TRANSPOWER

Lower South Island
Reliability Investment Proposal

Attachment B

Analysis assumptions and methodology

May 2010

Document Revision Control

Document Number/Version	Description	Date
001/Rev	Attachment B – Analysis Assumptions and Methodology, Revision A	May 2010

Contents

1 Introduction

This document describes the assumptions and methodologies used in the Grid Investment Test (GIT) analysis for the Lower South Island Reliability Investment Proposal, the results of which are presented in Attachment A.

Under Rule 13.3 of Section III, Part F of the Rules, the Commission must, in relation to any proposed reliability investment, publish a notice and provide an opportunity for designated transmission customers to comment on Transpower's proposed investment. The assumptions and methodologies described in this document are intended to facilitate the understanding required for those comments.

1.1 Assessment of proposals under the Rules

To determine the expected net market benefit of an option, Transpower has adopted certain input assumptions, parameters and market scenarios in its application of the GIT. A sensitivity analysis has also been undertaken to test the robustness of applying the GIT to the options.

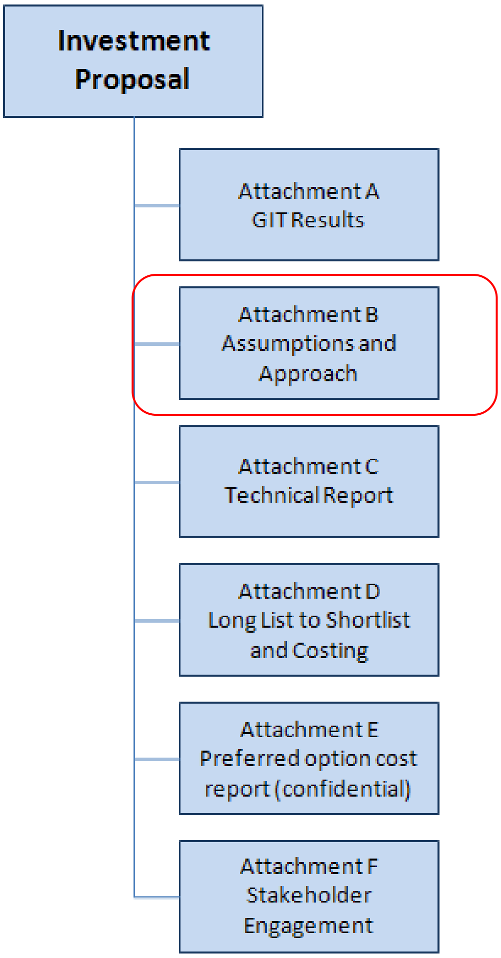
There are some areas where the Rules constrain Transpower's input or approach. Transpower has identified where this is the case in the relevant sections below.

1.2 Long-list and Short-list options

To develop a list of appropriate options for the potential investment proposal, Transpower consulted on a long list of options in April 2009. Following this consultation Transpower, upon considering the feedback, developed a short list of options to which the GIT is applied. Detail of the long list to short list process can be in Attachment D.

Document Structure

This document forms part of the Lower South Island Renewables Investment Proposal. The documentation is structured according to the following diagram:



1.3 Outline of this document

This document follows the structure below.

- Section 2 - approach to the application of the GIT
- Section 3 - market costs used in the GIT
- Section 4 - market benefits calculated
- Section 5 - sensitivity analysis
- Appendix A – Summary of assumptions
- Appendix B – LSI build plans
- Appendix C – Models and data
- Appendix D - Covec Demand Forecast

All references to the Rules in this document refer to Section III of Part F of the Electricity Governance Rules 2003 unless otherwise specified.

2 Approach to the application of the GIT

This section describes the economic approach Transpower has used for assessing the short-listed options in the GIT, including:

- the market development scenarios
- the modelling approach
- use of NPV analysis
- assessing a staged development plan and inclusion of modelled projects
- approach to calculating market costs and benefits
- the analysis period.

The GIT involves assessing the expected value of each short-listed option[1] against a Base Case. The Proposal is the option that maximises the expected net market benefit (or minimises the net market cost) compared with the other options.

The remaining options form the “alternative projects” to be considered in relation to the GIT[2]. Should the Electricity Commission grant approval for the Proposal, Transpower will be able to recover the cost through the transmission pricing methodology set out in the Electricity Governance Rules.

There is uncertainty inherent in the assumptions to be used in this analysis. In applying the GIT, Transpower has attempted to account for these uncertainties in a way that is appropriate and reasonable for the scale of analysis commensurate with the estimated capital expenditure required for the proposed investment.

2.1 The market development scenarios

The GIT requires Transpower to develop market development scenarios and analyse the base case and each short-list option against each scenario.[3] The market development scenarios utilise a set of generation drivers as inputs. These drivers include details of generation cost, timing, location, carbon charges, demand etc.

To date, the Electricity Commission has established the scenarios by using the drivers within its generation expansion model (GEM). These scenarios are set out in the Commission’s Statement of Opportunities (SoO) published in accordance with Rule 9. There are five scenarios within the SoO.

For this Proposal, Transpower has used the same base scenarios as those in the Lower South Island Renewables Grid Investment Proposal[4] but has updated some of the assumptions about new generation between 2010 and 2015. The key changes are as follows:

- MDS1: Lake Mahinerangi wind generation is now a staged investment of 40MW in 2011 and 93 MW in 2015
- MDS2: Lake Mahinerangi wind is built more slowly with 40 MW in 2011 and 160 MW in 2015, Project Hayes stage 1 is delayed from 2012 to 2015, Project Hayes stage 2 is delayed from 2013 to 2015 and reduced in size from 217 MW to 127 MW. Kaiwera Downs wind (240 MW) is built in the updated scenario. Project Hayes stage 3 is not built.
- MDS3: 40 MW of wind at Lake Mahinerangi in included at 2011.
- MDS4: 40 MW of wind at Lake Mahinerangi in included at 2011 and Manapouri Discharge is delayed from 2010 to 2012.
- MDS5: 40 MW of wind at Lake Mahinerangi in included at 2011 and Manapouri Discharge is delayed from 2010 to 2012.

[1] Refer to Attachment D for a detailed list of short listed options.
[2] Refer to the definition of “alternative projects” at clause 19, Schedule F4 of the Rules.
[3] Refer to definition of “market development scenarios” at clause 28 of Schedule F4, Part F of the Rules.
[4] These scenarios were based on the 2008 SoO scenarios. For full details of the LSI renewables scenarios, see http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/gup/2009/LSI/AttachmentB.pdf.

Full build plans can be found in Appendix B.

2.1.1 Demand Assumptions

The SoO demand data has been used as a basis for the analysis, however some amendments have been made to GXP forecasts drawing on more recent analysis by Covec Limited, an independent consultant. Covec Limited's LSI report of June 2010 can be found in Appendix D.

Subsequent discussions with stakeholders resulted in three changes to the Covec demand forecast:

(1) The growth in the Gore prudent values has been delayed by 2 years from 2010 on, i.e. 2012 has been set to the previous 2010 value, 2013 to the previous 2011 value, etc.

(2) The assumption is made that if the growth at Edendale and Brydone exceeds the capacity of the Edendale-Invercargill line (the N-1 capacity with the Gore-Brydone line out) then the excess will be managed at a distribution level by shifting load to Gore. This results in the Edendale and Brydone combined loads being capped at the level of capacity of the Edendale-Invercargill line.

(3) The prudent forecast at Tiwai has been increased by 5 MW per annum from 2015 to 2024 to a maximum of 690 MW.

The prudent and expected regional demand forecasts are shown in Table 2-1 below. Details on the GXP demand forecasts used can be found in Appendix A of Attachment C.

Table 2-1: Peak demand forecast for the LSI region (MW)

Year	Expected	Prudent
2009	1,086	1,133
2010	1,095	1,145
2011	1,104	1,177
2012	1,130	1,194
2013	1,141	1,213
2014	1,149	1,234
2015	1,157	1,252
2016	1,164	1,270
2017	1,172	1,288
2018	1,180	1,304
2019	1,159	1,316
2020	1,190	1,328
2021	1,196	1,339
2022	1,201	1,350
2023	1,207	1,361
2024	1,212	1,372
2025	1,218	1,378
2026	1,224	1,385
2027	1,229	1,391
2028	1,235	1,398
2029	1,241	1,405
2030	1,246	1,411
2031	1,251	1,419
2032	1,257	1,426

The prudent forecast has been used in the construction of the development plans (see Attachment D) to ensure the built network can meet peak demand under a high load growth scenario. The unserved energy model and resulting GIT analysis uses a combination of 70% of the expected and 15% of the prudent forecast results to reflect the differing probability of the forecasts eventuating.

The values of 70% expected and 15% prudent are estimated from the probability of each forecast occurring and the value of unserved energy that occurs under each forecast. The 15% remaining to make 100% represents a demand forecast level with a probability of exceedance on 90% which is assumed to have no unserved energy and therefore no value of unserved energy.

For a full explanation of the demand forecasts used in the calculation of unserved energy, please refer to Attachment A, GIT Results.

2.1.2 Carbon costs, technology trends, fuel costs and other inputs

Along with the generation list and demand assumptions, there are a number of other inputs used within the GIT analysis. These have largely been taken from the 2008 SoO. The following is a list of those assumptions.

- Technology trends
- Fuel costs and trends
- Carbon sequestration factors and costs
- Fuel resource limits (limits the availability of gas and LNG in the modelling)
- LNG prices
- Plant efficiency adjustments
- Renewables capacity targets
- Carbon charge data
- Emission factors
- Adjustments to NZ peak demand
- Hydro output adjusters

2.1.3 Transpower's scenarios compared to the SoO scenarios

The figures in Appendix B illustrate the differences between Transpower's and the SoO scenarios in the LSI region. They show that Transpower's scenarios are generally associated with higher levels of generation in the LSI with the exception of scenarios 1 and 4 where the SoO scenarios have higher levels of generation towards the end of the analysis period.

As is evident from the figures, the North Bank Tunnel is built in all of Transpower's scenarios and in none of the SoO scenarios. There are different views on the costs of this project between Meridian, the proponent of this project, and the Electricity Commission, where the Commission have used a cost almost twice that quoted by Meridian in construction of the SoO scenarios. The lower cost provided by Meridian has been adopted for this analysis.

2.1.4 Conclusion on reasonableness of generation expansion plans

Transpower considers that it is reasonable to use the alternative plans constructed as the basis for the analysis given that it:

- uses more recent data than that used by the Commission in the construction of the SoO scenarios
- fixes near term generation to better reflect current options being considered by generators.

The scenarios also provide a wide range of development in the LSI region. Commission approval of alternative scenarios

Transpower considers the updated market development scenarios are more appropriate than the possible future scenarios outlined in the SoO. Transpower seeks a determination from the Commission for the purposes of clause 6.1 of the GIT that the scenarios are more appropriate than the use of the SoO scenarios.

2.1.5 Generation scenario weightings

Transpower has used equal weighting for the five scenarios (the same as the weighting for the scenarios set out in the SoO).

2.2 The modelling approach

Transpower has utilised the SDDP model to assess dispatch and loss benefits of each development plan.

Reliabilty costs have been assessed in an Excel model which utilises inputs from the power system analysis studies.

2.2.1 SDDP

The operational benefits arising from implementing each short-list option have been assessed using the SDDP optimal dispatch model.

SDDP is a stochastic generation dispatch model used for assessing national generation costs based on a distribution of hydro inflows into the storage lakes and thermal fuel prices (which vary by MDS). In this project we have utilised SDDP to model each stage of all the short-list options (including the Base Case). The difference in the average fuel and variable operating costs between the Base Case and each short-list option is the benefit attained by upgrading lines.

The model has been run in monthly time steps, using 5 load blocks within each month, from 2010 to 2042. SDDP runs are split into 2 components, an optimisation which determines the value of water for hydro storage and a simulation which determines the dispatch in each time step using the information from the optimisation. The optimisation component balances demand and generation in each island assuming no intra-island transmission network. The HVDC is modelled as an interconnector between the North and South Islands. Hydro storage levels and outflows are optimised against the cost of thermal fuel to produce hydro release policies that are passed to the simulation component of SDDP. The simulation in SDDP uses the hydro release policy information from the optimisation to determine least cost dispatch in each time step. The simulation models the transmission network within each island but only enforces line limits and group security constraints in the LSI region and for the HVDC link.

Details of the SDDP studies can be found in Appendix B of Attachment A, GIT Results report. All the SDDP files are available upon request.

2.2.2 Reliability cost model

The value of expected unserved energy is calculated in two separate models. The first considers unserved energy from N-1 contingencies and with all assets in service. The second model considers unserved energy from a contingency occurring during a maintenance outage during planned maintenance outages.

- The N-1 contingency model firstly identifies if the 110 kV network in Southland should be split to avoid overloading. Once the network configuration is known a number of contingencies are tested to identify the amount and cost of expected unserved energy under each outage scenario. This analysis is undertaken on the reference only as the development plan options have N-1 security and no load will be lost due to a single contingent event.
- The contingent event during maintenance outage model calculates the expected unserved energy due to a contingency occurring during a planned maintenance outage. This analysis considers only the summer period as it is assumed that maintenance will only occur during this time period. The expected unserved energy (MWh) is calculated and historical outage data gives the probability of the contingency occurring during a maintenance outage.

In both parts of the reliability cost model an additional cost is calculated as a 'per event' cost for unserved energy at Edendale. Edendale is the location of Fonterra's largest dairy processing plant. The VoLL used for this GXP has a per MWh component and an event cost to better reflect the costs incurred by Fonterra during a loss of supply.

Further detail can be found in Attachment A, GIT Results.

2.3 Net present value versus real options analysis

Clause 13 of Schedule F4 requires that:

> *"Either standard net present value analysis or real options analysis must be applied in assessing the **expected net market benefit** of a **proposed investment** or **alternative project**….."*

Transpower considers that a real options approach is not practicable, and is at a level of complexity unnecessary for this Proposal. Power system analysis is complex and time consuming, and the integration of the power systems analysis required to compare the alternative development plans with the economic modelling of costs and benefits in a real option setting would not be practicable. As such, Transpower has utilised an NPV approach for this Proposal.

2.4 Discount rates

Clause 14 of Schedule F4 of the Rules requires that the discount value used in present value calculation be:

> *14.1.the discount rate determined by the **Board**, from time to time, for the purposes of this **grid investment test**; or*
>
> *14.2. if the **Board** has not determined a discount rate for the purposes of clause 14.1, a discount rate of, or equivalent to, a pre-tax real rate of 7%*

Accordingly, Transpower uses the required pre-tax, real rate of 7%, with sensitivities of 4% and 10%, in its GIT analysis.

2.5 Analysis in current or future dollars

The economic analysis has been undertaken in 2010 dollars. The approval cost has been calculated based on commissioning year dollars.

2.6 Analysis period

Clause 27 of Schedule F4 of the Rules requires that in applying the GIT, the market benefit of a proposed investment or alternative project be assessed:

> *"…over a period of 20 years from the commissioning date (unless significant **market benefits** or **costs** are expected to arise from the **proposed investment** or **alternative project** after that time, in which case the then present-value of any future benefits may also be included…)"*

The generally accepted approach in cost benefit analysis is used to assess the cash flows arising from costs and benefits over the full economic/useful life of a proposed investment.

Transmission lines have an expected life of 30 or more years and it is expected that there will be significant benefits arising from any upgraded transmission circuits during the period between 20 years and the end of its expected life. In order to assess these additional benefits SDDP has been run to 2042.

The reliability costs have been calculated over a 20 year period as additional investment after this time give the N-1 security and no unserved energy will occur during a contingent event. Additional years of analysis past 20 years would not have a material effect on the costs calculated.

3 Market costs

The definition of "cost" for the purpose of the GIT analysis is set out in clause 23 of Schedule F4 of the Rules.

The costs used in the short-list options are expected costs. Expected costs represent the estimated cost (referred to as the P50 cost) plus a contingency for accuracy in the scope of the proposal or alternative options (referred to as scope allowance). This allows for unexpected variations in the design scope and a standard allowance, for items not considered in the design. In this respect, expected costs are more than a P50 estimate and represent the maximum cost of the short-list option, excluding financial contingencies such as exchange and commodity cost variations, and interest during construction.

For the purposes of a GIT application, Transpower considers that costing accuracy needs to be sufficient to be able to:

(1) distinguish between the net market benefits of the options being considered. If the difference in the net market benefits between two options is small, then it may be necessary to further refine the costs of one or both of them (or the benefits)

(2) determine that the benefits are greater than the costs involved. However, for the purpose of determining whether an option has satisfied the GIT there is no merit in refining costs beyond the margin of error in the overall net market benefit calculation.

Consequently, for the purposes of applying the GIT, Transpower has costed options to a level of accuracy that:

- allows for the difference in the net benefit of each option to be identified
- is sufficiently robust for a decision to be made on which option should be put forward as the proposal.

Although it is slightly inconsistent to use expected costs for transmission and estimated costs for generation and all market benefits, it is a conservative approach which will tend to underestimate the value of the expected net market benefit of any short-listed options. Transpower considers that the rigour and comprehensiveness of this analysis is commensurate with the estimated capital expenditure required for the Proposal.

No contingency or equivalent is included in the market benefit calculation for scope allowance.

The cost categories considered in this analysis are as follows.

- Transmission costs for each transmission option
- Non-transmission alternative payments
- Statutory compliance costs
- Inflation costs
- Community care costs
- Interest during construction
- Exchange rates

Each of these are discussed below

3.1 Transmission costs

The process of costing a transmission solution is a process of refining the cost estimates over time, recognising there is a trade-off between cost accuracy and timely and efficient investment decisions. This is similar to any cost estimation process where, as more detailed design is undertaken, costs become more refined.

The costs used and the costing approach for the Proposal are set out in detail in Attachment D.

As noted, the approach to the LSI Reliability Project has been to analyse the costs to an accuracy required to robustly differentiate between the options. Series capacitor costs have been based on a Solution Study Report; while the cost of new lines, shunt compensation, transformers and substation works have been assessed at a higher level. It is Transpower view that these costs have been presented at an appropriate level.

The transmission costs used in this Proposal have been summarised into the following components.

- Line and substation capital costs
- Property and easement costs
- Environmental costs
- Project management
- Operating and maintenance costs

Each of these factors is described below.

a. Line and substation capital costs

Transpower has considered the capital costs of the equipment that would be incurred prior to the commissioning of each option, including substation works, line works and any cable works required for each option. New transmission line costs are based on indicative costing corridors only.

b. Property and easement costs

Transpower has taken into account the probable range of property and easement costs as relevant for each short-listed option.

c. Environmental costs

The costs associated with undertaking all necessary environmental assessments and satisfying the requirements of the RMA and other environnmental legislation have been estimated and taken into account in the cost analysis. These costs include those incurred in determining routes/sites for Greenfield assets, assessments of impacts such as noise and visual effects and obtaining designations, resource consents and other approvals potentially required to undertake works contemplated in the short list of options.

d. Project management costs

Transpower has allowed for project management costs to reflect the cost of managing the design, construction and commissioning of works to be undertaken for each short-list option.

e. Operating and maintenance costs

Operating and maintenance costs over the operating life of each short-listed option are included in the analysis.

3.2 Statutory compliance costs and benefits

The relevant statutory costs have been identified and are included as necessary.

3.3 Inflation

The expected cost of each short-list option has been derived in real terms and the results are presented in dollars relative to the current year.

3.4 CommunityCare costs

In 2006, Transpower established its CommunityCare Fund, which recognises that Transpower needs to offset the impact on communities of major grid investment projects and contribute to communities where we operate, particularly those communities which accommodate Transpower assets which benefit the whole country. The CommunityCare Fund allocation is distinct from any costs associated with environmental mitigation required to satisfy RMA requirements.

The Fund has been developed along similar models used by other power companies in New Zealand and overseas and aims to ensure that the mitigation or benefit the community receives reflects the impact of Transpower's works in that community.

Transpower's community funding approach is aligned with project approval. The funding formula for new build and upgrades to existing lines is based on the type of activity and the relative impact on the community. Substation work is based on a percentage of the total value of the project.

For the LSI Reliability Investment Proposal $0.2m has been added to the approval amount.

When an Investment Proposal is approved by the Electricity Commission, community organisations in the affected area may apply to the CommunityCare Fund for nominated projects that meet specific funding criteria.

The CommunityCare Fund is managed in accordance with the guidelines established by the Office of the Auditor General (OAG).

3.5 Interest During Construction

Interest during construction has not been included in the GIT analysis, but is reflected in the approval cost calculation for the Proposal. The reason for this approach is that financing costs are not added within the GIT and it is incorrect to add them to discounted cashflow analysis.

In addition, IDC does not impact on the GIT results in that:

- it does not change the ranking of the options
- it does not impact on whether the expected net market benefits of the Proposal are greater than zero, as the market benefits of the Proposal substantially outweigh the market costs.

3.6 Exchange rate approach

Where costs have a foreign exchange component, Transpower has used an exchange rate determined by taking an average rate calculated over +/- 20 business days from 30 April 2010.

As the foreign exchange component can in some cases differ significantly between short-listed options, the exchange rate assumption may be significant and so Transpower has also undertaken a sensitivity run on the exchange rates using the 10 year average rates.

4 Market benefits

The GIT requires Transpower to analyse the market benefits of the options which will make up its short list. Market benefit for the purposes of the GIT is defined at clause 27 of Schedule F4 of the Rules.

To evaluate the economic benefits of the short-list options versus the Base Case the following key measures are used.

- Capital benefits
- Fuel cost benefits
- Greenhouse gas emission, spill and load shedding
- Competition benefits
- Other benefits

Each of these measures is discussed in more detail below.

4.1 Capital benefits

These are benefits in capital reductions or deferrals arising from reductions in the need for, or deferral of, new generation (modelled projects), or new transmission investment (either alternative projects or modelled projects).

Some of the capital expenditure savings result from a changing mix of new generation required.

4.2 Fuel cost benefits

Fuel cost benefits arise when a proposed transmission investment enables generation plants with lower fuel costs to be dispatched.

4.3 Greenhouse gas emission, spill and load shedding benefits

These are benefits from reductions in greenhouse gas emissions (valued at the carbon charge appropriate to the generation scenario), reductions in the amount of hydro spill and reductions in the amount of load shedding.

4.4 Competition benefits

Competition benefits can be included in the GIT under the Rules,[5] but due to the difficulty in estimating these and the resultant uncertainty over their magnitude, Transpower has not quantified competition benefits other than those already reflected in the generation expansion modelling. However, competition benefits are likely to favour the higher capacity options and are reflected in a qualitative assessment of the market service benefits for each option.

4.5 Other benefits

The GIT allows for the situation where a material market benefit (or cost) cannot be quantified. In such a situation, the direction of the market benefit and likely magnitude of the market benefit must be identified[6]. In this context Transpower has conducted a qualitative assessment of operational, market services, consumer and community related benefits.

[5] Clause 10 of Schedule F4, Part F of the Rules.
[6] Clause 9 of Schedule F4, Part F of the Rules.

5 Sensitivity analysis

The GIT provides that sensitivity analysis may be conducted to determine if the preferred investment is sufficiently robust. Transpower has conducted a sensitivity analysis for the Proposal in accordance with clause 17 of Schedule F4 of the Rules.

The treatment by Transpower of each of the items for sensitivity analysis as listed in clause 17 is considered below. Notably, the sensitivity calculations also need to be considered in light of the modelling approach that has been adopted. Table 5-1 details the sensitivities that have been considered in the analysis. Attachment A contains the results of the sensitivity analysis.

Table 5-1 - Sensitivity Analysis

Sensitivity	Value
Discount rate	4% and 10%
Capital cost	Included, Low 80%, high 120%
Value of expected unserved energy	Included, $10,000/MWh, $40,000/MWh inflated for 5 years at 3% and VoLL at Edendale @$25,000/MWh and $700,000 per incident
Forecast demand	Included –Prudent forecast (adjusted for Covec)
Property Costs	Included, 200%
Carbon charges	Included, low 80%, high 120% in addition to the variation between scenarios
Variations in the size, timing, location, and operating and maintenance costs	Not included as a sensitivity
Timing of decommissioned assets	No assets are being decommissioned and therefore not included.
Variation in hydrological inflow sequences	Included in base analysis and therefore not included as a sensitivity, modelled within SDDP analysis
Generator and demand side bidding strategies	Not included as a sensitivity, included in scenarios
Competition benefits	Not included

Appendix A Summary of Assumptions

The following table is a summary of the approach and the assumptions used in the analysis.

A.1 Approach and Assumptions

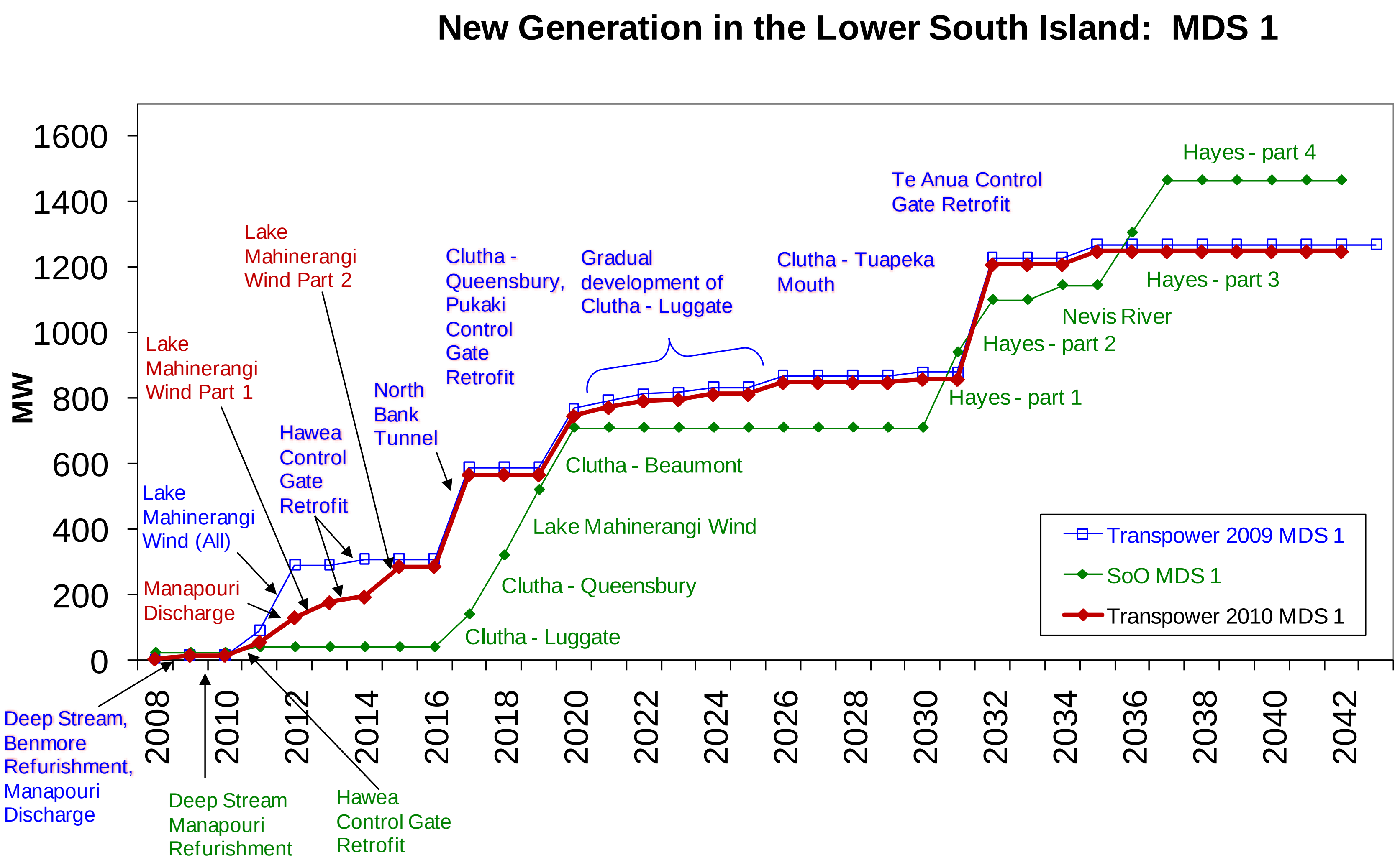
Item		Approach	
Type of Investment case		Reliability investment case.	
Market development scenarios (MDS)		5 Scenarios based on LSI Renewables Investment Proposal Scenarios	
Scenario weightings		Equally weighted.	
Analysis Period		20 years	
Discount rate		7%.	
Net present value or real options analysis		PV with scenarios	
Demand Forecast		2008 SoO, adjusted for Covec work in LSI, and Waitaki Valley.	
Analysis in current or future dollars		$2010	
Cost Accuracy		Thermal upgrades and reconductoring to SSR level, New Lines and substation works to HLR level.	
Approach to calculating market costs	Transmission costs	Line and Substation capital costs	Included
		Property and easement costs	Included
		Project management	Included
		Environmental costs	Included
		Operating and maintenance costs	Included
		Decommissioning costs	Not applicable.
	Generation costs	Capital	Based on Electricity Commission Scenarios and altered after consultation
		Fuel	Included
		Carbon Charges	Included
	Statutory compliance costs	Included	
	Inflation costs	Included, 3%	
	Community Care costs	Included where appropriate @ 0.5% of project costs.	
	Interest during construction	In approval amount but not in GIT.	
	Exchange rates	Average over +/- 20 business days, sensitivity on 10 average	
Approach to calculating market benefits	Reduction in capital costs	Not included	
	Capital benefits – capital cost of generation	Not included	
	Fuel costs and transmission losses	Included	
	Greenhouse gas emission, spill and load shedding	Included	
	Reliability benefits	Included	
	Operational benefits	Not included[7]	

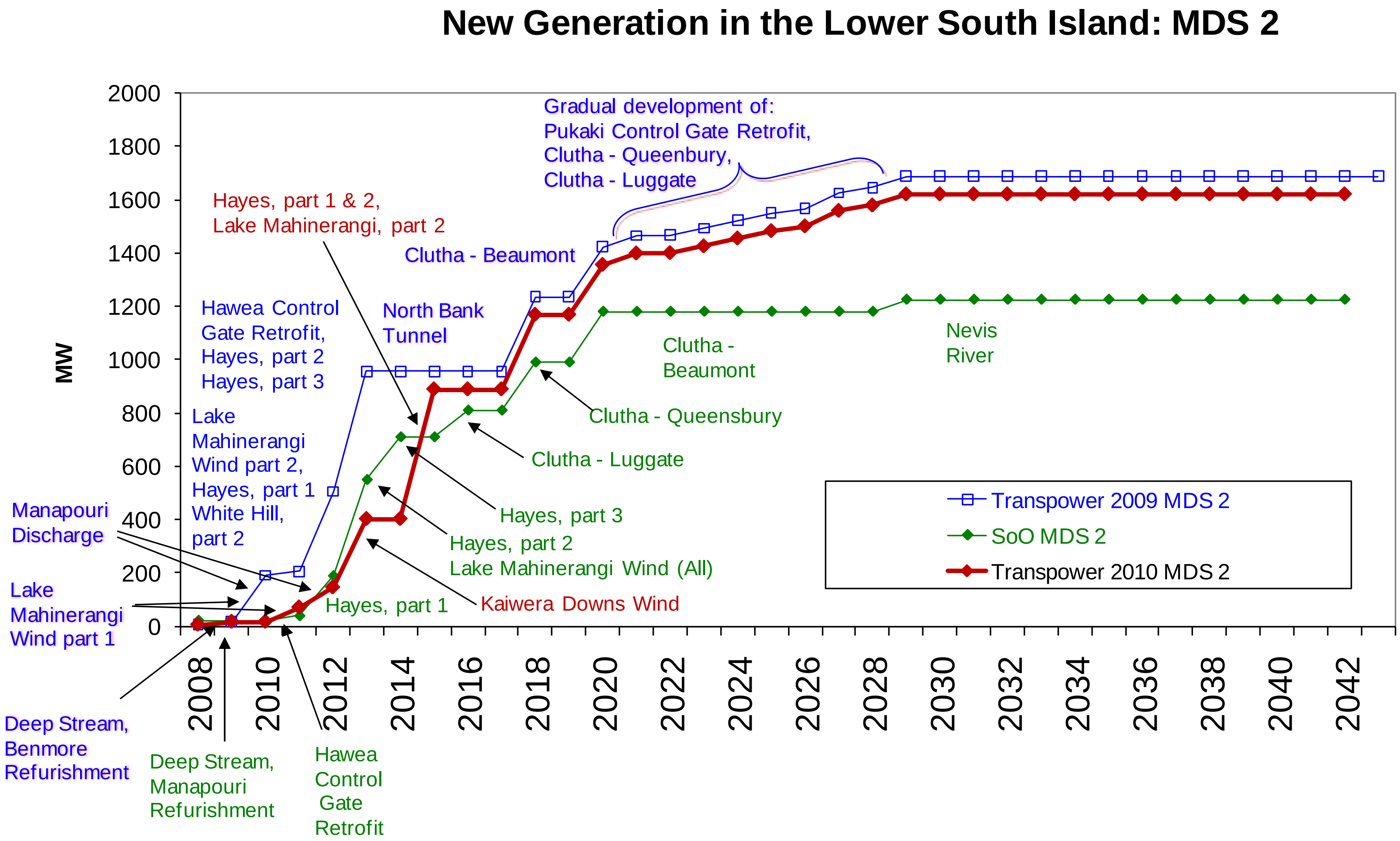
[7] Clause 9 of the GIT provides that where a material benefit cannot be quantified, the direction and likely magnitude of the benefit must be identified. Transpower did not consider estimating the "likely magnitude" to be possible or commensurate with the project spend. However, such benefits are important and have been accounted for as discussed in section 6.1.3.

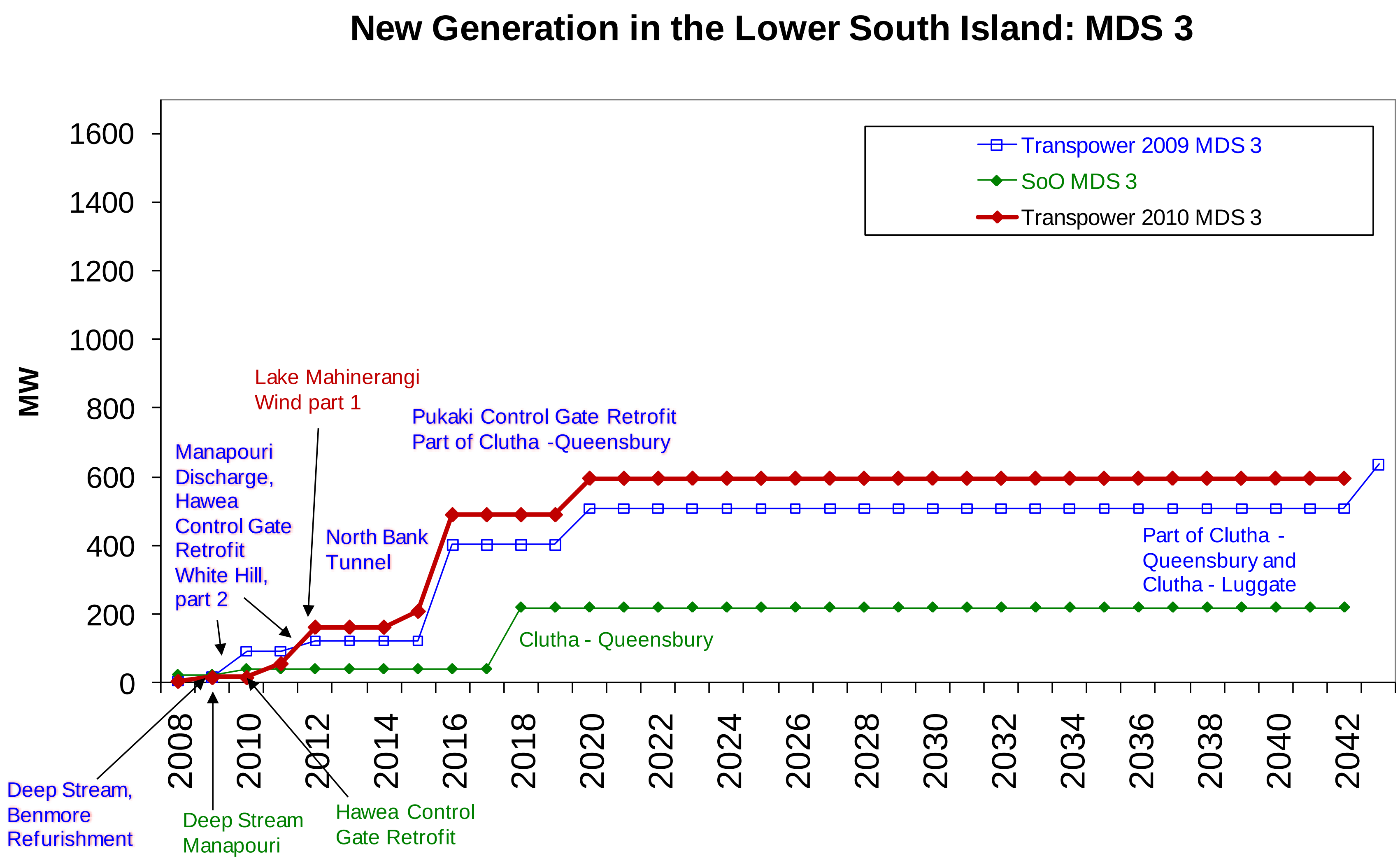
Item		Approach
	Market services (ancillary services and reserves)	Not included
	Competition benefits	Not included
	Consumer benefits	Not included
	Future options	Not included
	Terminal benefits	Not Included[8]
Analysis period		2010 to 2032.

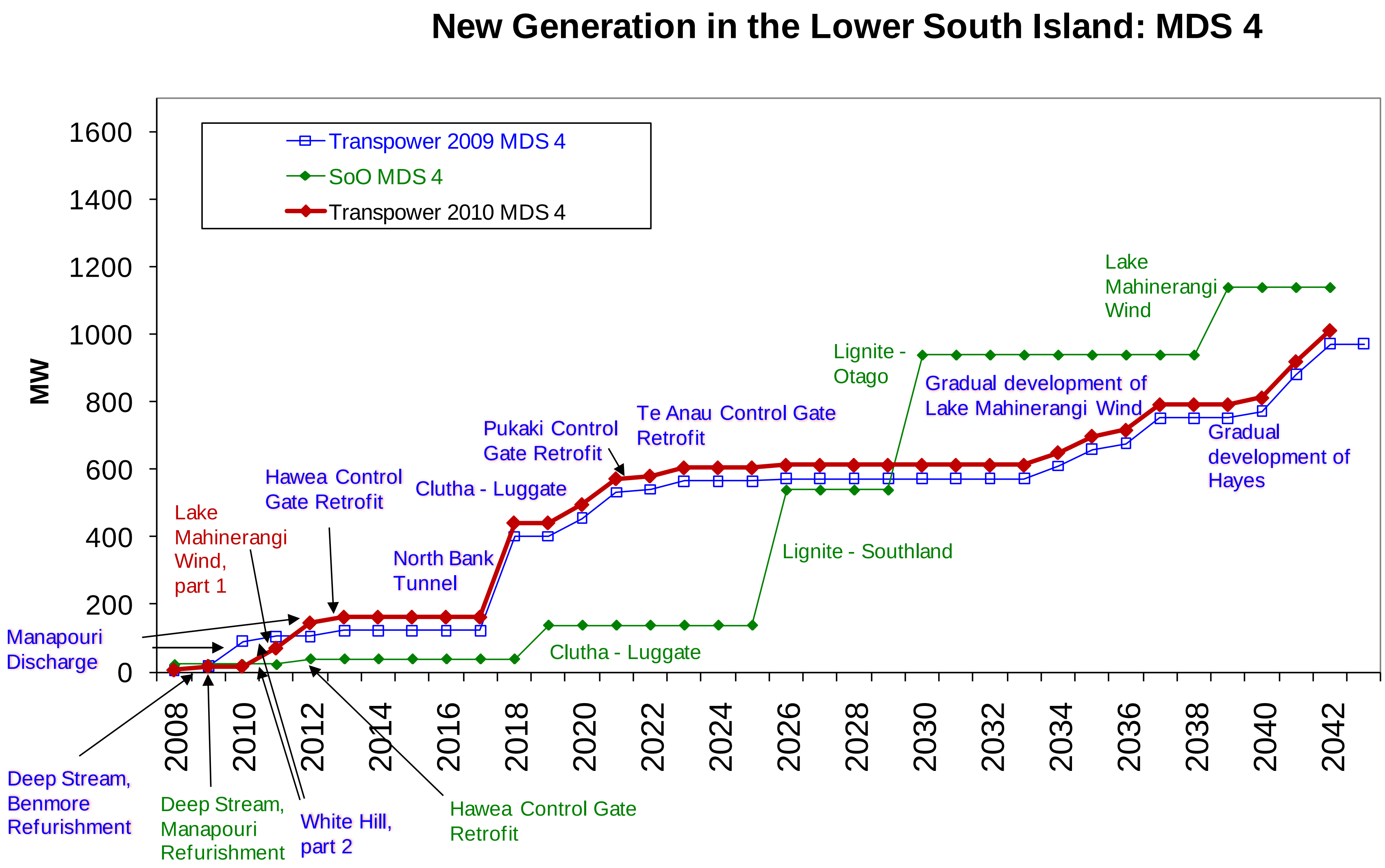
[8] Terminal benefits only include those benefits that have been quantified.

Appendix B LSI build plans




New Generation in the Lower South Island: MDS 2
MW
2000
1800
1600
1400
1200
1000
800
600
400
200
0
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
Gradual development of:
Pukaki Control Gate Retrofit,
Clutha - Queenbury,
Clutha - Luggate
Hayes, part 1 & 2,
Lake Mahinerangi, part 2
Clutha - Beaumont
Hawea Control Gate Retrofit,
Hayes, part 2
Hayes, part 3
North Bank Tunnel
Lake Mahinerangi Wind part 2,
Hayes, part 1
White Hill, part 2
Manapouri Discharge
Lake Mahinerangi Wind part 1
Clutha - Beaumont
Nevis River
Clutha - Queensbury
Clutha - Luggate
Hayes, part 3
Hayes, part 2
Lake Mahinerangi Wind (All)
Hayes, part 1
Kaiwera Downs Wind
Transpower 2009 MDS 2
SoO MDS 2
Transpower 2010 MDS 2
Deep Stream, Benmore Refurishment
Deep Stream, Manapouri Refurishment
Hawea Control Gate Retrofit


New Generation in the Lower South Island: MDS 3
MW
1600
1400
1200
1000
800
600
400
200
0
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
Transpower 2009 MDS 3
SoO MDS 3
Transpower 2010 MDS 3
Lake Mahinerangi Wind part 1
Pukaki Control Gate Retrofit Part of Clutha -Queensbury
Manapouri Discharge, Hawea Control Gate Retrofit
White Hill, part 2
North Bank Tunnel
Part of Clutha - Queensbury and Clutha - Luggate
Clutha - Queensbury
Deep Stream, Benmore Refurishment
Deep Stream Manapouri
Hawea Control Gate Retrofit


New Generation in the Lower South Island: MDS 4
Transpower 2009 MDS 4
SoO MDS 4
Transpower 2010 MDS 4
MW
1600
1400
1200
1000
800
600
400
200
0
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
Lake Mahinerangi Wind
Lignite - Otago
Gradual development of Lake Mahinerangi Wind
Te Anau Control Gate Retrofit
Pukaki Control Gate Retrofit
Gradual development of Hayes
Hawea Control Gate Retrofit
Clutha - Luggate
Lake Mahinerangi Wind, part 1
North Bank Tunnel
Lignite - Southland
Manapouri Discharge
Clutha - Luggate
Deep Stream, Benmore Refurishment
Deep Stream, Manapouri Refurishment
White Hill, part 2
Hawea Control Gate Retrofit

Appendix C Models and data

This appendix outlines the models and data used in the reliability and economic analysis in the Lower South Island Reliability Proposal. The large amount of information used and produced by the models utilised in this project means the published information has been consolidated. However, should further information be requiredit is available on request. To request further information, models or data files please email gridinvestmentprojects@transpower.co.nz with “Request for additional information – Lower South Island Reliability” in the subject line.

C.1 SDDP Data

SDDP input and output files are very large therefore have not been provided directly. They are available upon request.

Detailed information on the input and output is available from the PSR-Inc website, the developers of SDDP[9].

C.2 Unserved Energy Data and Model

The unserved energy models are split into two parts, the N-1 contingency analysis and the contingent event during maintenance outage analysis.

N-1 Unserved Energy Model

The amount of unserved energy (MWh) are calculated by a Matlab script;

- CalcUnservedEnergyNoSplit_160510.m

which in turns uses the input data in the .mat files;

- basedemanddata.mat
- inputdataLSI.mat

The output from the CalcUnservedEnergyNoSplit_160510.m is put into the file;

- VUSE_NoSplit.xlsx

The MWh’s of unserved energy are output into the green cells in the ‘Prudent’ and ‘Expected’ tabs of the VUSE_N-1.xlsx file. The pink cells at the bottom of each of these tabs calculate the value of expected unserved energy. The data on the ‘Limits’ tab is provided from DigSilent system studies.

All files need to be in the same directory for the model to work.

Contingent Event During Maintenance Outage Unserved Energy Model

The file Nminus2events.xlsx calculates the number of MWh of unserved energy under contingencies occurring during maintenance outages. The MWh’s of unserved energy by is calculated by GXP in the cells AA13:EO78 in each of the option tabs. Each option (0 = base case,8 and 9) has a tab for the expected (mean) and prudent forecast. The columns I:N in each options tab represent the GXP loads that would be lost if the specified contingency (column E) occurred during the specific maintenance outage (column A).

The cost per incident of lost load at Edendale is calculated in the Nminus2events_perincident.xlsx file. This file is set up similarly to Nminus2events.xlsx with each option having a tab for expected and prudent forecast.

[9] See http://portal.psr-inc.com/web

Final Report

Lower South Island Peak Electricity Demand Forecast

Prepared for

Transpower

June 2009

covec
expert analysis + practical advice

Covec is an applied economics practice that provides rigorous and independent analysis and advice. We have a reputation for producing high quality work that includes quantitative analysis and strategic insight. Our consultants solve problems arising from policy, legal, strategic, regulatory, market and environmental issues, and we provide advice to a broad range of companies and government agencies.

Covec develops strategies, designs policy, and produces forecasts, reports, expert testimony and training courses. Our commitment to high-quality, objective advice has provided confidence to some of the largest industrial and governmental organisations in Australasia.

Authorship

This document was written by Chris Sweetman. For further information email chris@covec.co.nz or phone (09) 916-1965

Disclaimer

Although every effort has been made to ensure the accuracy of the material and the integrity of the analysis presented herein, Covec Ltd accepts no liability for any actions taken on the basis of its contents.

covec
expert analysis + practical advice

Covec Limited Level 15 Qantas House 191 Queen Street
PO Box 3224 Shortland Street Auckland New Zealand
t: (09) 916-1970 f: (09) 916-1971 w: www.covec.co.nz

Contents

Executive Summary

Peak electricity load has increased a significant amount in the lower South Island over the last decade. Between 1997 and 2007 the peak demand in the region increased by over 165MW. During this time the average peak load growth was 1.6% per annum. The grid exit points of Cromwell, Edendale and North Makarewa have all experienced over 5% annual growth.

This report provides a prudent and expected peak load forecast for the lower South Island region, by estimating the step load changes and organic growth for the next twenty years for the summer and winter period.

Consultation with various stakeholders identified several key industries in the lower South Island. These are dairy farming and milk processing, meat processing, timber processing, oil and gas exploration, coal (lignite) and the aluminium smelter.

Over the next twenty years considerably peak load growth is anticipated in the lower South Island. The 2028 expected diversified peak loads are 1,215MW and 1,248MW for summer and winter respectively. The prudent forecasts reach 1,260MW and 1,292MW for summer and winter respectively. The following figure illustrates the peak demand forecasts.

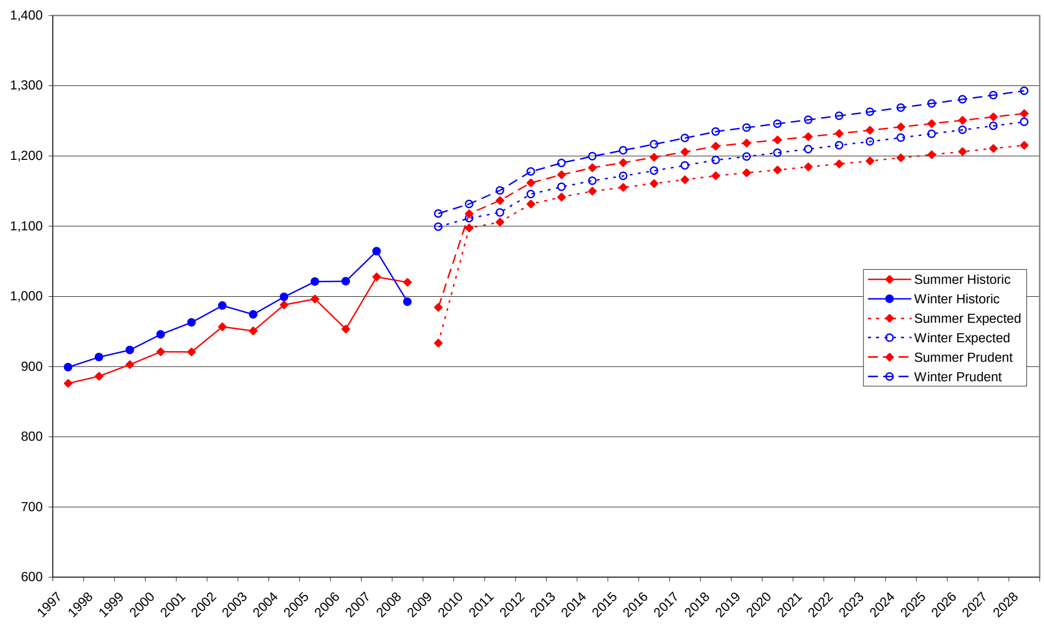


Figure 1: Diversified Load for the Lower South Island

These forecasts do not include any projects that are speculative in nature such as the development of a LNG plant, oil production and storage, coal to lignite plant, silicon smelter and capacity expansion at the aluminium smelter. These projects could potentially increase the lower South Island load by a few hundred megawatts above the forecasts in this report.

1 Introduction

The purpose of this report is to provide a prudent and expected peak load forecast for the lower South Island region, by estimating the step load changes and organic growth for the next twenty years for the summer and winter period. The summer period is defined as between 20th October and 9th May and is recorded in the year in which it ends. Forecasts have been developed through a combination of consultation and analysis. Consultation occurred with some of the attendees of the Lower South Island Stakeholder Forum that took place on October 10th 2008. These companies include: Alliance Group, Dongwha Pattina, Environment Southland, Fonterra, L & M Group, Rio Tinto, Silver Fern Farms and Venture Southland. We used information provided by these parties on anticipated step load changes and our own analysis of organic growth.

For the purposes of this report, the lower South Island contains the following GXPs:

Balclutha (BAL), Brydone (BDE), Clyde (CYD), Cromwell (CML), Edendale (EDN), Frankton (FKN), Gore (GOR), Halfway Bush (HWB), Invercargill (INV), Naseby (NSY), North Makarewa (NMA), Palmerston (PAL), South Dunedin (SDN) and Tiwai (TWI).

2 Historic Trends

2.1 GXP Peak Load

The first place to look when forecasting load is the past. We have obtained half-hour electricity load data from the Electricity Commissions centralised dataset[10] for 1997-2006 and Transpower's dataset for 2007-08. Both datasets are from the same source, Energy Market Services, however there are slight differences up to a magnitude of a few kW. These differences are minor in comparison to the GXP loads, so we have assumed the datasets are comparable. A longer time period would give better indications of long term trends but the centralised dataset has only got half-hour electricity load data back until 1 October 1996 for some of the GXPs in the region. For consistency we have used the same time period for all GXPs. We have collated the half-hour demands into seasonal data which are illustrated in the figures and tables below and in the appendix. The following figures show peak half-hour demands by season at the GXPs.

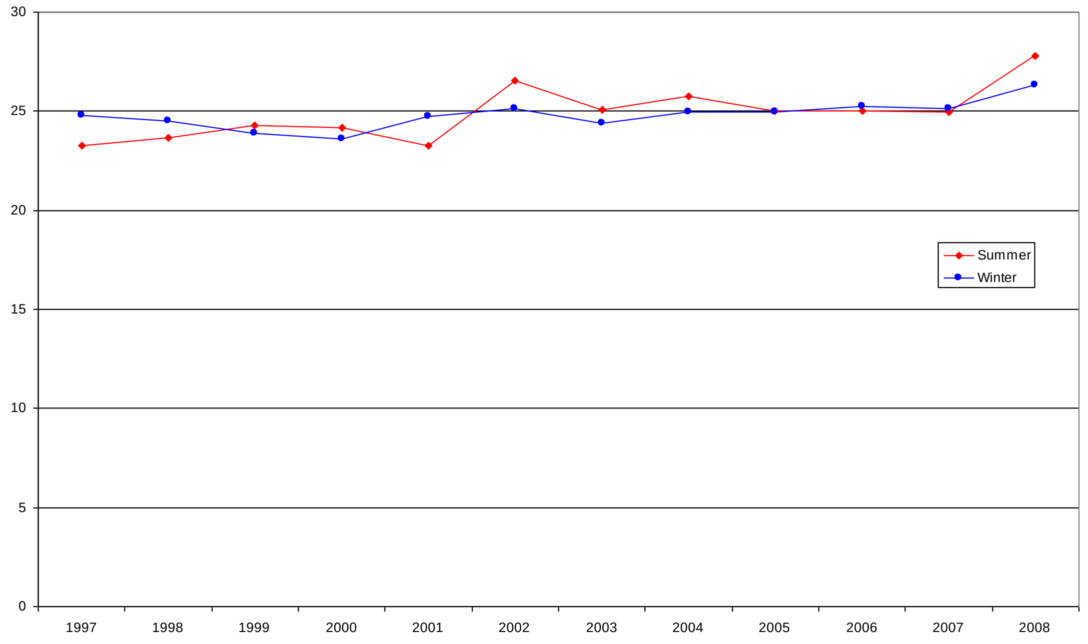


Figure 2: Balclutha GXP Load

There has been very low load growth over the last decade in Balclutha. The summer and winter loads are very similar. In summer 2002 there was a load spike and peak load in 2008 increased significantly from the previous year.

[10] Available at www.electricitycommission.govt.nz/opdev/modelling/centraliseddata/index.html

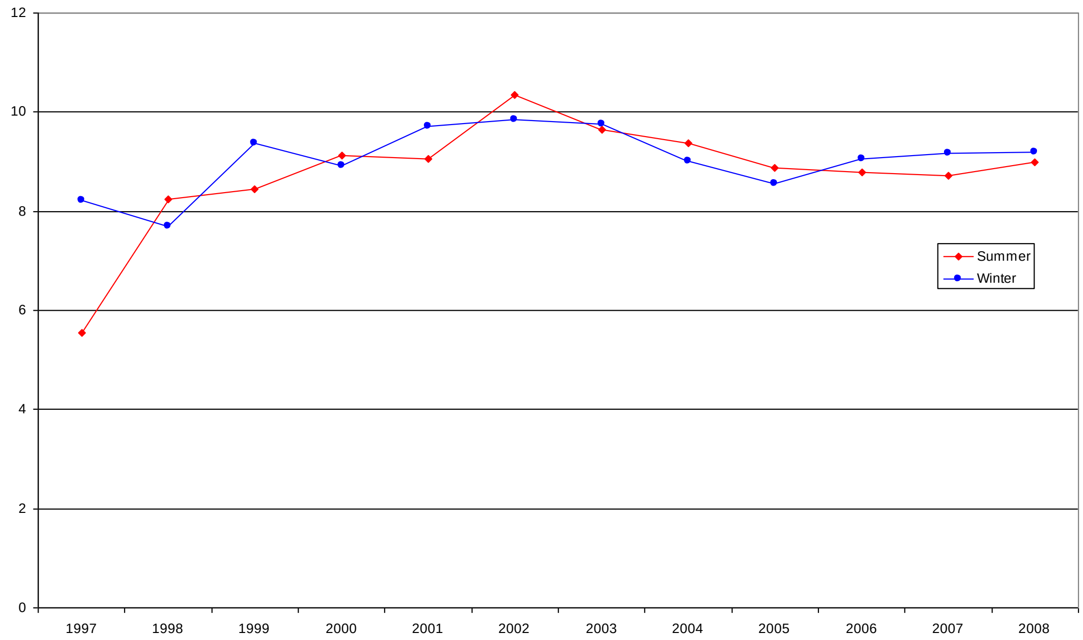


Figure 3: Brydone GXP Load

Brydone has experienced strong growth prior to 2002. Over the next three years peak load began to steadily decline and has remained relatively stable since 2005. Summer and winter loads are similar.

Figure 4: Clyde GXP Load

The peak demand at Clyde has fluctuated considerably over the last decade, with a maximum peak load of 9.5MW in summer 1999 and a minimum peak load of just over

2MW in winter 2000. This could be related to the large amount of embedded generation available in the Clyde area. Since 2000 the trend has been increasing.

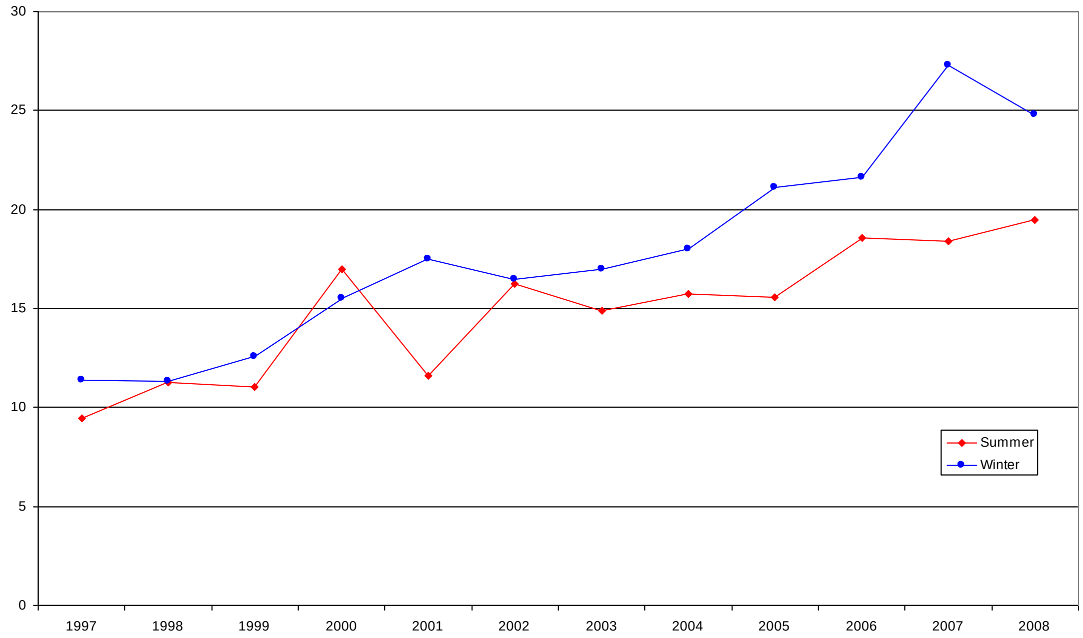


Figure 5: Cromwell GXP Load

Cromwell has seen considerable and steady growth over the last decade with both its summer and winter loads doubling between 1997 and 2008. Cromwell is a winter peaking GXP.

Figure 6: Edendale GXP Load

There has been strong growth at Edendale over the last decade especially during the winter which has doubled in the last ten years. The peak load has fluctuated especially in the summer since 2001 and the winter over the last few years.

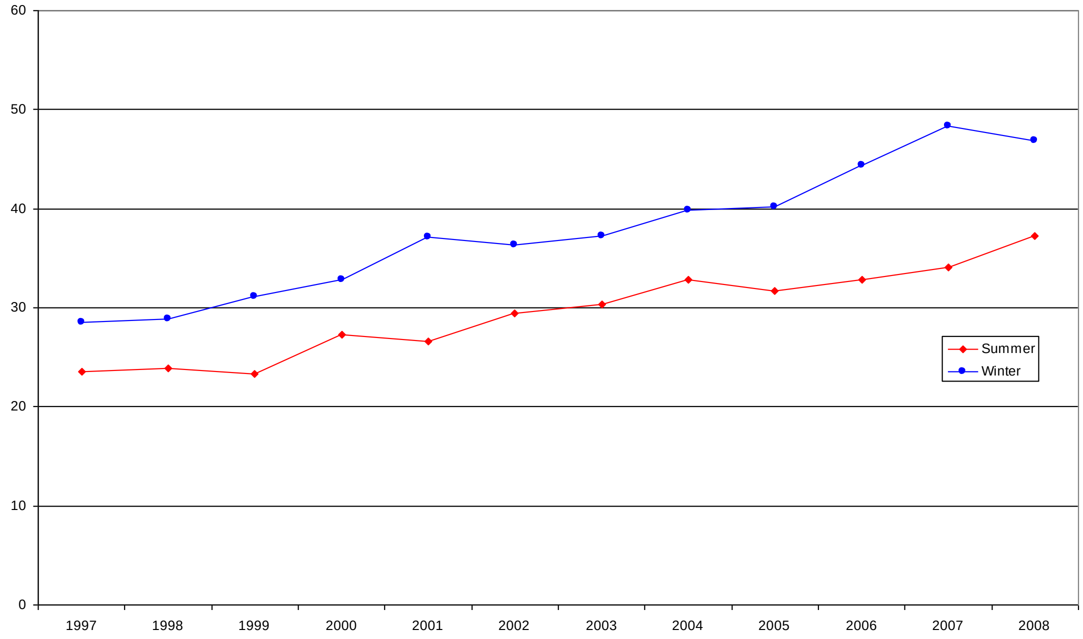


Figure 7: Frankton GXP Load

Frankton is a winter peaking GXP that has experienced strong steady growth. The peak load has increased by over 1.2MW and 1.6MW per year for the summer and winter periods respectively.

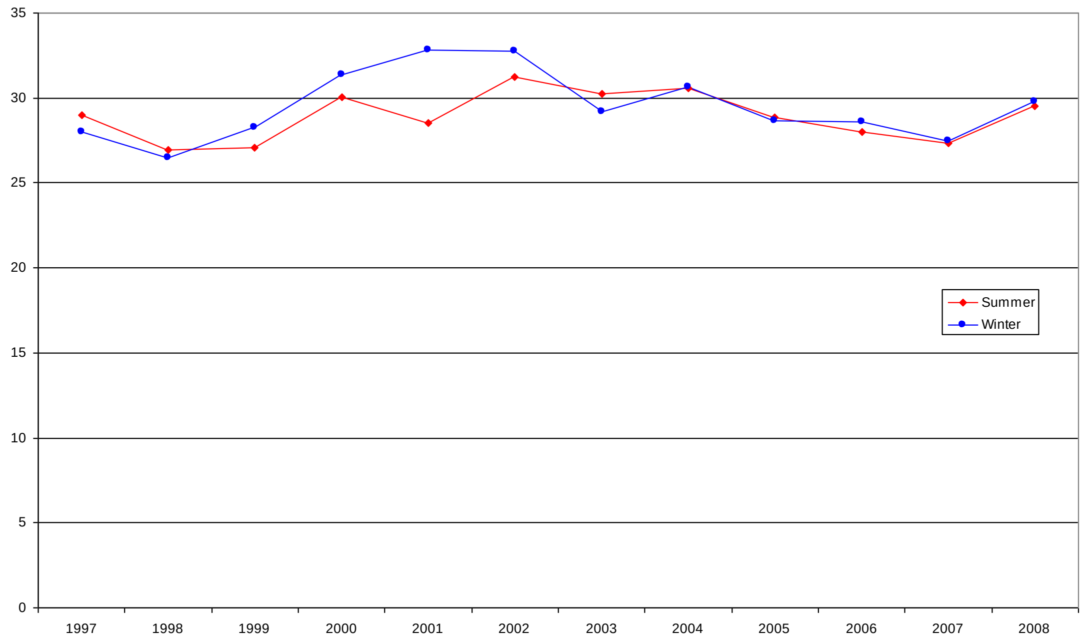


Figure 8: Gore GXP Load

Gore's peak load has fluctuated around 30MW over the last decade. In the first five years peak load increased and then decreased for the following five years to approximately the initial levels. Summer and winter loads are fairly similar with the exception of 2001. There was a moderate increase in load in 2008.

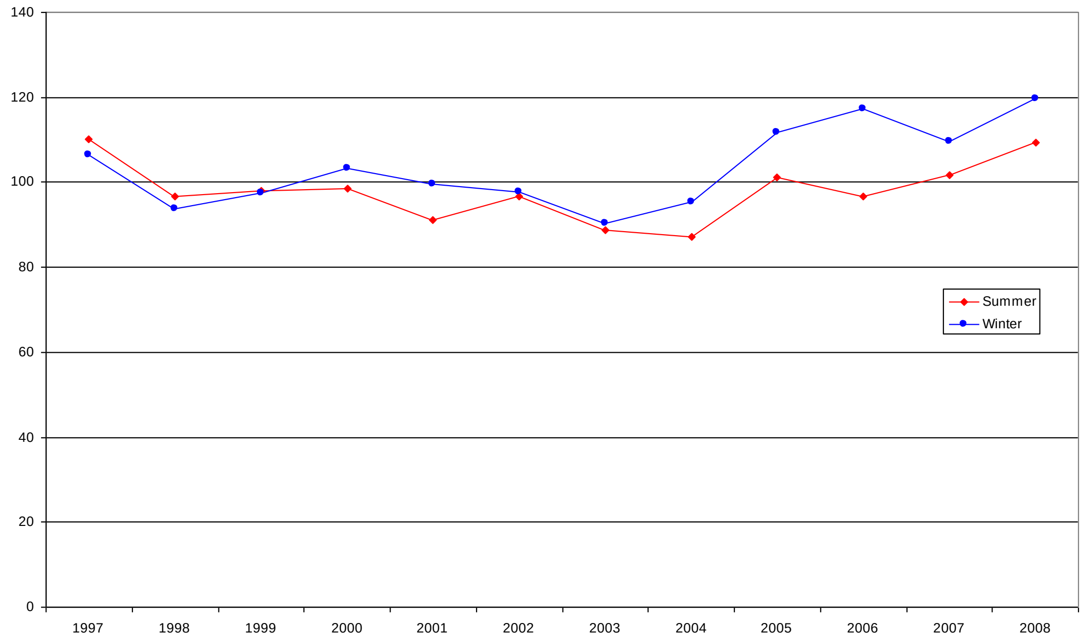


Figure 9: Halfway Bush GXP Load

Until 2003, Halfway Bush's peak load was decreasing, over 20MW for the summer period. Since then peak load has increased significantly, 4MW and 6MW per year for summer and winter respectively. Halfway Bush is now a winter peaking GXP.

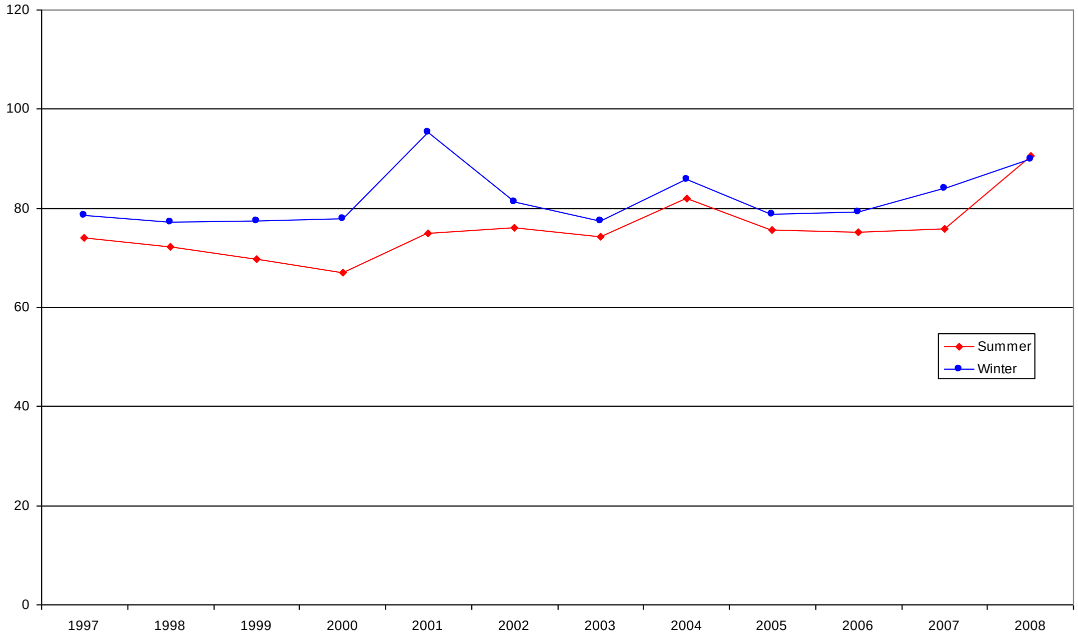


Figure 10: Invercargill GXP Load

Invercargill is a winter peaking GXP that has seen peak demand spike in winter 2001 and for both seasons in 2004. There has also been a large increase in 2008 especially in the summer (almost 15MW).

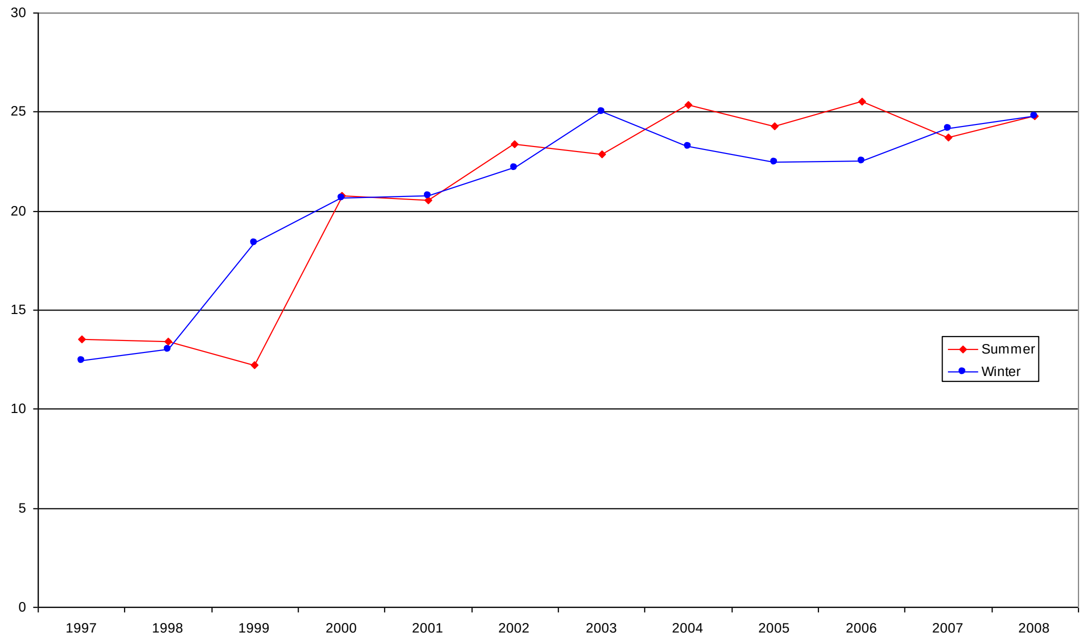


Figure 11: Naseby GXP Load

In winter 1999 and summer 2000 there was a large step load increase at Naseby. This was followed by moderate growth in the next few years. For the last five years, peak demand has been around 25MW.

Figure 12: North Makarewa GXP Load

North Makarewa has experienced significant growth and fluctuations. After a downward trend for the first few years, a 20MW step load came on in winter 2000 and summer 2001. The load decreased in the following seasons before strong growth has increased demand by 15MW.

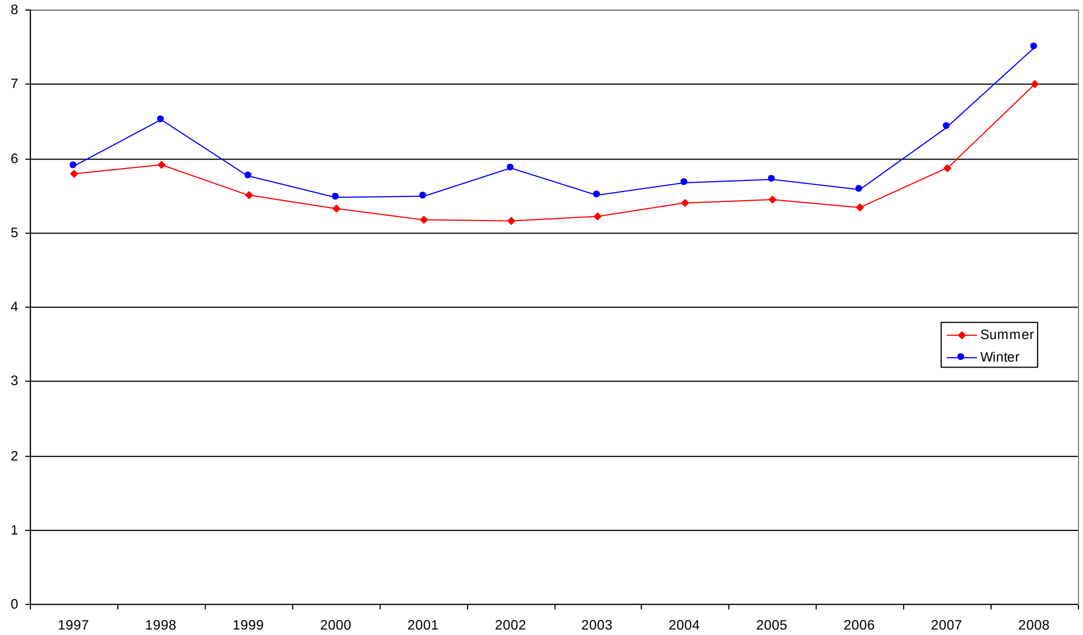


Figure 13: Palmerston GXP Load

Prior to 2007, peak load for Palmerston had remained between 5-6MW for 10 years with the exception of winter 1998. Load has increased steadily in the last two years to put peak demand over 7MW. Palmerston is a winter peaking GXP.

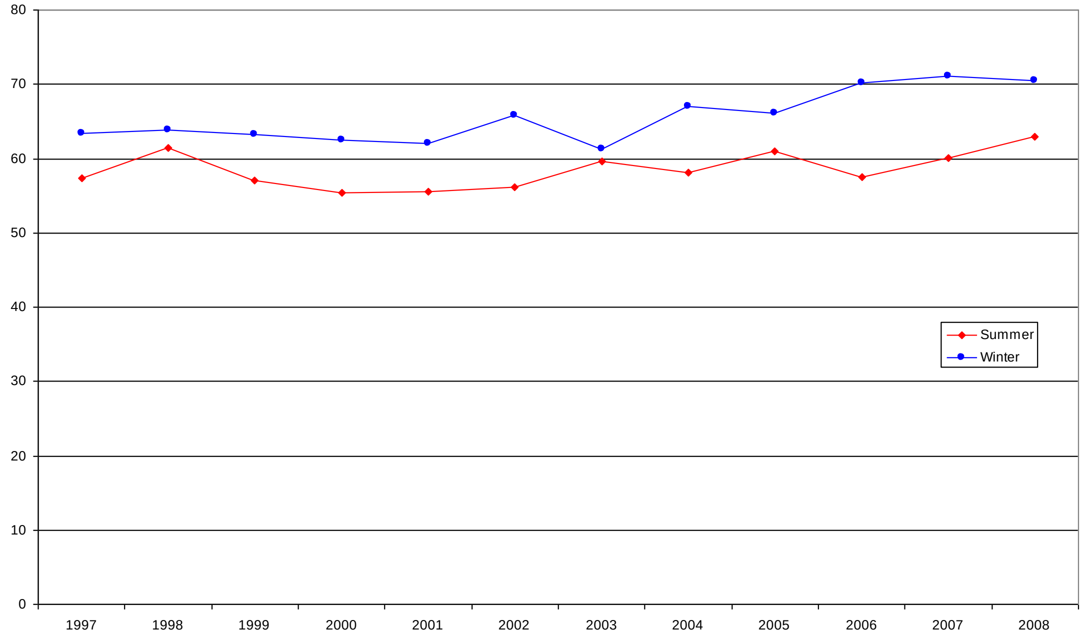


Figure 14: South Dunedin

There has been low demand growth for the winter peaking GXP of South Dunedin although the winter load has increased by over 10MW in the last five years.

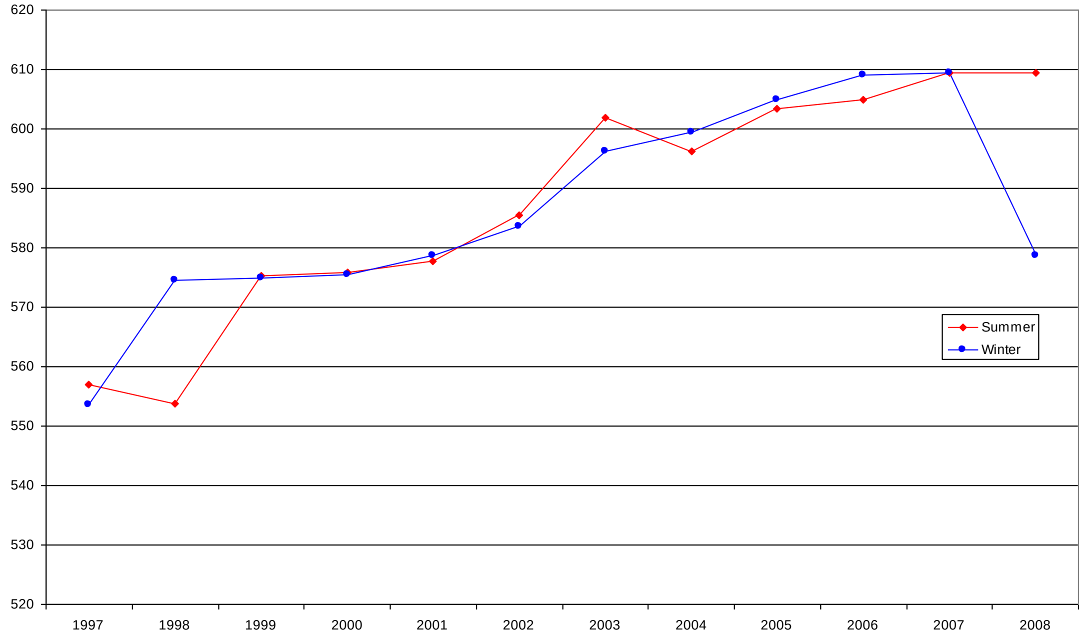


Figure 15: Tiwai GXP Load

A large step load increase of approximately 20MW took place in winter 1998 and summer 1999 at Tiwai. Strong load growth over the next decade increased peak demand by 34MW to 610MW in 2007. Winter 2008 has seen a fall in peak load of 5% (30MW).

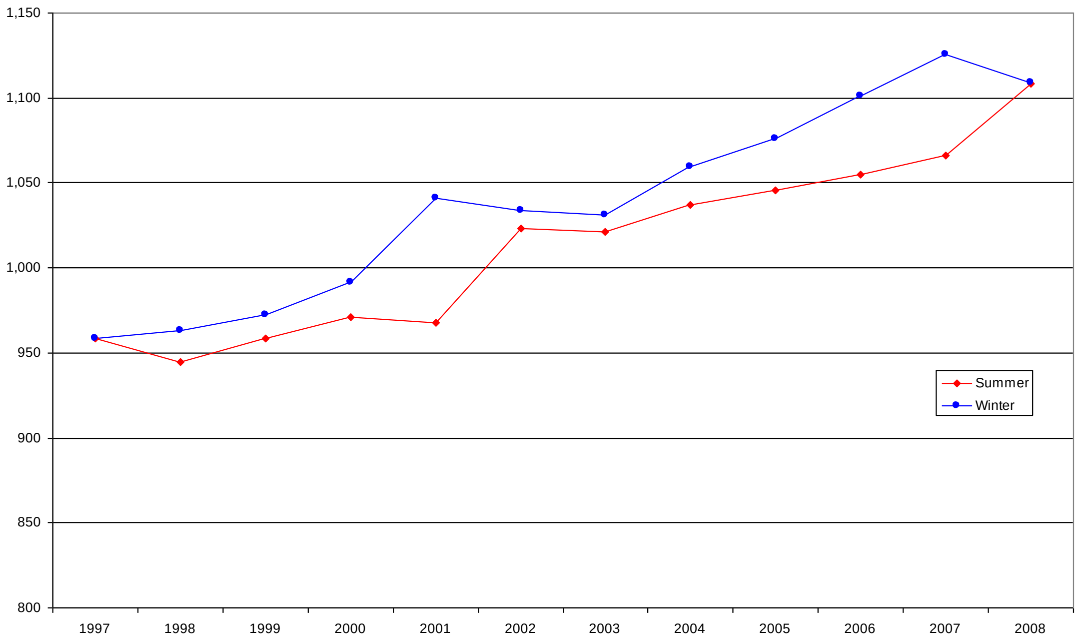


Figure 16: Undiversified Lower South Island GXP Load

The undiversified load for the lower South Island region has been steadily increasing with a large step change in winter 2001 and summer 2002 corresponding to the increase at North Makarewa. The region has been winter peaking although the seasonal peaks were approximately the same in 2008.

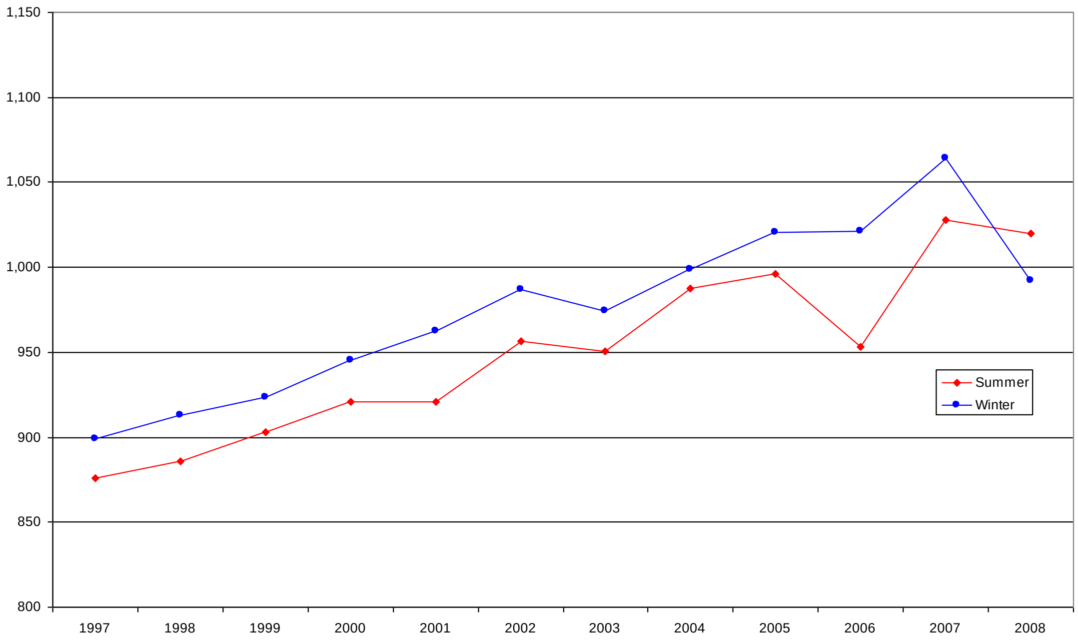


Figure 17: Diversified Lower South Island GXP Load

The diversified load has also been steadily increasing in the lower South Island region. The step load increase in 2000/01 has significantly less impact on the diversified load.

There have been some fluctuations over the last few years, notably in summer 2006 and winter 2008. The region has been winter peaking for all years except 2008.

The five and ten year growth rates for the GXPs and the region are shown in Table 2 below. These growth rates have been calculated by fitting a linear least squares line to each demand dataset. This allows a gradient to be determined which can be interpreted as the average annual change (in MW) in electricity demand. The annual growth rate is then calculated as the average annual change divided by the fitted midpoint. This method has the advantage of putting equal weight on each year's electricity demand whereas more traditional methods generally only consider the initial and final years' load.

Table 2: Five & Ten Year Load Growth Rates (% per annum)

GXP	Season	1998-2003	2003-2008	1998-2008
Balclutha	Summer	1.5%	1.2%	1.0%
	Winter	0.5%	1.2%	0.7%
Brydone	Summer	4.0%	-1.7%	0.3%
	Winter	3.9%	-0.5%	0.4%
Clyde	Summer	-12.8%	3.1%	-1.0%
	Winter	-7.9%	8.8%	6.2%
Cromwell	Summer	5.9%	5.7%	4.9%
	Winter	8.0%	8.9%	7.6%
Edendale	Summer	2.1%	5.3%	5.3%
	Winter	11.5%	5.0%	7.0%
Frankton	Summer	5.3%	3.3%	4.2%
	Winter	5.2%	5.2%	4.8%
Gore	Summer	2.7%	-1.4%	0.3%
	Winter	2.7%	-0.6%	-0.2%
Halfway Bush	Summer	-1.5%	4.2%	0.8%
	Winter	-0.6%	5.2%	2.1%
Invercargill	Summer	1.4%	2.3%	1.8%
	Winter	1.0%	2.0%	0.7%
Naseby	Summer	12.2%	0.7%	5.4%
	Winter	10.2%	0.2%	3.9%
North Makarewa	Summer	13.0%	6.7%	8.5%
	Winter	17.9%	9.1%	10.2%
Palmerston	Summer	-2.4%	5.1%	1.3%
	Winter	-2.4%	5.7%	1.2%
South Dunedin	Summer	-0.6%	0.9%	0.6%
	Winter	-0.3%	2.6%	1.3%
Tiwai	Summer	1.4%	0.4%	0.9%
	Winter	0.7%	-0.3%	0.5%
Undiversified Region	Summer	1.7%	1.4%	1.5%
	Winter	1.6%	1.6%	1.5%
Diversified Region	Summer	1.5%	1.2%	1.4%
	Winter	1.5%	0.8%	1.2%

Table 1 shows that the lower South Island's diversified load has been growing at 1.4% in summer and 1.2% in the winter over the last decade.[11] The undiversified growth rates are slightly higher the diversified growth rates. The rural GXPs of North Makarewa and Edendale have experienced the strongest growth over the last decade with North Makarewa averaging 10% annual growth in the winter. The more urban GXPs of Cromwell and Frankton have also seen strong growth throughout the last 10 years.

2.2 Dairy Growth

The dairy industry in the lower South Island has experienced considerable growth over the last decade. The total number of farms in the region[12] has increased at an annual rate of 3.4% since 1999, the number of cows by 7.2% and total hectares by 6.7% over the same period.[13] This is considerably higher than the growth rates for New Zealand which have been -2.5%, 2.2% and 1.1% respectively. Farms in the Southland Region are among some of the most productive in the country with average litres per cow and average kg of milk solids per cow 20% higher than the New Zealand averages in 2008.

Table 3: Dairy Statistics for the Lower South Island and New Zealand

Region	Dairy Statistic	1999	2008	Annual Growth
Lower South Island	Total Farms	691	933	3.4%
	Total Cows	242,973	453,214	7.2%
	Total Hectares	92,504	166,003	6.7%
	Average Cows per Farm	352	486	3.7%
	Average Cows per Hectare	2.6	2.7	0.4%
	Average Litres per Cow	3,458	4,286	2.4%
	Average kg Milk Solids per Cow	287	369	2.8%
New Zealand	Total Farms	14,362	11,436	-2.5%
	Total Cows	3,289,319	4,012,867	2.2%
	Total Hectares	1,306,942	1,436,549	1.1%
	Average Cows per Farm	229	351	4.9%
	Average Cows per Hectare	2.5	2.8	1.2%
	Average Litres per Cow	3,085	3,573	1.6%
	Average kg Milk Solids per Cow	256	307	2.0%

2.3 Population

The population of the lower South Island region has increased by over 9,000 from 269,460 in 1996 to 278,590 in 2008.[14] This represents an average annual increase of 0.3%, as shown in Table 4 below. This is well below the 1.1% that New Zealand grew at over

---

[11] The winter rate is lower due to the large reduction in load in 2008. Without this reduction, the summer and winter growth rates would have been similar.

[12] Approximated by the districts of Dunedin, Clutha, Gore, Invercargill and Southland. Central Otago is not included as there were less than 5 farms in 2007/08 so the data was merged with the Waitaki District.

[13] New Zealand Dairy Statistics, LIC, www.lic.co.nz/lic_Publications.cfm accessed 5 March 2009

[14] Estimated Subnational Population, Stats NZ. The lower South Island region comprises of the following districts; Central Otago District, Queenstown-Lakes District, Dunedin City, Clutha District, Gore District, Southland District, Invercargill City and the area units of Palmerston, Waihemo and Nenthorn in the Waitaki District.

the same period. The population of the Cromwell and Frankton areas grew by over 4% per year and the majority of the other areas had negative growth.

Table 4: Historic and Projected Population Growth Rates by GXP in the lower South Island

GXP			Population			Business
	Historic	Low	Medium	High	Geo Units	Employees
Balclutha	-0.5%	-0.9%	-0.4%	0.1%	1.9%	1.8%
Brydone	-0.6%	-0.7%	-0.2%	0.2%	2.0%	2.6%
Clyde	0.1%	-1.2%	0.0%	0.9%	2.3%	2.7%
Cromwell	4.9%	0.9%	1.9%	2.8%	9.8%	9.8%
Edendale	-0.6%	-0.7%	-0.2%	0.2%	2.0%	2.6%
Frankton	4.1%	1.1%	1.8%	2.5%	9.2%	6.0%
Gore	-0.8%	-1.2%	-0.7%	-0.3%	1.6%	1.2%
Halfway Bush	0.2%	-0.2%	0.2%	0.6%	2.6%	2.5%
Invercargill	-0.4%	-1.3%	-0.5%	0.3%	2.4%	2.3%
Naseby	-0.5%	-1.4%	-0.2%	0.8%	1.3%	3.4%
North Makarewa	-0.6%	-0.7%	-0.2%	0.2%	2.0%	2.6%
Palmerston	-0.7%	-1.4%	-0.9%	-0.4%	0.3%	1.4%
South Dunedin	0.2%	-0.2%	0.2%	0.6%	2.6%	2.5%
Lower South Island	0.3%	-0.4%	0.2%	0.7%	3.4%	2.9%

The medium population projection has the lower South Island population continuing to increase at a similar rate of 0.2% per annum to 2031.[15] The population growth in the Cromwell and Frankton areas is expected to half to less than 2%.

All areas of the lower South Island have experienced growth in the number of geographic units (separate businesses) and employees and the region grew at 3.4% and 2.9% respectively between 2000 and 2008.[16] The strongest growth occurred in the Cromwell and Frankton areas.

[15] Subnational Population Projections, Stats NZ.
[16] Business Demography Tables, Stats NZ.

3 Electricity Commission Demand Forecasts

The Electricity Commission prepares national and regional level demand forecasts. The national demand forecasts are based off historical data. Econometric models are fitted to determine which key drivers are the most appropriate at explaining the historic demand and projecting future load.[17]

The electricity (energy consumption) demand modelling is split into three sectors; residential demand, commercial and industrial demand and heavy industrial direct connects (such as the aluminium smelter at Tiwai Point). The model is based on three key drivers of national residential demand: GDP per capita, households per capita and price. Commercial and industrial demand is related to GDP and shortage adjustments and the heavy industry direct connect demands are assumed to remain constant. Total demand is the summation of the three sectors plus lines companies losses minus the embedded generation.

In determining the regional forecasts, the Electricity Commission allocates the residential demand on the basis of projected population in each network area. GXP residential demand is forecast by splitting the network area demand on the basis of the current load at each GXP.

The commercial and industrial forecast demands are allocated on the basis of projected regional GDP. As with residential demand, commercial and industrial forecast demand at the GXP level is allocated based on the current GXP demand.

An adjustment is made to reflect recent trends within regions resulting from high electricity demand growth relative to changes in GDP and population. A forecast based on a simple trend is calculated for each region using March year data from 1997. The energy regional demand forecast is a weighted average (exponentially declining) of the trend based forecast and the allocated forecast based on GDP and population.

As there is uncertainty in the key drivers used as inputs into the forecast model, there is also forecast uncertainty. Monte Carlo simulations are run to obtain the mean and prudent (90th percentile) forecasts.

[17] Electricity Demand Forecast Review June 2006, Electricity Commission, www.electricitycommission.govt.nz/opdev/modelling/gpas/May2007/Demand/index.html accessed 1 May 2008

The peak demand expected forecast is based on two sources, historical peak data from the Electricity Commission's Centralised Dataset (CDS) and the energy demand forecasts mentioned above.[18]

At a regional level, an exponential curve is fitted to the historical peaks from 1997 using weighted least squares estimation. The peak demand forecast begins in the current year with the fitted value and for the next three years the forecast grows at the higher of the peak demand forecast growth rate or the energy demand forecast growth rate. After this point, the expected peak demand grows in proportion with the energy demand forecast.

The prudent demand forecasts are made by using a Monte Carlo simulation of the peak demand forecast, with the prudent forecast being the 90th percentile. The variation is obtained by assuming a normal distribution of peaks around the expected forecast with a standard deviation being estimated by the standard deviation of the fitted trend of the historic peaks and from the uncertainty in the energy forecasts.

Some modifications are made in specific regions due to events such as major step load changes. There are no such modifications for the GXP's in the lower South Island region.

The 2007 EC mean and prudent forecasts for the grid exit points are located in the appendix and the lower South Island region are shown in the figures below.[19]

---

[18] Regional Peak Demand Forecast, Electricity Commission, www.electricitycommission.govt.nz/pdfs/opdev/modelling/GPAs/Expected-and-prudent-peak-forecast.pdf accessed 1 May 2008

[19] The historic data and the EC's forecasts are calendar year. The 2008 historic data is based on the year to 19th October 2008.

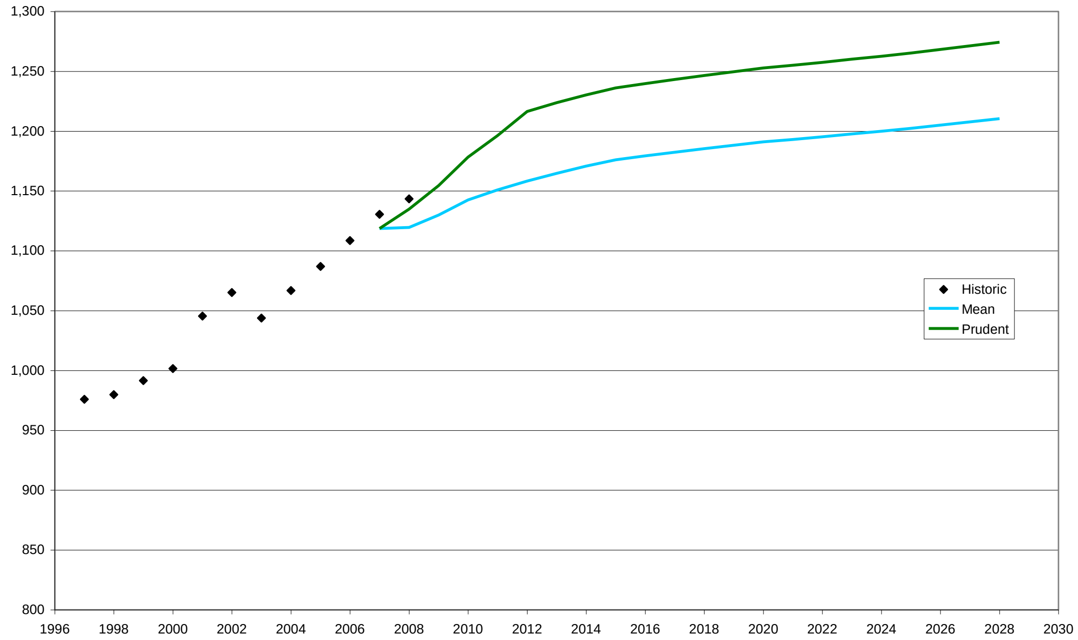


Figure 18: EC's 2007 Lower South Island Undiversified Peak Demand Forecast

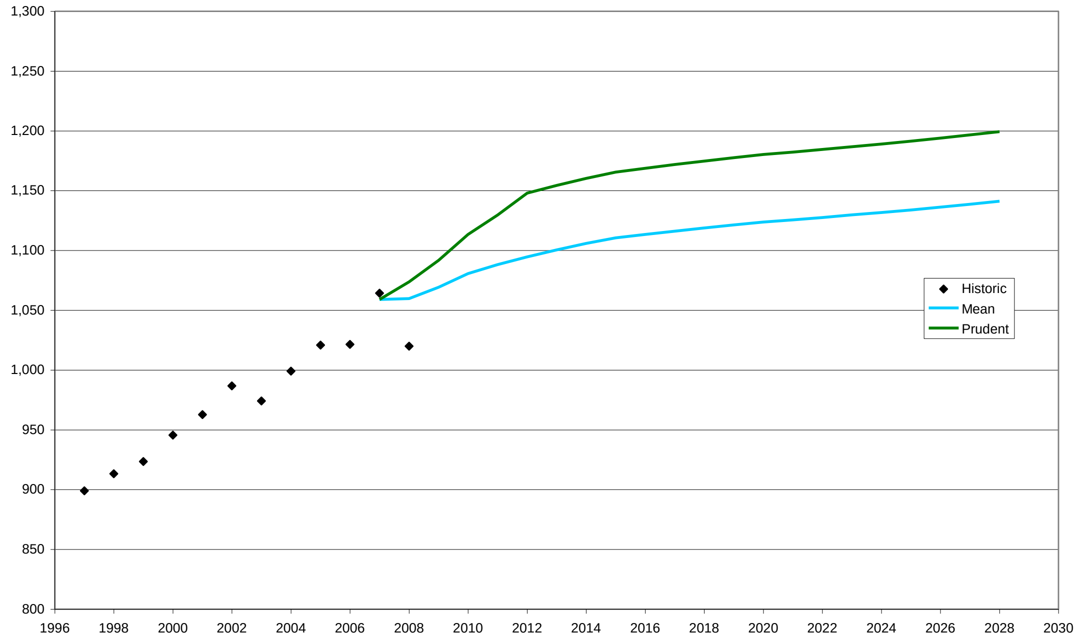


Figure 19: EC's 2007 Lower South Island Diversified Peak Demand Forecast

For the lower South Island region, the 2008 undiversified regional load is above the Electricity Commission's prudent forecast by 24MW. The diversified load is almost 40MW below the mean EC forecast in 2008.

The prudent EC forecasts are below the actual peak load in 2008 for seven of the fourteen GXPs. Five GXPs peak loads were below the mean EC forecast and the remaining two were similar to the mean forecast.

Table 5: Historic and EC's Forecast Growth Rates in the Lower South Island Region

	Historic		Electricity Commission					
	1998-2008	2003-2008	2007-2012 Mean	2007-2012 Prudent	2012-2028 Mean	2012-2028 Prudent	2007-2028 Mean	2007-2028 Prudent
Balclutha	0.8%	1.3%	1.1%	3.2%	0.3%	0.3%	0.5%	1.0%
Brydone	0.1%	-0.6%	1.5%	3.6%	0.5%	0.5%	0.7%	1.2%
Clyde	1.1%	7.8%	5.9%	8.0%	2.8%	2.8%	3.6%	4.1%
Cromwell	7.3%	8.9%	2.1%	4.2%	1.0%	1.0%	1.3%	1.7%
Edendale	5.3%	3.5%	1.1%	3.1%	0.2%	0.2%	0.4%	0.9%
Frankton	4.8%	5.2%	1.8%	3.9%	0.8%	0.8%	1.1%	1.6%
Gore	-0.2%	-1.1%	1.2%	3.2%	0.3%	0.3%	0.5%	1.0%
Halfway Bush	2.0%	5.2%	1.8%	3.9%	0.8%	0.8%	1.1%	1.6%
Invercargill	0.8%	2.1%	1.0%	3.1%	0.2%	0.2%	0.4%	0.9%
Naseby	3.7%	-0.5%	1.6%	3.6%	0.6%	0.6%	0.8%	1.3%
North Makarewa	8.0%	7.8%	1.2%	3.3%	0.3%	0.3%	0.5%	1.0%
Palmerston	1.3%	5.8%	1.1%	3.2%	0.3%	0.3%	0.5%	1.0%
South Dunedin	1.3%	2.6%	1.3%	3.4%	0.5%	0.5%	0.7%	1.2%
Tiwai	0.7%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Undiversified Region	1.5%	1.9%	0.7%	1.7%	0.3%	0.3%	0.4%	0.6%
Diversified Region	1.3%	1.2%	0.7%	1.6%	0.3%	0.3%	0.4%	0.6%

Table 5 above gives a comparison of the short and long term mean and prudent and historic growth rates. The historic growth rates are for calendar years and are calculated in the same way as the seasonal growth rates in Table 2. The forecast growth rates are annually compounded rates.

The historic growth rates are similar to those found in table 1. Cromwell, Edendale and North Makarewa all experienced over 5% average annual growth over the last decade and Clyde, Cromwell, Frnakton, Halfway Bush, North Makarewa and Palmerston have in the last five years. In the short term only Clyde is expected to have over 5% annual growth. The mean short term forecasts for all non-industrial GXPs have growth rates ranging from 1-2%. The prudent GXP forecasts growth rates are approximately 2% higher than their mean short term forecast. No growth is forecast at Tiwai. In the long term the mean and prudent forecasts have the same growth rates. Clyde and Cromwell are the only GXPs with long term growth rates above 1%.

The lower South Island region diversified peak demand is expected to grow by 0.4% per year under the mean forecast and 0.6% under the prudent forecast over the next twenty years.

4 Network Company Forecasts

The electricity distribution network in the lower South Island is owned by four network companies; Aurora Energy Limited, OtagoNet Joint Venture, The Power Company Limited and Electricity Invercargill Limited, the latter three being part of PowerNet Limited, a joint venture company that manages their electricity networks. Demand forecasts at the HV feeder, zone substation and GXP level are made by the network companies on a yearly basis in their respective asset management plans (AMPs).

According to these plans, the key drivers of localised electricity demand growth are demographics & lifestyle, climatic effects, conservation, economic activity and industry& technology trends. The demand forecasts are based on past trends and known future developments. Historically, distribution companies in the Southland Region have been given little warning of changes in demand from large consumers. This results in very few step load projects being included in the demand forecasts. The method used is to estimate growth rates based on the key drivers above.

Key electricity load industries in the lower South Island region include timber milling, irrigation, dairy conversions, gold mining and tourism. There is an abundance of trees in the region coming to maturity so the recent growth is likely to continue. There is potential for expansion of existing mills or new mills but as this is dependent on such things as timber prices, exchange rates and decisions over climate change policies, the long term load growth is difficult to predict. There is still a lot of potential for dairy conversions and irrigation in certain areas of the lower South Island. This may give rise to expansions and/or additional processing plants, which again cause unpredictable load growth in the long term. Also with dairy conversions and irrigation, the load is not fully seen until dry years where there is a huge increase in load. This makes it difficult to accurately forecast the electricity demand on a yearly basis as it is heavily dependent on the weather.

The forecasts in the most recent asset management plans (2007-2017) don't include the Brydone and Tiwai GXPs. None of the forecasts provide an annual peak demand at the GXP level to 2017. Some of the forecasts are GXP demand plus embedded generation whereas others are solely GXP demand. The units for maximum demand are also inconsistent, with some measured in real power (units: MW) and others in apparent power (MVA). Due to the inconsistencies in the forecasts contained in the asset management plans, we have only used forecast growth rates in our analysis. These are shown in Table 6 below.

Table 6: Actual and Forecast Growth Rates by GXP in the Asset Management Plans

Grid Exit Point	Growth rates	
	Actual	Forecast
	1998-2008	2007-2017
Balcultha	0.8%	0.5%
Clyde	1.1%	1.0%
Cromwell	7.3%	5.6%
Edendale	5.3%	4.1%
Frankton	4.8%	4.1%
Gore	-0.2%	2.2%
Halfway Bush	2.0%	1.0%
Invercargill	0.8%	0.6%
Naseby	3.7%	1.5%
North Makarewa	8.0%	2.2%
Palmerston	1.3%	0.5%
South Dunedin	1.3%	1.0%

The forecast growth rates are in line with has been seen historically at the majority of GXPs with Cromwell, Gore, Naseby and North Makarewa differing by over 1.5%.

Transpower asked the distribution companies to provide demand forecasts at the GXP level between 2007 and 2011. Although they are over a shorter period, they all estimate peak demand in MW at each GXP.

The implied growth rates are in Table 7 below. There are some significant differences in these forecast growth rates compared with those in the asset management plans, but they relate to different time periods.

Table 7: Actual and Forecast Growth Rates by GXP in forecasts supplied to Transpower

Grid Exit Point	Growth rates		
	Actual		Forecast
	1998-2008	2003-2008	2007-2011
Balcultha	0.8%	1.3%	0.5%
Clyde	1.1%	7.8%	-0.3%
Cromwell	7.3%	8.9%	5.1%
Edendale	5.3%	3.5%	2.5%
Frankton	4.8%	5.2%	4.1%
Gore	-0.2%	-1.1%	1.0%
Halfway Bush	2.0%	5.2%	0.6%
Invercargill	0.8%	2.1%	0.8%
Naseby	3.7%	-0.5%	1.5%
North Makarewa	8.0%	7.8%	0.7%
Palmerston	1.3%	5.8%	0.5%
South Dunedin	1.3%	2.6%	1.2%

Cromwell and Frankton are forecast to have the greatest growth in the short term. The growth rates in the forecasts supplied to Transpower are equal or lower than those in the AMPs, except for Invercargill, even though they are for a shorter period.

5 Consultation with Stakeholders

Upon consultation with the various lower South Island stakeholders, we believe there are a few key industries that will have a significant impact on electricity load in the region. These industries are dairy farming and milk processing, meat processing, timber processing, oil and gas exploration, coal (lignite) and the aluminium smelter. We look at each industry in detail. Consultation took place via phone with the various parties in early November 2008. A list of the stakeholders that were contacted is located in the appendix.

5.1 Dairy Industry

The dairy industry in the lower South Island, especially Southland has experienced considerably growth recently. There is a high rate of dairy conversions with Venture Southland reporting over 100 conversions just in the Southland Region in 2008 with a similar number expected in 2009. Each dairy conversion adds 50-55kVA to load, although efficiency gains would be expected.

Fonterra estimate that the milk supply will increase by 5.5 - 8.5% annually from 2009-2014 in the lower South Island. Based on this growth rate, the number of dairy conversions are expected to be between 50-90 per annum. By 2011 the milk processing capacity of the region is expected to be reached. Additional capacity will be required which can be provided at the existing Fonterra facility at Edendale or at new location (likely to be either connected to the Gore or North Makarewa GXPs).

The new processing plant is estimated to have a peak load of 7MW and will take about a year from construction to operation. If the plant is at Fonterra's existing premises it is likely to only produce an additional 4MW to peak load because of the opportunities for load-spreading within the plant. If this growth in the dairy industry continues, it is likely another processing plant will be needed in about 4-5 years time.

From our discussions, we have established there are potentially 2 step load changes in the dairy industry in the lower South Island, both being additional milk processing plants. As the milk processing is a competitive industry in the region, it is difficult to determine the location of the new processing plants.

Mataura Valley Milk's air and storm water consents were approved in late 2008 which means a milk processing factory is one step closer at the McNab site in Gore. We have assumed this plant is likely to go ahead which will result in step load change at the Gore GXP. The 7MW load is spread over a few years from construction to full operation.

A second additional processing plant is a possibility for the region. This will depend on the rate of dairy conversions and the growth of the milk supply. We have assumed an additional plant may be located at the Fonterra facilities in Edendale under our prudent forecast in 2015-2016.

The reason the second additional plant is only under our prudent forecast is because they is relatively little information on the medium and long term outlook for this industry. We expect the recent trends to slow slightly in the short term due to the current global economic conditions making it harder for farmers to borrow funds for dairy conversion. There also are constraints on the availability of water for irrigation and security of electricity supply issues.

Dairy conversions are shown as dairy growth in our forecasts for the Edendale, Gore, Invercargill and North Makarewa GXP's. Our expected forecasts assume this growth will remain until 2013-2014 whereas our prudent forecasts use a higher growth rate over the entire time period.

5.2 Meat Processing

As a consequence of the recent high growth in the dairy industry, there has been a reduction in meat production. In the upcoming season, Alliance Group are expecting a reduction in lamb production of 10% and mutton kill of 25% with beef production remaining constant. Approximately 90% of Alliance's meat production is from lamb. It is likely that there will be a shortening of the season as a result. It is likely that Alliance may need to close some plant in the Southland Region.

Silver Fern Farms have also felt similar effects. The Burnside venison plant closed down earlier this year and the Silverstream refrigeration plant is currently beginning sold to Polarcold.

With additional dairy cows beef processing may also increase especially in the dry summers. With a dry summer there is little grass growth so farmers need to have some of their stock killed to protect the grass for subsequent seasons.

Our forecasts assume that the some of the processing plant at Mataura will be closed which will halve the peak load from 6.5MW to 3.25MW in the summer of 2010/11. The closure of the Burnside plant (load 1.4MW) wouldn't have been seen in the current years load so has been deducted from the start of next years.

5.3 Timber Processing

Dongwha Pattina specialise in producing Medium Density Fibreboard (MDF). They are not anticipating any load changes in the foreseeable future. The current economic situation may result in a decrease in demand for their product but it's unlikely to cause any change in peak load. The plants still operate at full capacity when the demand is there. There may be a decrease in energy consumption but not peak load.

5.4 Oil and Gas Exploration

Exploration licenses were issued in the middle of last year for oil, gas and minerals in the great southern basin. The area is over 500,000 sq km making it one of New Zealand's largest petroleum basins. Recent exploration may show it has the thick sediments to produce the necessary hydrocarbons. Two major investors ExxonMobil and OMV are currently conducting seismic tests to confirm the stability of the area to ensure it is not affected by large scale seismic faults that are found in most of New Zealand's basins.

The initial exploration is expected to take between 1-5 years, with offshore exploration and drilling in 2-10 years and development and production in 10-25 years.

There a number of variables that will determine whether it reaches the development stage. Discovery of oil and gas, large enough fields, ease of access to the field, current oil prices, security of electricity supply and emissions trading among many others. Currently we are at the initial stages of exploration with only $1.2m committed. The possibility of potential LNG plant at this time is purely speculative.

We haven't included the LNG plant in our forecasts due to its speculative nature.

5.5 Coal/Lignite

The Southland Region has 75% of New Zealand recoverable lignite reserves. Most of these deposits are located in the Mataura and Waituna Ashers area. Two companies, Solid Energy and L+M Lignite, are currently in phase 2 of the feasible study. L+M Lignite expect to complete their feasibility study in three years time and if the conditions support it they hope to begin planning and construction straight away. Production in the lignite to liquids process is expected to begin after 3.5 years from the start of construction. It is likely that only one plant will be developed in the region. L+M Lignite plan to be self-sufficient in their energy consumption with on-site generation of 690MW. A grid connect is also likely to supplement L+M Lignite's additional power needs or to inject electricity into the grid depending on commercial and/or political reasons. We were unable to obtain details of Solid Energy's plans.

As these projects are in the early stages of their feasibility studies they are very much speculative. The lignite to liquids plant proposed by L+M Lignite has on site generation to match its consumption. If Solid Energy's proposal is similar in its energy policy, there will be no increase to peak demand regardless of what project goes head. We have not included lignite mining and processing in our load forecasts for these reasons.

Solid Energy has contacted Transpower with plans for a pilot plant which converts coal to brickettes which will have a load of 1.2MW from 2010. If successful, a full commercial operation will be undertaken in 2012 which add between 15-20MW. This will be connected to the Gore GXP. We have been unable to confirm this with Solid

Energy. Our expected forecasts include 1.2MW for the pilot plant in 2010 and our prudent forecast also includes 5.8MW in 2011 and 10.5MW in 2012 to give a total load of 17.5MW.

5.6 Other Minerals

Southland contains a large amount of silicon reserves estimated to be in the order of a billion tonnes of 98% pure silicon oxide. Three international companies have shown some serious interest but no significant investment. The processing plant is estimated to require 100MW which may come from the national grid or embedded generation from local coal. The initial timeframe for construction to begin is 2013 with production starting in 2016. We have not included this potential load in the forecasts due to its speculative nature. A silicon smelter requires security of electricity supply and with the uncertainty in this in the Southland Region it may prove to be too bigger risk to the potential investors.

There are many other overseas companies in various industries such as coal, steel, chemicals and oil and gas that have shown interest in setting up business in the lower South Island but the vast majority are frightened off by the security of supply issues that face the region. They feel that it is too risky with the uncertainty of supply especially in the dry years.

5.7 Aluminium Smelter

The aluminium smelter at Tiwai Point operates under the Tiwai Point Connection Contract (TPCC). Under this agreement, New Zealand Aluminium Smelters operates at a maximum of 610MW until the end of 2012 (expiry of TPCC). This constrains the smelter as it can utilise 620MW at full cell capacity. By replacing transformers the smelter can potentially use 640MW. NZAS hopes to increase load to 620MW by Jan 2009 and 640MW by Jan 2011. In the long term (5 years +) NZAS is looking to increase production to 700MW which would require significant capital investment ($200million) as well as long term electricity price contracts and sufficiently high metal prices. Currently this is highly speculative.

In May 2008 NZAS reduced their load by 5% due to the dry summer and the below average lake levels. In June they dropped their load by a further 5% to give a peak load of approximately 540-550MW until October. During October, NZAS began to ramp up their operations but during the first week of November a transformer was lost resulting in the current peak load of approximately 420MW. The transformer was due to be repaired within 6 weeks and will take at least 3-4 months (possibly twice as long) to get back to full operations. Another transformer is on order with potentially another one being ordered shortly. This investment would be sufficient for the smelter to reach 640MW.

According to the minutes of the Lower South Island Stakeholder Conference, NZAS is facing problems explaining the security issues due to the New Zealand market operation and the plant's remoteness from generation (security of supply) to its owners. The emission trading scheme will also have a large impact on the long term viability of the smelter. Together with the current transformer problems, there is some uncertainty and risk in the companies continued operations.

Our expected and prudent forecasts assume the 2009 summer peak will ramp up 25% and 50% respectively of the way to 619.4MW. It is forecast to reach the 620MW limit in winter 2009 and 640MW and 635MW in the summer of 2011 and 2012 for the prudent and expected forecasts respectively.

6 Lower South Island Load Forecasts

The expected and prudent forecasts are comprised of the step load changes outlined in the previous section and organic growth rates. The organic growth rates used in our forecasts are based on the growth rates in the Electricity Commissions (EC) forecasts, network companies' Asset Management Plans (AMP) and historic rates. A comparison of these rates is shown in Table 8 below.

Table 8: Growth Rates for GXP from various sources.

GXP		Historic				Electricity Commission		AMP	Network Company
	1998-2008	2003-2008	2007-2012 Mean	2007-2012 Prudent	2012-2018	2007-2018 Mean	2007-2018 Prudent	2007-2017	2007-2011
Balclutha	0.8%	1.3%	1.1%	3.2%	0.4%	0.8%	1.7%	0.5%	0.5%
Brydone	0.1%	-0.6%	1.5%	3.6%	0.7%	1.1%	2.0%		
Clyde	1.1%	7.8%	5.9%	8.0%	4.0%	4.8%	5.8%	1.0%	-0.3%
Cromwell	7.3%	8.9%	2.1%	4.2%	1.3%	1.7%	2.6%	5.6%	5.1%
Edendale	5.3%	3.5%	1.1%	3.1%	0.4%	0.7%	1.6%	4.1%	2.5%
Frankton	4.8%	5.2%	1.8%	3.9%	1.1%	1.4%	2.3%	4.1%	4.1%
Gore	-0.2%	-1.1%	1.2%	3.2%	0.5%	0.8%	1.7%	2.2%	1.0%
Halfway Bush	2.0%	5.2%	1.8%	3.9%	1.1%	1.5%	2.4%	1.0%	0.6%
Invercargill	0.8%	2.1%	1.0%	3.1%	0.4%	0.7%	1.6%	0.6%	0.8%
Naseby	3.7%	-0.5%	1.6%	3.6%	0.9%	1.2%	2.1%	1.5%	1.5%
North Makarewa	8.0%	7.8%	1.2%	3.3%	0.5%	0.9%	1.8%	2.2%	0.7%
Palmerston	1.3%	5.8%	1.1%	3.2%	0.4%	0.7%	1.7%	0.5%	0.5%
South Dunedin	1.3%	2.6%	1.3%	3.4%	0.7%	1.0%	1.9%	1.0%	1.2%
Tiwai	0.7%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%		

In some cases there are significant differences between the forecast growth rates for GXPs, for example the EC mean forecast for Clyde is 4.8% compared with the AMP of 1.0% and Cromwell's mean EC forecast is 1.7% compared to 5.6% in the AMP. All of these growth rates incorporate the total load growth; step load, building and construction developments, dairy growth as well as base load growth. The base load growth needs to be separated out from these factors.

The EC and AMP forecasts don't include any step load changes but the historical figures indicate there have been a few in the region over the last decade, such as Naseby in 1999, North Makarewa 2001, Palmerston 2008 and Tiwai 1998, 2002.

Upon consultation with the various stakeholders, development and dairy growth has been able to be estimated. Development growth is the result of medium scale building and construction developments that are not large enough to be step loads but are not put of base load growth. The development growth rates are shown in Table 9 below.

Table 9: Development Growth Rates by GXP

GXP	Expected		Prudent	
	Summer	Winter	Summer	Winter
Balclutha				
Brydone				
Clyde				
Cromwell	2.5%	3.0%	3.0%	3.5%
Edendale				
Frankton	2.0%	2.5%	3.0%	3.5%
Gore				
Halfway Bush	1.0%	1.0%	1.5%	2.0%
Invercargill	0.25%	0.25%	0.5%	0.5%
Naseby	1.0%	1.0%	1.0%	1.0%
North Makarewa				
Palmerston				
South Dunedin	0.5%	0.5%	1.0%	1.0%
Tiwai				

The development growth extends for different lengths of time for each of the GXPs. Cromwell and Frankton are over a ten year period, Halfway Bush and Naseby are over a five year period and Invercargill is for three years. The expected development growth for South Dunedin is for five years and the prudent development growth is for ten years but at half the rate after the first five years.

Dairy growth is the result of dairy conversions, additional milk sheds and other small scale expansions. The dairy growth rates are shown in Table 10 below.

Table 10: Dairy Growth Rates by GXP

GXP	Expected		Prudent	
	Summer	Winter	Summer	Winter
Balclutha				
Brydone				
Clyde				
Cromwell				
Edendale	3.0%	1.5%	4.0%	2.0%
Frankton				
Gore	3.0%	2.25%	4.0%	3.0%
Halfway Bush				
Invercargill	0.25%	0.125%	0.5%	0.25%
Naseby				
North Makarewa	2.5%	1.25%	3.0%	1.5%
Palmerston				
South Dunedin				
Tiwai				

There are only four GXPs where dairy growth has been included. Higher growth is expected at Edendale and Gore than North Makarewa as they are closer to the major milk production plants. Gore has a higher winter growth rate than Edendale because of the potential production plant being located there. There is only minor growth at Invercargill. The expected dairy growth is for a six year period whereas the prudent dairy growth is for ten years. Gore and Invercargill have half the rate for the last four years of the prudent dairy growth. Under the expected forecast, the dairy growth allows of approximately 56 dairy conversions in the lower South Island region in 2009, the prudent forecast allows for 73 dairy conversions. This is at the lower end of Fonterra's estimates and well below Venture Southland's. This is because of the global recession in which it has become more difficult to obtain funds for expansions and conversions and the reduction in dairy payouts.

Table 11: Base Load Growth Rates by GXP

GXP	Expected			Prudent
	Summer	Winter	Summer	Winter
Balclutha	0.5%	0.5%	0.5%	0.5%
Brydone	1.0%	1.0%	1.5%	1.5%
Clyde	1.5%	1.5%	1.5%	1.5%
Cromwell	1.5%	2.0%	1.5%	2.0%
Edendale	1.0%	1.0%	1.0%	1.0%
Frankton	1.5%	1.5%	1.5%	1.5%
Gore	1.0%	1.0%	1.0%	1.0%
Halfway Bush	0.5%	0.5%	0.5%	0.5%
Invercargill	0.5%	0.75%	0.5%	0.75%
Naseby	0.5%	0.5%	1.0%	1.0%
North Makarewa	1.0%	1.0%	1.0%	1.0%
Palmerston	0.5%	0.5%	1.0%	1.0%
South Dunedin	0.5%	1.0%	0.5%	1.0%
Tiwai	0.0%	0.0%	0.0%	0.0%

The base load growth rates are shown in Table 11 above. They are applied over the entire twenty year period. They are determined by approximately matching the overall growth rates in Table 12 with the forecast rates from the Electricity Commission, Asset Management Plans and the network companies and also taken into account the historic growth rates.

Table 12: Overall Growth Rates from 2008-2018 excluding Potential Step Loads

GXP	Expected			Prudent
	Summer	Winter	Summer	Winter
Balclutha	0.5%	0.5%	0.5%	0.5%
Brydone	1.0%	1.0%	1.5%	1.5%
Clyde	1.5%	1.5%	1.5%	1.5%
Cromwell	4.0%	5.0%	4.5%	5.5%
Edendale	2.8%	1.9%	4.2%	2.6%
Frankton	3.5%	4.0%	4.5%	5.0%
Gore	2.8%	2.3%	4.2%	3.4%
Halfway Bush	1.0%	1.0%	1.2%	1.5%

Invercargill	0.7%	0.9%	1.0%	1.1%
Naseby	1.0%	1.0%	1.5%	1.5%
North Makarewa	2.5%	1.7%	4.0%	2.5%
Palmerston	0.5%	0.5%	1.0%	1.0%
South Dunedin	0.7%	1.2%	1.2%	1.7%
Tiwai	0.0%	0.0%	0.0%	0.0%

The overall growth rates have been determined to more closely resemble the AMP growth rates. Balclutha's growth rate is the same as forecast in the AMP and by the network companies. There is no forecast for Brydone in the AMP, the growth rate is less than the Electricity Commission's forecast to take into account the recent low growth. Clyde's forecast is slightly above the AMP forecast to allow for the strong recent growth but is still well below the Electricity Commission's forecasts. Cromwell and Frankton have experienced strong growth over the last decade and this is expected to continue but at a slightly lower rate than forecast in the AMP. Prudent growth at Edendale is in line with the AMP whereas the expected growth is closer to the network company forecast. Gore's growth rate is higher than historic trends and all for the other forecasts. This is due the anticipated dairy expansion in the region. The Dunedin GXPs of Halfway Bush and South Dunedin have growth rates similar to the AMP with South Dunedin having a slightly higher winter forecast due to the higher network company forecast. Invercargill's growth rate is slightly above the AMP rate due to stronger growth over the last few years. Naseby's prudent forecast is the same as the AMP and network company rates but its expected growth rate is lower due to low growth over the last five years. The expected growth at North Makarewa is similar to the AMP rate but the prudent growth rate is higher due to the strong recent growth. Palmerston expected growth rates are the same as the AMP and network company rates, prudent is higher due to more potential load transfers from Naseby. All growth at Tiwai is expected to be from step load changes.

The base load, development and dairy growth are added to the potential step loads mentioned in the previous section. These are included in Table 15 in the appendix.

There is a significant amount of embedded generation, approximately 150MW, in the lower South Island. The majority of generation is in the North Makarewa GXP area (65.5MW), Halfway Bush GXP area (44MW) and the Naseby GXP area (15MW). Embedded generation reduces the load on the national grid but doesn't add much to the security of supply. If, for some reason, the embedded generation cannot be produced, the electricity demand will have to be supplied from the national grid.

Transpower provided us with embedded generation data from Waipori (Halfway Bush GXP) over the last couple years. This allowed a total load for the area, GXP load plus embedded generation, to be calculated. This gives a comparison between the area peak load and the GXP load. For Halfway Bush the combined GXP plus embedded generation peak load (at the 99.9% percentile) was approximately 10MW and 3MW higher for summer and winter 2008 respectively. For 2007 the values were about 14MW and 13MW. Our prudent forecasts have allowed for embedded generation to fall to zero at peak times. 14MW are added to produce the prudent summer and winter forecasts for Halfway Bush. Due to the difficulty in accessing embedded generation for Whitehill (58MW near the North Makarewa GXP), Powernet have estimated that 58.0MW would be a reasonable figure for the prudent summer forecast for 2009. According to our forecasts, this projected load indicates that the combined GXP load and embedded generation is only 4.3MW above the peak GXP load. This indicates that only 7% (4.3/65.5) of the embedded generation is running at peak times. The prudent forecasts for North Makarewa include the 4.3MW for embedded generation failure.

For embedded generation near other GXPs with the exception of Clyde and Naseby, we have assumed that the embedded generation is operating at peak times so the full embedded load is included in the prudent forecast. For the Clyde GXP, which has historically had a significant amount of variation in GXP load due to the timing of the use of embedded generation, we have assumed 3.3MW is operating at peak times which is less than a third of the 11MW embedded generation. In 2008 there was very little embedded generation produced at Naseby as it was a dry year. There was only a small increase in load at the Naseby GXP which can be attributable to base load growth. As a result we can conclude that there is little embedded generation at Naseby produced at peak loads, therefore we have assumed that less than 4MW (a quarter of available generation) will be operational at peak times. We have assumed embedded generation in all areas will remain constant at the current levels.

The prudent forecasts also include a buffer level in case of increases in load due to unpredictable events such as weather. The weather has a large impact on GXP load, dry years result in increased irrigation usage and cold snaps cause an increase in heating. We have used the variation over the last 10 years to estimate an appropriate level for the buffer for each GXP. No buffer is provided for GXPs with a significant amount of embedded generation.

Within the region there is large amount of temporary load transfers between GXPs due to load management, maintenance, capacity restraints and pricing. Forecasting these load tranfers is beyond the scope of this report however it is assumed the summer peaking GXPs of Edendale, Gore and North Makarewa may some load transfer during the winter period. Under the winter expected and prudent forecasts, we have assumed a temporary increase of 2% due to load transfers. No assumptions are made about load reductions due to transferring at any GXPs.

There have been some adjustments to the base value for which the forecasts are made. If historical data suggest a similar load between summer and winter, the base value for summer and winter has been equated to give equivalent forecasts for summer and winter. The initial scope for this report was until 2018, but this has been extended a further ten years to 2028. Our consultation with the stakeholders in November 2008 over potential step load changes was only concerned with the next decade. From 2019-2028 we have assumed that each GXP load will increase at the base load growth rate shown in Table 11. A sample of a load forecast is shown as Table 16 in the appendix.

The summer and winter, expected and prudent forecasts are shown in Table 17 to Table 20 in the appendix and the following figures.

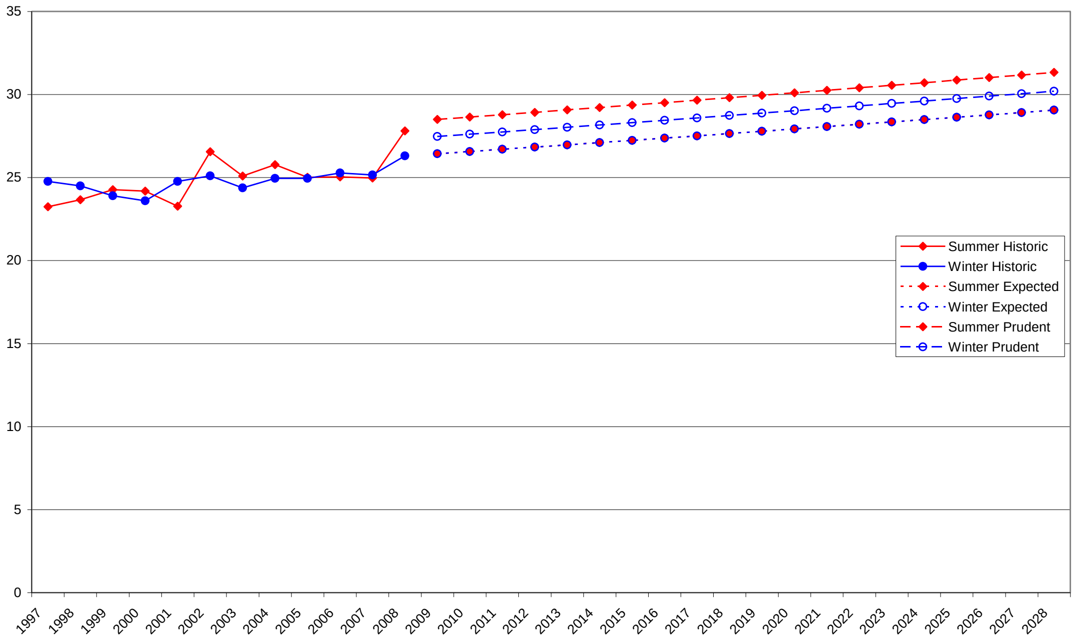


Figure 20: Balclutha GXP Load Forecast

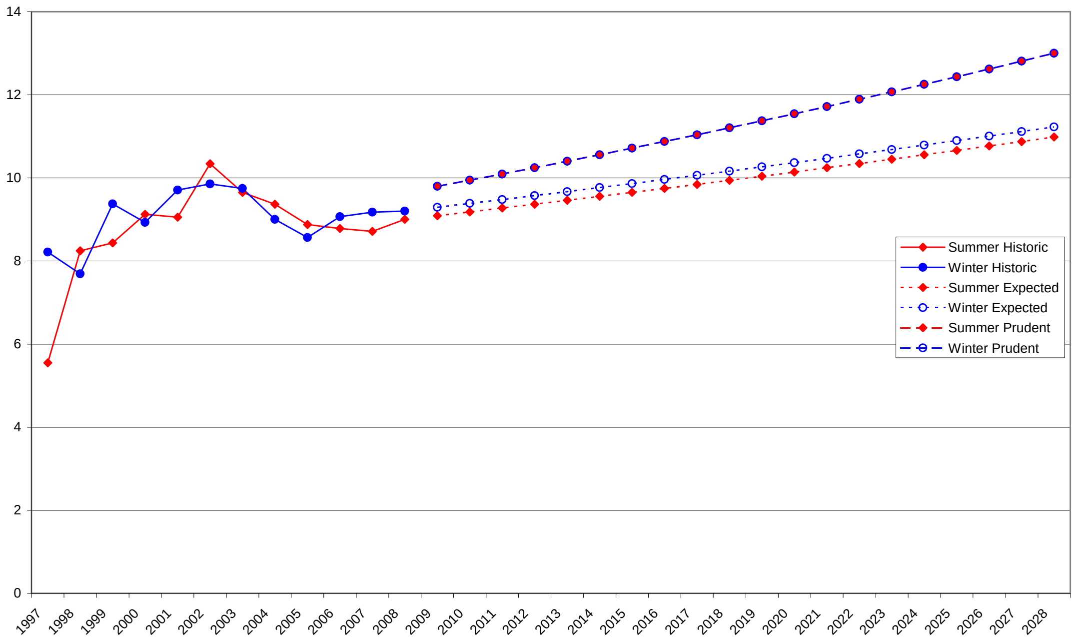


Figure 21: Brydone GXP Load Forecast

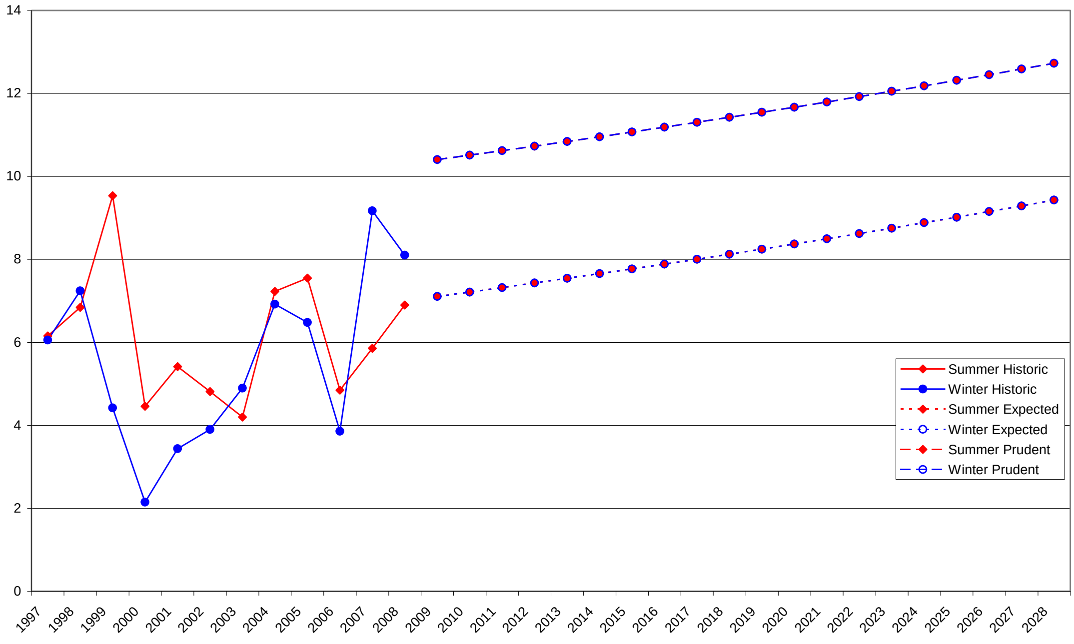


Figure 22: Clyde GXP Load Forecast

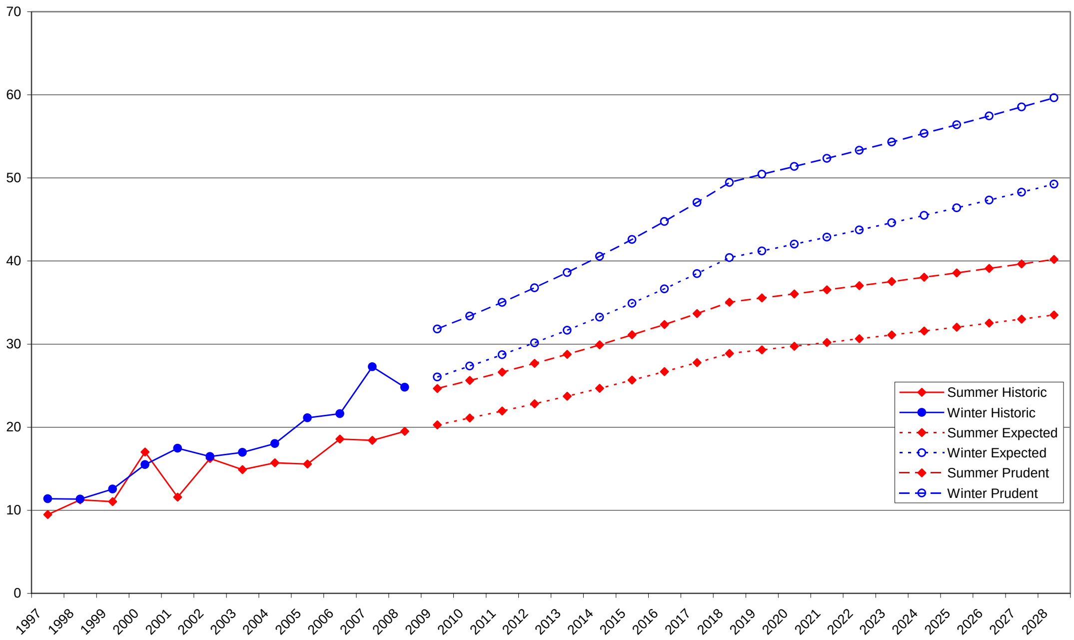


Figure 23: Cromwell GXP Load Forecast

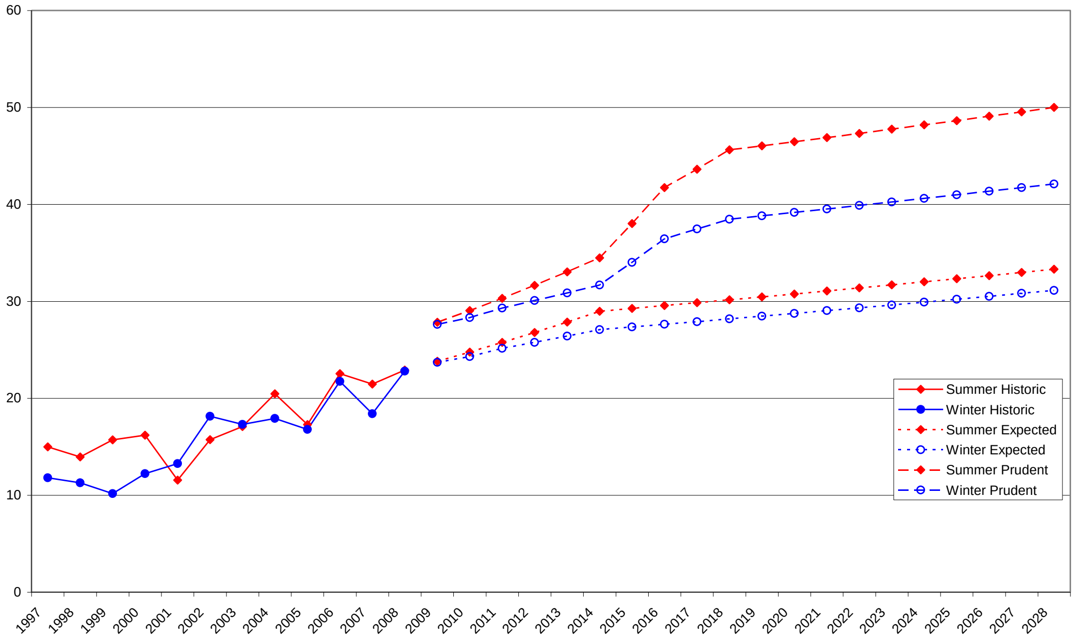


Figure 24: Edendale GXP Load Forecast

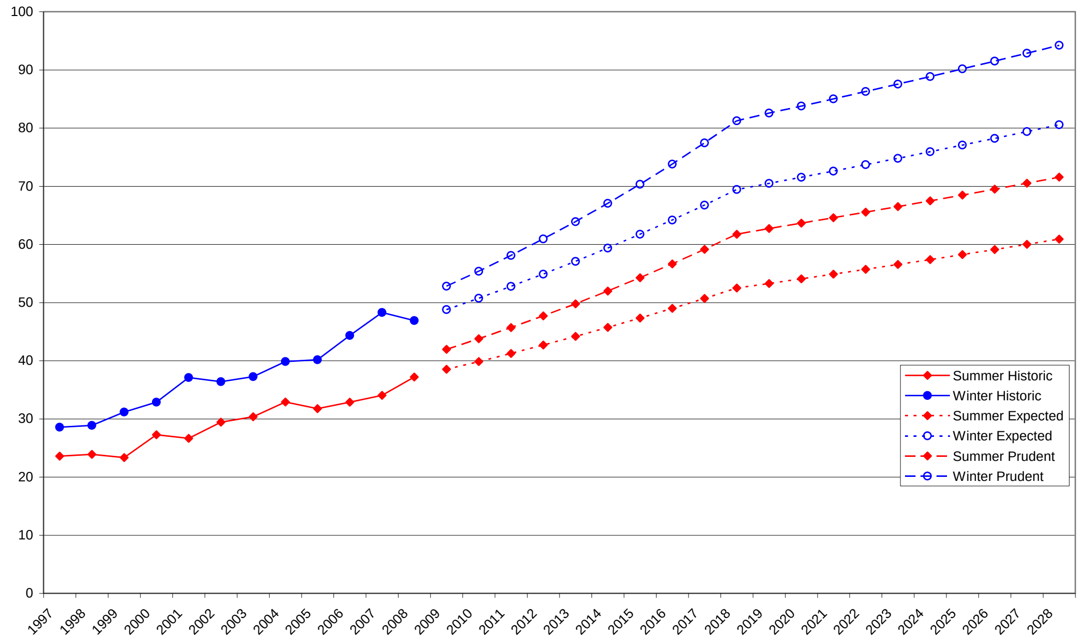


Figure 25: Frankton GXP Load Forecast

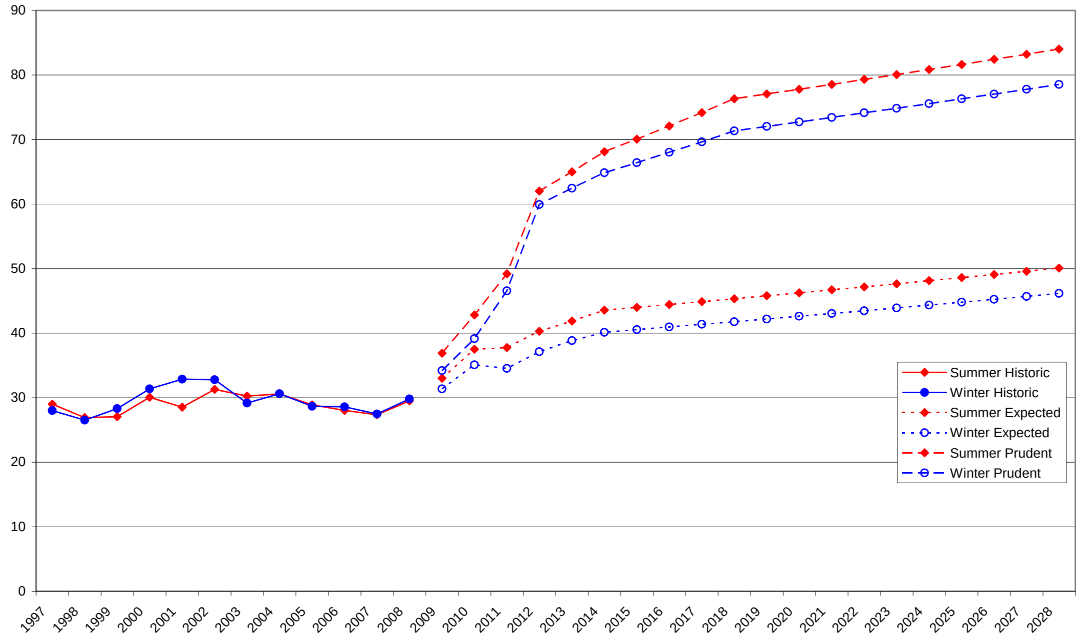


Figure 26: Gore GXP Load Forecast

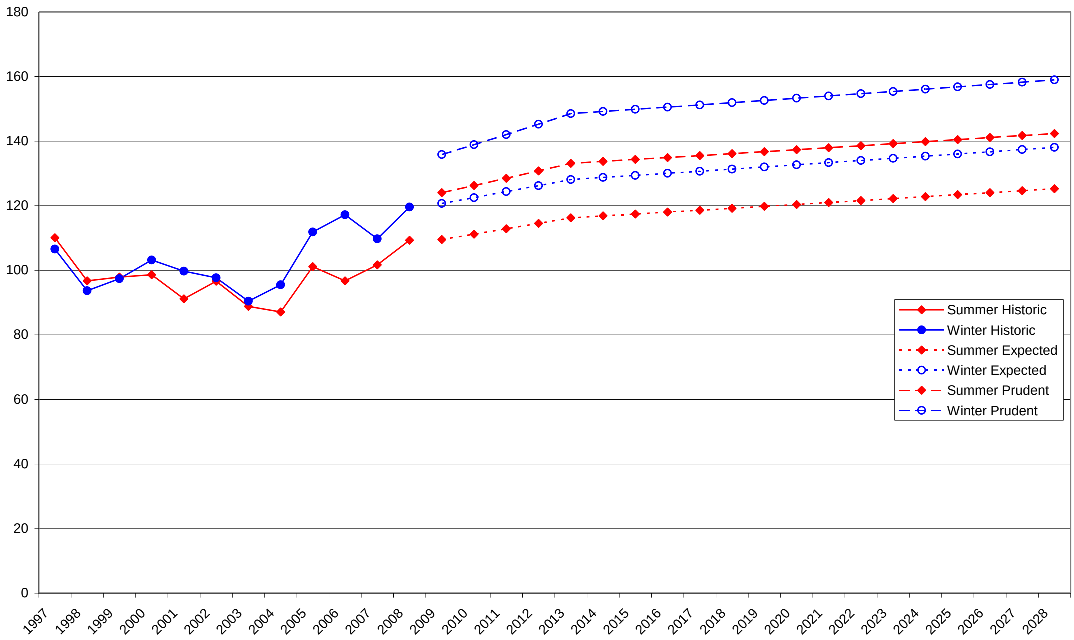


Figure 27: Halfway Bush GXP Load Forecast

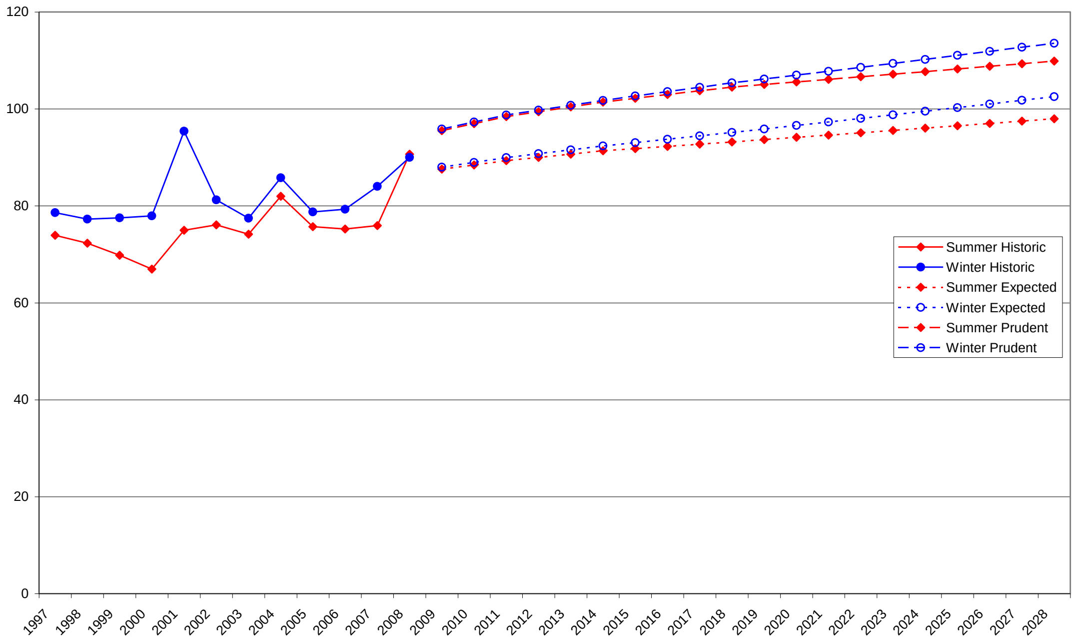


Figure 28: Invercargill GXP Load Forecasts

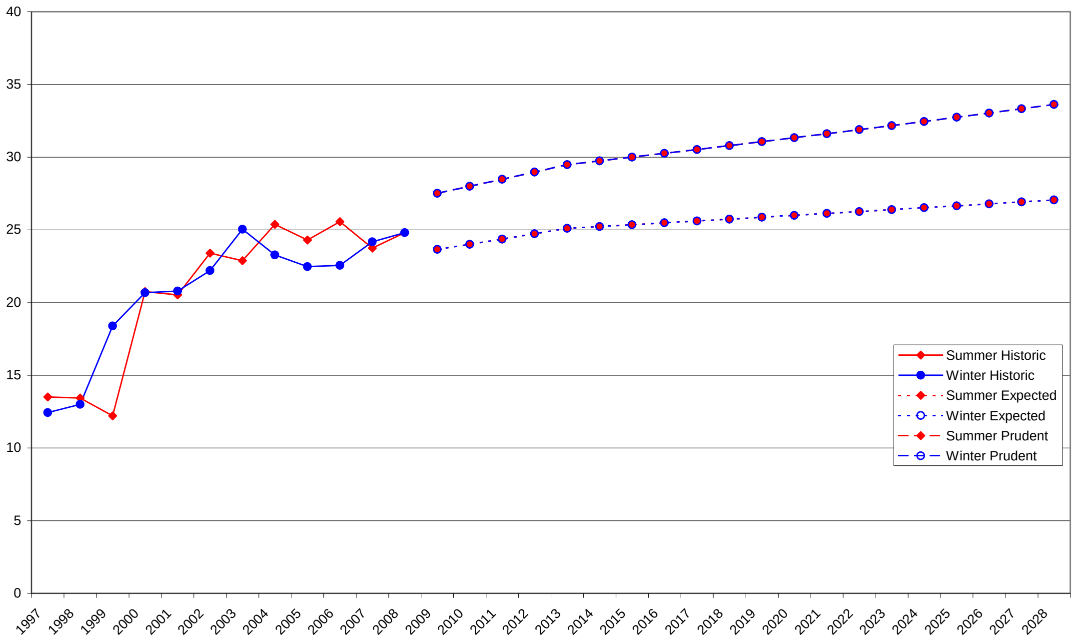


Figure 29: Naseby GXP Load Forecast

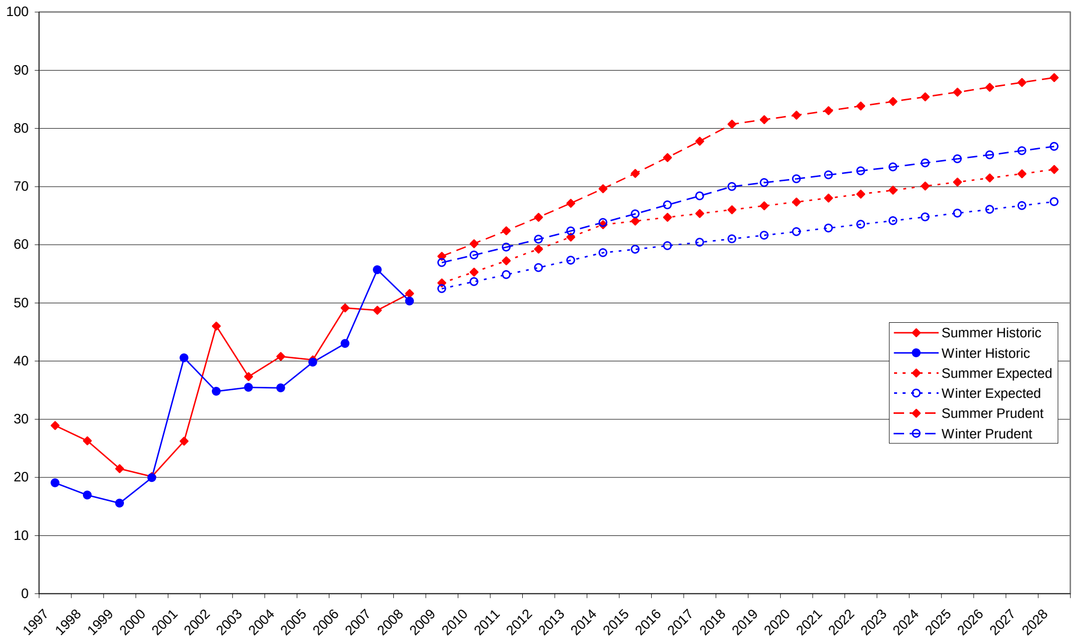


Figure 30: North Makarewa GXP Load Forecast

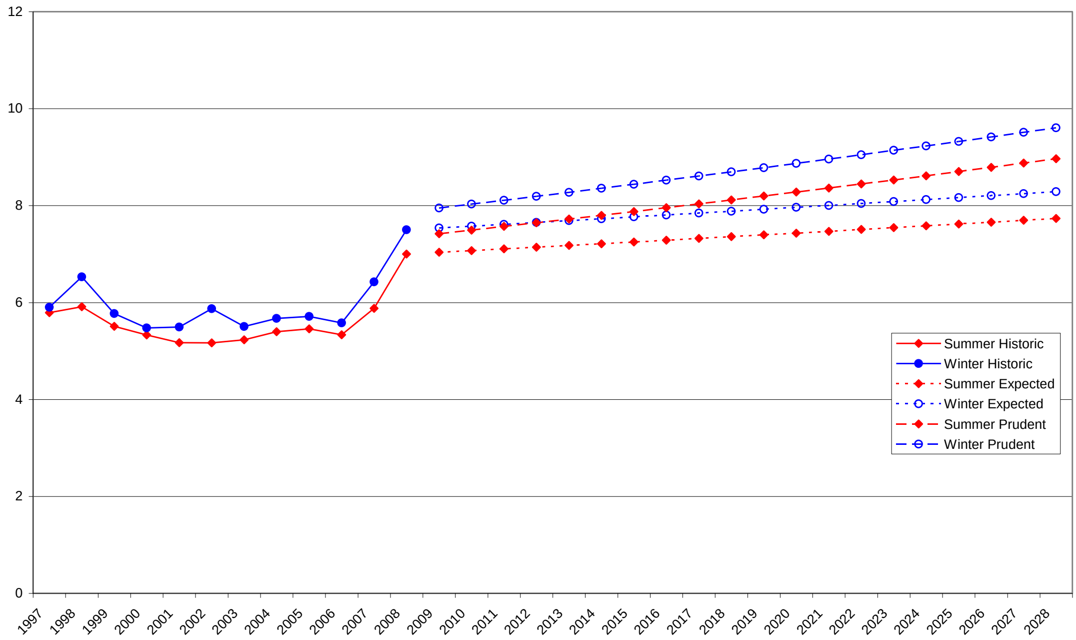


Figure 31: Palmerston GXP Load Forecast

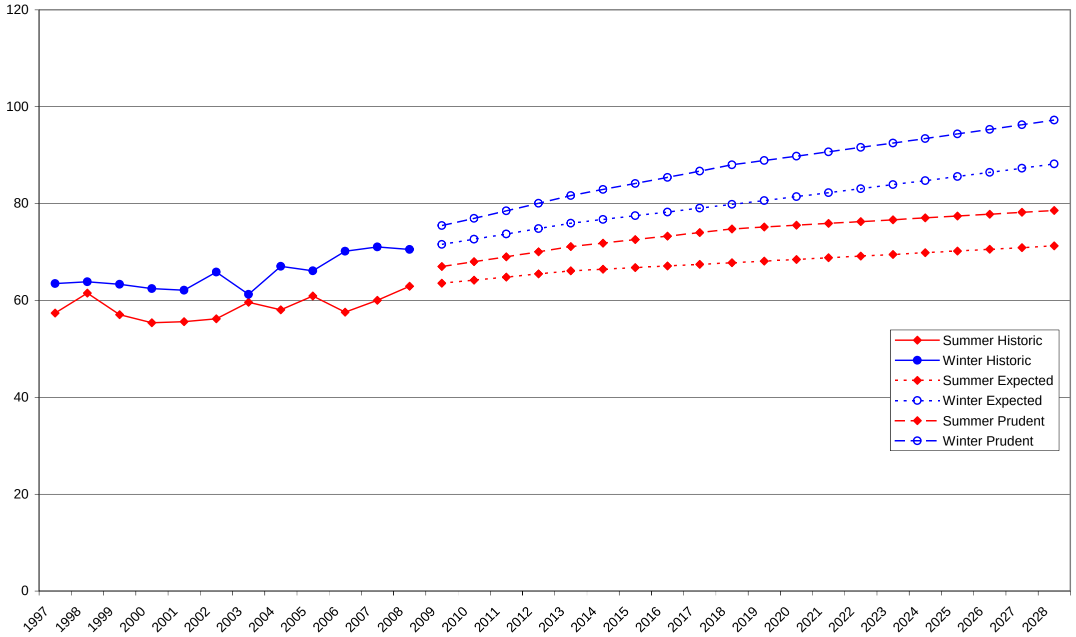


Figure 32: South Dunedin GXP Load Forecast

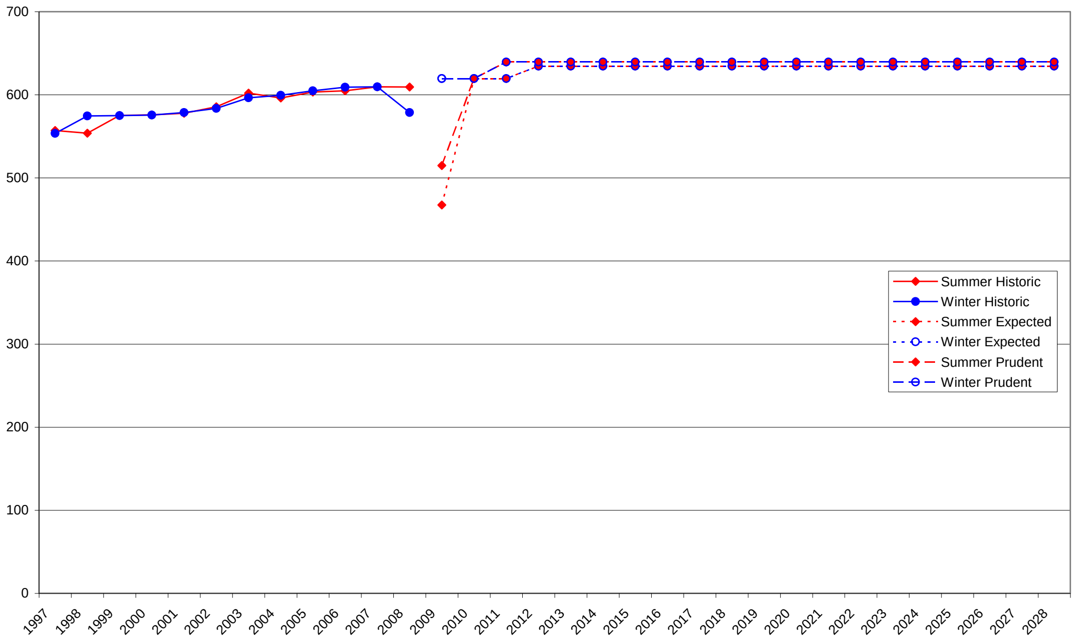


Figure 33: Tiwai GXP Load Forecast

The expected load for the lower South Island region can be found by summing the product of the expected peak load for each GXP with its corresponding diversity factor. The 2007 summer and winter diversity factors for the region have been provided by Transpower and are shown in Table 15 in the appendix. The prudent load for the region cannot be found using the same method as described above as this would result in a probability of exceedence (PoE) of significantly less than 10%. The probability of all the GXPs being at their forecasted prudent level in the same season is less than 10%. In order to determine the region's prudent forecast, a different method is employed. It is assumed that the future peak load at GXP level is normally distributed about the expected forecast. This allows a standard deviation to be calculated by using the prudent forecasts as a 10% PoE. Assuming independence between the peak loads of the GXPs allows the standard deviation for the region to be calculated as a weighted (by the diversity factors) sum of squares of the GXP standard deviations. The prudent regional forecast is determined from the expected forecast and the standard deviation.[20] The diversified regions are shown in the following two figures with the table in the appendix.

---

[20] Prudent = Expected + 1.28 × std dev. 1.28 is the z-value for a cumulative probability of 90%.

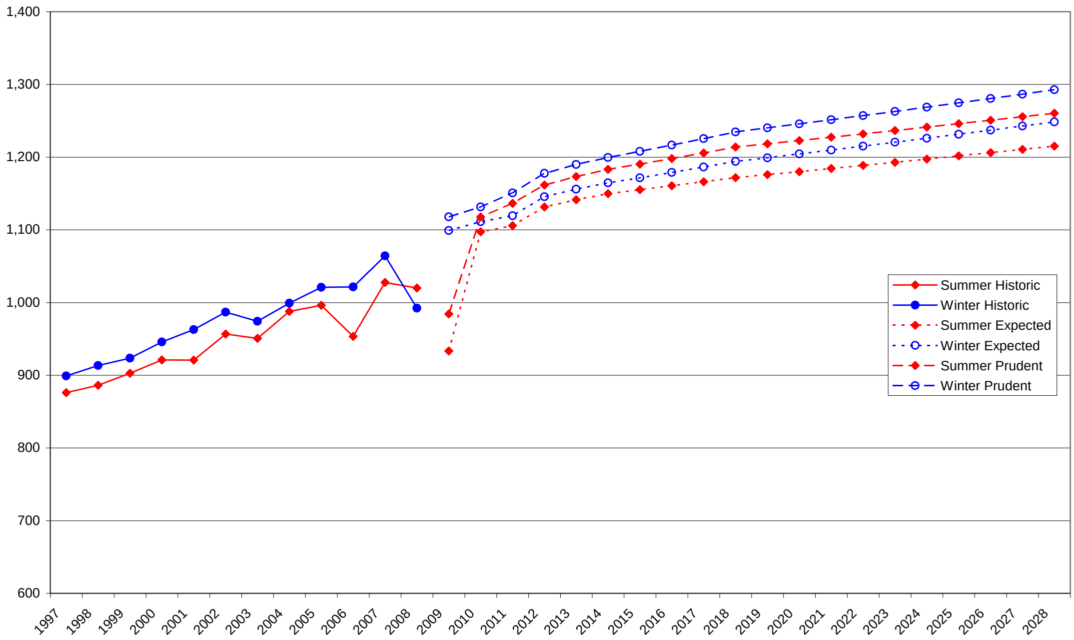


Figure 34: Diversified Load for the Lower South Island

Over the next twenty years the lower South Island's summer and winter load is expected to grow at an average annual rate of 0.6%. The prudent forecasts have summer and winter growth rates of 0.7%.[21] The 2028 expected diversified peak loads are 1,215MW and 1,248MW for summer and winter respectively. The prudent forecasts reach 1,260MW and 1,292MW for summer and winter respectively.

These forecasts include all potential step loads from the stakeholders that fall into at least the likely category. No speculation loads such as that from the development of a LNG plant, oil production and storage, coal to lignite plant, silicon smelter, capacity expansion at the aluminium smelter or any project of similar nature. These projects could potentially increase the lower South Island load by a few hundred megawatts above the forecasts in this report.

Figure 35 below shows a comparison with the Electricity Commissions forecasts. Covec's expected forecast is at a similar level to the Electricity Commission's prudent forecast for the next decade. In 2028, the Covec's expected forecast is over 100MW

---

[21] These growth rates are calculated from 2010 to 2028. This is because the reduced load at the aluminium smelter would artificially inflate the growth rates if calculated from 2008 or 2009.

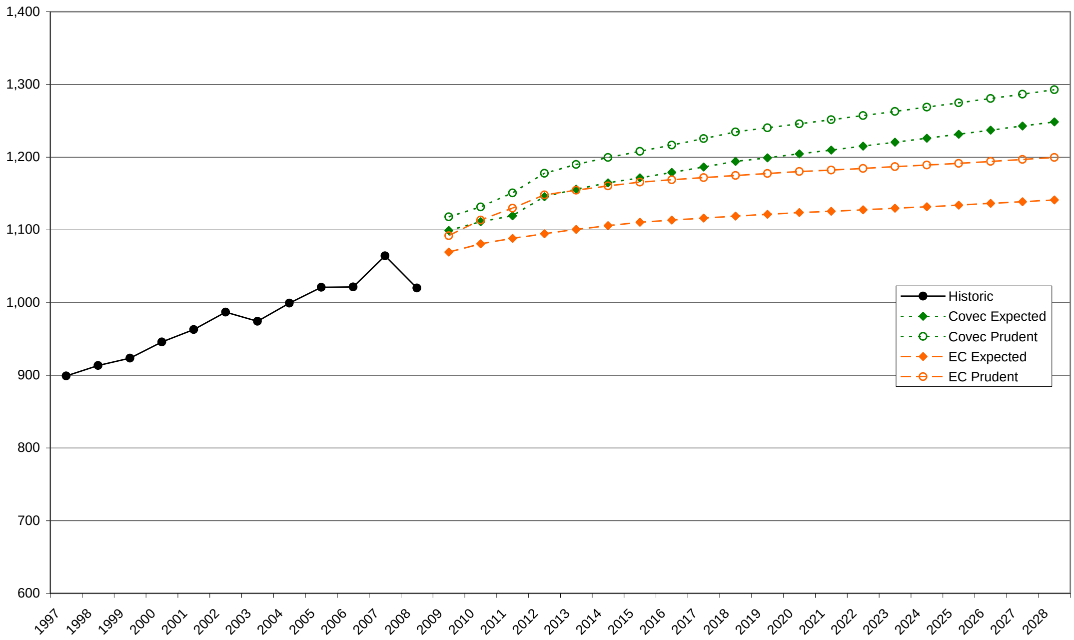


Figure 35: Diversified Peak Load Comparison

Appendix

Electricity Commission's 2007 Peak Demand Forecasts

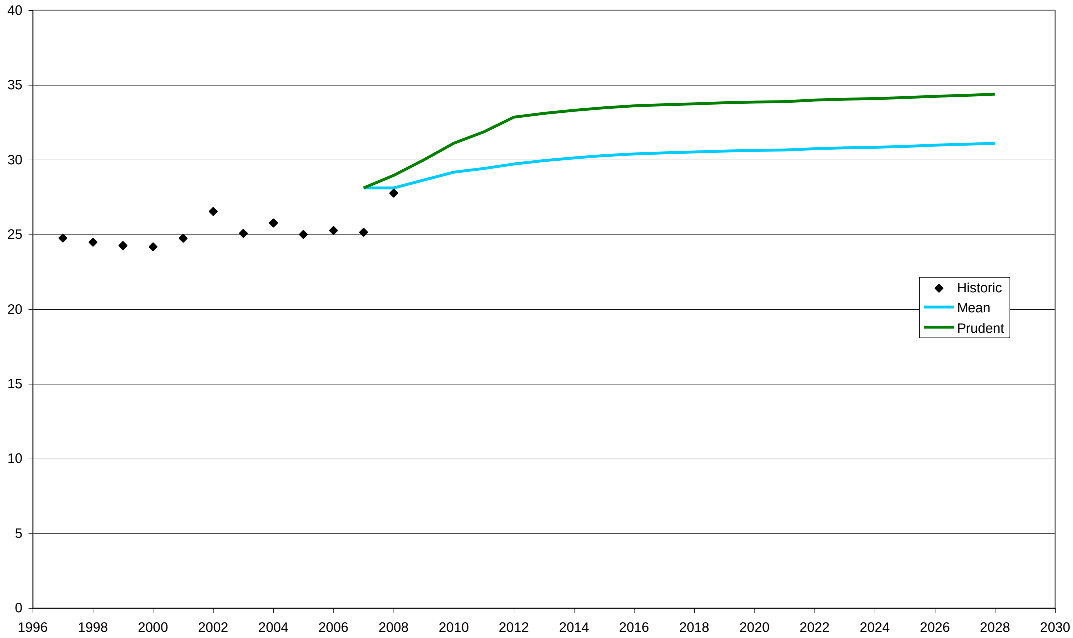


Figure 36: EC's 2007 Balclutha Peak Demand Forecast

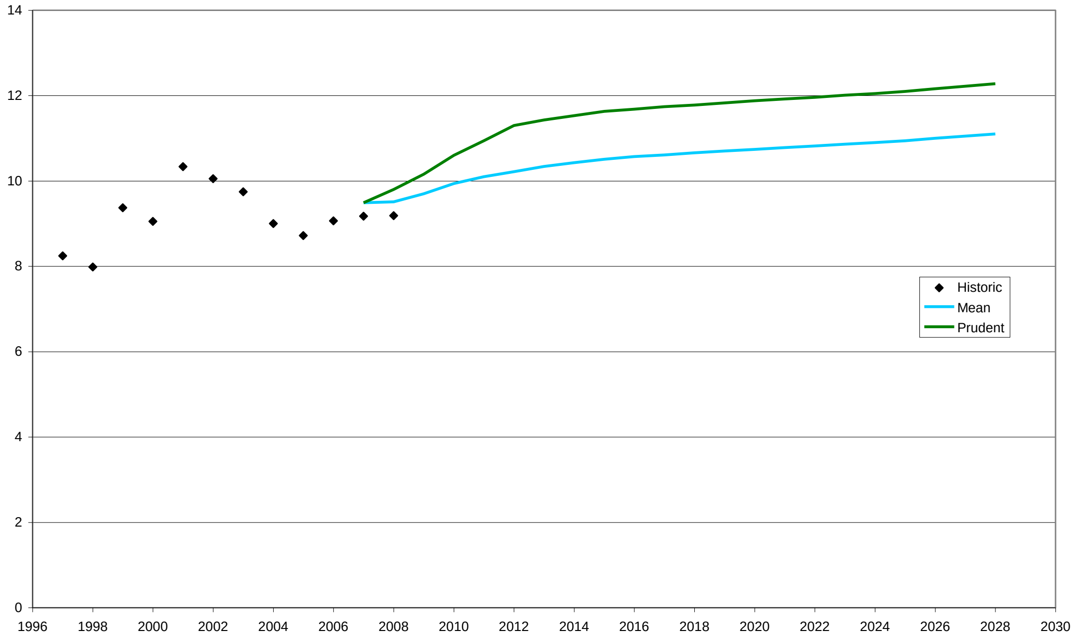


Figure 37: EC's 2007 Brydone Peak Demand Forecast

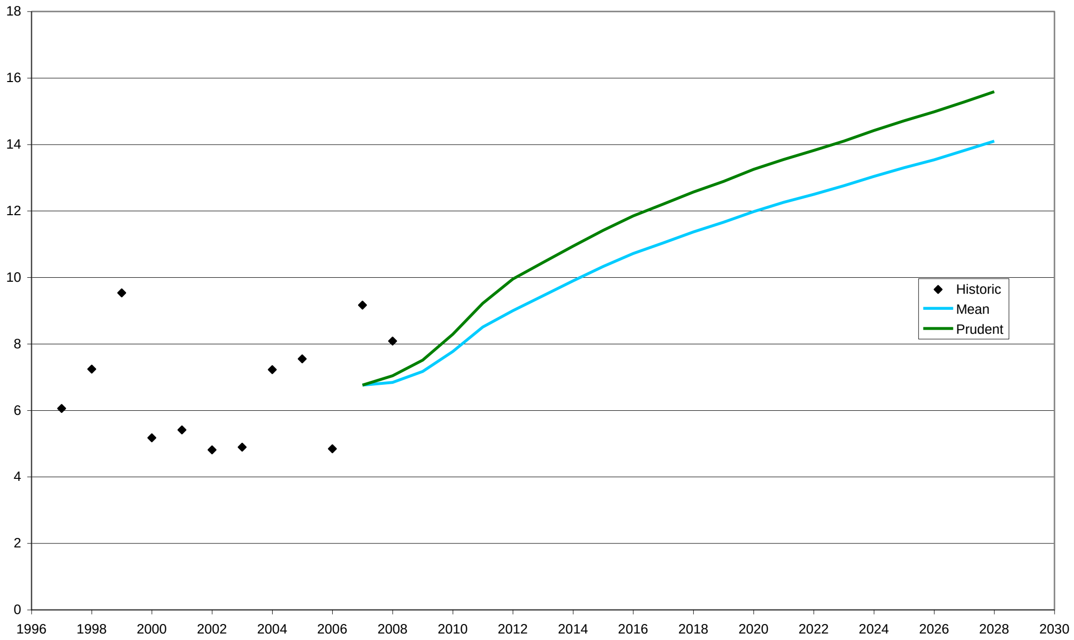


Figure 38: EC's 2007 Clyde Peak Demand Forecast

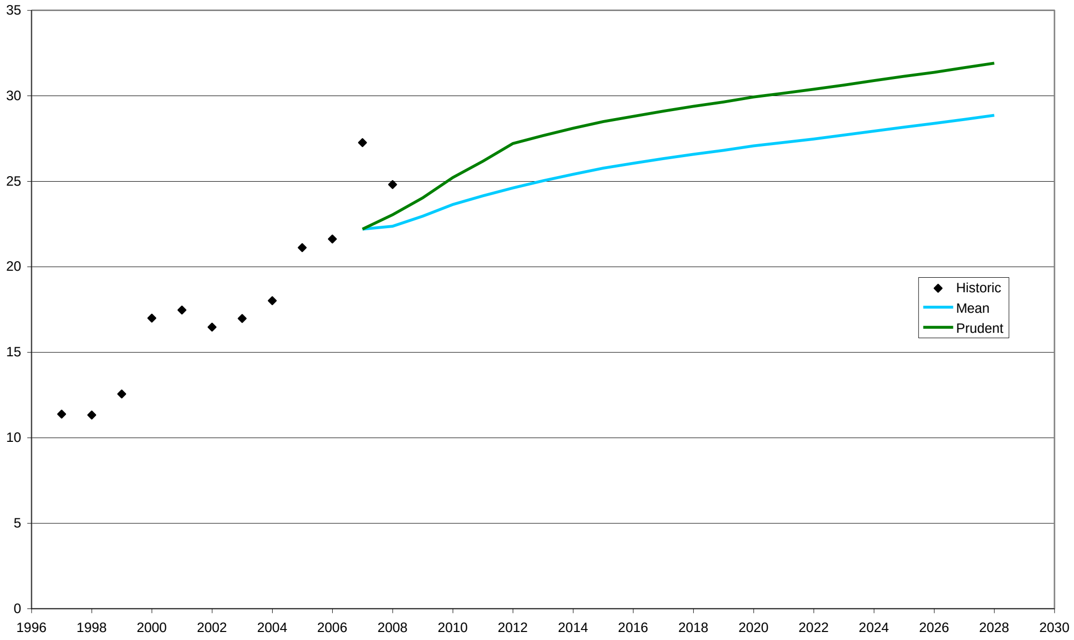


Figure 39: EC's 2007 Cromwell Peak Demand Forecast

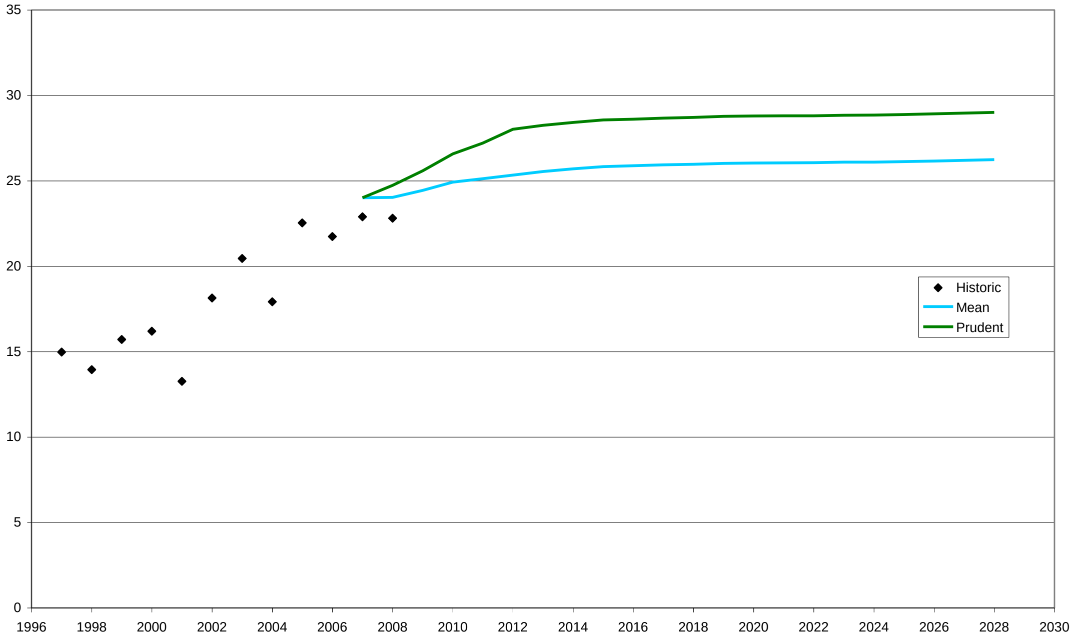


Figure 40: EC's 2007 Edendale Peak Demand Forecast

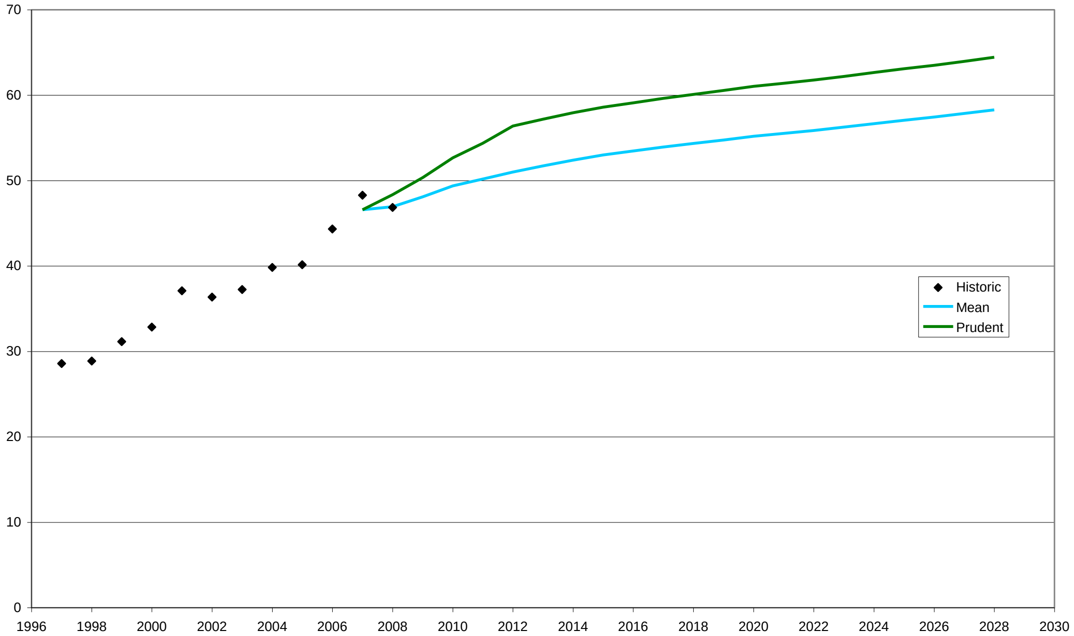


Figure 41: EC's 2007 Frankton Peak Demand Forecast

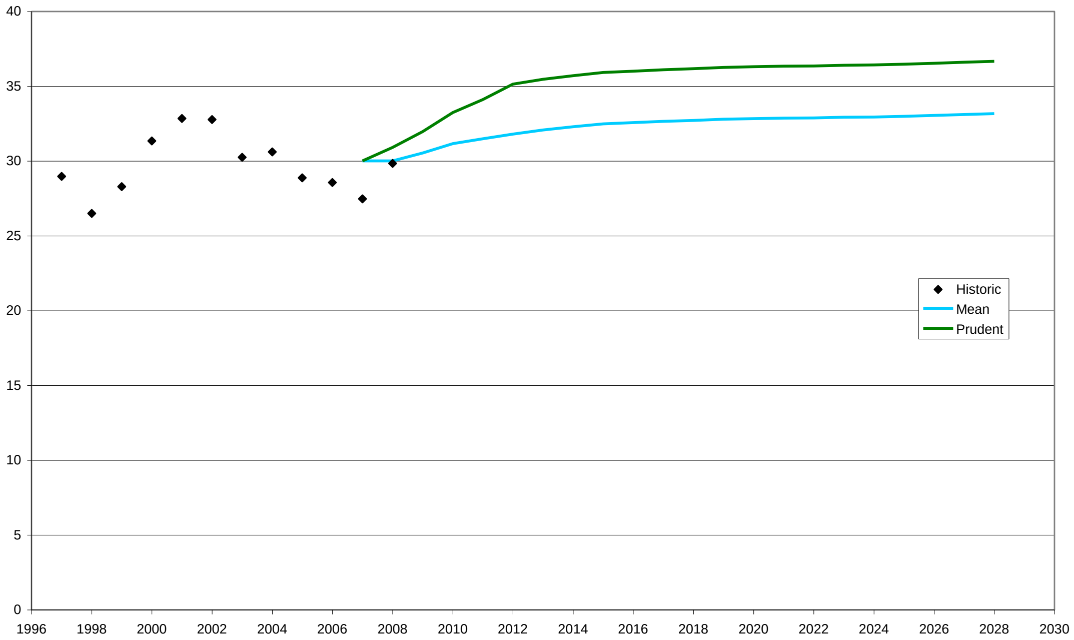


Figure 42: EC's 2007 Gore Peak Demand Forecast

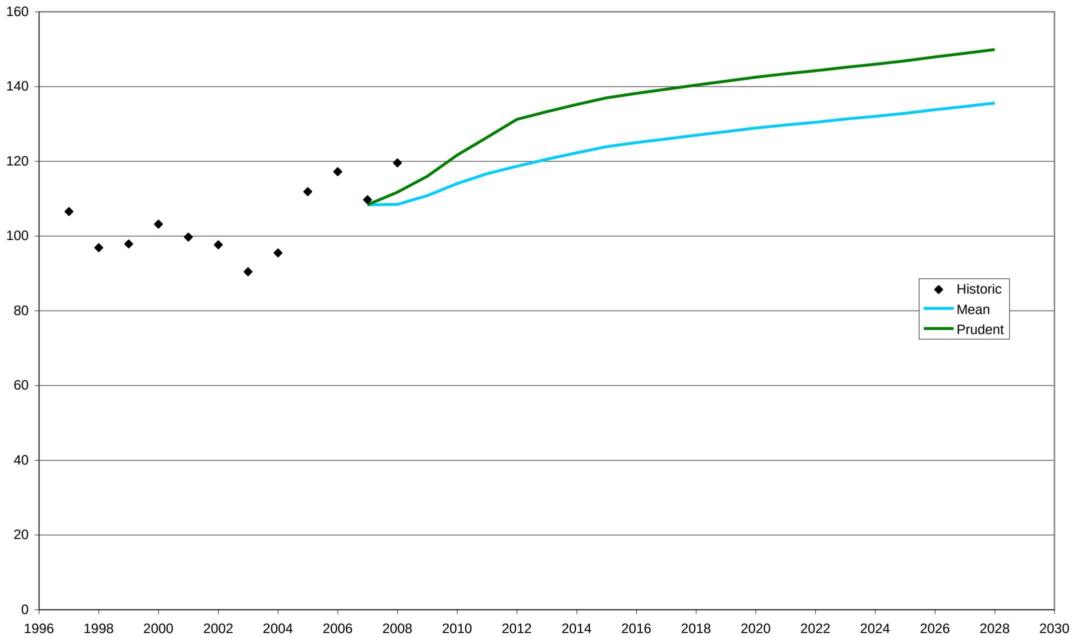


Figure 43: EC's 2007 Halfway Bush Peak Demand Forecast

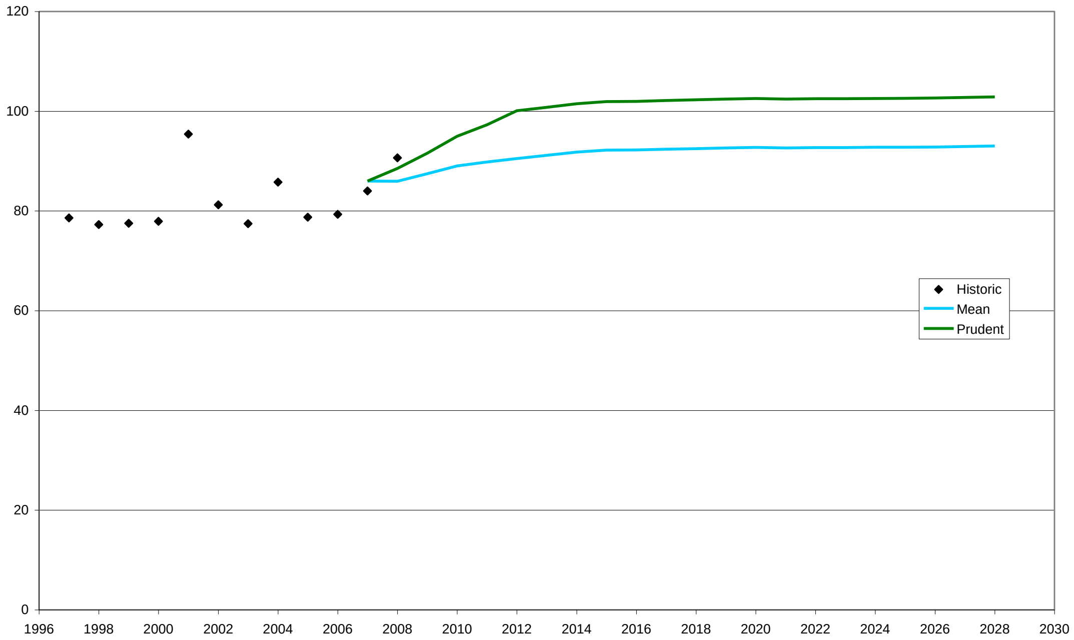


Figure 44: EC's 2007 Invercargill Peak Demand Forecast

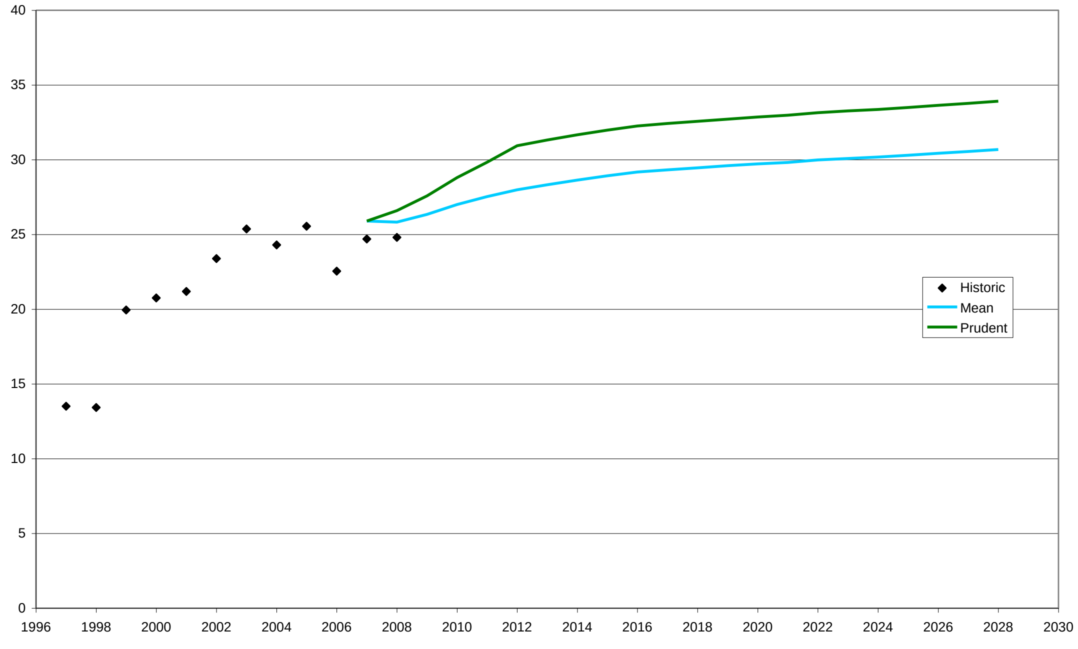


Figure 45: EC's 2007 Naseby Peak Demand Forecast

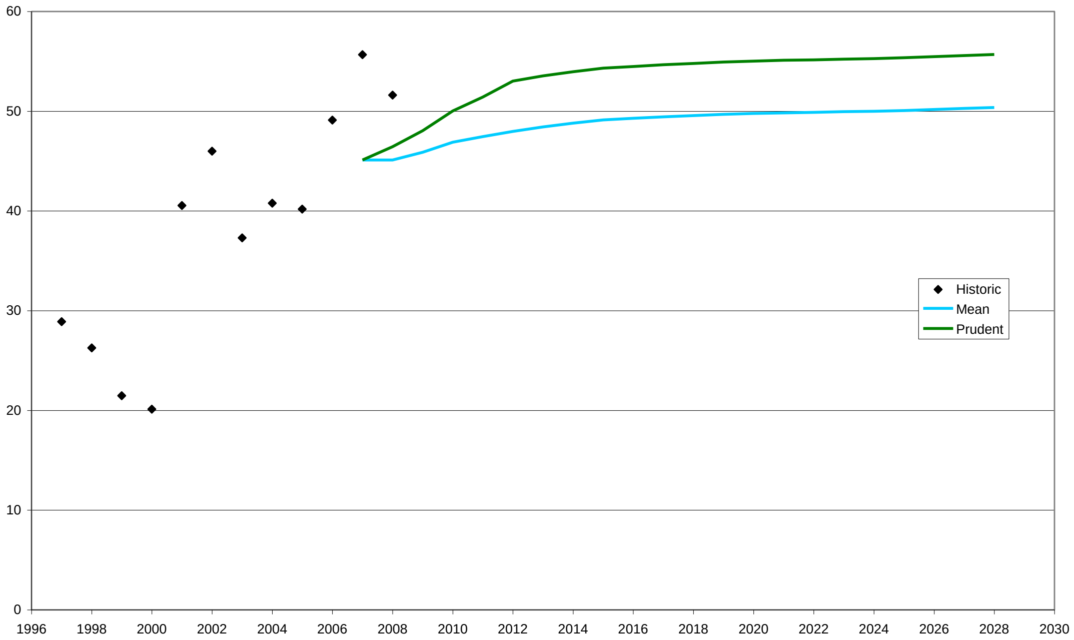


Figure 46: EC's 2007 North Makarewa Peak Demand Forecast

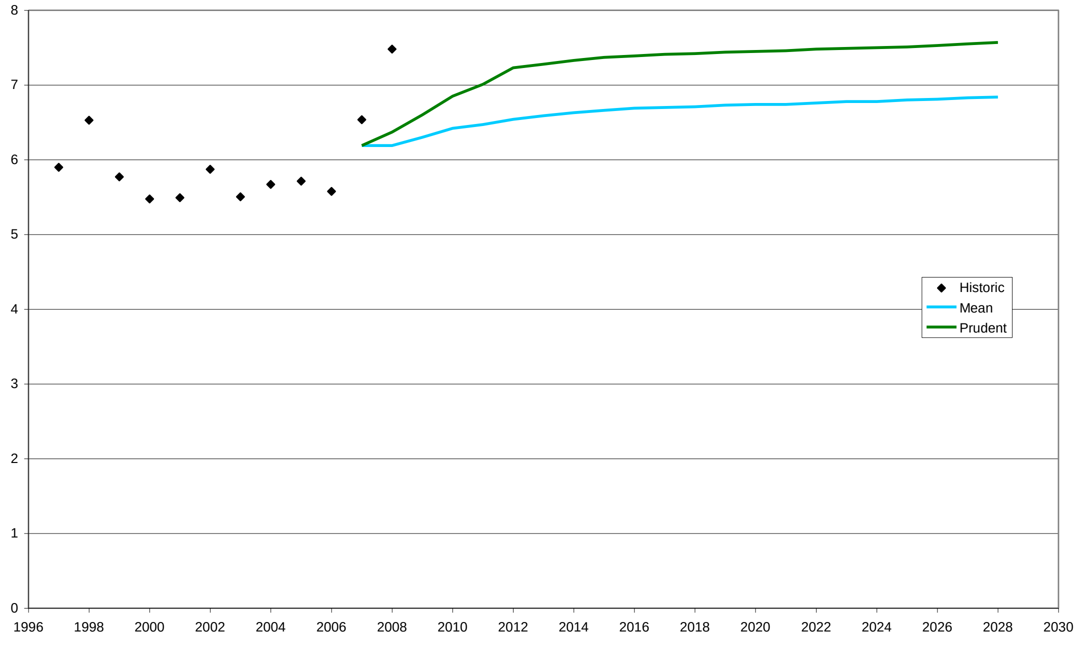


Figure 47: EC's 2007 Palmerston Peak Demand Forecast

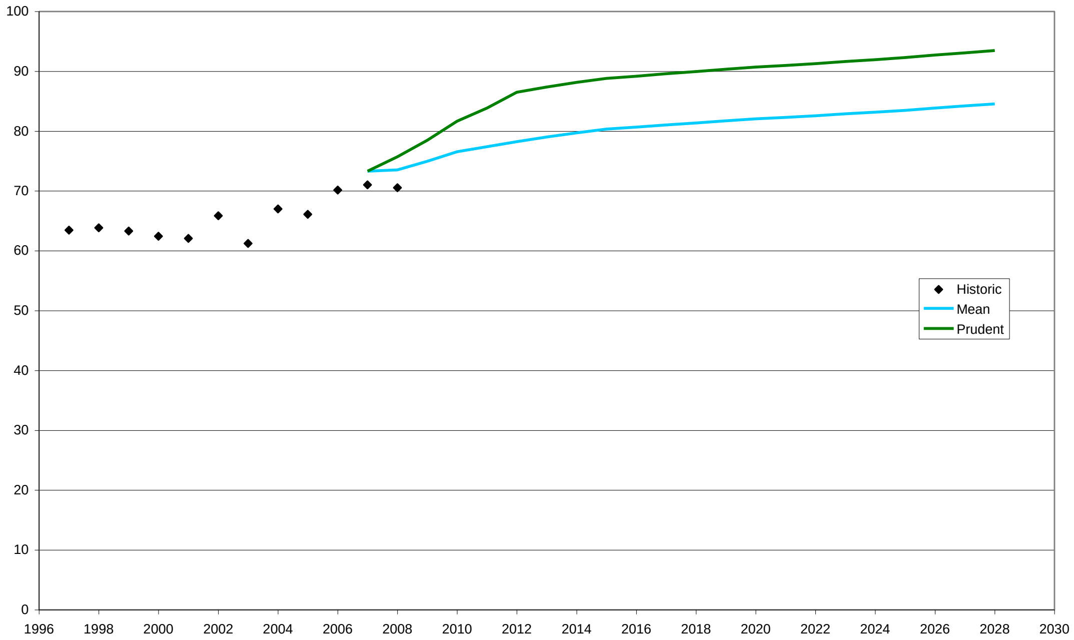


Figure 48: EC's 2007 South Dunedin Peak Demand Forecast

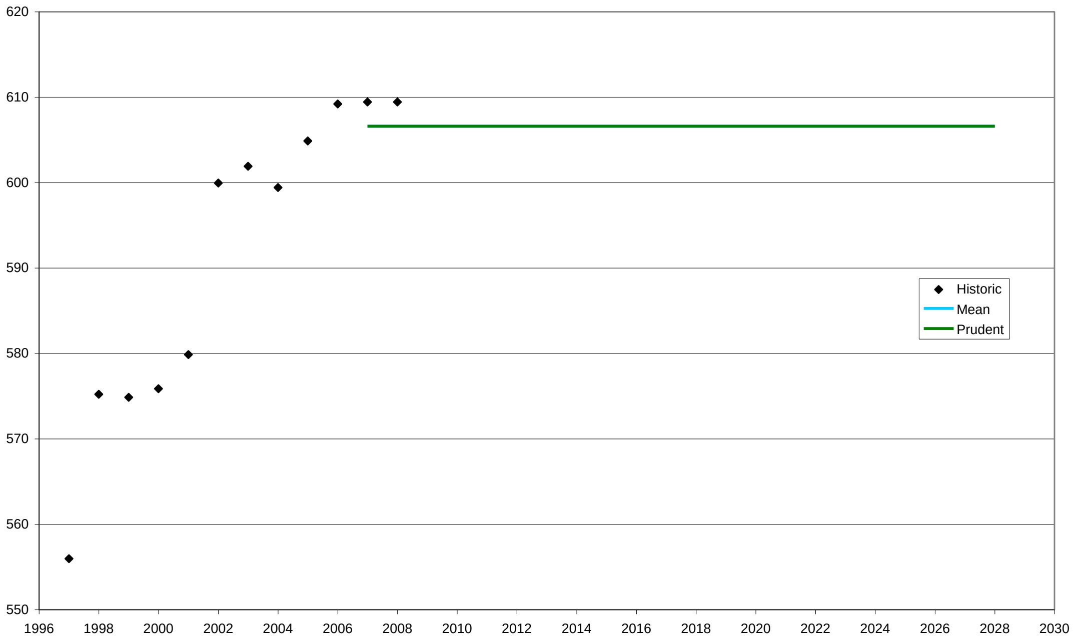


Figure 49: EC's 2007 Tiwai Peak Demand Forecast

Table 14: Stakeholders Contacted in November 2008

Industry	Company	Contact
Dairy	Fonterra	Glen Sullivan
Dairy	Venture Southland	Steve Canny, Jeff Troon
Meat Processing	Alliance	Frank Wilson
Meat Processing	Silver Fern Farms	Malcolm Buchanan
Timber	Dongwha Pattina	Simon Callaghan
Oil & Gas	Venture Southland	Steve Canny, Jeff Troon
Coal/Lignite	L+M Mining	Kent Anson
Coal/Lignite	Transpower	Siobhan Procter
Coal/Lignite	Venture Southland	Steve Canny, Jeff Troon
Aluminium Smelter	Rio Tinto	Ray Deacon
Other Minerals	Venture Southland	Steve Canny, Jeff Troon
Network Company	Aurora	Lindsay McLennan
Network Company	OtagoNet	Terry Jones
Network Company	Powernet	Roger Paterson

Table 15: 2007 Lower South Island Diversity Factors

GXP	Winter Diversity Factor	Summer Diversity Factor
Balclutha	94.65%	88.34%
Brydone	67.27%	66.64%
Clyde	76.50%	78.56%
Cromwell	87.35%	86.37%
Edendale	47.21%	57.99%
Frankton	91.81%	92.72%
Gore	97.30%	96.02%
Halfway Bush	92.73%	97.70%
Invercargill	97.36%	98.26%
Naseby	89.80%	85.62%
North Makarewa	78.13%	96.48%
Palmerston	88.56%	83.89%
South Dunedin	95.27%	98.88%
Tiwai	99.85%	99.74%

Table 15: Potential Step Load Changes for the Lower South Island 2008-2019

GXP	Description	Customer	Forecast	Season	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Edendale	Dairy Plant	Fonterra	Prudent	Summer								2.0	2.0		
Edendale	Dairy Plant	Fonterra	Prudent	Winter								1.5	1.5		
Edendale	Meat Processing Plant	Alliance	Expected	Both				-3.3							
Edendale	Meat Processing Plant	Alliance	Prudent	Both				-2.4							
Gore	Dairy Plant	Mataura Valley Milk	Expected	Summer		2.0	2.0	2.0	1.0						
Gore	Dairy Plant	Mataura Valley Milk	Expected	Winter			1.5	1.5	1.5	0.5					
Gore	Dairy Plant	Mataura Valley Milk	Prudent	Summer		3.0	3.0	1.0							
Gore	Dairy Plant	Mataura Valley Milk	Prudent	Winter			2.5	2.5	1.0						
Gore	Pilot Coal Plant	Solid Energy	Both	Both			1.2								
Gore	Full Coal Plant	Solid Energy	Prudent	Both				5.8	10.5						
Halfway Bush	Meat Processing Plant	Silverfernfarms	Both	Summer	-1.4										
Halfway Bush	Meat Processing Plant	Silverfernfarms	Both	Winter	-0.7										
Naseby	Gold Mine Transfer	Oceana Gold	Both	Both	-1.5										
Palmerston	Gold Mine Transfer	Oceana Gold	Both	Both	1.5										
Tiwai	Aluminium Smelter	Rio Tinto	Expected	Summer			10		15						
Tiwai	Aluminium Smelter	Rio Tinto	Expected	Winter		10			15						
Tiwai	Aluminium Smelter	Rio Tinto	Prudent	Summer			10	20							
Tiwai	Aluminium Smelter	Rio Tinto	Prudent	Winter		10		20							

Table 16: Edendale Prudent GXP Load Forecast 2008-2018

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	…	2028
Summer Starting Load			22.9	24.0	25.2	26.5	27.8	29.2	30.7	34.2	37.9	39.8	…	45.7
Base Load Growth	1.00%		0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	…	0.5
Dairy Growth	4.00%		0.9	1.0	1.0	1.1	1.1	1.2	1.2	1.4	1.5	1.6		
Dairy Plant	4.0								2.0	2.0				
Embedded Generation	3.8		3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	…	3.8
Summer Ending Load		22.9	27.8	29.0	30.3	31.6	33.0	34.5	38.0	41.7	43.6	45.6	…	50.0
Winter Starting Load			22.9	23.6	24.3	25.0	25.8	26.5	27.3	29.7	32.1	33.0	…	37.2
Base Load Growth	1.00%		0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	…	0.4
Dairy Growth	2.00%		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.7		
Dairy Plant	4.0								1.5	1.5				
Transfer	2.00%		0.2	0.2	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.7	…	0.7
Embedded Generation	3.8		3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	…	3.8
Winter Ending Load		22.8	27.6	28.3	29.3	30.1	30.9	31.7	34.0	36.4	37.5	38.5	…	42.1

Table 17: Summer Expected Peak Load Forecast by GXP

Year	Balclutha	Brydone	Clyde	Cromwell	Edendale	Frankton	Gore	Halfway Bush	Invercargill	Naseby	North Makarewa	Palmerston	South Dunedin	Tiwai
2009	26.4	9.1	7.1	20.3	23.8	38.5	33.0	109.5	87.6	23.6	53.4	7.0	63.5	467.4
2010	26.6	9.2	7.2	21.1	24.8	39.8	37.5	111.2	88.4	24.0	55.3	7.1	64.2	619.4
2011	26.7	9.3	7.3	21.9	25.8	41.2	37.8	112.8	89.3	24.4	57.2	7.1	64.8	619.4
2012	26.8	9.4	7.4	22.8	26.8	42.7	40.3	114.5	90.0	24.7	59.2	7.1	65.5	634.4
2013	27.0	9.5	7.5	23.7	27.9	44.2	41.9	116.2	90.7	25.1	61.3	7.2	66.1	634.4
2014	27.1	9.6	7.7	24.7	29.0	45.7	43.6	116.8	91.4	25.2	63.4	7.2	66.4	634.4
2015	27.2	9.6	7.8	25.7	29.3	47.3	44.0	117.4	91.8	25.4	64.1	7.2	66.8	634.4
2016	27.4	9.7	7.9	26.7	29.6	49.0	44.4	118.0	92.3	25.5	64.7	7.3	67.1	634.4
2017	27.5	9.8	8.0	27.8	29.9	50.7	44.9	118.6	92.7	25.6	65.4	7.3	67.4	634.4
2018	27.6	9.9	8.1	28.9	30.2	52.5	45.3	119.2	93.2	25.7	66.0	7.4	67.8	634.4
2019	27.8	10.0	8.2	29.3	30.5	53.3	45.8	119.8	93.7	25.9	66.7	7.4	68.1	634.4
2020	27.9	10.1	8.4	29.7	30.8	54.1	46.2	120.4	94.1	26.0	67.3	7.4	68.5	634.4
2021	28.1	10.2	8.5	30.2	31.1	54.9	46.7	121.0	94.6	26.1	68.0	7.5	68.8	634.4
2022	28.2	10.3	8.6	30.6	31.4	55.7	47.2	121.6	95.1	26.3	68.7	7.5	69.1	634.4
2023	28.3	10.4	8.8	31.1	31.7	56.5	47.6	122.2	95.5	26.4	69.4	7.5	69.5	634.4
2024	28.5	10.6	8.9	31.6	32.0	57.4	48.1	122.8	96.0	26.5	70.1	7.6	69.8	634.4
2025	28.6	10.7	9.0	32.0	32.3	58.2	48.6	123.4	96.5	26.6	70.8	7.6	70.2	634.4
2026	28.8	10.8	9.2	32.5	32.7	59.1	49.1	124.0	97.0	26.8	71.5	7.7	70.5	634.4
2027	28.9	10.9	9.3	33.0	33.0	60.0	49.6	124.6	97.5	26.9	72.2	7.7	70.9	634.4
2028	29.1	11.0	9.4	33.5	33.3	60.9	50.1	125.3	98.0	27.1	72.9	7.7	71.2	634.4

Table 19: Winter Expected Peak Load Forecast by GXP

Year	Balclutha	Brydone	Clyde	Cromwell	Edendale	Frankton	Gore	Halfway Bush	Invercargill	Naseby	North Makarewa	Palmerston	South Dunedin	Tiwai
2009	26.4	9.3	7.1	26.0	23.7	48.8	31.4	120.7	88.0	23.6	52.4	7.5	71.6	619.4
2010	26.6	9.4	7.2	27.3	24.3	50.7	35.1	122.5	89.0	24.0	53.6	7.6	72.6	619.4
2011	26.7	9.5	7.3	28.7	25.1	52.8	34.5	124.3	90.0	24.4	54.8	7.6	73.7	619.4
2012	26.8	9.6	7.4	30.1	25.8	54.9	37.1	126.2	90.8	24.7	56.1	7.7	74.8	634.4
2013	27.0	9.7	7.5	31.7	26.4	57.1	38.9	128.1	91.6	25.1	57.3	7.7	75.9	634.4
2014	27.1	9.8	7.7	33.2	27.1	59.3	40.1	128.7	92.4	25.2	58.6	7.7	76.7	634.4
2015	27.2	9.9	7.8	34.9	27.4	61.7	40.5	129.4	93.0	25.4	59.2	7.8	77.5	634.4
2016	27.4	10.0	7.9	36.6	27.6	64.2	40.9	130.0	93.7	25.5	59.8	7.8	78.2	634.4
2017	27.5	10.1	8.0	38.5	27.9	66.8	41.4	130.7	94.4	25.6	60.4	7.8	79.0	634.4
2018	27.6	10.2	8.1	40.4	28.2	69.4	41.8	131.3	95.2	25.7	61.0	7.9	79.8	634.4
2019	27.8	10.3	8.2	14.2	28.5	70.5	42.2	132.0	95.9	25.9	61.6	7.9	80.6	634.4
2020	27.9	10.4	8.4	42.0	28.7	71.5	42.6	132.6	96.6	26.0	62.2	8.0	81.4	634.4
2021	28.1	10.5	8.5	42.9	29.0	72.6	43.0	133.3	97.3	26.1	62.9	8.0	82.2	634.4
2022	28.2	10.6	8.6	43.7	29.3	73.7	43.5	134.0	98.0	26.3	63.5	8.0	83.1	634.4
2023	28.3	10.7	8.8	44.6	29.6	74.8	43.9	134.6	98.8	26.4	64.1	8.1	83.9	634.4
2024	28.5	10.8	8.9	45.5	29.9	75.9	44.3	135.3	99.5	26.5	64.8	8.1	84.7	634.4
2025	28.6	10.9	9.0	46.4	30.2	77.0	44.8	136.0	100.3	26.6	65.4	8.2	85.6	634.4
2026	28.8	11.0	9.2	47.3	30.5	78.2	45.2	136.7	101.0	26.8	66.1	8.2	86.4	634.4
2027	28.9	11.1	9.3	48.3	30.8	79.4	45.7	137.4	101.8	26.9	66.7	8.2	87.3	634.4
2028	29.1	11.2	9.4	49.2	31.1	80.6	46.1	138.0	102.5	27.1	67.4	8.3	88.2	634.4

Table 20: Summer Prudent Peak Load Forecast by GXP

Year	Balclutha	Brydone	Clyde	Cromwell	Edendale	Frankton	Gore	Halfway Bush	Invercargill	Naseby	North Makarewa	Palmerston	South Dunedin	Tiwai
2009	28.5	9.8	10.4	24.7	27.8	41.9	36.9	124.0	95.5	27.5	58.0	7.4	67.0	514.7
2010	28.6	9.9	10.5	25.6	29.0	43.8	42.8	126.2	97.0	28.0	60.1	7.5	68.0	619.4
2011	28.8	10.1	10.6	26.6	30.3	45.7	49.2	128.5	98.4	28.5	62.4	7.6	69.0	639.4
2012	28.9	10.2	10.7	27.7	31.6	47.7	62.0	130.8	99.4	29.0	64.7	7.6	70.0	639.4
2013	29.1	10.4	10.8	28.8	33.0	49.8	65.0	133.1	100.4	29.5	67.1	7.7	71.1	639.4
2014	29.2	10.6	11.0	29.9	34.5	52.0	68.1	133.7	101.4	29.7	69.6	7.8	71.8	639.4
2015	29.4	10.7	11.1	31.1	38.0	54.2	70.1	134.3	102.2	30.0	72.2	7.9	72.5	639.4
2016	29.5	10.9	11.2	32.4	41.7	56.6	72.1	134.9	103.0	30.3	75.0	8.0	73.3	639.4
2017	29.7	11.0	11.3	33.7	43.6	59.1	74.2	135.5	103.7	30.5	77.8	8.0	74.0	639.4
2018	29.8	11.2	11.4	35.0	45.6	61.7	76.3	136.1	104.5	30.8	80.7	8.1	74.7	639.4
2019	30.0	11.4	11.5	35.6	46.0	62.7	77.1	136.7	105.0	31.1	81.5	8.2	75.1	639.4
2020	30.1	11.5	11.7	36.0	46.5	63.6	77.8	137.3	105.6	31.3	82.3	8.3	75.5	639.4
2021	30.3	11.7	11.8	36.5	46.9	64.6	78.5	137.9	106.1	31.6	83.0	8.4	75.9	639.4
2022	30.4	11.9	11.9	37.0	47.3	65.5	79.3	138.6	106.6	31.9	83.8	8.4	76.3	639.4
2023	30.6	12.1	12.1	37.5	47.8	66.5	80.1	139.2	107.2	32.2	84.6	8.5	76.6	639.4
2024	30.7	12.2	12.2	38.0	48.2	67.5	80.9	139.8	107.7	32.5	85.4	8.6	77.0	639.4
2025	30.9	12.4	12.3	38.6	48.6	68.5	81.6	140.4	108.2	32.7	86.2	8.7	77.4	639.4
2026	31.0	12.6	12.5	39.1	49.1	69.5	82.4	141.1	108.8	33.0	87.0	8.8	77.8	639.4
2027	31.2	12.8	12.6	39.6	49.5	70.5	83.2	141.7	109.3	33.3	87.9	8.9	78.2	639.4
2028	31.3	13.0	12.7	40.2	50.0	71.5	84.0	142.4	109.9	33.6	88.7	9.0	78.6	639.4

Table 20: Winter Prudent Peak Load Forecast by GXP

Year	Balclutha	Brydone	Clyde	Cromwell	Edendale	Frankton	Gore	Halfway Bush	Invercargill	Naseby	North Makarewa	Palmerston	South Dunedin	Tiwai
2009	27.5	9.8	10.4	31.8	27.6	52.8	34.2	135.8	95.9	27.5	56.9	8.0	75.4	619.4
2010	27.6	9.9	10.5	33.4	28.3	55.4	39.2	138.9	97.3	28.0	58.2	8.0	76.9	619.4
2011	27.7	10.1	10.6	35.0	29.3	58.1	46.6	142.0	98.7	28.5	59.6	8.1	78.5	639.4
2012	27.9	10.2	10.7	36.8	30.1	60.9	59.9	145.2	99.8	29.0	60.9	8.2	80.1	639.4
2013	28.0	10.4	10.8	38.6	30.9	63.9	62.4	148.5	100.8	29.5	62.4	8.3	81.7	639.4
2014	28.2	10.6	11.0	40.5	31.7	67.0	64.8	149.2	101.8	29.7	63.8	8.4	82.9	639.4
2015	28.3	10.7	11.1	42.6	34.0	70.3	66.4	149.8	102.7	30.0	65.3	8.4	84.1	639.4
2016	28.4	10.9	11.2	44.8	36.4	73.8	68.0	150.5	103.6	30.3	66.8	8.5	85.4	639.4
2017	28.6	11.0	11.3	47.0	37.5	77.4	69.6	151.2	104.5	30.5	68.4	8.6	86.7	639.4
2018	28.7	11.2	11.4	49.4	38.5	81.2	71.3	151.9	105.4	30.8	70.0	8.7	88.0	639.4
2019	28.9	11.4	11.5	50.4	38.8	82.6	72.0	152.6	106.2	31.1	70.7	8.8	88.9	639.4
2020	29.0	11.5	11.7	51.4	39.2	83.8	72.7	153.3	107.0	31.3	71.3	8.9	89.8	639.4
2021	29.2	11.7	11.8	52.3	39.5	85.0	73.4	154.0	107.8	31.6	72.0	9.0	90.7	639.4
2022	29.3	11.9	11.9	53.3	39.9	86.3	74.1	154.7	108.6	31.9	72.7	9.0	91.6	639.4
2023	29.5	12.1	12.1	54.3	40.2	87.6	74.8	155.4	109.4	32.2	73.3	9.1	92.5	639.4
2024	29.6	12.2	12.2	55.3	40.6	88.8	75.6	156.1	110.2	32.5	74.0	9.2	93.4	639.4
2025	29.8	12.4	12.3	56.4	41.0	90.2	76.3	156.8	111.0	32.7	74.7	9.3	94.4	639.4
2026	29.9	12.6	12.5	57.4	41.4	91.5	77.0	157.5	111.9	33.0	75.4	9.4	95.3	639.4
2027	30.1	12.8	12.6	58.5	41.7	92.9	77.8	158.2	112.7	33.3	76.2	9.5	96.2	639.4
2028	30.2	13.0	12.7	59.6	42.1	94.2	78.5	158.9	113.6	33.6	76.9	9.6	97.2	639.4

Table 22: Diversified and Undiversified Peak Demand Forecast for the Lower South Island Region

	Diversified Peak Demand				Undiversified Peak Demand			
	Summer Expected	Winter Expected	Summer Prudent	Winter Prudent	Summer Expected	Winter Expected	Summer Prudent	Winter Prudent
2009	933.4	1,099.1	984.3	1,117.8	970.3	1,156.0	1,021.7	1,176.6
2010	1,097.4	1,111.1	1,117.5	1,131.4	1,135.7	1,169.3	1,157.0	1,191.6
2011	1,105.8	1,119.3	1,136.4	1,150.8	1,145.0	1,178.9	1,176.6	1,211.9
2012	1,131.4	1,145.4	1,161.6	1,177.6	1,171.6	1,206.3	1,203.4	1,240.5
2013	1,141.3	1,156.0	1,173.2	1,189.7	1,182.6	1,218.3	1,216.0	1,254.1
2014	1,149.8	1,164.5	1,183.1	1,199.4	1,192.1	1,228.0	1,227.0	1,265.1
2015	1,155.1	1,171.6	1,190.3	1,207.8	1,198.0	1,236.0	1,235.2	1,274.7
2016	1,160.5	1,178.8	1,198.0	1,216.5	1,203.9	1,244.1	1,244.0	1,284.7
2017	1,166.1	1,186.3	1,205.7	1,225.4	1,210.0	1,252.5	1,252.7	1,294.7
2018	1,171.7	1,193.9	1,213.8	1,234.6	1,216.2	1,261.0	1,261.7	1,305.1
2019	1,175.8	1,199.1	1,218.2	1,240.2	1,220.7	1,266.9	1,266.6	1,311.3
2020	1,180.0	1,204.3	1,222.7	1,245.7	1,225.3	1,272.8	1,271.6	1,317.6
2021	1,184.3	1,209.6	1,227.3	1,251.4	1,230.0	1,278.8	1,276.6	1,323.9
2022	1,188.5	1,215.0	1,231.9	1,257.0	1,234.7	1,284.9	1,281.6	1,330.4
2023	1,192.8	1,220.4	1,236.5	1,262.8	1,239.4	1,291.0	1,286.7	1,336.8
2024	1,197.2	1,225.9	1,241.2	1,268.6	1,244.2	1,297.2	1,291.9	1,343.4
2025	1,201.6	1,231.4	1,245.9	1,274.5	1,249.0	1,303.4	1,297.1	1,350.0
2026	1,206.0	1,237.0	1,250.7	1,280.5	1,253.9	1,309.8	1,302.3	1,356.8
2027	1,210.5	1,242.7	1,255.5	1,286.5	1,258.8	1,316.2	1,307.6	1,363.5
2028	1,215.0	1,248.4	1,260.4	1,292.6	1,263.8	1,322.7	1,313.0	1,370.4