-fired OCGT	150
	Wairau	Hydro, run of river	73
2014	Generic OCGT NI 1	Peaker, diesel-fired OCGT	150
2015	Huntly coal unit 1	Coal	-226
	Huntly coal unit 2	Coal	-226
	Rodney CCGT stage 1	Combined cycle gas turbine	240
	Rodney CCGT stage 2	Combined cycle gas turbine	240
	Taranaki Cogen	Co-generation, gas-fired	50
	Generic OCGT NI 2	Peaker, diesel-fired OCGT	150
2016	Mokai 4	Geothermal	40
2017	Mangawhero to Wanganui Div	Hydro, run of river	60
	New IL 1	Interruptible load	50
2018	Clutha River Queensberry	Hydro, peaking	180
2019	Tauhara stage 2	Geothermal	200
2021	Clutha River Luggate	Hydro, peaking	100
	Demand-side response 2 SI	Price-responsive load curtailment	50
2022	Taranaki CC	Combined cycle gas turbine	-360
	TCC - in limited operation	Combined cycle gas turbine	360

Year	Plant description	Technology description	MW
	New IL 2	Interruptible load	50
2023	Otahuhu C	Combined cycle gas turbine	407
2025	Coal seam gas plant	Co-generation, other	50
2026	Kawerau stage 2	Geothermal	67
2027	Rotokawa 3	Geothermal	67
	New IL 3	Interruptible load	50
2028	Generic OCGT NI 3	Peaker, diesel-fired OCGT	150
2029	Ngatamariki	Geothermal	67
2030	Huntly coal unit 3	Coal	-226
	Marsden Coal	Coal	320
	Glenbrook upgrade	Co-generation, other	80
2031	Huntly gas	Open cycle gas turbine - gas	-66
	Generic OCGT NI 4	Peaker, diesel-fired OCGT	150
	Turitea	Wind	150
	Demand-side response 4 NI	Price-responsive load curtailment	50
2032	Huntly coal unit 4	Coal	-226
	Generic gas 1 Auckland	Combined cycle gas turbine	410
2033	TCC - in limited operation	Combined cycle gas turbine	-360
	Taranaki CC 2	Combined cycle gas turbine	380
	Puketiro	Wind	120
2034	Pouto	Wind	300
2035	Generic coal 3 Christchurch	Coal	400
2036	Generic coal 1 Glenbrook	Coal	400
2038	Otahuhu B	Combined cycle gas turbine	-365
	Generic gas 2 Taranaki	Combined cycle gas turbine	410
2039	Marsden Point Refinery	Co-generation, gas-fired	85

Appendix 7 Capacity stackplots – total installed capacity (MW) by fuel and year, for each market development scenario

Figure 50 Capacity stackplot by fuel and by year for the Sustainable Path scenario

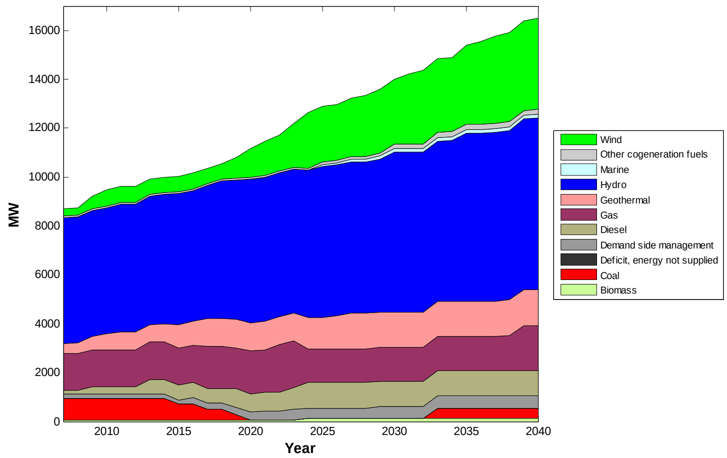


Figure 51 Capacity stackplot by fuel and by year for the South Island Surplus scenario

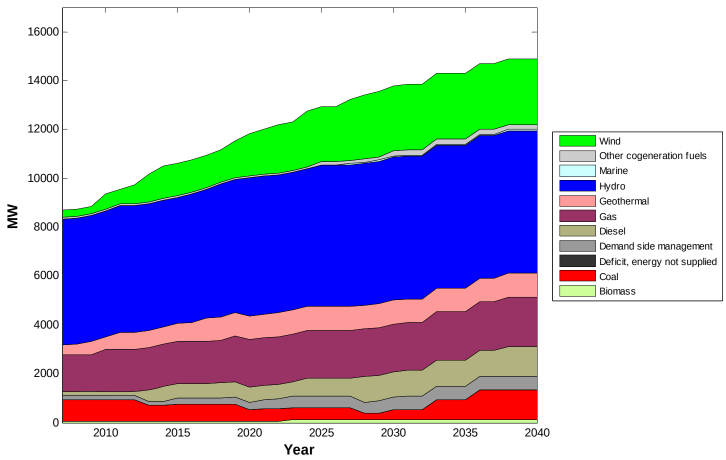


Figure 52 Capacity stackplot by fuel and by year for the Medium Renewables scenario

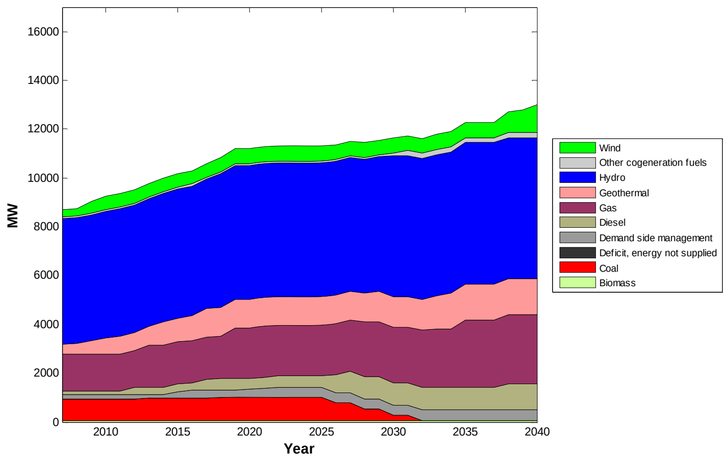


Figure 53 Capacity stackplot by fuel and by year for the Demand-side Participation scenario

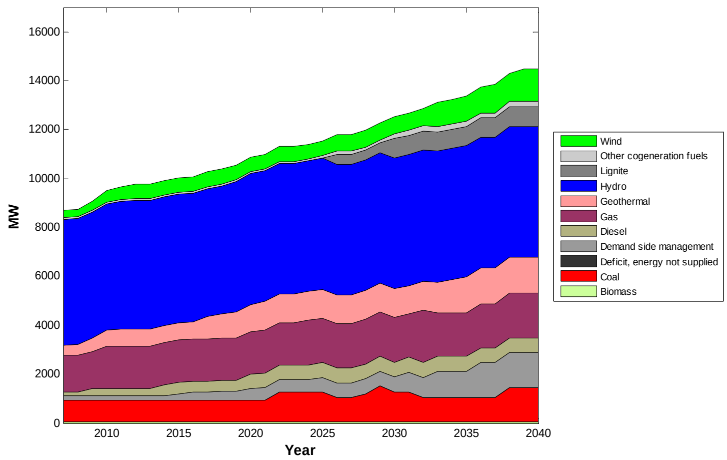
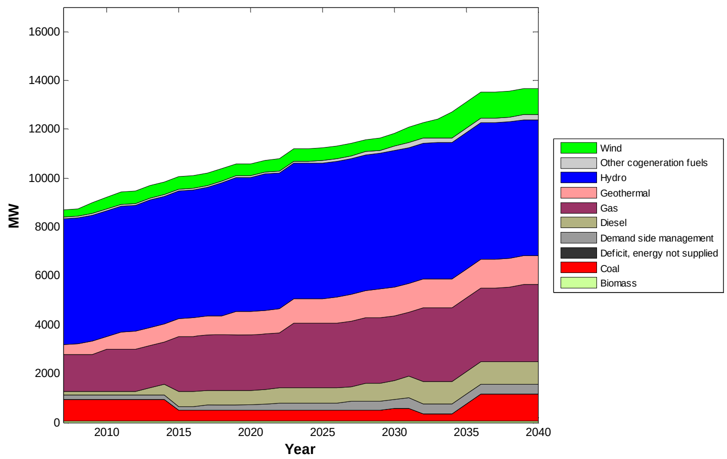


Figure 54 Capacity stackplot by fuel and by year for the High Gas Discovery scenario



Appendix 8 Technology lineplots – total installed capacity by market development scenario and year, for each technology

Figure 55 Installed capacity of wind

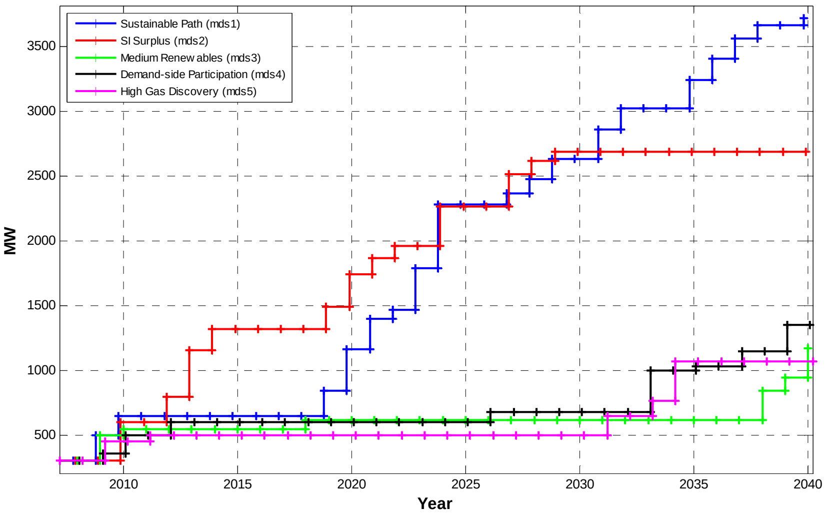


Figure 56 Installed capacity of co-generation, biomass-fired

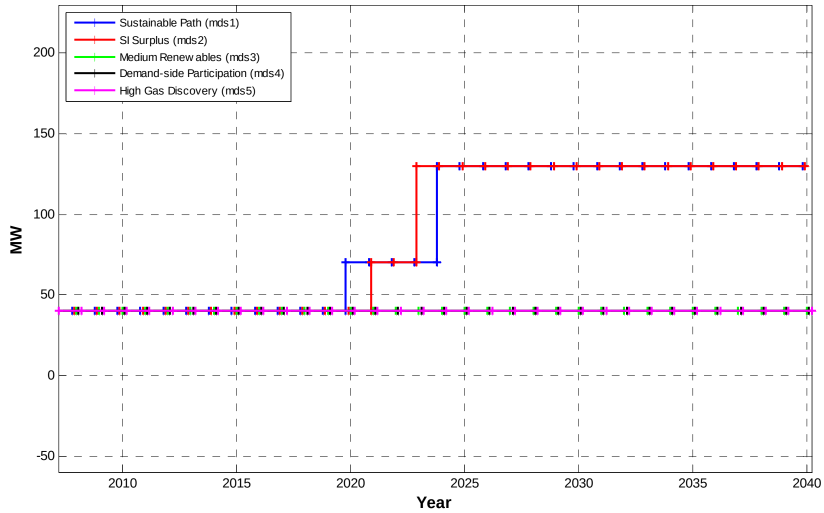


Figure 57 Installed capacity of gas

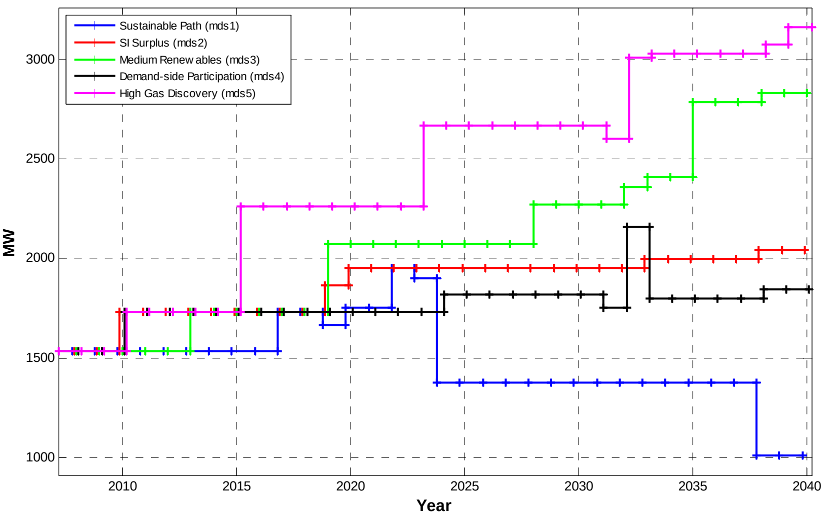


Figure 58 Installed capacity of geothermal

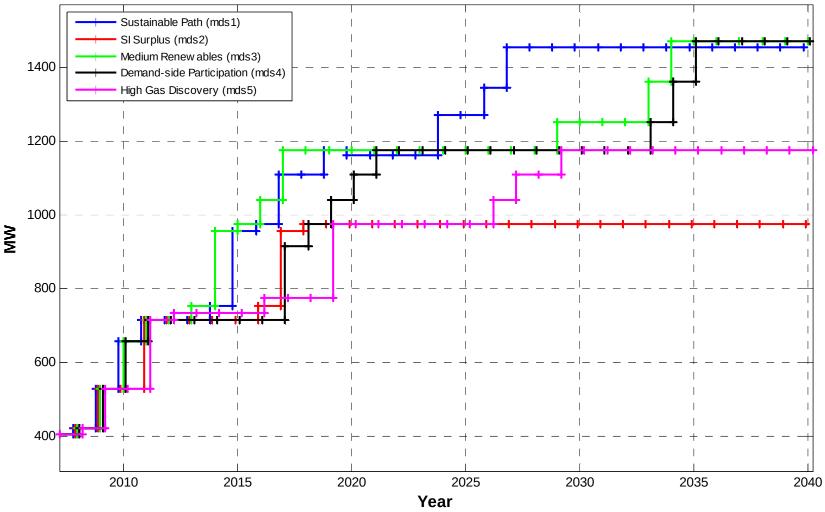


Figure 59 Installed capacity of hydro

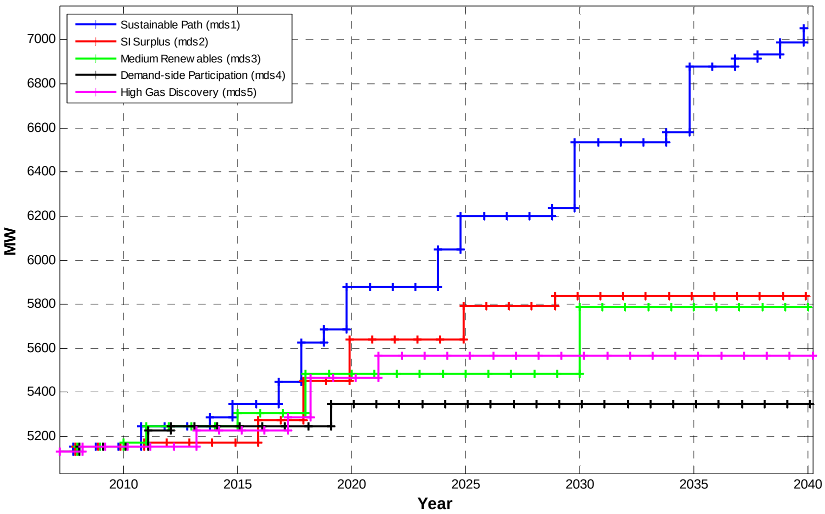


Figure 60 Installed capacity of interruptible load and price-responsive load curtailment

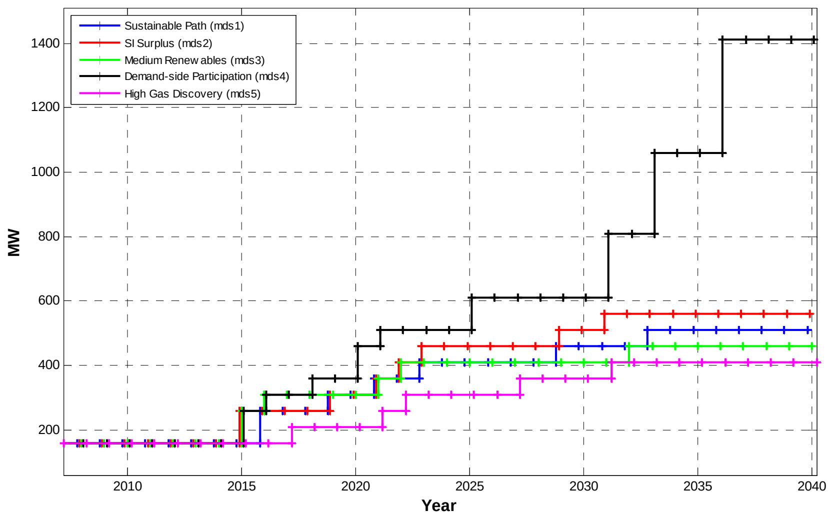


Figure 61 Installed capacity of peaker, diesel-fired open cycle gas turbine

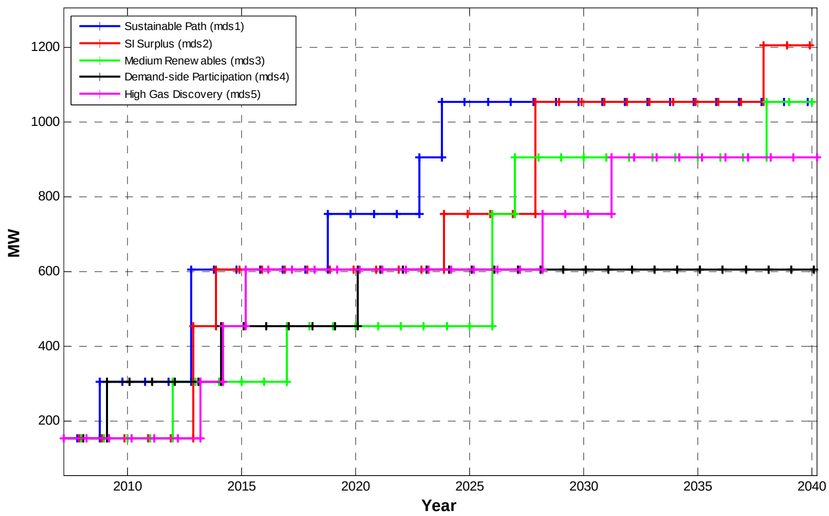


Figure 62 Installed capacity of coal

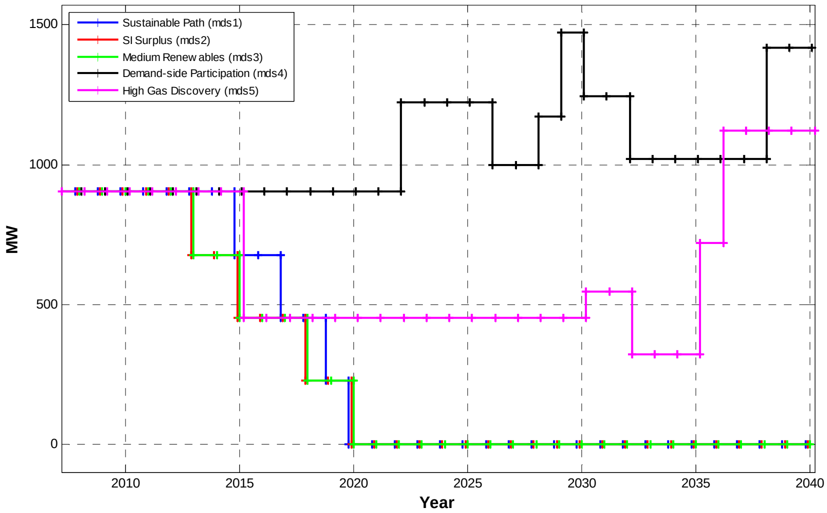


Figure 63 Installed capacity of lignite

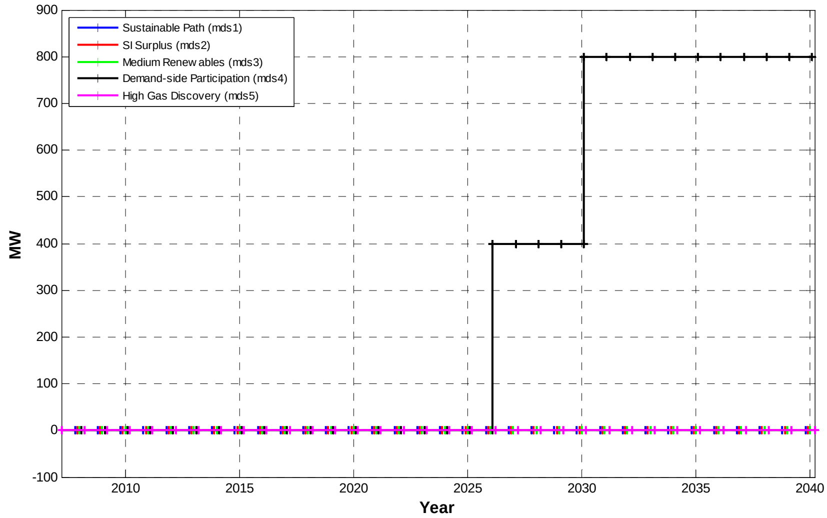


Figure 64 Installed capacity of carbon capture and storage

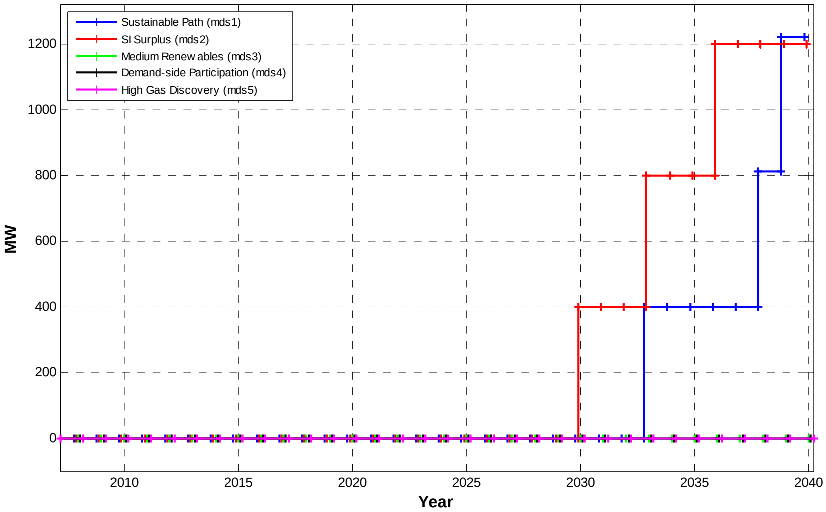
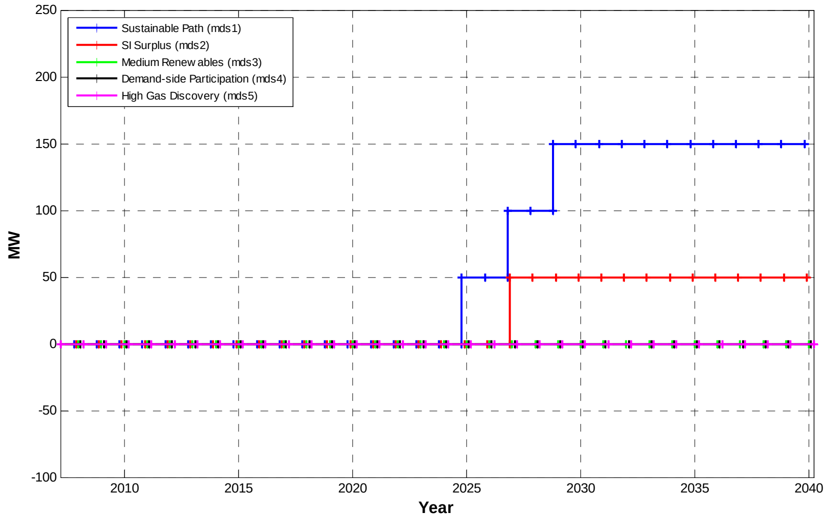


Figure 65 Installed capacity of marine generation



Appendix 9 Energy stackplots – average generation (GWh) by fuel type and year, for each market development scenario

Figure 66 Energy stackplot by fuel and by year for the Sustainable Path scenario

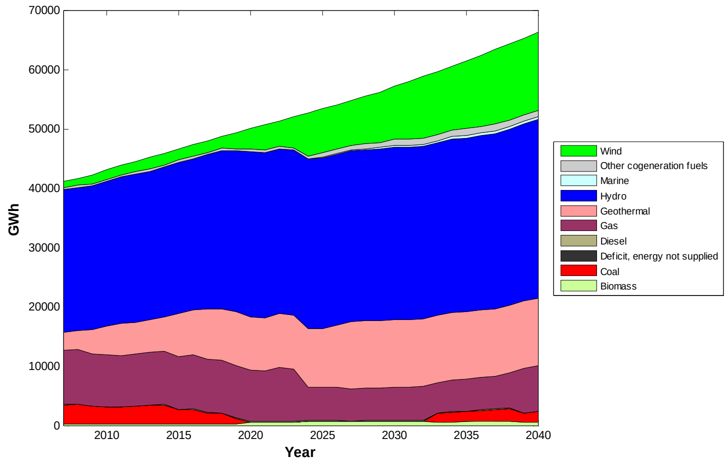


Figure 67 Energy stackplot by fuel and by year for the South Island Surplus scenario

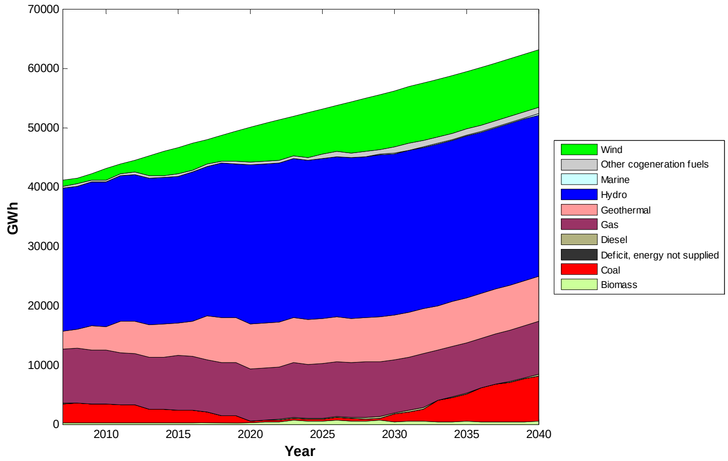


Figure 68 Energy stackplot by fuel and by year for the Medium Renewables scenario

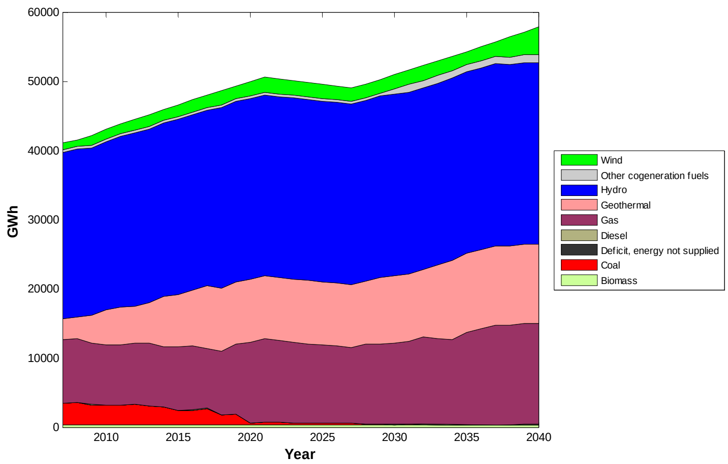


Figure 69 Energy stackplot by fuel and by year for the Demand-side Participation scenario

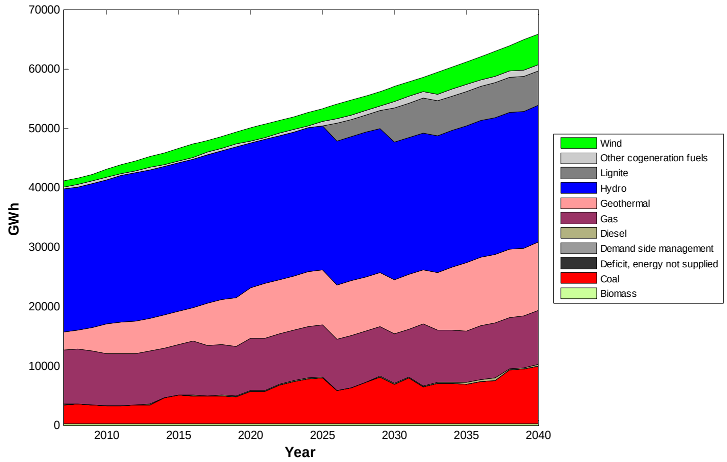
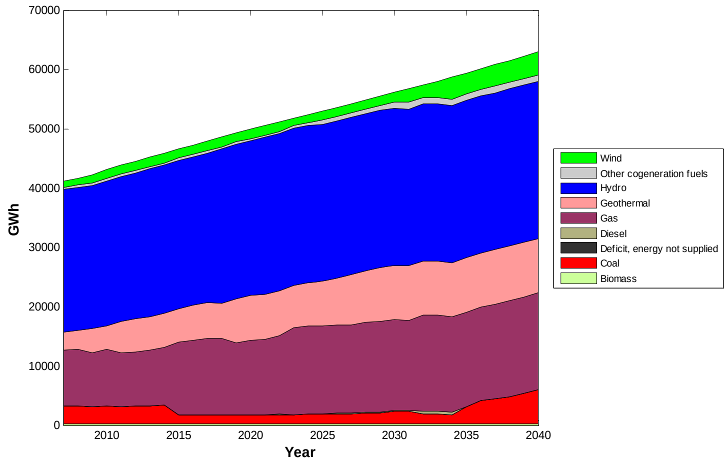


Figure 70 Energy stackplot by fuel and by year for the High Gas Discovery scenario



Appendix 10 Greenhouse gas emissions by technology by year for the five scenarios

Figure 71 Emissions stackplot by technology and by year for the Sustainable Path scenario

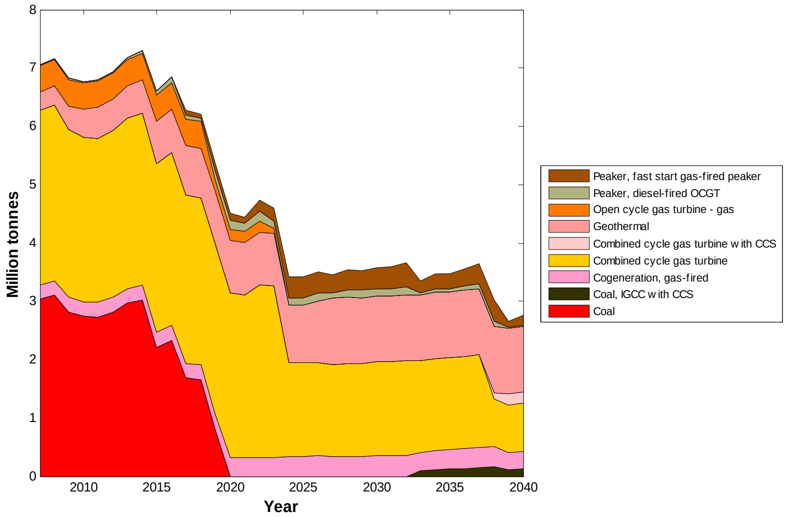


Figure 72 Emissions stackplot by technology and by year for the South Island Surplus scenario

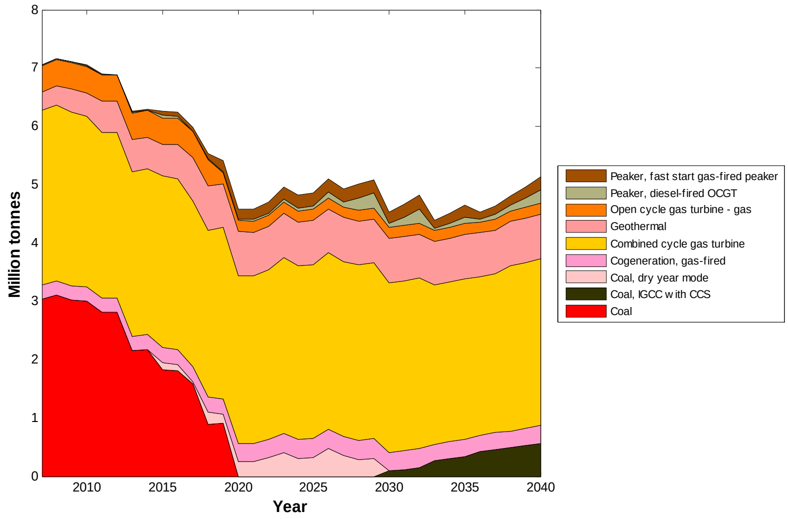


Figure 73 Emissions stackplot by technology and by year for the Medium Renewables scenario

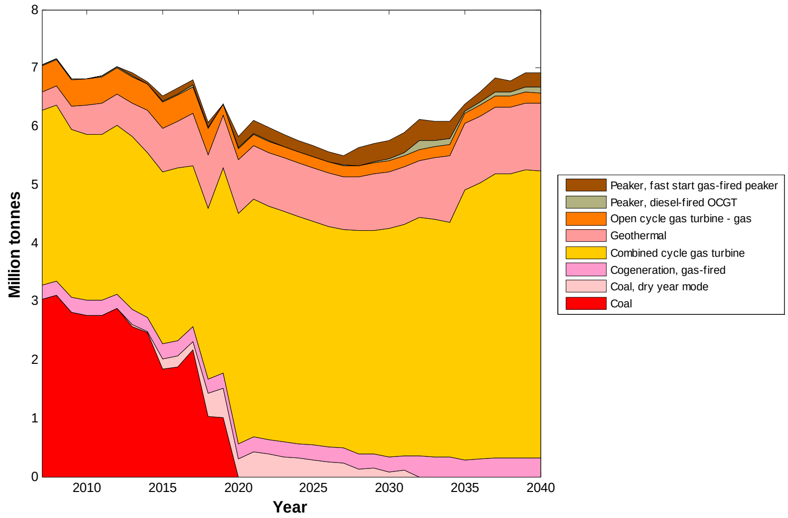


Figure 74 Emissions stackplot by technology and by year for the Demand-side Participation scenario

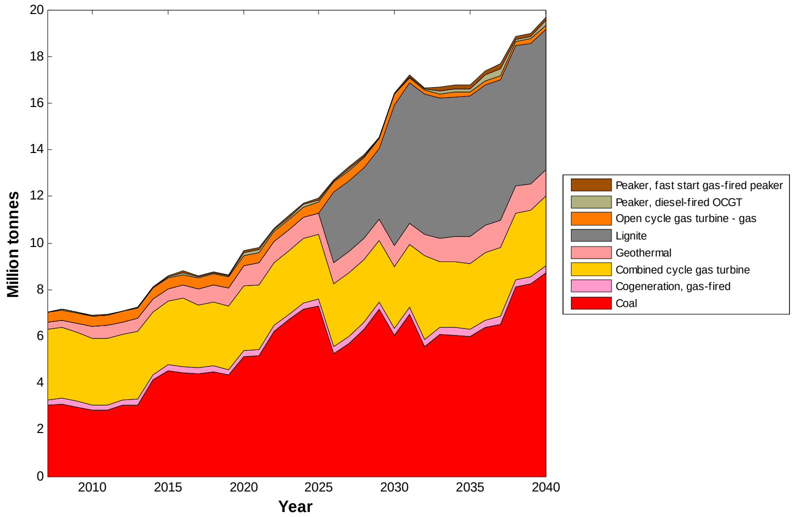
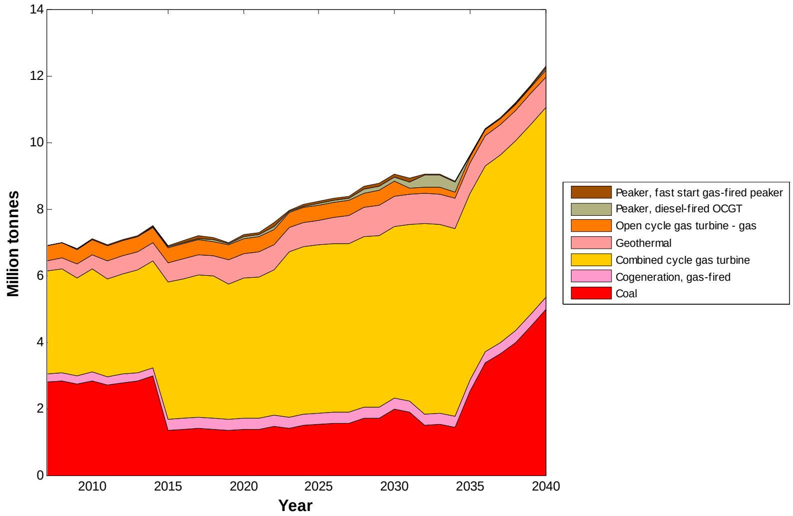


Figure 75 Emissions stackplot by technology and by year for the High Gas Discovery scenario



Appendix 11 Installed, firm and North Island firm capacity for the five scenarios

Figure 76 Installed capacity

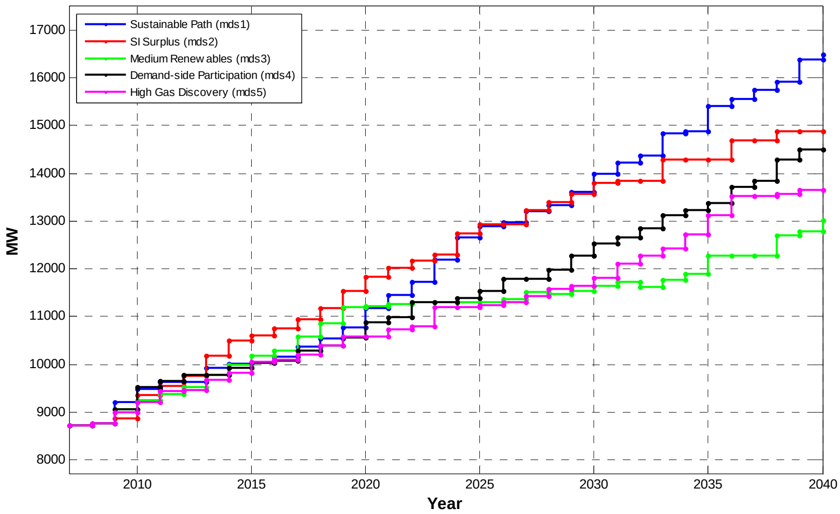


Figure 77 Firm capacity

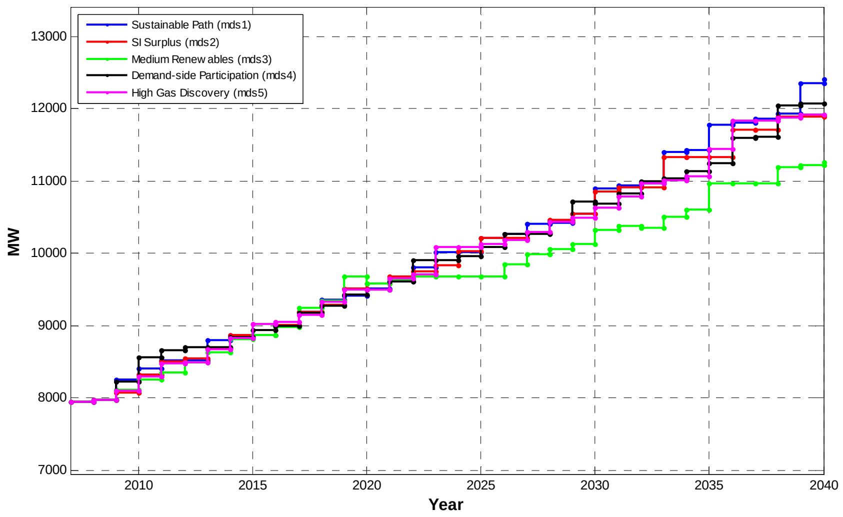
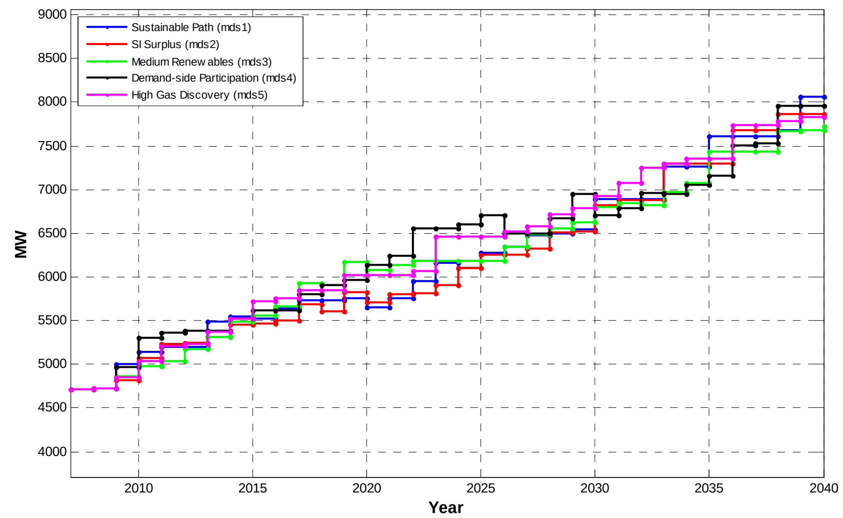


Figure 78 North Island firm capacity



Appendix 12 HVDC transfers

Figure 79 HVDC transfer for the Sustainable Path scenario

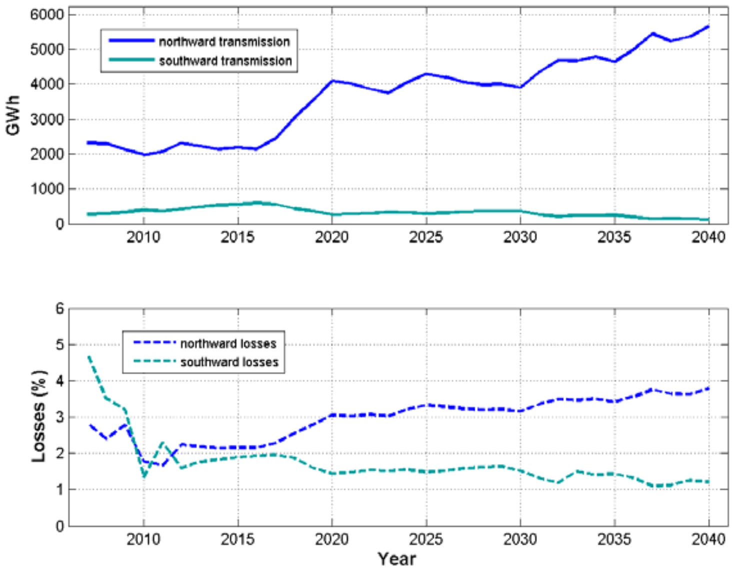


Figure 80 HVDC transfer for the South Island Surplus scenario

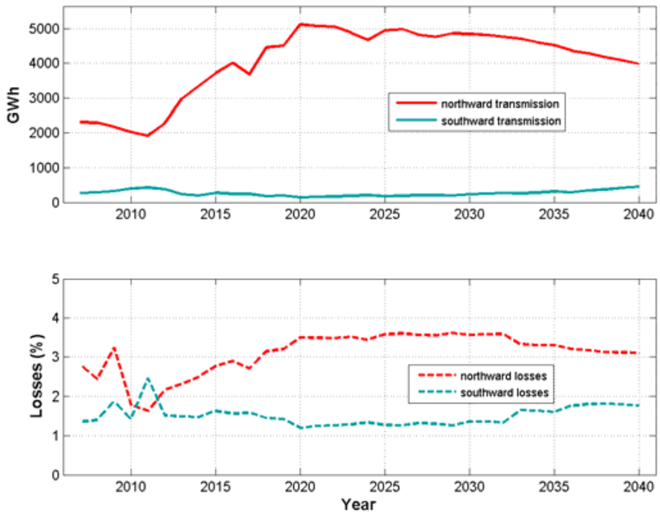


Figure 81 HVDC transfer for the Medium Renewables scenario

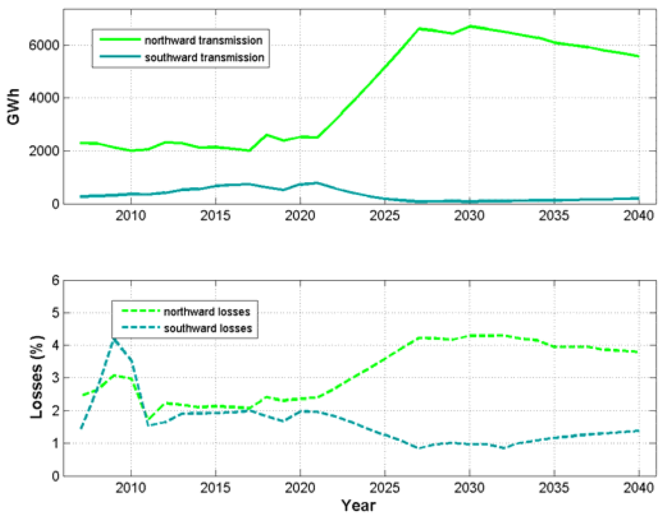


Figure 82 HVDC transfer for the Demand-side Participation scenario

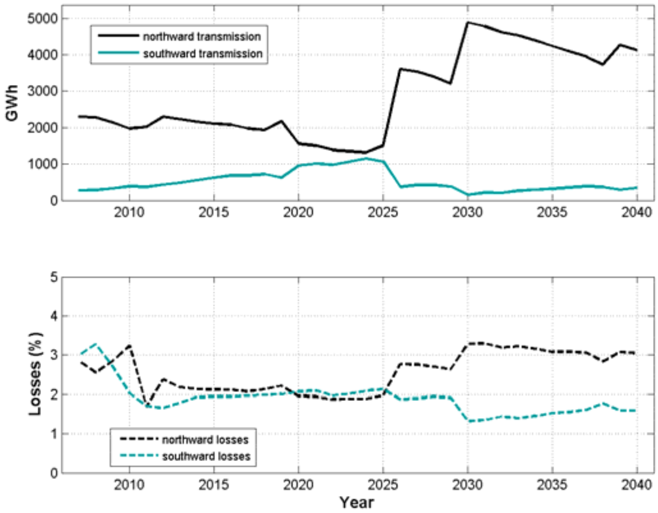
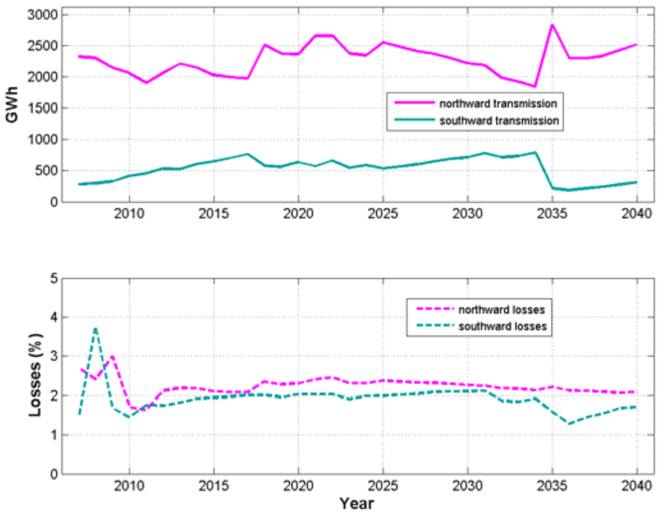


Figure 83 HVDC transfer for the High Gas Discovery scenario



Appendix 13 Transmission network development projects

This appendix provides transmission data to define the base case market development scenarios required for application of the GIT and the GRS. By defining the base case scenarios a fixed reference point has been created to enable consistent comparison of the net market benefits of various transmission and non-transmission alternatives. As such, the base case scenarios cannot, and are not intended to, form a central plan for the electricity supply industry.

Table 36 Common completed or committed transmission augmentations

Year	Augmentation	Reason	Status
2007	1 x 50 Mvar Capacitor HEP 110 kV (total 2 x 50 Mvar)	Increase reactive support in UNI	Completed
	1 x 100 Mvar Capacitor ALB 220 kV	Increase reactive support in UNI	Completed (APR 2008)
	1 x 220/33 kV 120 MVA new supply transformer at Silverdale. New 2nd ALB–SVL 220 kV circuit	Increase capacity	Completed (APR 2008)
	1 x 50 Mvar Capacitor BOB 110 kV	Reactive support for BOB when BOB–WIR circuits are opened to alleviate loading on HAM–BOB and ARI–BOB	Completed (APR 2008)
	SPS to trip BOB–WIR 110 kV circuits if ARI–BOB or HAM–WES–BOB 110 kV circuits are overloaded	Increase thermal capacity into UNI	Completed (APR 2008)
	New 110 kV switching station at Kaitimako. Uprate KMO–TGA and KMO–PKE–TGA from 77/63 MVA to 88/76 MVA	Increase thermal capacity within Bay of Plenty	Completed (APR 2008)
	Replaced 110/33 kV supply transformers at Carrington St with 2x 85 MVA	Increase capacity	Completed (APR 2008)
	Uprate HAY–TKR 110 kV Circuits 1 and 2 from 303/281 MVA to 431/411 MVA	Improve N-1 Capacity	Completed (APR 2008)
	Add 3rd 220/110 kV interconnecting Transformer at MDN	(while T2 and condenser are out)	Completed
	Complete duplexing of LIV–ISL 220 kV circuit from Simplex Goat 75 deg (309/278 MVA) to Duplex Goat 50 deg (476/404 MVA)	Increase thermal capacity Waitaki–Canterbury	Completed (APR 2008)
	Replace 50 MVA interconnecting transformers at STK and KIK with 150 MVA transformers	Increase thermal capacity from 220 kV–110 kV Nelson/Marlborough	Completed (APR 2008)
	Uprate both 110/33 kV Frankton supply transformers to 40 MVA each	Increase capacity	Completed

Year	Augmentation	Reason	Status
2012	1 x 25 Mvar Capacitor TGA 110 kV	Increase reactive support in BOP	Committed (APR 2008)
	1 x +/- 100 Mvar SVC ALB 220 kV	Increase reactive support in UNI	Committed (APR 2008)
	Uprate OTA–WKM 220 kV Circuits 1 and 2 from 246/202 MVA to 323/293 MVA	Increase thermal capacity into UNI	Committed (APR 2008)
	Close Mt Roskill–Hepburn Road 110 kV splits	Increase capacity to Northland	Committed (APR 2008)
	Thermal Upgrade KMO–TGA and KMO–PKE–TGA 110 kV circuits from 88/77 MVA to 105/96 MVA	Increase capacity to Bay of Plenty	Committed (customer)
	New switching station at Ohinewai. Bus OTA–WKM Line C at OHW. Uprate OTA–OHW 3 to 670/614 MVA (northern section of OTA–WKM Line C)	Increase thermal capacity into UNI	Committed (APR 2008)
	Uprate OHW–HAM–WKM and OHW–WKM 220 kV circuits to 670/614 MVA (southern section of OTA–WKM Line C)	NIGUP	Committed (APR 2008)
	2 x 11.2 Mvar Capacitors KTA 33 kV	Increase reactive support in Far North	Committed (APR 2008)
	New 2nd 110/33 kV 40 MVA supply transformer at Te Matai	Increase capacity	Committed (APR 2008)
	New 3rd 50 Mvar Capacitor at Hepburn Road 110 kV	NIGUP	Committed (APR 2008)
	New 3rd & 4th 50 Mvar Capacitor at Penrose 110 kV	NIGUP	Committed (APR 2008)
	New 2 x 100 Mvar Capacitors at Otahuhu 220 kV	NIGUP	Committed (APR 2008)
	New 220 kV switching station at Drury	NIGUP	Committed (APR 2008)
	A new double circuit 400 kV line (operated at 220 kV) from WKM to ORM and two 220 kV cables from ORM to PAK. ARI–PAK 110 kV circuit removed. PAK on 220 kV. Existing OTA–PAK 110 kV bonded circuit now operated as double OTA–PAK 220 kV circuits. PAK 33 kV load moved to PAK 220 kV bus. PAK–PEN 110 kV circuit removed and PAK 110 kV bus removed.	NIGUP	Committed (APR 2008)
	Bus the 220 kV ISL–TWZ circuit at ASB	Improve post-contingent voltage stability Waitaki–Canterbury	Committed (APR 2008)
	New 75 Mvar Capacitor at Islington 220 kV bus	Improve post-contingent voltage stability	Committed (APR 2008)
	New -75/+100 Mvar SVC at Islington 220 kV	Improve post-contingent voltage stability	Committed (APR 2008)
	New +/- 40 Mvar SVC at Kikiwa 220 kV	Improve post-contingent voltage stability	Committed (APR 2008)
	Replace both 220/33 kV supply transformers at Invercargill with 120 MVA each	Increase capacity	Committed (APR 2008)

Comment [B1]: Is this correct?

Year	Augmentation	Reason	Status
	New 3rd 110/33 kV 30 MVA supply transformer at Hawera	To supply Kupe	Committed (APR 2008)
	Replace both 66/11 kV supply transformers at Kaiapoi with 40 MVA each	Increase capacity	Committed (APR 2008)
	New 3rd Cromwell 220/110/33 kV 150/150/50 MVA interconnecting transformer (and parallel the two existing ICTs); new 3rd Frankton 110/33 kV 85 MVA supply transformer (and parallel the two existing supply transformers)	Increase capacity	Committed (APR 2008)
	New 2nd DOB–RFT circuit and 2nd DOB 110/66 kV 75 MVA interconnecting transformer Add new 14 Mvar capacitor at HKK 11 kV bus	Improve transmission reliability and voltage support in the West Coast	TP West Coast proposal (approved)

Table 37 Common potential opportunities transmission augmentations

Year	Augmentation	Reason	Status	Indicative Cost
2007	Uprate KMO–TRK circuits 1 and 2 to 146/120 MVA (to reflect zebra 50C constructed at 220 kV operated at 110 kV)	Increase thermal capacity within Bay of Plenty	Modelled by SSG	N/A
	Change ratings of circuits (110 kV HEP–ROS 1and2, MNG–OTA 1and2, OTA–PAK 1, OTA–PEN 2, PAK–PEN 1and 220 kV OTA–PEN 5and6)	North Auckland and Northland GUP (Attachment B, Appendix A)	Modelled by SSG	N/A
	Uprate MOK–WKM 110 kV line to 152/152 MVA	Overload due to high Mokai generation	Modelled by SSG	N/A
2012	2 x 51 Mvar Synchronous Compensator OTA (bringing the total OTA compensator capacity to 3 x 31 + 2 x 51Mvar)	Increase reactive support in UNI	Modelled by SSG	$20m
	Increase OTA–HEN and OTA–SWN–HEN 220 kV circuits to 984/938 MVA	NAaN assumed max limit	Modelled by SSG	N/A
	Uprate BPE–TKU 220 kV circuits 1and 2 to 335/307 MVA	2005 GUP	Modelled by SSG	$5–$10m (Band B, T Grid NZ)
	Switch in MDN T2 and condenser, and switch out MDN T3	Repair T2 for condenser reactive support	Modelled by SSG	N/A
	Nitrogen reconductor HAY–MLG 110 kV circuits 1 and 2 to 134/126 MVA	Overload on loss of parallel circuit	Modelled by SSG	$3m
	Thermally upgrade 110 kV KMO–TGA line (KMO–TGA and KMO–PKE–TGA circuits) to 105/96 MVA	Increase thermal capacity to Tauranga, and improve voltage at Mount Maunganui and Tauranga	Under progress (http://www.gridnewzealand.co.nz)	$5m (Band A, TP A 2008)
	Replace WIL 220/110 kV T8 with new 200 MVA interconnecting transformer	Alleviate overloading of existing Wilton T8	Modelled by SSG	$4m

Year	Augmentation	Reason	Status	Indicative Cost
	Replace WKM 220/110/33 kV T8 with new 150 MVA interconnecting transformer	Alleviate overloading of existing Whakamaru T8 interconnecting transformer particularly when Mokai is generating at peak	Modelled by SSG	$4m
	Replace MPE T1 (10 MVA) interconnecting transformer with a new 110/50 kV 30 MVA interconnecting transformer	T1 overload on loss of parallel T3 (30 MVA)	Modelled by SSG	$1m
	Add new 3rd GIS 110/50 kV 30 MVA supply transformer	Alleviate overloading on existing GIS transformers at high-demand periods	Modelled by SSG	$1m
	Thermally upgrade 110 kV circuits around OAM–BPT–WTK–GNY–STU to 101/92 MVA and add capacitors	Increase thermal capacity to Oamaru area	TP preferred project	$4m
	Shift load from ISL 66 kV to BRY 66 kV	Overloading of ISL 220/66 kV interconnecting transformer during N-1 contingencies	Modelled by SSG	NA
	Uprate BRY 220/66 kV T5 and T6 interconnecting transformers to 150MVA Add new 3rd BRY 220/66 kV 150 MVA interconnecting transformer	Overload on loss of parallel transformer To accommodate shifting of ISL 66 load to BRY 66 kV bus	TP APR 2008 (section 18.6.1)	$5m–$10m (Band B, TP APR 2008)
	Added new 3rd 16 kV bus at Benmore with new 3rd 220/16 kV interconnecting transformer, two generators shifted to new 16 kV bus	To reduce overloading on interconnecting transformers	Modelled by SSG	$6m

Year	Augmentation	Reason	Status	Indicative Cost
2017	Pole 1 Upgrade to new thyristor pole on Haywards and Benmore 220 kV buses, filters doubled on these buses	First stage of Pole 1 upgrade	Modelled by SSG	$555m
	One PEN–HOB–WRU–ALB 220 kV 543 MVA cable plus HOB and WRU GXPs New 1st HOB 220 kV to LST 110A 338/318/250 MVA interconnecting transformer Move WRU 33 kV bus and load to 220 kV bus First PAK–PEN 220 kV 667 MVA cable	Overloading on ALB–HEN circuits on loss of ALB T4, overload on HEN T1 and T5 on loss of parallel transformer Overloading on OTA–PEN 220 kV circuits 5 and 6 on loss of parallel cct	First part of North Auckland and Northland GUP proposal by TP	$456m
	Duplex WKM–ATI–OHK–WRK 220 kV circuits from Simplex Goat 90 deg (358/333 MVA) to Duplex Goat 80 deg (670/614 MVA)	Overload on loss of PPT–WKM 220 kV circuit	Modelled by SSG	$11m
	Duplex WRK–PPI–WKM 220 kV circuits from Simplex Zebra 100 deg (448/421 MVA) to Duplex Zebra 75 deg (765/695 MVA)	Overload on loss of ATI–OHK–WRK 220 kV circuits	Modelled by SSG	$8m
	Nitrogen reconductor PNI–TKR 110 kV circuit 1 and 2 to 134/126 MVA	Overload on loss of parallel circuit	Modelled by SSG	$2m
	Kaitimako at 220 kV, TRK–KMO 110 kV circuits now operated at 220 kV, add two new 220/110 kV 200 MVA interconnecting transformers at KMO	Transmission security to Kaitimako	TP APR 2008 (section 11.6.2)	$40m
	Intertrip taking out OTA–PEN 110 kV circuit 2 on loss of Penrose 220/110 kV T10	Overload of OTA–PEN 110 kV circuit 2 on loss of Penrose 220/110 kV T10	NAaN GUP proposal (Attachment B) and TP APR 2008 (section 9.6.6)	N/A

Year	Augmentation	Reason	Status	Indicative Cost
2022	Split ISL 66 kV bus: Add 3 × 200 MVA 220/66 kV interconnecting transformers (to supply each 66 kV bus with 3 transformers)	Increase thermal capacity from 220 kV–66 kV in the Canterbury region 66 kV bus split at ISL to limit fault level	Modelled by SSG	$20m
	-75/+150 Mvar SVC at Ashburton	Reactive support for Waitaki–Islington transmission	Modelled by SSG	$15m
	Uprate ROT–TRK 110 kV circuits 1 and 2 to 100/90 MVA	Overload on loss of parallel circuit	TP APR 2008 (section 11.6.7)	N/A
	Add new 4th 200 MVA HAY interconnecting transformer	Overload on loss of parallel interconnecting transformer	Modelled by SSG	$4m
	Add new 5th OTA 220/110 kV 200 MVA interconnecting transformer (3rd ICT in parallel with T4 and T2)	Overload on loss of parallel interconnecting transformer	Modelled by SSG	$4m
	New 4th submarine cable 350 kV 500 MW for HVDC link	Increase HVDC capacity	Modelled by SSG	$97.5m
2027	Add new 3rd HEN 200 MVA 220/110 kV interconnecting transformer	Overload on loss of parallel interconnecting transformer	Modelled by SSG	$4m
	Nitrogen reconductor HEN–HEP 110 kV 1,2,3,4 circuits to 134/126 MVA	Overload on loss of parallel circuit	Modelled by SSG	$4m
	Add new 30 Mvar capacitors at WHU 110 kV bus	Improve voltage in area	Modelled by SSG	$2m
	Duplex/Reconductor Lower West Coast 66 kV circuits, including: DOB–GYM/GYM–KUM/HKK–KUM/HKK–OTI/KUM –OTI	Overloads on contingent events in area	Modelled by SSG	$10m
2032	Nitrogen reconductor KMO–TGA, KMO–MTM, KMO–PKE, PKE–TGA, PKE–MTM 110 kV circuits to 134/126 MVA	Overload on loss of parallel circuit	Modelled by SSG	$5m
	Add new 2x15 Mvar capacitors at PRM 110 kV buses	Improve voltage in area	Modelled by SSG	$2m
	Add new 3rd HAM-WHU 110 kV circuit rated at 167/154 MVA	Overload on loss of parallel circuit	TP APR 2008 (section 10.6.5)	$10m - $20m (Band C, TP APR 2008)
	Add new 40 Mvar capacitors at ROT 110 kV bus and 60 Mvar capacitors at KMO 110 kV bus	Improve voltage in area	Modelled by SSG	$5m
2037	No common modelled augmentations			

Table 38 MDS1—Additional transmission augmentations

Year	Augmentation	Reason	Status	Indicative Cost

Year	Augmentation	Reason	Status	Indicative Cost
2012	No additional augmentations			
2017	Nitrogen reconductor ARI–HAM 110 kV circuit 1 and 2 to 134/126 MVA	Overload on loss of parallel circuit	Modelled by SSG	$14m
2022	New 2nd WKM–ATI–OHK–WRK line rated 670/614 MVA	Increase thermal capacity in the Wairakei Ring region	Modelled by SSG	$20m–$50m (Band I APR 2008)
	Nitrogen reconductor MPE–KOE 110 kV circuits 1 and 2 to 134/126 MVA	Overload on loss of parallel circuit	Modelled by SSG	$17m
	Duplex ROX–NSY–LIV 220 kV circuit from Simplex Goat 50 deg (247/202 MVA) to Duplex Goat 50 deg (493/404 MVA)	Increase thermal capacity Otago–Waitaki	TP provisional project	$28m
	Thermal upgrade of both AVI–BEN 220 kV circuits (Simplex Goat) from 50 deg (247/202 MVA) to 75 deg (323/292 MVA)	Increase thermal capacity through Waitaki Valley	TP provisional project	$2m
2027	Add new OTA–WIR 110 kV cable and new 3rd WIR 110/33 kV supply transformer	Overload on loss of parallel circuit	Modelled by SSG	$34m
	Nitrogen reconductor KIN–LFD–TRK 110 kV circuits 1 and 2 to 134/126 MVA	Overload on loss of parallel circuit	Modelled by SSG	$17m
	Load shift from Liverpool Street to Hobson Road (all load).	Overload on OTA–PEN 110 kV circuit on contingency (220 kV circuits around OTA and PEN T10)	Modelled by SSG	N/A
	Add new 4th BPE 220/110 kV 50 MVA interconnecting transformer	Overload on loss of parallel interconnecting transformer	Modelled by SSG	$4m
	Thermal duplexing of COL–HOR 1 and 2 circuits to 60.8/70.4 MVA	Thermal overloading N security	Modelled by SSG	$15m

Year	Augmentation	Reason	Status	Indicative Cost
2032	Change ORM–PAK cables to forced cooling at 1115 MVA	Overload on loss of parallel cable	TP 400 kV project	$8.5m
	Add a new 3rd MNG–OTA 110 kV circuit (cable)	Overload on loss of parallel circuit	Modelled by SSG	$29m
	Thermal upgrade of midsection (50 deg) of the CML–TWZ 220 kV circuits so both circuits become rated as Single Chukar at 75 deg (626/569 MVA)	Increase thermal capacity Otago–Waitaki	Modelled by SSG	$2m
2037	Add second PAK–PEN 220 kV 667 MVA cable	OTA–PEN 220 kV circuits 5 and 6 and OTA–PEN 110 kV circuit 2 overload on loss of first PAK–PEN cable	Second part of NAaN GUP proposal	$60.5m
	Nitrogen reconductor ARI–BOB 110 kV circuit to 134/126 MVA	Overload in base case	Modelled by SSG	$18m
	Nitrogen reconductor HAM–WES–BOB 110 kV circuits 1 and 2 to 134/126 MVA	Overload on loss of parallel circuits	Modelled by SSG	$23m
	Nitrogen reconductor MNG–ROS 110 kV circuits 1 and 2 to 134/126 MVA	Overload on loss of parallel circuit	Modelled by SSG	$4m
	Add a new 3rd ARI–HAM 110 kV circuit	Overload on loss of parallel circuits	Modelled by SSG	$24m
	Change PEN reactor from 17.5 ohm to 12 ohm	To increase loading on the Auckland cable and reduce loading on parallel 220 kV circuits	Modelled by SSG	N/A
	Add new 6th OTA 220/110 kV 250 MVA interconnecting transformer (3rd ICT in parallel with T3 and T5)	Overload on parallel interconnecting transformer	Modelled by SSG	$4m

Table 39 MDS2—Additional transmission augmentations

Year	Augmentation	Reason	Status	Indicative Cost
2012	No additional augmentations			
2017	No additional augmentations			
2022	Load shift from Liverpool Street to Hobson Road (all load)	Overload on OTA–PEN 110 kV circuit on contingency (220 kV circuits around OTA and PEN T10)	Modelled by SSG	N/A
	Additional new 2nd 200MVA PEN 220/110 kV interconnecting transformer	Overload on loss of parallel interconnecting transformer.	Modelled by SSG	$4m
	Nitrogen reconductor 110 kV ARI–HAM circuits to 134/126 MVA	Overload on loss of parallel circuit	Modelled by SSG	$14m
	Duplex ROX–NSY–LIV 220 kV circuit from Simplex Goat 50 deg (247/202 MVA) to Duplex Goat 50 deg (493/404 MVA)	Increase thermal capacity Otago–Waitaki	Modelled by SSG	$28m
2027	Add new OTA–WIR 110 kV cable and new 3rd WIR 110/33 kV supply transformer	Overload on loss of parallel circuit	Modelled by SSG	$34m

Year	Augmentation	Reason	Status	Indicative Cost
2032	Additional new 6th 200MVA OTA 220/110 kV interconnecting transformer (3rd ICT in parallel with T3 and T5)	Overload on loss of parallel interconnecting transformer	Modelled by SSG	$4m
	Add second PAK–PEN 220 kV 667 MVA cable	OTA–PEN 220 kV circuits 5 and 6 and OTA–PEN 110 kV circuit 2 overload on loss of first PAK–PEN cable	Second part of NAaN GUP proposal	$60.5m
	Cross-harbour PEN reactor changed from 0.036pu reactance to 0.02pu reactance	Allows more power flow on the 220 kV network, alleviating overloads on the 110 kV system	Modelled by SSG	N/A
	Additional new 3rd OTA–MNG 110 kV circuit (cable)	Overload on loss of parallel circuit	Modelled by SSG	$29m
	Additional new 4th 200MVA BPE 220/110 kV interconnecting transformer	Overload on loss of parallel interconnecting transformer	Modelled by SSG	$4m
	Thermal upgrade of midsection (50 deg) of the CML–TWZ 220 kV circuits so both circuits become rated as Single Chukar at 75 deg (626/569 MVA)	Increase thermal capacity Otago–Waitaki	Modelled by SSG	$2m
2037	Nitrogen reconductor MPE–KOE 110 kV circuits 1 and 2 to 134/126 MVA	Overload on loss of parallel circuit	Modelled by SSG	$17m
	Switch back in MDN 3rd 220/110 kV 100MVA interconnecting transformer	Overload on loss of parallel interconnecting transformer	Modelled by SSG	N/A

Table 40 MDS3—Additional transmission augmentations

Year	Augmentation	Reason	Status	Indicative Cost
2012	No additional augmentations			
2017	No additional augmentations			
2022	Add new OTA–WIR 110 kV cable and new 3rd WIR 110/33 kV supply transformer	Overload on loss of parallel circuit	Modelled by SSG	$34m
	Load shift from Liverpool Street to Hobson Road (all load).	Overload on OTA–PEN 110 kV circuit on contingency (220 kV circuits around OTA and PEN T10)	Modelled by SSG	N/A
2027	*Tiwai Decommissioned*			
	Duplex ROX–NSY–LIV 220 kV circuit from Simplex Goat 50 deg (247/202 MVA) to Duplex Goat 50 deg (493/404 MVA)	Increase thermal capacity Otago–Waitaki	SSG modelled project	$28m
2032	Add second PAK–PEN 220 kV 667 MVA cable	OTA–PEN 220 kV circuits 5 and 6 and OTA–PEN 110 kV circuit 2 overload on loss of first PAK–PEN cable	Second part of NAaN GUP proposal	$60.5m
	Nitrogen reconductor MPE–KOE 110 kV circuits 1 and 2 to 134/126 MVA	Overload on loss of parallel circuit	Modelled by SSG	$17m
	Add a new 3rd MNG–OTA 110 kV circuit (cable)	Overload on loss of parallel circuit	Modelled by SSG	$29m
	Nitrogen reconductor 110 kV ARI–HAM circuits to 134/126 MVA.	Overload of remaining circuits on the loss of one circuit	Modelled by SSG	$14m
	Additional new 4th 200MVA BPE 220/110 kV interconnecting transformer	Overload on loss of parallel interconnecting transformer	Modelled by SSG	$4m
	New 220 kV double circuit transmission line from Roxburgh to Twizel. Modelled as parallel line to the ROX–CYD–CML–TWZ line.	Overload on transmission lines out of Southland upon line outage	Modelled by SSG	$250m
	Reactor installed at Invercargill on the INV– EDN circuit to limit 110 kV northward power flow	Solves overload issues between GOR and ROX 110 kV system	Modelled by SSG	$1m
2037	Second PEN–HOB–WRU–ALB 220 kV cable	Overload on parallel circuits	Second part of Northland and North Auckland GUP proposal	$110m (Attachment NAaN GUP)

Year	Augmentation	Reason	Status	Indicative Cost
	Additional new 6th 200MVA OTA 220/110 kV interconnecting transformer (3rd ICT in parallel with T3 and T5)	Overload on loss of parallel interconnecting transformer.	Modelled by SSG	$4m
	New transmission line required through the Wairaki ring. Modelled as 2nd WRK–OHK–ATI–WKM 220 kV single circuit	Overload on Wairaki ring upon several contingencies	Modelled by SSG	$50m

Table 41 MDS4—Additional transmission augmentations

Year	Augmentation	Reason	Status	Indicative Cost
2012	No additional augmentations			
2017	No additional augmentations			
	Add new OTA–WIR 110 kV cable and new 3rd 110/33 kV supply transformer at WIR	Overload on loss of parallel circuit	Modelled by SSG	$34m
	Switch back in MDN 3rd 220/110 kV interconnecting transformer	Overload on loss of parallel interconnecting transformer	Modelled by SSG	N/A
2027	Load shift from Liverpool Street to Hobson Road (all load)	Overload on OTA–PEN 110 kV circuit on contingency (220 kV circuits around OTA and PEN T10)	Modelled by SSG	N/A
	Nitrogen reconductor ARI–HAM 110 kV circuits 1 and 2 to 134/126 MVA	Overload on loss of parallel circuits	Modelled by SSG	$14m
	Duplex ROX–NSY–LIV 220 kV circuit from Simplex Goat 50 deg (247/202 MVA) to Duplex Goat 50 deg (493/404 MVA)	Increase thermal capacity from Otago to Waitaki	TP provisional project	$28m
	Thermal uprate of INV–NMA 220 kV circuit to 620/557 MVA	Overload on loss of parallel circuit	Modelled by SSG	$1m
2032	Nitrogen reconductor KIN–LFD–TRK 110 kV circuits 1 and 2 to 134/126 MVA	Overload on loss of parallel circuit	Modelled by SSG	$17m
	Nitrogen reconductor MPE–KOE 110 kV circuits 1 and 2 to 134/126 MVA	Overload on loss of parallel circuit	Modelled by SSG	$17m
	Remove transducer limitation (455/455 MVA) on OTA–PEN 220 kV circuits 5 and 6 (492/469 MVA)	Overload on loss of parallel circuit	Modelled by SSG	N/A
	Thermal upgrade of midsection (50 deg) of the CML–TWZ 220 kV circuits so both circuits become rated as Single Chukar at 75 deg (626/569 MVA)	Increase thermal capacity Otago–Waitaki	SSG modelled project	$2m

Year	Augmentation	Reason	Status	Indicative Cost
2037	New second PAK–PEN 220 kV 667 MVA cable	OTA–PEN 220 kV circuits 5 and 6 and OTA–PEN 110 kV circuit 2 overload on loss of first PAK–PEN cable	Second part of NAaN GUP proposal	$60.5m
	New second WKM–ATI–OHK–WRK 220 kV circuit at 670/614 MVA	Increase thermal capacity in the Wairakei Ring region	Modelled by SSG	$50m
	Add new 3rd MNG–OTA 110 kV circuit (cable)	Overload on loss of parallel circuit	Modelled by SSG	$29m
	Add new 4th BPE 220/110 kV 50MVA interconnecting transformer	Overload on loss of parallel interconnecting transformer	Modelled by SSG	$4m
	Add new 6th OTA 220/110 kV 250 MVA interconnecting transformer (3rd ICT in parallel with T3 and T5)	Overload on loss of parallel interconnecting transformer	Modelled by SSG	$4m

Table 42 MDS5—Additional transmission augmentations

Year	Augmentation	Reason	Status	Indicative Cost
2012	No additional augmentations			
2017	No additional augmentations			
2022	Nitrogen reconductor ARI–HAM 110 kV circuit 1 and 2 to 134/126 MVA	Overload on loss of parallel circuit	Modelled by SSG	$14m
	Duplex ROX–NSY–LIV 220 kV circuit from Simplex Goat 50 deg (247/202 MVA) to Duplex Goat 50 deg (493/404 MVA)	Increase thermal capacity Otago–Waitaki	Modelled by SSG	$28m
2027	Add new OTA–WIR 110 kV cable and new 3rd WIR 110/33 kV supply transformer	Overload on loss of parallel circuit	Modelled by SSG	$34m
	Load shift from Liverpool Street to Hobson Road (all load)	Overload on OTA–PEN 110 kV circuit on contingency (220 kV circuits around OTA and PEN T10)	Modelled by SSG	N/A
	Switch back in MDN 3rd 220/110 kV 100MVA interconnecting transformer	Overload on loss of parallel interconnecting transformer	Modelled by SSG	N/A
2032	Nitrogen reconductor MPE–KOE 110 kV circuits 1 and 2 to 134/126 MVA	Overload on loss of parallel circuit	Modelled by SSG	$17m
2037	Add a second PAK–PEN 220 kV 667 MVA cable	OTA–PEN 220 kV circuits 5 and 6 and OTA–PEN 110 kV circuit 2 overload on loss of first PAK–PEN cable	Second part of NAaN GUP proposal	$60.5m
	Add a new 3rd MNG–OTA 110 kV circuit (cable)	Overload on loss of parallel circuit	Modelled by SSG	$29m
	Further upgrade (thermal) of the HEN–HEP 110 kV 1,2,3,4 circuits to around 160/151 MVA	Overload on loss of parallel circuits	Modelled by SSG	$1m

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