2009 Electricity Demand Forecasts

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16 December 2009

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1. Introduction and purpose of this report

1.1 Introduction

1.1.1 The Commission is required to publish a Statement of Opportunities (SOO), as part of its duties in overseeing aspects of transmission investment (Rule 9 of section III of Part F of the Electricity Governance Rules 2003 (Rules)).

1.1.2 Rule 9.1.2 states that the purpose of the SOO is to enable identification of potential opportunities for efficient management of the grid, including investment in upgrades and transmission alternatives. In practice, the SOO also has a wider role to play in informing stakeholders about the Commission's views of possible future developments in the power system.

1.1.3 Under Rule 9.1.1.2, the SOO must include the Grid Planning Assumptions (GPA). The GPA must include (amongst other things):

(a) a reasonable range of credible demand forecasts by region or grid exit point (e.g. high, medium and low growth) (Rule 10.3.1.2); and

(b) a reasonable range of credible future, high-level generation scenarios (Rule 10.3.1.3).

1.1.4 The Electricity Commission prepares long-term national, regional and grid exit point (GXP) demand forecasts. The forecasts form part of the GPA that underlie the grid investment test and are intended to support industry transmission planning processes. These are separate to the medium term 5-year forecast prepared by the Commission for security of supply purposes.

1.1.5 In October 2009, the Commission developed draft GPA as an initial step towards releasing the 2010 SOO. This included the preparation and publication of five generation scenarios for consultation with interested parties. As mentioned at the time, the generation scenarios were prepared using the 2008 demand forecasts.

1.1.6 The rationale for doing so was that changes in the population growth forecasts produced by Statistics New Zealand had greatly impacted on the Commission's forecasts. The Commission considered it prudent to have its methodology peer reviewed before publishing an updated version. Two reviews have now been completed (or are nearing completion) and indicate that the Commission's approach is reasonable.

1.1.7 While the Commission did not consult on the forecasts themselves in October 2009, it sought feedback from stakeholders on specific aspects of the demand forecasts.

1.1.8 Some submitters suggested that the documentation and publications supporting the demand forecasts should be more explicit about their purpose and limitations. The Commission would like to stress that the forecasts are intended to represent a business-as-usual projection of future consumption. The Commission believes that the approach it is using produces reasonable national and regional projections, but acknowledges that the allocation approach used in the forecasts may not produce ‘accurate’ projections at a GXP level. The Commission is not attempting to replicate the detailed forecasting activities carried out by the individual lines companies. There is a need to balance the resources required to undertake comprehensive GXP level forecasts against the purpose and likely use of the GPAs. Therefore the GXP level forecasts should be treated as indicative only. Appropriate adjustments can be made to the forecasts used in the application of the grid investment test if additional information is available.

1.1.9 A number of submitters suggested the use of a wider range of demand drivers rather than just GDP and population. The Commission agrees that other drivers can be useful when considering areas where future demand growth may be affected by local issues, but believes that projections of economic and population growth, combined with electricity price and household density forecasts, provide the best indicators of likely long term future electricity demand growth at a national level.

1.1.10 A number of alternative demand scenarios were suggested by submitters, including consideration of heat pump uptake, electric vehicles, the closure of the Tiwai aluminium smelter, climate variability, distributed generation, demand side participation, and the implementation of smart grids. The Commission agrees that many of the suggested alternative demand scenarios are useful and are worth exploring as part of the wider analysis of demand. Most of these are unlikely to be published in the actual SOO document but separately as they are assessed..

1.1.11 Submitters commented on the emergence of distributed generation technologies which may affect demand supplied through the transmission network. It remains unclear at this time whether emerging technologies will result in the wide spread distribution of generation, or whether economies of scale will result in potentially distributable forms of generation being installed as large grid connected installations (as has been the case with the larger wind farms). The wide-scale uptake of distributed generation is therefore considered as a demand scenario rather than being considered as part of the base forecasts.

1.1.12 The impact of increasing prices on demand was noted by some submitters. Demand response to price increases, and variation in price increases, are explicitly considered as part of the demand modelling, and are therefore already reflected, to a limited extent, in the forecasts. Larger changes can be assessed through the use of scenarios.

1.1.13 The issue of winter vs. summer peaking and possible changes in the characteristics of peak demand in some regions was also raised. The detailed assessment of peaking issues is an important aspect of preparing the SOO and is considered through the Power Systems Analysis which is required as part of the SOO.

1.1.14 Having considered the outcome of the two methodology reviews, and the initial comments received from submitters, the Commission is now comfortable with the 2009 demand forecast and is seeking stakeholders' comments on the technical aspects of the forecasts.

1.2 How to provide feedback

1.2.1 The Commission is seeking stakeholders' feedback though written submissions. The Commission's preference is to receive submissions in electronic format (Microsoft Word). It is not necessary to send hard copies of submissions to the Commission, unless it is not possible to do so electronically. Submissions in electronic form should be emailed to submissions@electricitycommission.govt.nz with "**Consultation Paper—2009 Demand Forecasts**" in the subject line. The Commission will acknowledge receipt of all submissions electronically. Please contact Kate Hudson if you do not receive electronic acknowledgement of your submission within two business days.

1.2.2 Your submission is likely to be made available to the general public on the Commission's website. Submitters should indicate any documents attached, in support of the submission, in a covering letter and clearly indicate any information that is provided to the Commission on a confidential basis. However, all information provided to the Commission is subject to the Official Information Act 1982.

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

Kate Hudson
Electricity Commission
Level 7, ASB Bank Tower
2 Hunter Street
Wellington

Tel: 0-4-460 8860

1.2.4 Submissions should be received by **5pm** on **Friday 29 January 2010**. Please note that late submissions are unlikely to be considered.

1.2.5 Responses received will be collated and considered by the Commission before finalising the 2009 demand forecasts which will be used to develop the 2010 generation scenarios. and key input assumptions for the next phase of SOO preparation, in particular, the PSA.

2. Forecasting process

2.1.1 The existing Commission models were used as the starting point for the 2009 update described here. In brief, the process undertaken was to:

- obtain updated input data series where available, including national statistical data, half hourly electricity meter data, and grid configuration information;
- update and test the existing forecasting scripts, including the removal of older unused code and making a number of changes to improve the clarity and robustness of the models; and
- review raw forecast figures and make adjustments as necessary (generally this occurs at a GXP level and corrects for configuration changes or other distortions that can result from unusual conditions reflected in the meter data).

2.1.2 There are three components to the demand forecasts:

- National level energy forecasts are produced using an econometric model that relates Historic electricity growth to key drivers such as population and GDP. The national forecasts are then allocated out to the regions and individual GXPs using GDP, population, and meter data.
- Regional level prudent and expected peak forecasts are developed as part of a separate process. These are combined with the GXP level forecasts to produce (prudent) After-Diversity Maximum Demand (ADMD) grid exit point forecasts.
- Load probability curves describing the likelihood of defined levels of demand being exceeded at a regional level were prepared and published as part of the 2008 SOO. These will be prepared after the energy and peak demand forecasts have been finalised (expected to be sometime in 2010)

2.1.3 The remainder of this report discusses the energy and peak demand forecasts.

3. National energy forecasts

3.1.1 The modelling approach is unchanged from that used in the 2008 SOO, though some of the input assumptions have changed. A summary of the approach is included here for completeness.

3.2 Overview of approach

3.2.1 National electricity demand is the aggregate of three main sectors, each of which is modelled separately:

- Residential
- Commercial and industrial
- Heavy industrial (Tiwai Point aluminium smelter)

3.2.2 The forecasts are for energy consumption at grid exit points. The forecasts therefore include energy consumed by losses across the local lines network behind the grid exit point, but exclude end-user consumption met by generation embedded within those local networks.

3.2.3 Model development has been carried out in MATLAB. No significant changes were made to the econometric models used to forecast national demand as part of the 2008 review[1].

3.2.4 The model used for each sector uses the relationship between historic demand and key drivers (such as GDP and population) to forecast future demand based on forecasts of the key drivers which have been shown to yield the best predictor of demand for each sector[2]. The forecasts therefore implicitly assume a business-as-usual environment. Significant changes in the underlying drivers of demand, such as major step changes in energy efficiency improvements or the possible uptake of electric vehicles, are dealt with separately using a scenario based approach. Similarly, changes to demand from issues such as the global economic situation are only taken into account insofar as they affect GDP or household population forecasts.

3.2.5 Significant changes in demand as a result of dry-years or for other reasons (e.g., the lower demand at Tiwai Point in 2009 from the transformer outage in late 2008) are handled by excluding demand in those years from the analysis. These excluded years are listed in Table 1.[3]

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1 http://www.electricitycommission.govt.nz/pdfs/opdev/modelling/pdfconsultation/GPA/Demand-Forecast-Review.pdf

2 See the discussion in Section 3 of the 2008 Electricity Demand Forecast Review.

3 Note that the peak demand forecasting models use data from 2000 onwards.

Table 1: Historic years excluded from energy demand forecasting models

Excluded years (March years)
1993 2002 2004 2009

3.2.6 Table 2 summarises the key drivers used in the residential, commercial and industrial and heavy industrial models.

Table 2: Drivers used in forecasting models

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

3.2.7 Data for the key drivers was updated to produce the 2009 forecasts as follows:

- Revised national level statistics and projections were obtained from Statistics New Zealand publications and their INFOS data service. This included population and household data.
- National and regional GDP projections were obtained from NZIER.
- Updated national level demand data was published by the Ministry of Economic Development in their June 2009 Energy Data File publication.
- Forward price data was based on that published in the 2008 SOO.
- GXP level meter data was sourced from the Centralised Dataset published by the Electricity Commission.

3.2.8 Population and GDP forecasts have been revised since the forecasts in the 2008 SOO were developed and warrant discussion.

Population

3.2.9 Statistics New Zealand publishes long-term projections of population based on different scenario assumptions around birth, death and immigration rates. As with the 2008 SOO forecast, the Commission has used the mid-level growth scenario as a baseline for forecasting. This scenario assumes medium fertility, medium mortality, and long-term net migration of 10,000 people per year.

3.2.10 Figure 1 and Figure 2 show historic and projected total New Zealand population in absolute and percentage growth terms.

Figure 1: Total New Zealand Population—mean projection

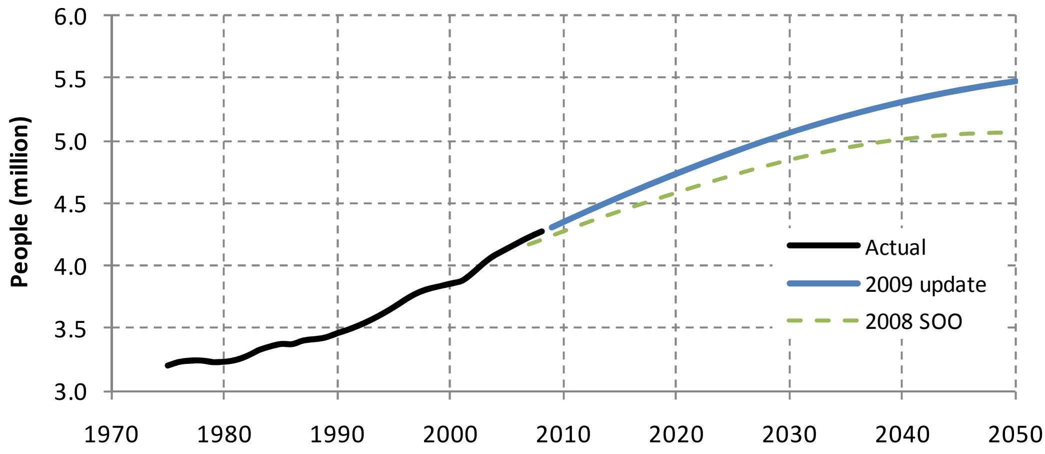
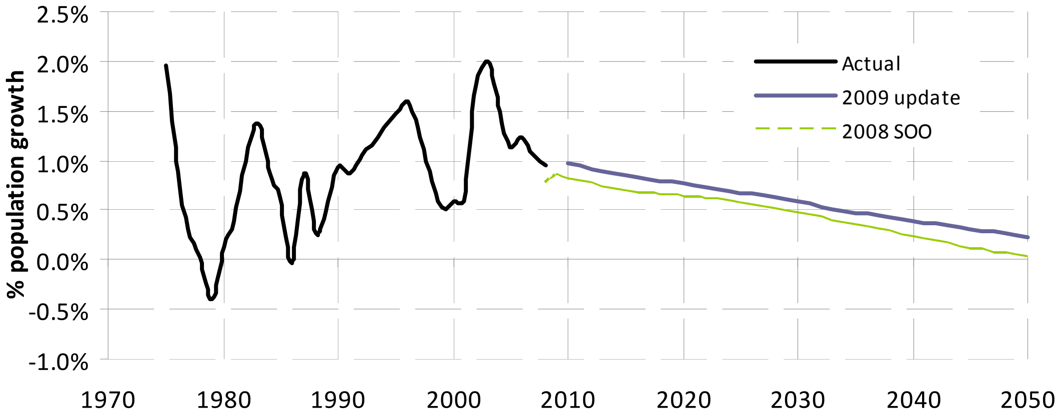


Figure 2: Total New Zealand Population—percentage growth



3.2.11 The current population projections from Statistics New Zealand have been updated to utilise information from the 2006 Census. Earlier population projections, as used as inputs to the Commission's demand forecasts over 2004-8, relied on data from the 2001 Census.[4]

3.2.12 An example of the compounding effect of growth rate around 0.2% higher (per annum) is the reduction in the projected time that a population of 5 million will be reached: it is now 2028 where previously it was around 2040. The effect of the higher population projection on demand is discussed later in this section.

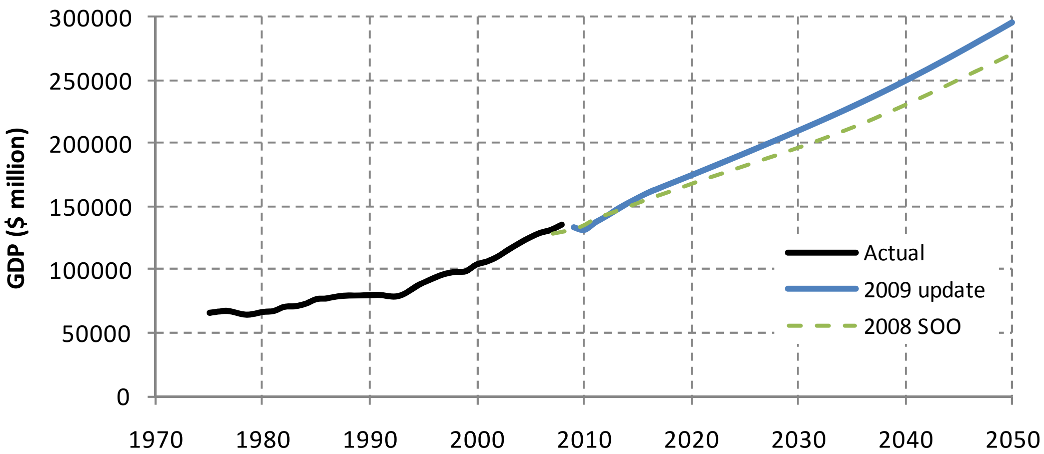
Gross domestic product

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

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

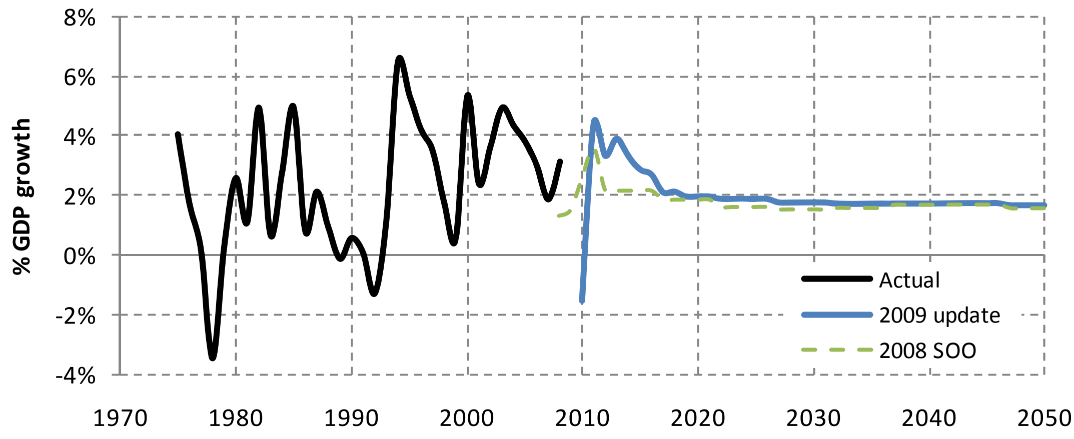
3.2.15 Figure 3 and Figure 4 show historic and forecast GDP in absolute and percentage growth terms.

Figure 3: Total New Zealand real GDP ($1995/1996)—mean forecast



4 Further commentary on Statistics New Zealand's projections is available here: http://www.stats.govt.nz/browse_for_stats/population/estimates_and_projections/nationalpopulationprojections_hotp06-61.aspx

Figure 4: Total New Zealand real GDP ($1995/1996)—percentage growth



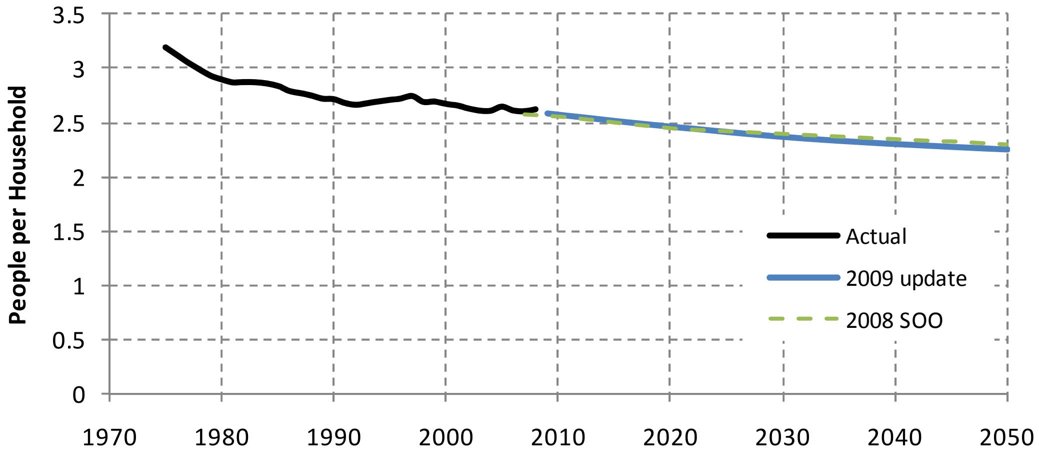
3.2.16 The effect of the higher GDP forecast on demand is discussed later in this section.

Households

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

3.2.18 The household projections are combined with the population projections to derive a forecast of the projected change in household size. Figure 5 shows historic and forecast average household size.

Figure 5: Average New Zealand household size



3.2.19 The household projections are similar, reflecting household forecasts which increase in proportion to population forecasts.

Historic demand

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

3.2.21 The definition used to split the modelling into different consumer sectors has been changed by the Commission as better consumption information became available. The Commission used data from the newly established centralised dataset to revise the various historic demand series. This produced an updated series that could be tracked back to a combination of the Energy Data File series and checked half-hourly historic meter data. Historic peak and energy demand data is illustrated in the context of the forecasts that follow.

3.3 Residential energy forecast

3.3.1 The residential model used by the Commission was selected following a review of the forecasts in 2004. Since then, several modifications have been made, as discussed in the 2008 Review: In summary:

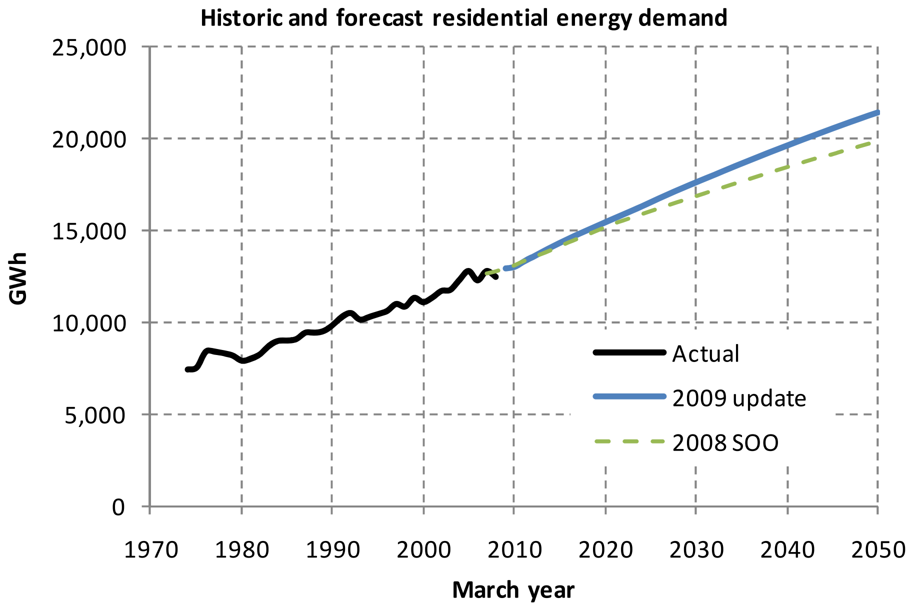
- As part of the 2006 review, the model was amended to remove the temperature adjustment applied to the raw demand series.[5]
- During the 2007 review it was noted that the origin of the first two years of demand data used as an input to the 2006 residential model is unknown.

[5] Additional information on the 2004 assessment of alternative model types can be found in the **Demand forecast model review 2004** document. The 2006 review of the models is discussed in the **National energy demand forecast review (June 2006)** document.

Data from 1974 onwards, available from MED's Energy Data File publication, is used.

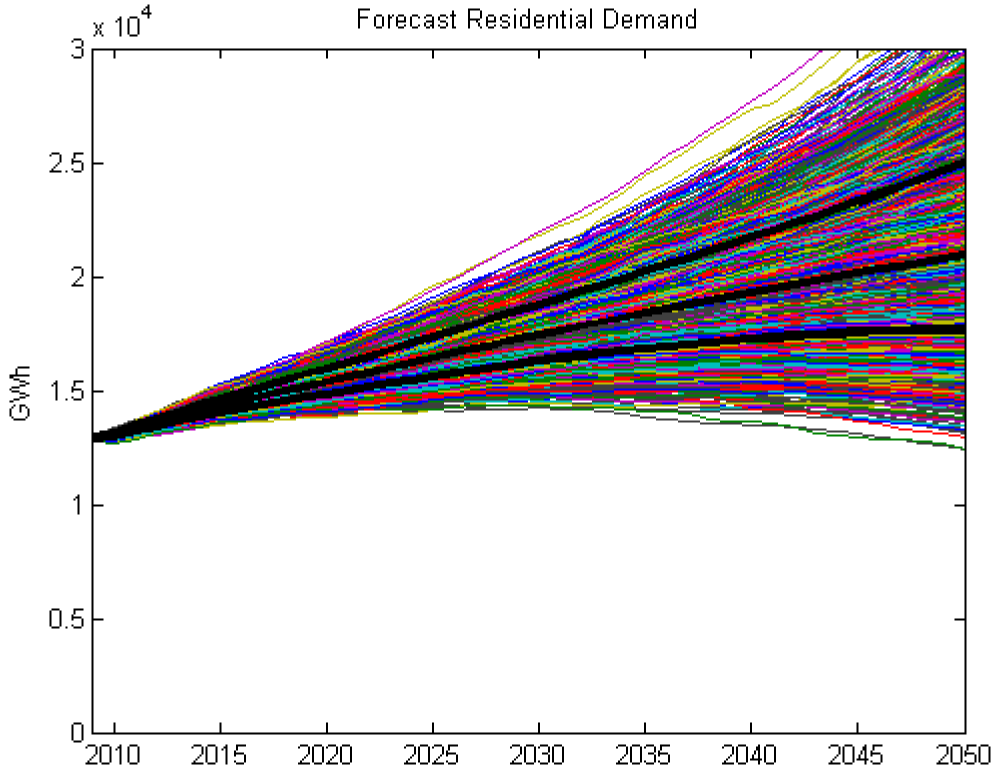
3.3.2 Figure 6 shows forecast residential demand based on the 2009 modelling compared to the results published in the 2008 SOO. Note that the energy modelling discussed in this report is calculated and presented on a year-ending-March basis as a number of the key input series are only available in that form. This contrasts with the peak forecasts discussed later which are generally calculated and presented in a calendar year form.

Figure 6: Residential energy demand forecasts



3.3.3 Modelling error is estimated using a Monte Carlo technique where a synthetic distribution is created for each input series based on the variation in each series compared to a 5 year moving average. Total forecast error is modelled based on estimated distributions for the forecasts of the key drivers used in the sector model (discussed in section 3.7)Total forecast uncertainty for residential demand is shown in Figure 7, with 10% tail confidence limits and the median forecast shown in black (i.e. 10% of forecasts exceed the upper confidence limit and 10% of forecasts are lower than the lower confidence limit).

Figure 7: Residential model confidence limits



3.4 Commercial and industrial forecasts

3.4.1 Commercial and industrial demand is modelled using a linear model that relates GDP to demand growth. This was adopted after a review in 2006.[6] This approach was used for developing the 2008 SOO forecasts and the update discussed here.

3.4.2 Figure 8 shows the updated 2009 forecast, which is higher than the 2008 SOO forecast and reflects the updated GDP forecasts, which are the primary driver in the regression model.

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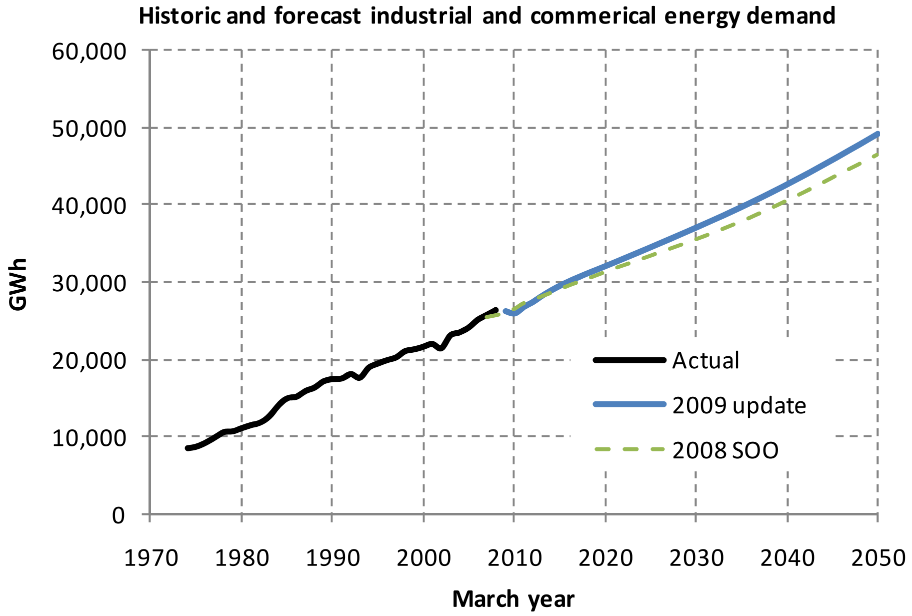
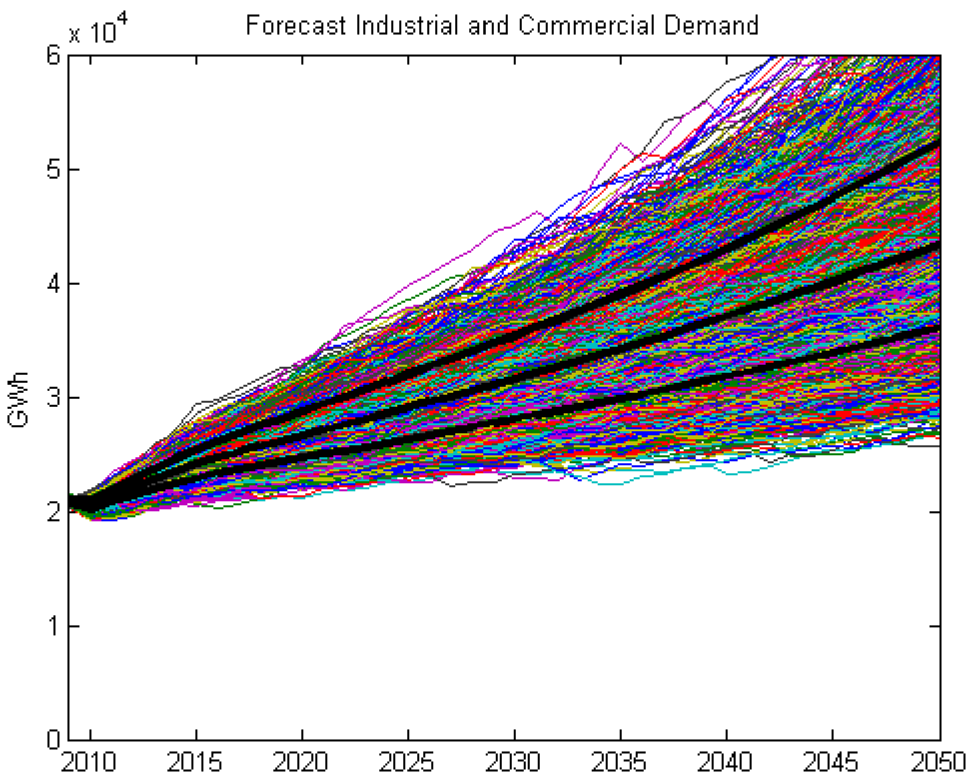
[6] See the 2006 demand forecasting review for the background for the selection of this particular model. http://www.electricitycommission.govt.nz/pdfs/opdev/modelling/GPAs/National-Demand-Forecast-Review-Jun06.pdf

Figure 8: Commercial and industrial energy demand forecasts



3.4.3 The following shows the forecast uncertainty and 10% tail confidence limits and the median forecast for the commercial and industrial forecasts.

Figure 9: Commercial and industrial model confidence limits

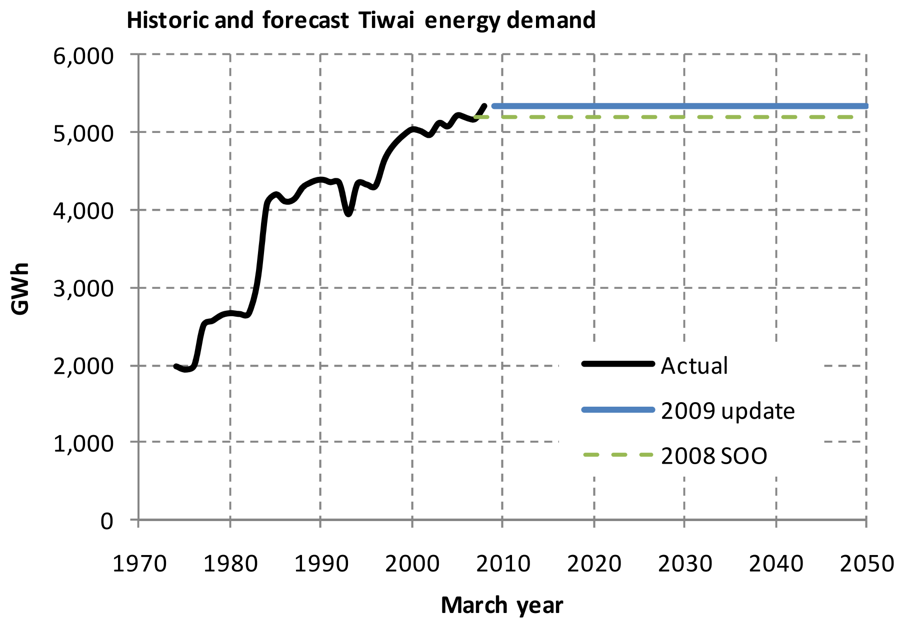


3.5 Heavy industrial forecasts

3.5.1 The Tiwai Point aluminium smelter has been separated out from the other industrial and commercial loads for the purposes of forecasting demand (see the commercial and industrial modelling section above). Future energy demand at Tiwai Point is assumed to remain constant with the exception of a 10 MW increase assumed to apply from 2011– i.e. no major expansions or downsizings of the aluminium smelter are explicitly included in the demand forecasts.

3.5.2 The following graph shows the updated 2009 forecast and 2008 SOO forecasts. Forecast demand is based on the highest historic March year demand by the smelter. Demand in the year to 31 March 2008 was the highest to date (5,331GWh) so this was used at the forecast; this is 122GWh higher than the next highest recorded demand of 5,209GWh in the year to 31 March 2005.

Figure 10: Heavy industrial demand forecasts



3.6 Total forecast demand

3.6.1 The forecasts published by the Commission are demand at grid exit point. The above demand models are based on end-use demand data, therefore local lines company losses need to be added to modelled demand, and embedded generation subtracted to obtain GXP level forecasts.

(a) Embedded generation is assumed to remain at its current proportion of total generation i.e. it will grow at the same rate as total demand. As embedded generation is roughly 5% of total generation this is equivalent to around 30-40 GWh of additional generating capacity each year (equivalent to roughly

10MW per year of wind generation going into local networks as opposed to being grid connected).

(b) Line company losses have been running at between 5-6% over the past few years. As lines company asset utilisation increases, it would be expected that average losses would increase. However improvements in the quality of local network assets should at least offset this so it is assumed that lines companies losses will remain at their current levels (a figure of 5.75% has been used).

3.6.2 Figure 11 shows total demand against historic demand and the 2008 SOO forecast. Figure 12 shows total forecast demand broken down by individual component (as discussed above).

Figure 11: Total forecast energy demand

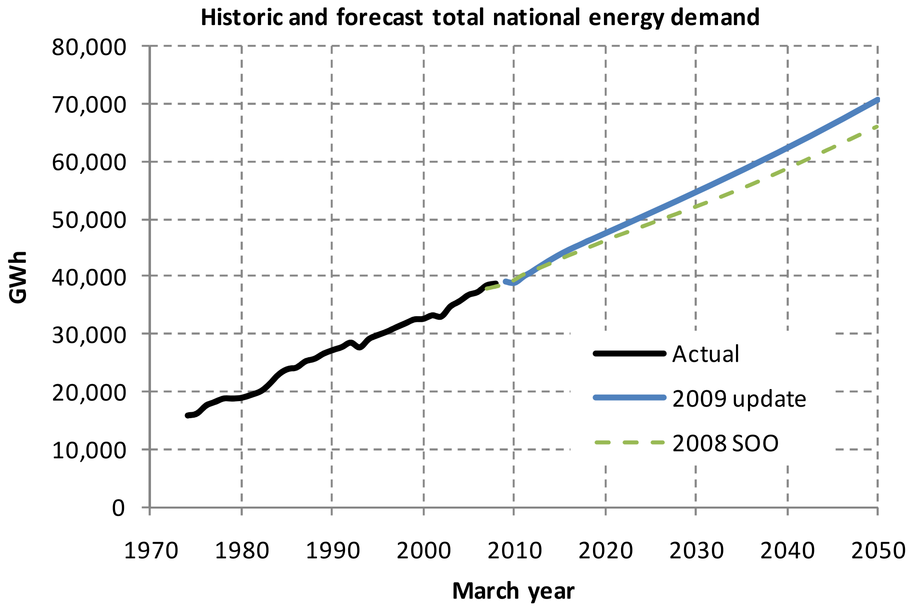
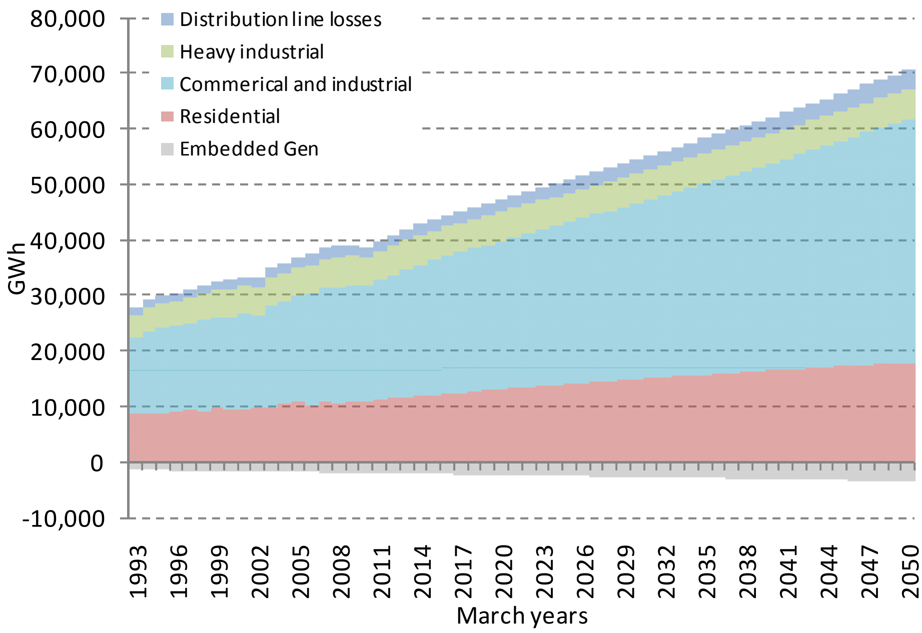


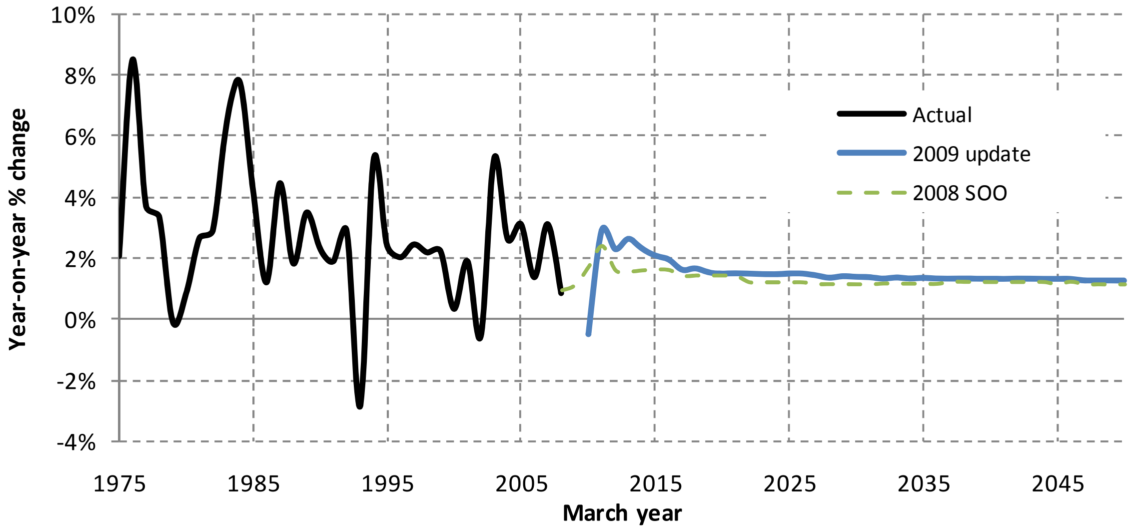
Figure 12: Total forecast energy demand by component



3.6.3 Total national demand has increased in a linear manner since the early 1970's. Forecast growth is also expected to increase in a similar manner based on the mean forecasts of the key drivers of demand, though reflects higher forecasts of population and GDP compared to those used to determine the forecasts in the 2008 SOO.

3.6.4 The graph below shows historic and forecast demand in percentage growth terms. Over the period 2011-2015, demand growth in the region of 2%-2.5% is forecast, after which rates drop slowly from around towards 1.25% at the end of the horizon.

Figure 13: Total historic and forecast energy demand - percentage growth



3.7 Demand uncertainty

3.7.1 Forecast uncertainty is modelled using a Monte Carlo based approach where model error and forecast uncertainty are assessed using distributions estimated for the historic input series and the forecast input series respectively.

3.7.2 The historic input distributions are synthetic distributions based on the variation between the various inputs (reported GDP, population, households) and a 5 year moving average[7]. Each Monte Carlo run involves adjusting the inputs based on the various synthetic distributions and re-estimating the model.

3.7.3 The forecast input distributions are based on assessments of likely variation for each series. The forecast series are kept internally consistent within each Monte Carlo run (i.e. GDP and household projections are linked to projected population).

3.7.4 Uncertainty in each of the various inputs is briefly described below:

(a) **GDP**. GDP has been broken into three components – population, productivity, and a random component. The population component in each run is kept consistent with the variation introduced in the population section below. Productivity variation is based on scaling productivity for all years by a factor drawn from a distribution based on an estimated historic range. The third component provides some year-on-year change caused by random external causes (such the international environment) and has been based on historic GDP variation.

(b) **Households**. Uncertainty in households had been broken into two components - population uncertainty (kept consistent with the population

[7] The impact of using alternative moving average periods was assessed and found to be minimal.

variation below) and a household size component. Household size is varied based on a scale factor applied and phased in over the forecast period.

(c) **Population**. Population variation is handled by applying a factor drawn from a distribution based on the various Statistics New Zealand population scenarios.

(d) **Price**. Variation is based on a simple estimated distribution used to scale price in each forecast year.

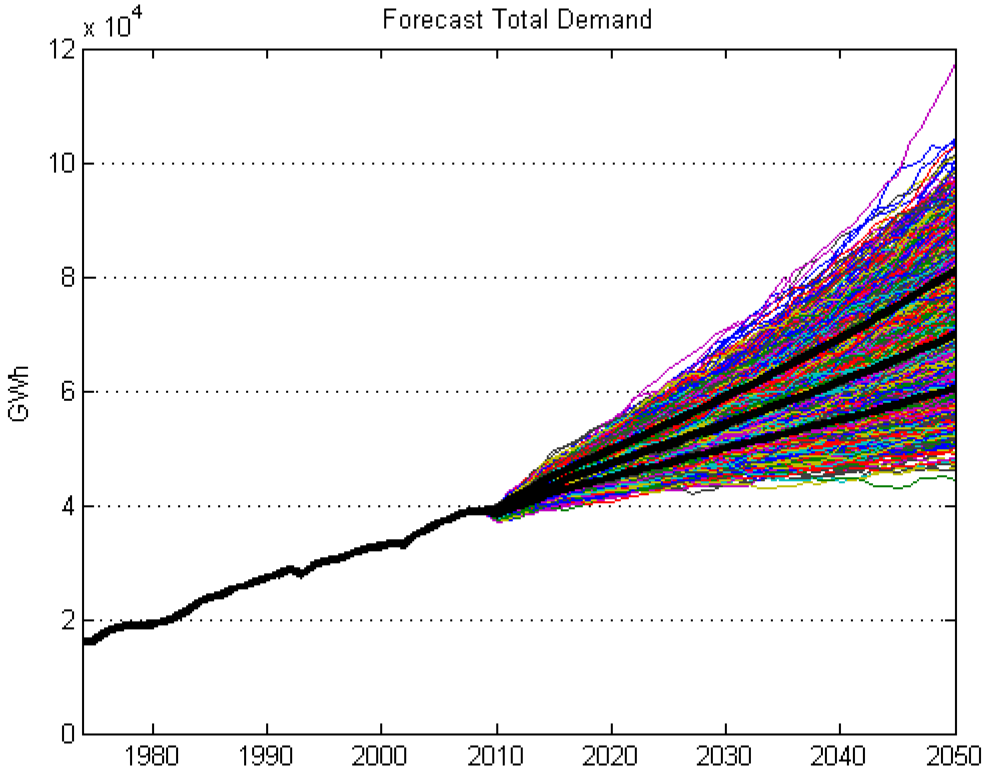
3.7.5 There are a wide range of other factors that will influence future demand growth. Two primary issues are future trends in energy intensity, and the balance between grid connected and embedded generation.

3.7.6 Energy intensity changes are reflected in the historic data the models have been estimated from. The forecasts therefore reflect an ongoing underlying rate of efficiency improvement. Step changes in energy efficiency resulting from policy initiatives that are demonstrably different to the historic rates of change have not been modelled explicitly as part of these forecasts. Where a material change from a confirmed policy can be robustly established and independently confirmed, explicit adjustments to future forecasts will be considered. The possible impacts of broader technology and social changes will be dealt with through scenario analysis.

3.7.7 The relative balance between embedded generation and grid connected generation in the future will be determined by changes in technology and input costs. Economies of scale have resulted in smaller scale technologies such as wind farms being built at a size where direct connection to the grid is required rather than into the local networks. Possible changes in the mix of embedded generation vs. grid connected generation have not been assessed as part of the forecasting process but could be handled through scenario analysis.

3.7.8 Figure 14 shows total forecast variation with 10% tail confidence limits and the median forecast shown in black.

Figure 14: National energy forecast confidence limits



4. Regional modelling

4.1 Allocation of energy demand

4.1.1 A lack of consistent long-term historic regional data makes the development of individual econometric models for each region impractical. Regional and GXP level forecasts are therefore currently based on an allocation of the national forecasts.[8]

4.1.2 Total national residential demand was allocated to regions on the basis of projection population growth in each area. Population forecasts are available at a local network level (built up from mesh-block level to the old Electric Power Board areas) from Statistics New Zealand.

4.1.3 The allocation is based on the following formula:

For each network area,

$$\text{Res.Demand}(FY) = \frac{\text{Population}(FY)}{\text{Population}(BY)} \times \frac{\text{National Res. Demand Per Person}(FY)}{\text{National Res. Demand Per Person}(BY)} \times \text{Res.Demand}(BY)$$

where FY = forecast year, and BY = base year (the most recent year that actual values were available).

4.1.4 Note that residential demand in each network area was approximated based on the proportion of residential demand in the region compared to total demand.

4.1.5 Demand across all areas is then scaled so that the sum of each of the areas matches back to the national total.

4.1.6 This approach assumes that demand growth within a region due to an increase in population will have the same characteristics as the existing residential demand in that region (i.e. additional population growth in a high usage area will also be high usage). Changes in per-person energy intensity will be spread proportionately across the country (i.e. a 10% increase in demand per person at a national level will result in 10% growth across all regions).

4.1.7 Grid exit point residential demand is forecast by pro-rating the network area residential demand to each GXP within the network based on the current proportion of total load at the GXP compared to the total local network load. In effect this assumes that the mix of load at each of the GXPs within a local network is the same.

4.1.8 Regional residential demand is calculated by simply adding up the residential demand for each network within the region.

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8 A definition of the grouping of grid exit points to transmission regions can be found in the spreadsheets published with the consultation paper.

4.1.9 Industrial and commercial allocation : Total national industrial demand was allocated on the basis of projected GDP growth in each region. Long term regional GDP projections were obtained from the NZIER.

4.1.10 The allocation is based on the following formula:

For each region,

$$\text{IndCommDemand}(FY) = \frac{\text{GDP}(FY)}{\text{GDP}(BY)} \times \frac{\text{National Ind.Comm.Demand / National GDP}(FY)}{\text{National Ind.Comm.Demand / National GDP }(BY)} \times \text{IndCommDemand}(BY)$$

where FY = forecast year, and BY = base year.

4.1.11 Similar to the residential allocation above, this approach assumes that the energy intensity of additional demand in a region associated with an increase in production (GDP) will be the same as the existing energy intensity within the region. Forecast changes in modelled national level energy intensity are spread proportionately across the country.

4.1.12 Network level demand within each region is allocated on the basis of the current total network demand as a proportion of total regional demand. Demand at a GXP level is allocated based on current GXP demand as a proportion of the total network demand.

4.1.13 Embedded generation growth and local lines losses are simply spread across regions based on total load. While there are likely to be some differences between regions, the variation needs to be taken into context relative to the uncertainty in the forecast drivers of demand (GDP and population).

4.2 Inter-regional population uncertainty

4.2.1 Variation from uncertainty in population movements between regions is accounted for. An alternative final population forecast is calculated for each Electric Power Board (EPB) area using a proportion selected from a normal distribution (i.e. 100% of the current final forecast ± x% where x is drawn from a normal distribution). The original population path for each EPB is then scaled to gradually match that alternative forecast. Once an alternative path has been projected for each EPB, the full set of individual EPB projections are scaled so that the total population matches back to the national projection for the Monte-Carlo run.

4.2.2 The regional GDP projections are also scaled to maintain consistency with the population changes within the region. The allocation process is then run using the revised population and GDP profiles. The forecasts use a standard deviation of 10% for the distribution applied to each EPB population. The final impact on the regional forecast confidence limits was small.

4.3 Adjustment to reflect recent regional demand growth

4.3.1 The allocation methodology outlined above does not reflect recent trends within regions that may result from causes such as short-term changes in energy intensity in local industries. A good example of this is the intensification of farming in some areas which has resulted in high energy consumption growth over recent years relative to changes in GDP and population in those areas. Such changes are not likely to be sustainable in the long run, but it is preferable to incorporate some of the impact into the shorter term forecasts to allow for some continuation of the current trends.

4.3.2 A hybrid approach has been used where forecasts are calculated based on a simple trend for each region using March year data from 1997. A weighting factor is then applied between the trend based forecasts, and the regional forecasts calculated using the mixed GDP/population based method outlined above. The resulting forecasts in each region are then scaled so that the sum of all the regions matches back to the national level forecasts. Essentially the approach takes some of the demand from slower demand growth regions and allocates it to higher demand growth regions in those cases where the higher growth has outstripped the rate of growth that would have otherwise have been forecast by the model.

4.3.3 The forecasts use a logistic curve to determine the weighting in each year (see the 2008 Demand Forecast Review paper for more discussion). The calculation of demand uncertainty has been amended to introduce some variation in the parameters used to determine the exact shape of the logistic curve used for weighting. This amendment results in the trend phasing out at a different rate compared to the (faster or slower) compared to the mean case.

4.4 Regional step load changes

4.4.1 The demand forecasting model allows for additional explicit adjustments to be made to demand at a GXP level. This allows for the inclusion of known major new loads where these are committed or certain to go ahead (within reason), and where the loads are significant compared to the existing regional load.

4.4.2 A rough guideline adopted for the inclusion of step loads is that the load must meet the definition of ‘committed’ as defined in the grid investment test for committed projects. The load should also exceed 5% of the existing regional load (or be locally significant).

4.4.3 The step adjustments made to individual GXP loads are listed in Table 3.

Table 3: Step load adjustments to regional forecasts

Project	Date	MW	GWh	GXP	Region	2008 SOO assumption
Pike River coal mine Stage 1	2010	7	61	ATU1101	West Coast	2008
Pike River coal mine Stage 2	2010	7	61	ATU1101	West Coast	2008
Blackpoint irrigation Stage 2	2011	6.5	28	BPT1101	Otago/Southland	4MW /2008
Hawera gas processing plant	2010	10	65	HWA0331	Taranaki	12MW / 2008
Studholme Dairy	2011	3.5	15	BPT1101	Otago/Southland	New
Tiwai Point	2011	10	88	TWI2201	Otago/Southland	New

4.4.4 Energy demand changes associated with step loads are subtracted off the other GXPs in proportion to their total load. The national energy total is not affected by the inclusion of the step changes.

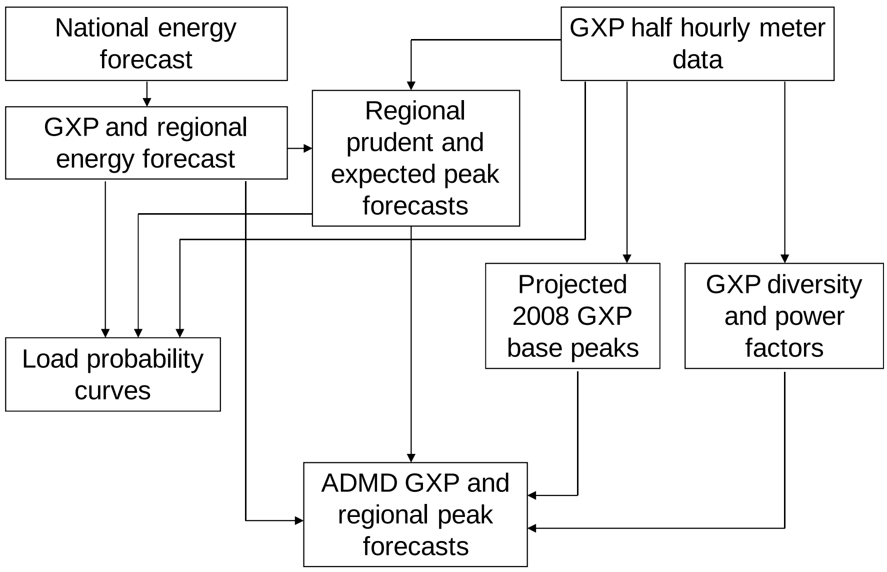
4.4.5 Appendix 1 shows tables and graphs of forecast demand for each region and confidence limits based on modelled national level and inter-regional uncertainty.

5. Peak forecasts

5.1 Forecasting process

5.1.1 The following diagram illustrates the high-level relationship between the main components of the demand forecasting processes.

Figure 15: Demand forecasting process flow diagram



5.1.2 The ADMD, GXP and regional peak forecasts include both expected and prudent GXP level peak forecasts (prudent in this context indicates that there is a 10% chance of exceeding the forecast).

5.2 Developing prudent and expected peak forecasts

5.2.1 A detailed description of the methodology used to prepare the prudent and expected peak forecasts was published in 2008[9] as part of the development of the 2008 SOO forecasts. That methodology has been re-applied using updated historic data and the energy demand forecasts.

5.2.2 The prudent peaks forecasts are a projection of the half hourly peak demand by transmission region with a 10% chance of excedance (i.e. there is a 10% chance of the regional forecast being exceeded in a given year). Table 4 illustrates the data exclusions for the peak model. While demand in some winter years is excluded, the demand over the summer period is included as it is considered to be representative of summer demand.

9 http://www.electricitycommission.govt.nz/pdfs/opdev/modelling/GPAs/demand-forecast08/Regional-peak-forecast-2Apr2008.pdf

Table 4: Historic years excluded from peak demand forecasting models

Annual	Summer	Extreme Summer	Winter
2001 2003 2008	2001 2008		2001 2003 2008

*All calendar years

5.2.3 The prudent peak forecasts are calculated using the following steps.

- An exponential fitted curve is estimated for each region from historic peak meter data and expected peak demand projected for the next five years.
- Expected (average) peak forecasts are calculated by transitioning from the growth rates calculated in Step 1 above to the growth rates from the regional energy forecast over the next five years, with the regional energy growth rates being used after that time.
- A distribution of peak forecasts is calculated for each individual region using:
  - between-year variation based on the distribution of historic peaks around the fitted trend calculated in Step 1;
  - uncertainty in the energy forecast drawn from the Monte-Carlo modelling carried out as part of the energy forecasting; and
  - an estimated 20% chance of exceptional growth (1.0% per annum higher) over a five year period.
- The 90th percentile peak forecast is selected as the prudent peak forecast.

5.2.4 The national expected and prudent peak forecasts are shown in Figure 16. These forecasts have also been produced separately for each island, and these are shown in Figure 17 and Figure 18 respectively. The forecasts are available in tabular form in Appendix 2.

Figure 16: National prudent and expected peak forecasts

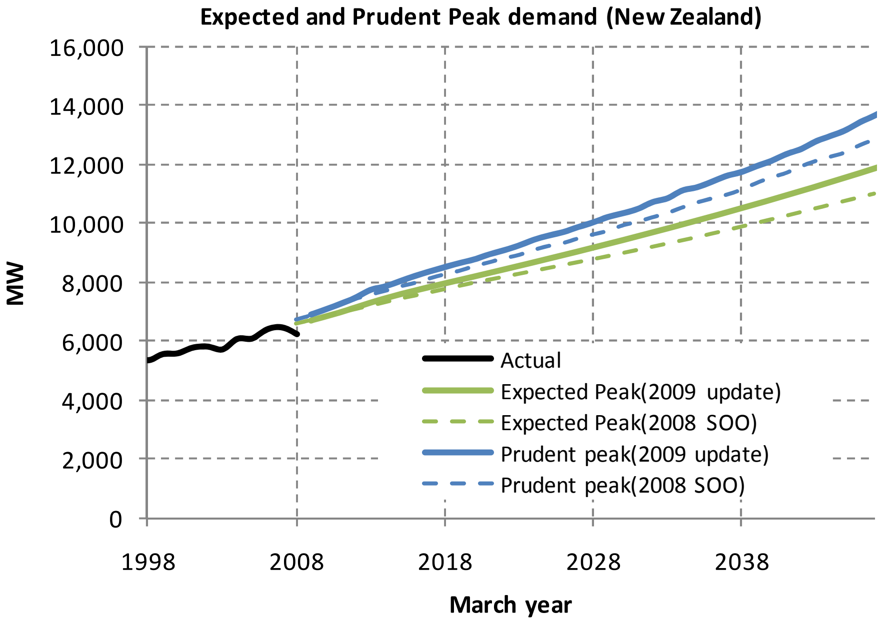


Figure 17: North Island prudent and expected peak forecasts

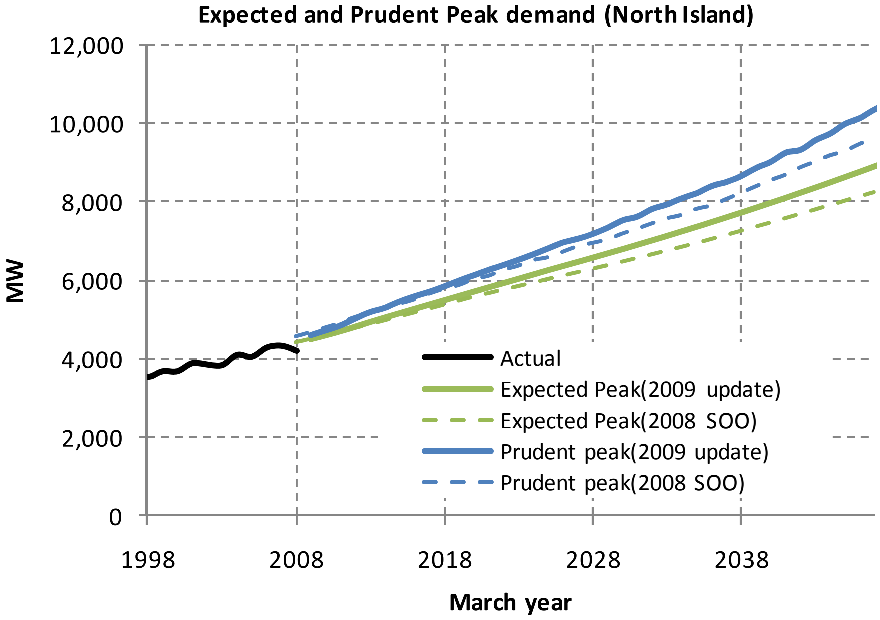
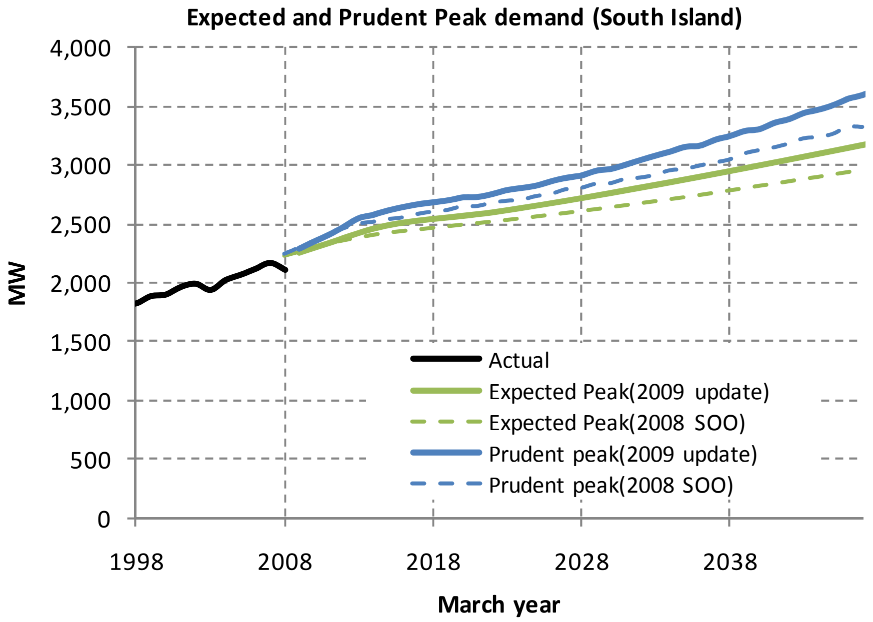


Figure 18: South Island prudent and expected peak forecasts



5.2.5 The expected forecast predicts approximately 2.1 percent annual growth in national peak from 2010 to 2015, 1.5 percent growth from 2016 to 2025, and 1.4 percent to 2040.

5.2.6 The prudent (P10) forecast of national peak is initially 150 MW higher than the expected forecast (about 2 percent higher) and grows at a faster rate from that point onwards: 2.6 percent from 2010 to 2015, 1.8 percent growth from 2016 to 2025, and 1.6 percent to 2040.

5.2.7 The prudent peak forecasts are an input to the calculation of the After Diversity Maximum Demand (ADMD) forecasts discussed below.

5.3 Developing ADMD forecasts

5.3.1 The starting point for the projected peak load at each GXP is based on recent historic load. The projections are based on the top 50 trading period peaks in each year. As such they are the ‘mean’ expected peak for the GXP. The use of a 50 peak average is intended to minimise the impact of unusual events on both the peaks and the diversity/power factors discussed below. The base peaks ultimately form the basis of the allocation of the prudent peak forecasts to individual GXPs. It is therefore preferable to have a set of likely peaks as a starting point rather than including a number of potentially abnormal ones that distort the later allocations.[10]

[10] It should be noted that the mean region peaks calculated as part of the prudent peak forecast are based on a single extreme peak (at a regional level the meter data does not suffer from the same ‘noise’ problems as the GXP level data) therefore the two peaks types are not directly comparable.

5.3.2 Each individual GXP was assessed and the starting peak projected forward using either a year-on-year trend or a simple average as appropriate. The subset of years to use for the projection for each GXP was determined as part of this assessment process. Years were excluded where there was a significant disruption or variations in the peak at that GXP that would distort the projected peak in an unreasonable way.

5.3.3 In a limited number of cases configuration changes or the addition of significant new load resulted in the historic meter data being of limited use. In these cases an estimated starting peak has been specified.

5.3.4 Diversity factors (relating the load at the GXP at the time of the Island and Region peaks to the maximum load at the GXP) and power factors were calculated for each GXP using 2007 calendar year data. Similar to the peak calculation above, these are based on the average load at the time of the top 50 region and island peaks.

5.3.5 Diversity and power factors are separately calculated for the winter and summer line rating periods. Because of the reduced size of these subsets, the averages are based on the top 40 and 20 peaks for the winter and summer rating times respectively.

5.4 Calculating ADMD forecasts

5.4.1 Calculation of the prudent ADMD forecasts consists of two primary steps:

- a set of expected peak forecasts is produced; and
- the individual expected peak forecasts are then scaled so that the after-diversity region totals match the prudent peak forecasts.

5.4.2 The expected peak demand forecast is calculated by growing the base peaks assessed above by the rate of growth calculated for each individual GXP in the regional energy forecasts. This approach assumes that the diversity of load behind each GXP stays constant. Long term trends suggest that diversity on average increases (i.e. peaks grow more slowly than total demand) as the load at each GXP increases, however this does not hold for all GXPs and is dependent on the nature of the existing load and that of any new load.

Direct connect customers

5.4.3 The Tiwai Point aluminium smelter peak demand has been projected at a constant level equivalent to its maximum historic peak, consistent with its treatment in the energy forecasts. From 2011, this peak is increased by 10MW.

5.4.4 The other direct connect heavy industrial loads have been allowed to grow at the underlying rate of increase for the EPB as calculated in the energy forecasts. It should be recognised that in many cases actual growth is unlikely to be at the individual direct connect GXP. This approach reflects a trade-off between the alternative of allocating the load growth to other GXPs (either within the region or nationally), and the likelihood that some growth will in fact be delivered through completely new GXPs in the long run. The current approach retains the expected growth associated with existing direct connect loads within the region currently supporting the direct connect customer.

Embedded generation

5.4.5 Generation embedded with local networks can have the effect of masking the true demand peak behind the associated GXP. Generation may or may not be operating at the time of the measured peak demand (in the case of many embedded generators, price signals are such that generation would be expected to be running at peak times if it is available). Metering at the grid exit point only 'sees' total demand behind the GXP net of any demand supplied by the embedded generation (currently embedded generation supplies around 5% of total demand nationally).

5.4.6 If only the net load at each GXP is grown it makes the assumption that embedded generation behind the GXP also grows sufficiently to absorb the growth in the underlying demand that it currently supplies. Growth in embedded generation is already accounted for in the energy forecasts[11]. To avoid understating growth at the GXP it is necessary to first 'gross up' the peak demand at the GXP by the amount of embedded generation operating at peak prior to applying the energy growth rates. Currently the assumption has been made that all embedded generation is operating at the time of the GXP peak. Once the growth in total underlying peak demand is calculated, the existing embedded generation capacity is netted off again.

5.4.7 As noted above, the underlying growth masked by embedded generation is already incorporated into the energy forecasts. The revised approach eliminates the partial double counting of such growth although it does result in possible inter-regional allocation issues (see footnote 11).

5.4.8 Meter data for embedded generation is not consistently available as far back as the GXP level meter data, however future analysis should allow a more sophisticated analysis of underlying peak demand behind each GXP.

[11] This is essentially spread over all GXPs in the regional energy forecasts. Further development may look at grossing up energy demand within EPBs as part of the regional energy forecasting prior to allocating energy demand growth between regions and GXPs. This would increase the allocation of growth to those GXPs where a significant proportion of underlying demand is masked by embedded generation. Because of the approach currently used to scale expected peaks to the regional prudent peaks, regions with a high proportion of embedded generation will have currently received a smaller share of the allocated demand growth than would be justified by the total underlying demand.

Step load changes

5.4.9 Adjustments to individual grid exit point load forecasts to allow for expected step increases in demand are made as part of the regional energy forecasting process (see Table 3).

5.4.10 In most cases the characteristics of any new load will be different to existing loads. New load behind a GXP may have the effect of altering the diversity of the existing GXP load relative to the regional peak load. Similarly, in the case of new grid exit points, the impact of the new load on the regional peak may be very different to the peak load at the new GXP. For example, at the time of the existing regional peak a new dairy plant may be expected to be operating at low demand levels relative to its own maximum demand.

5.4.11 Two steps are needed to integrate the new load into the ADMD forecasts.

- The peak demand for the GXP needs to be adjusted to incorporate the new loads. Because at least some of the increase in step load is already included in the energy forecast, it is necessary to first back out the implicitly included load before explicitly adding in the new load peak.
- The island and regional diversity factors calculated for the original GXP load need to be adjusted to take into account any difference in the diversity of the new load.

5.4.12 Assumed diversity factors for the new loads are included in the input tables used in the energy demand forecasts. In general it is assumed that new industrial loads will have a load factor, and therefore regional and island diversity factors, of 1. This essentially assumes they are 24/7 operations. New dairy processing plant is assumed to have region and island diversity factors of 0.3 on the basis that they generally operate at well under full capacity during the normal mid-winter peak period. Irrigation load has been treated similarly.

ADMD forecasts

5.4.13 Once individual GXP forecast have been determined and any diversity factor changes made to adjust for new loads, an expected region peak forecast can be calculated by simply multiplying each individual GXP load by its associated regional diversity factor and summing across each region.

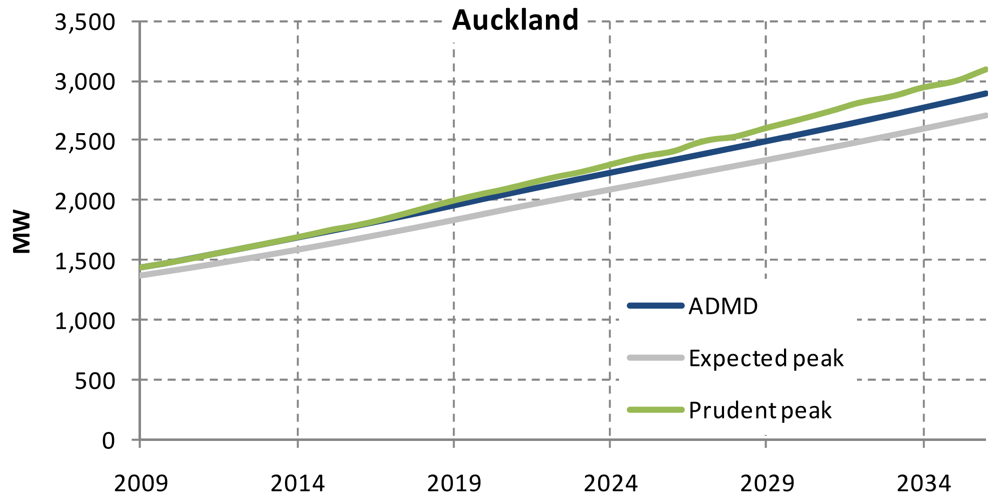
5.4.14 Calculating GXP level prudent peak forecasts then becomes the relatively straightforward exercise of scaling the individual GXP load forecasts so that multiplying the GXP loads by the diversity factors yields the same region peak forecast as was calculated using the prudent peak forecast methodology.

5.4.15 The scaling applied to the mean ADMD forecasts is adjusted after the first 5 forecast years. After that point the average growth rate is applied to the prudent peak forecasts rather than the full 90th percentile rate of growth calculated as part of the prudent peak process. The intention is to allow for shorter term variation in peaks that may occur over the timeframe required for the construction of new transmission assets, while providing a set of long term expected peak projections appropriate for assessing new transmission build. As noted, the mean ADMD forecast is calculated as part of preparing the raw ADMD forecasts prior to scaling to the prudent peak forecast. The expected peak is calculated as part of the prudent peak forecasting outlined above.

5.4.16 The mean ADMD forecast is lower than the expected peak forecast as the former is based on an average of the 50 highest peaks, whereas the latter is based on the single highest peak and uses recent growth trends (rather than the energy forecast) for projecting demand in the first few years of the forecasts. As discussed above, the regional ADMD forecast matches the prudent peak forecast for the first 5 years then starts to differ once the mean growth rate is applied.

5.4.17 Figure 19 shows the expected peak and (prudent) ADMD forecasts for Auckland.

Figure 19: Auckland ADMD, expected peak, and prudent peak forecasts



5.4.18 Appendix 2 contains tables and graphs of the prudent ADMD forecast by region. The regional loads are at the time of the island peak. Typically these are slightly lower than the absolute region peak, but are usually used for system modelling unless region-specific issues are being assessed. GXP and ADMD forecast data is published with this paper and available on the Commission's website

Appendix 1 Energy Demand Forecasts

1.1 Energy Demand Tables

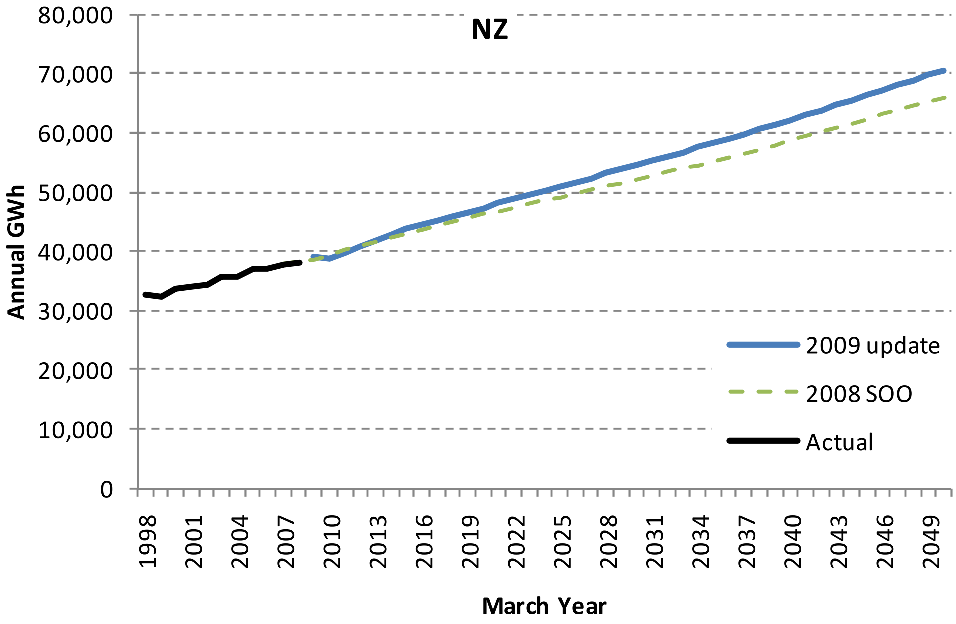
Table 5: Regional Energy Demand Projections – North Island

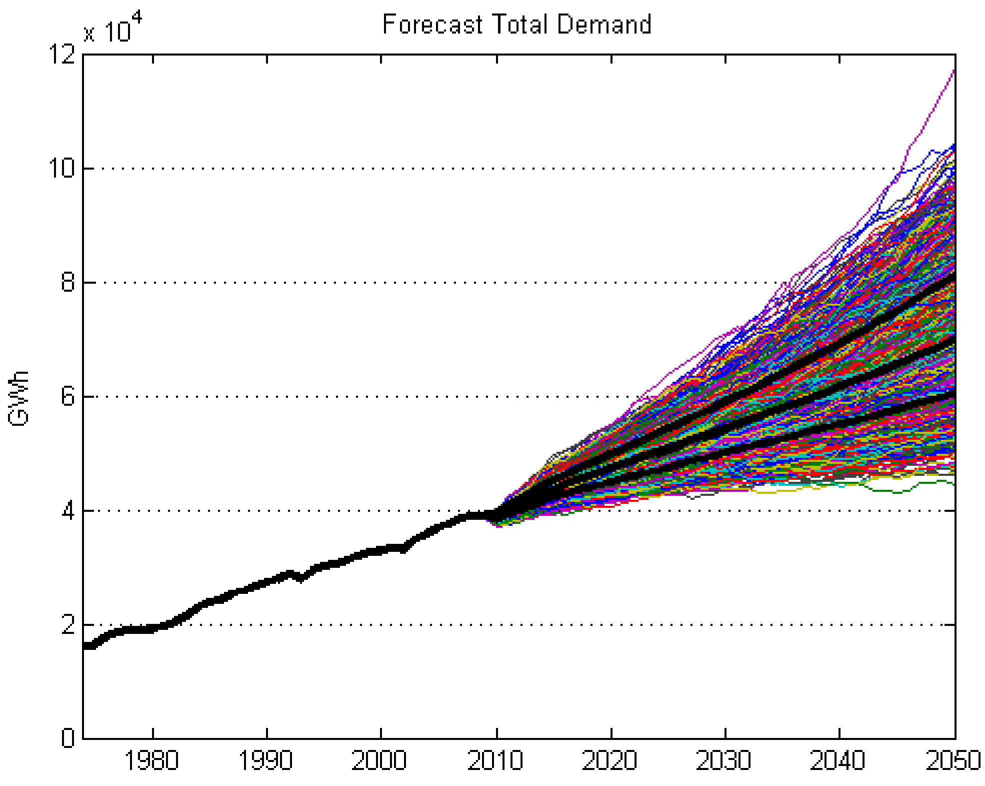
March Year	North Isthmus	Auckland	Waikato	BOP	Hawkes Bay	Central	Taranaki	Wellington	Total North Island
2009	4075	6973	3056	2832	1760	1705	812	3115	24328
2010	4064	6943	3014	2792	1730	1647	864	3083	24137
2011	4191	7153	3076	2850	1759	1708	878	3157	24772
2012	4313	7356	3134	2903	1786	1759	890	3228	25369
2013	4450	7594	3206	2969	1819	1822	906	3311	26077
2014	4578	7824	3273	3029	1848	1870	919	3388	26729
2015	4697	8056	3339	3086	1873	1910	930	3462	27353
2016	4811	8301	3407	3146	1896	1943	941	3534	27979
2017	4911	8545	3470	3201	1913	1963	948	3600	28551
2018	5015	8816	3542	3264	1931	1982	956	3670	29176
2019	5114	9090	3613	3328	1949	1998	962	3736	29790
2020	5213	9367	3683	3394	1966	2012	968	3800	30403
2021	5314	9645	3753	3462	1984	2028	975	3865	31026
2022	5419	9913	3819	3529	2003	2045	982	3927	31637
2023	5525	10174	3883	3594	2022	2063	988	3987	32236
2024	5634	10432	3944	3659	2040	2082	995	4046	32832
2025	5747	10690	4004	3723	2059	2102	1001	4107	33433
2026	5861	10947	4064	3788	2078	2122	1008	4168	34036
2027	5975	11198	4121	3848	2096	2142	1014	4226	34620
2028	6084	11444	4174	3907	2112	2159	1019	4280	35179
2029	6200	11698	4230	3968	2130	2179	1025	4337	35767
2030	6315	11953	4285	4029	2146	2197	1030	4394	36349
2031	6432	12212	4340	4091	2163	2216	1035	4450	36939
2032	6547	12469	4394	4155	2178	2233	1041	4503	37520
2033	6667	12735	4449	4220	2195	2251	1046	4558	38121
2034	6786	13002	4504	4285	2211	2268	1051	4611	38718
2035	6909	13276	4560	4351	2227	2286	1057	4667	39333
2036	7031	13553	4616	4418	2243	2304	1062	4721	39948
2037	7156	13836	4672	4485	2258	2321	1067	4775	40570
2038	7282	14123	4729	4554	2274	2339	1072	4830	41203
2039	7409	14415	4786	4623	2289	2356	1078	4885	41841
2040	7539	14712	4844	4694	2305	2373	1083	4940	42490

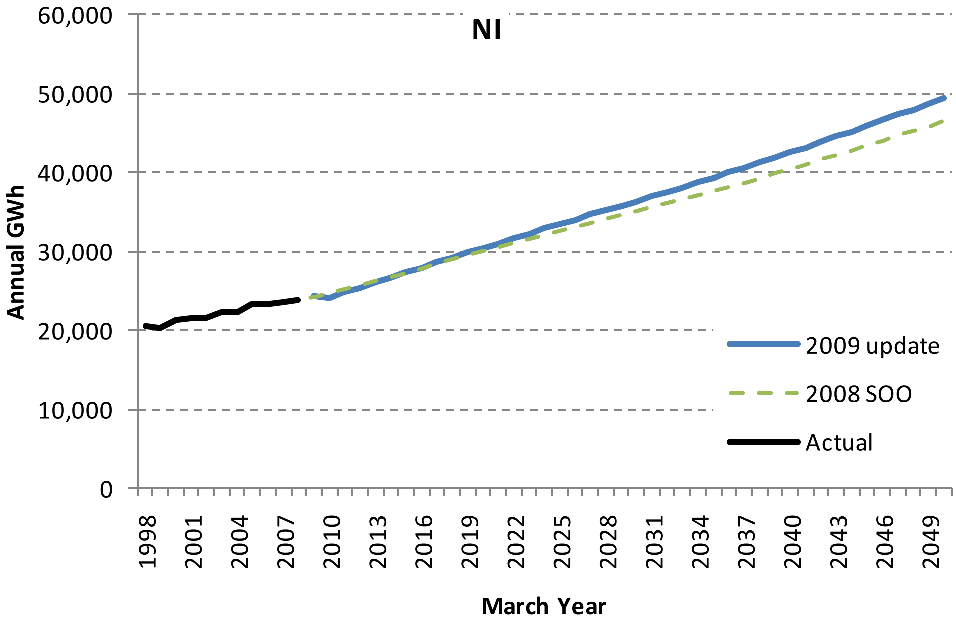
Table 6: Regional Energy Demand Projections – South Island (GWh)

March Year	Nelson / Marlborough	West Coast	Canterbury	South Canterbury	Otago / Southland	Total South Island	Total NZ
2009	1166	296	4382	639	8112	14595	38923
2010	1163	417	4370	641	7995	14586	38723
2011	1200	426	4508	665	8271	15070	39842
2012	1234	435	4639	688	8381	15377	40746
2013	1271	445	4787	713	8516	15732	41809
2014	1304	454	4921	735	8622	16036	42765
2015	1331	463	5043	755	8702	16294	43647
2016	1353	471	5154	771	8759	16508	44487
2017	1365	478	5242	782	8778	16645	45196
2018	1372	485	5328	790	8786	16761	45937
2019	1375	491	5401	795	8779	16841	46631
2020	1377	496	5470	799	8768	16910	47313
2021	1380	501	5542	804	8764	16991	48017
2022	1385	505	5617	809	8766	17082	48719
2023	1393	509	5696	816	8777	17191	49427
2024	1402	513	5779	824	8793	17311	50143
2025	1414	517	5867	833	8816	17447	50880
2026	1427	521	5958	843	8843	17592	51628
2027	1438	525	6049	853	8870	17735	52355
2028	1451	529	6134	862	8896	17872	53051
2029	1464	533	6227	873	8925	18022	53789
2030	1478	537	6318	883	8954	18170	54519
2031	1490	540	6411	894	8983	18318	55257
2032	1503	544	6498	904	9010	18459	55979
2033	1517	548	6589	915	9039	18608	56729
2034	1530	552	6678	926	9067	18753	57471
2035	1543	556	6770	936	9096	18901	58234
2036	1556	560	6860	947	9124	19047	58995
2037	1570	564	6951	958	9152	19195	59765
2038	1583	568	7043	969	9181	19344	60547
2039	1596	572	7135	980	9209	19492	61333
2040	1609	576	7228	991	9237	19641	62131

1.2 Energy Demand Figures






NI
Annual GWh
60,000
50,000
40,000
30,000
20,000
10,000
0
1998
2001
2004
2007
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2037
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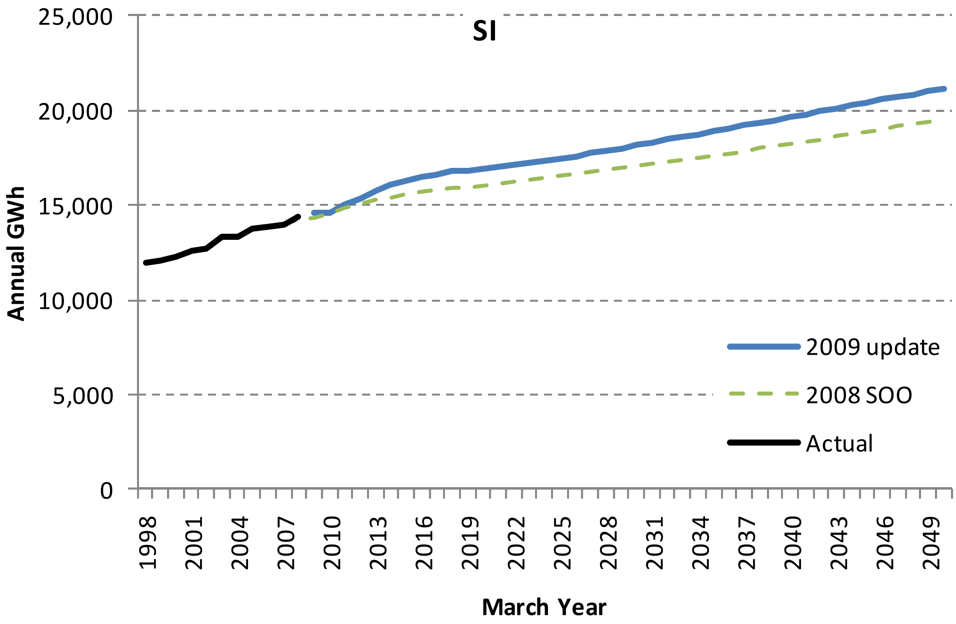
2043
2046
2049
March Year
2009 update
2008 SOO
Actual


SI
Annual GWh
25,000
20,000
15,000
10,000
5,000
0
1998
2001
2004
2007
2010
2013
2016
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2037
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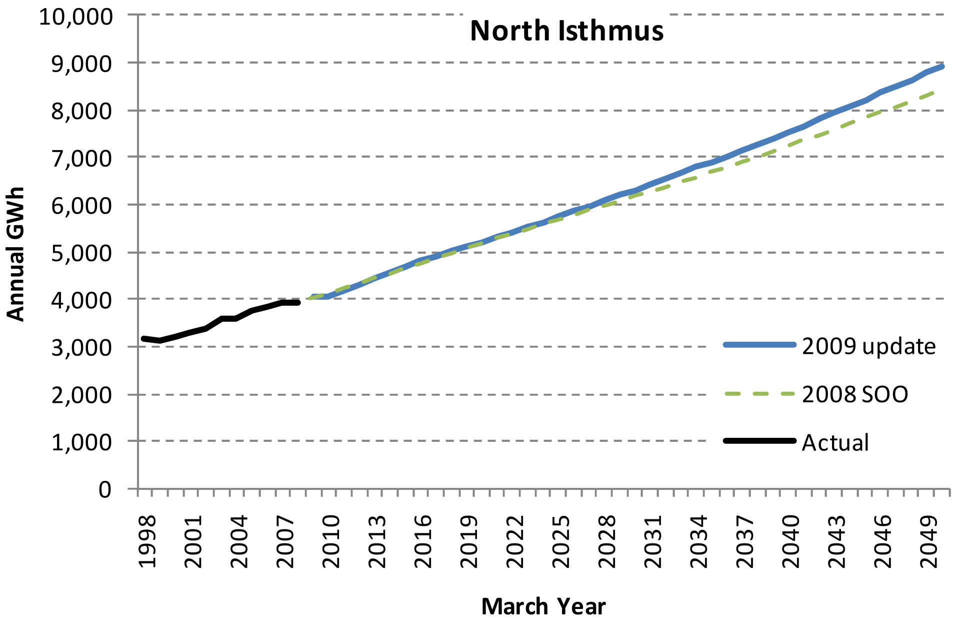
2049
March Year
2009 update
2008 SOO
Actual


North Isthmus
Annual GWh
March Year
2009 update
2008 SOO
Actual
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
1998
2001
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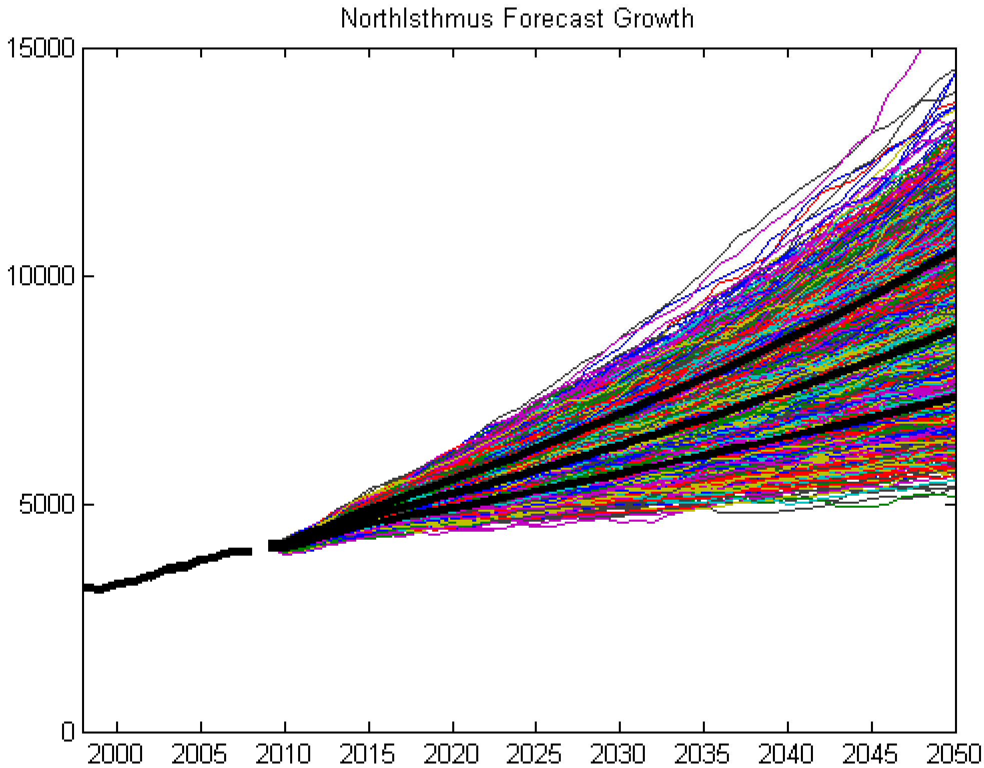
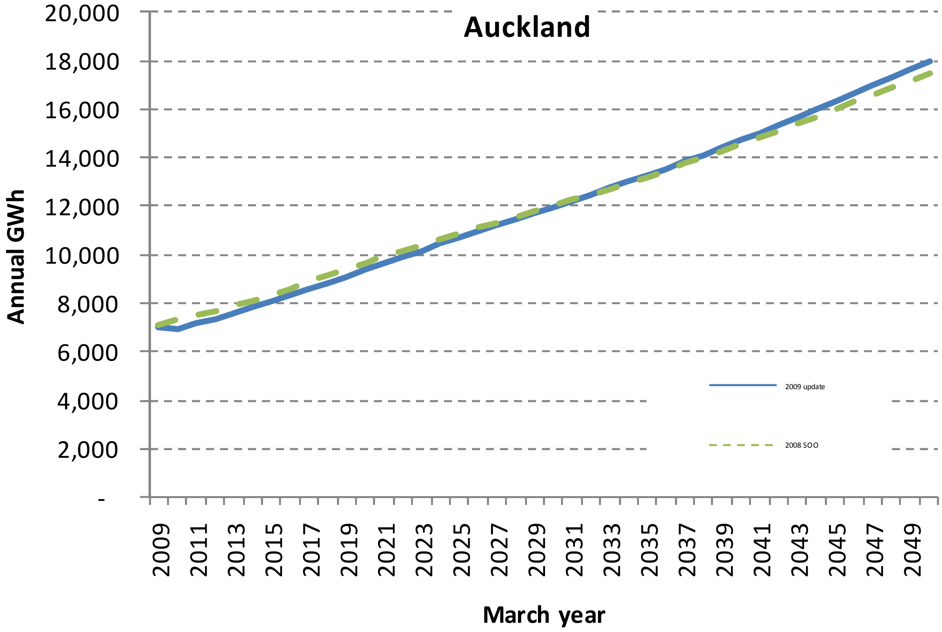
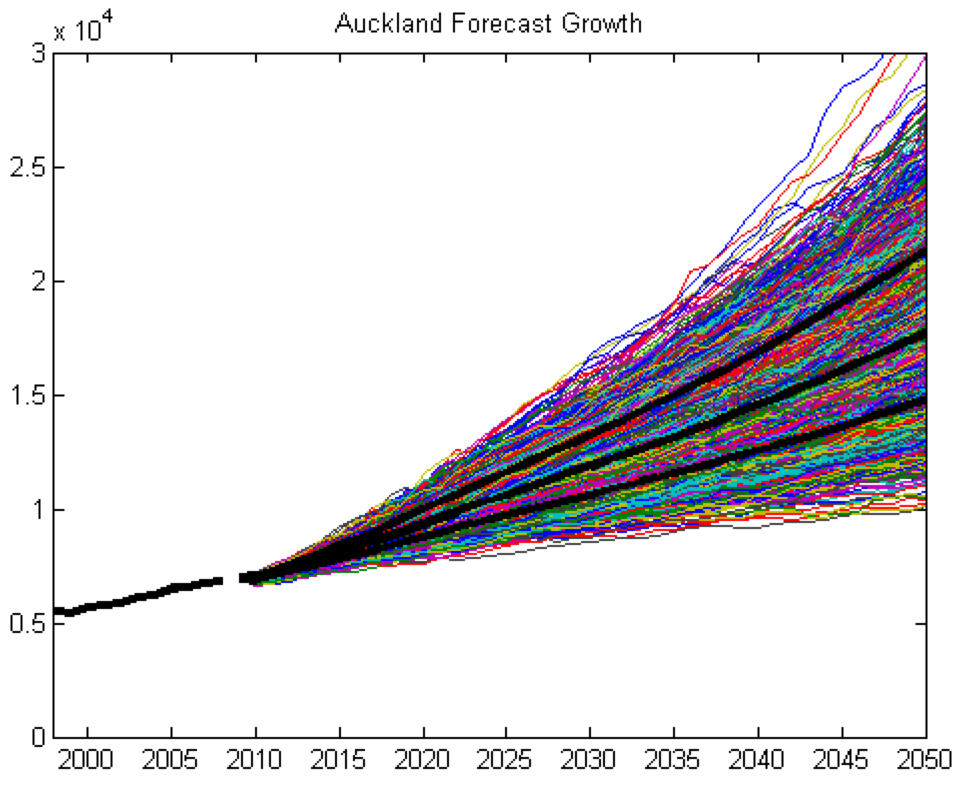
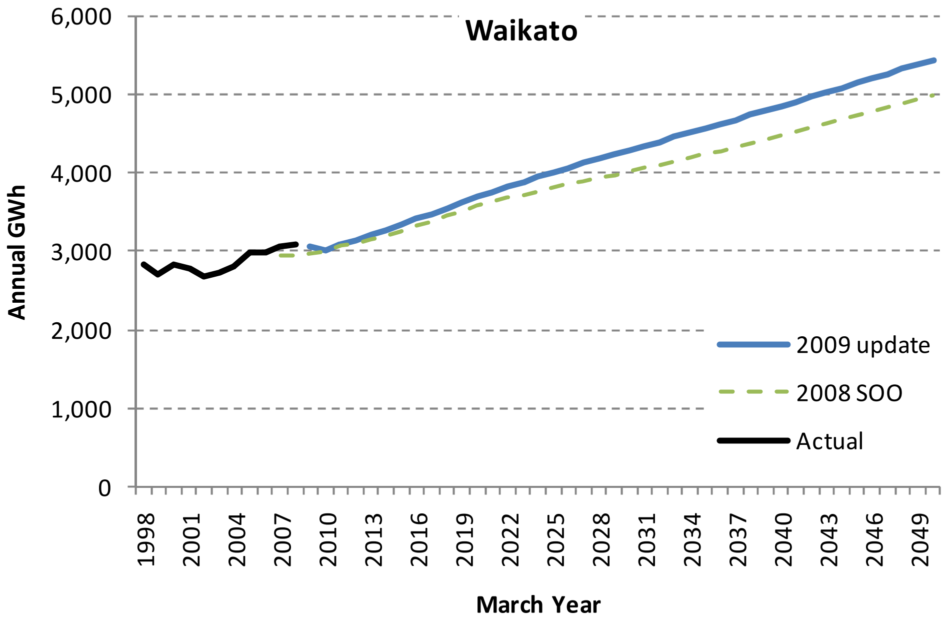

NorthIsthmus Forecast Growth
15000
10000
5000
0
2000
2005
2010
2015
2020
2025
2030
2035
2040
2045
2050


Auckland
Annual GWh
March year
2009 update
2008 SOO


Auckland Forecast Growth
x 10^4


Waikato
Annual GWh
6,000
5,000
4,000
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2,000
1,000
0
1998
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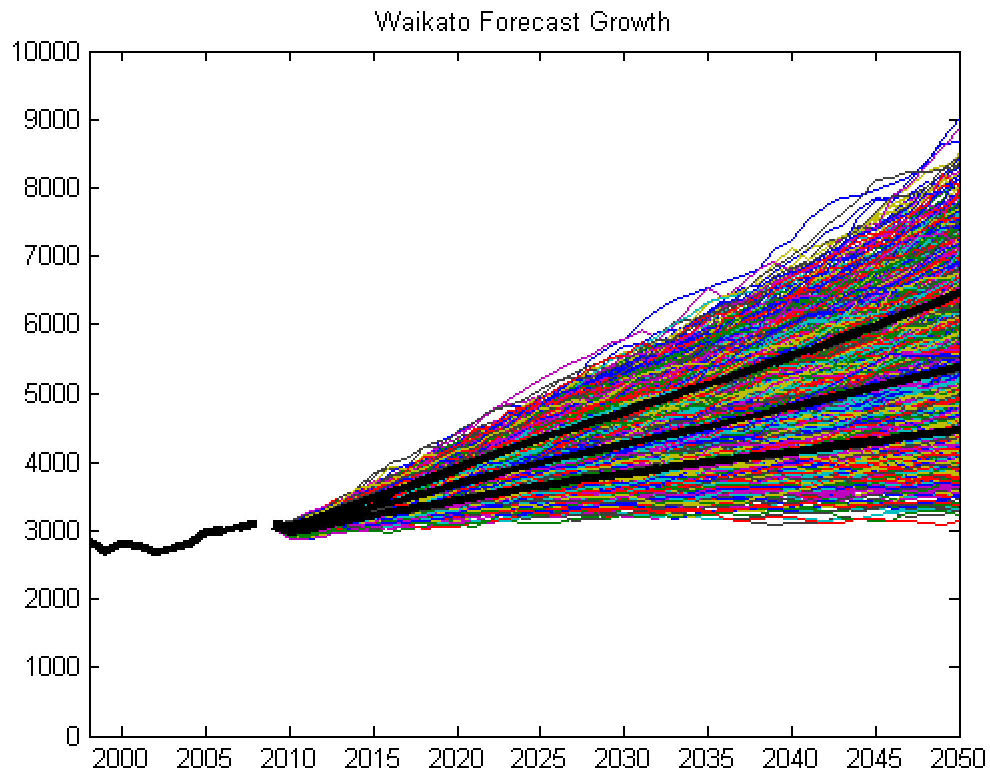
March Year
2009 update
2008 SOO
Actual


Waikato Forecast Growth
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9000
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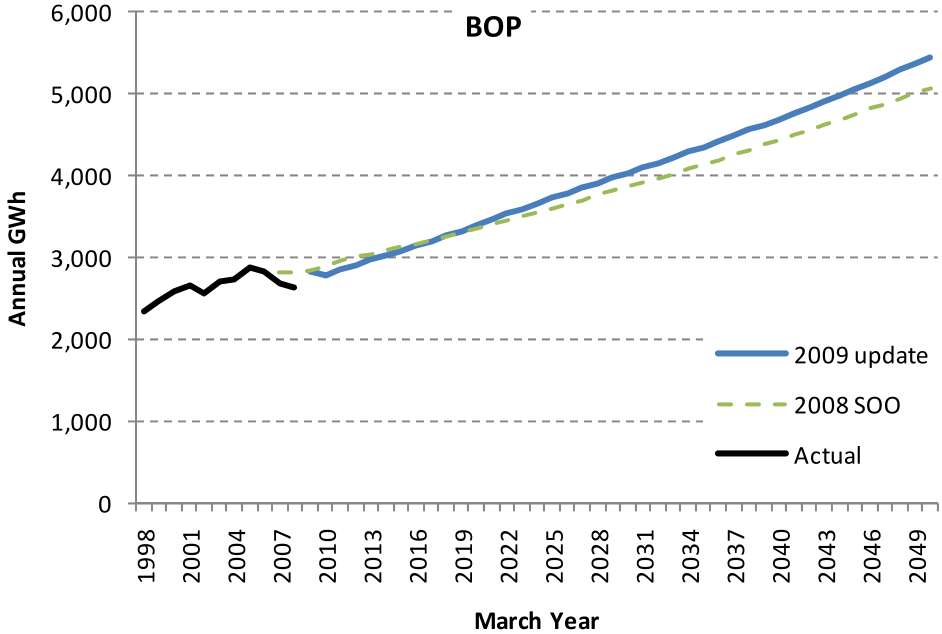
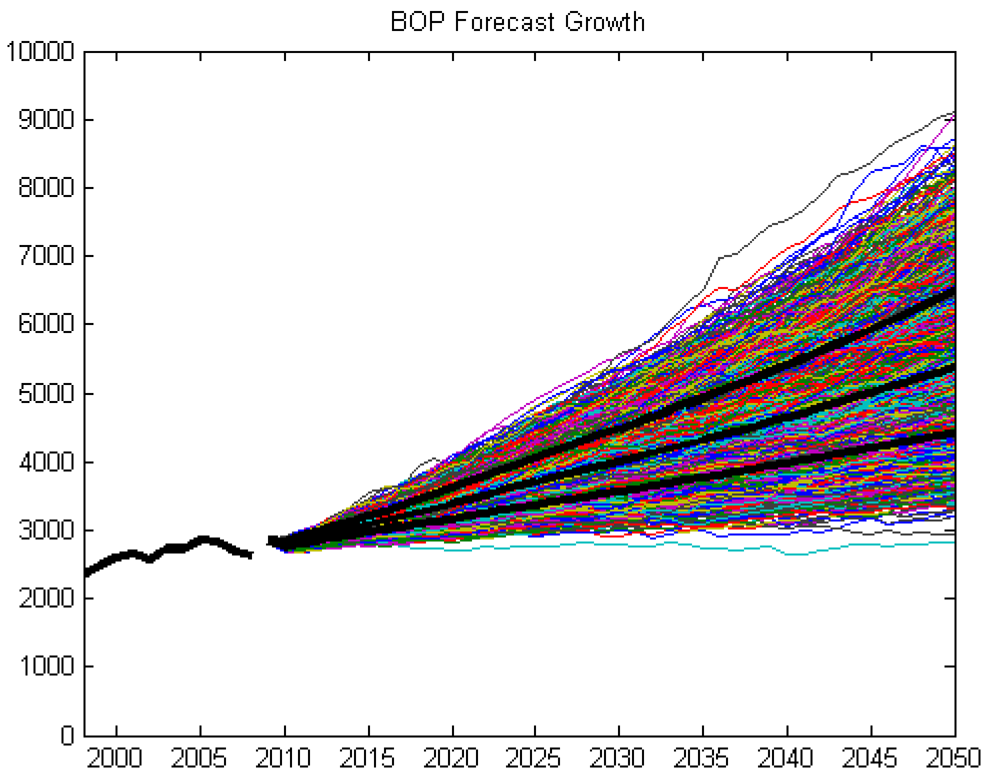
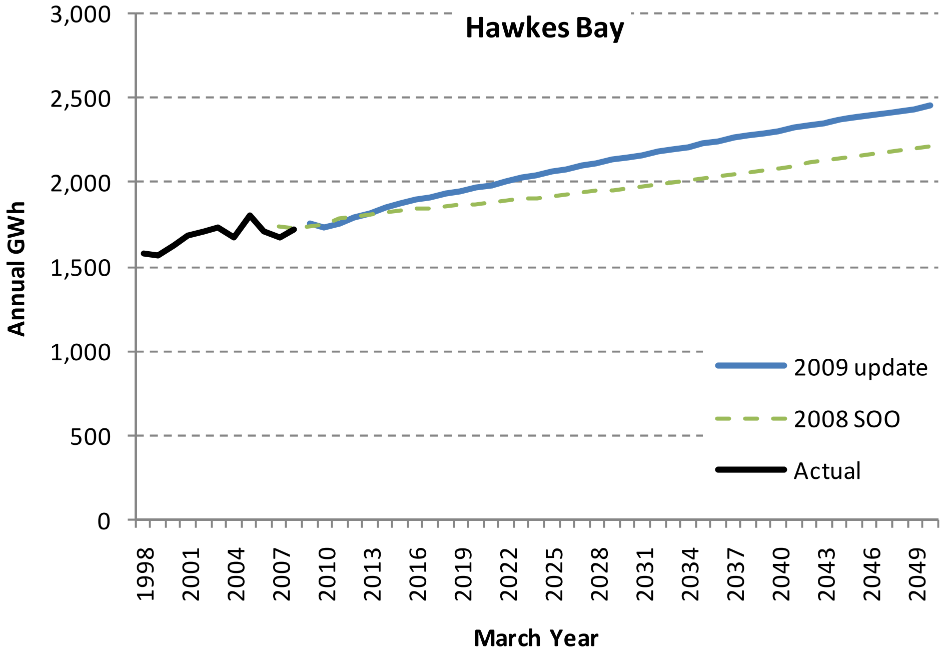
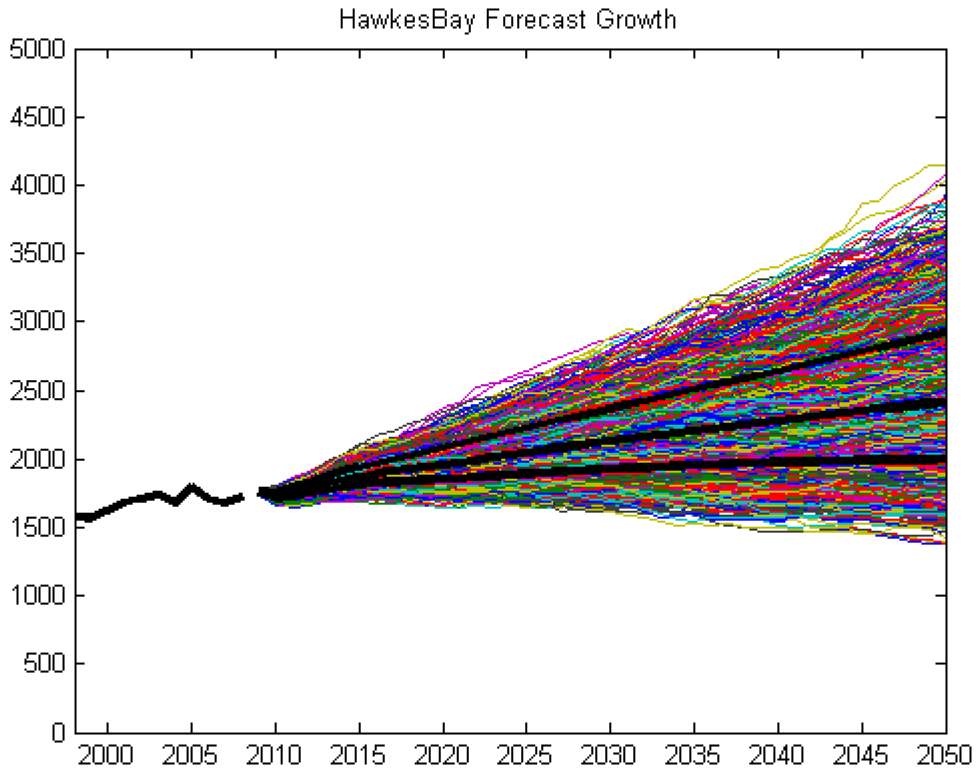
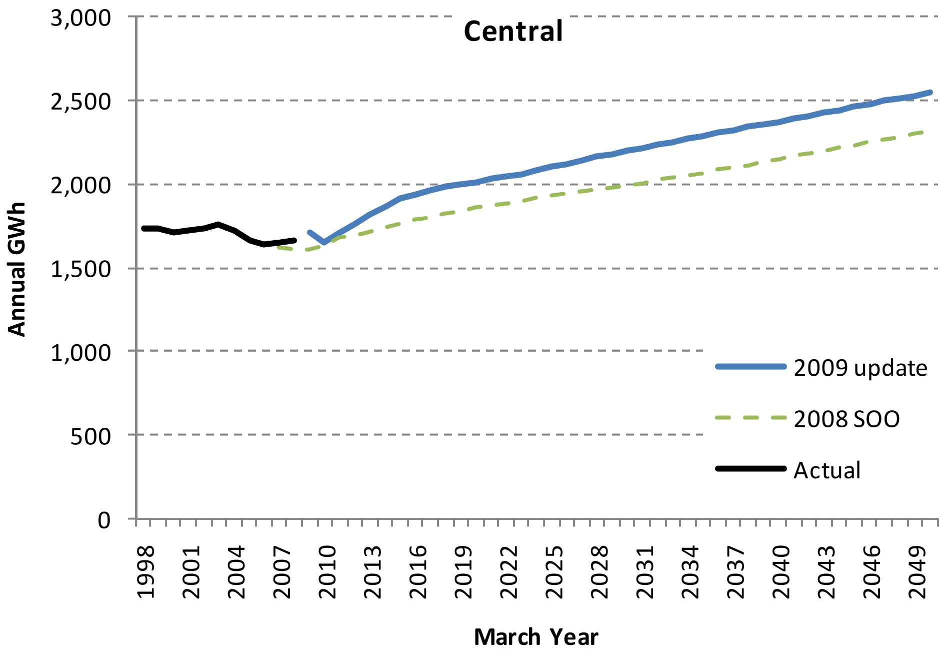
2035
2040
2045
2050


BOP
Annual GWh
March Year
2009 update
2008 SOO
Actual

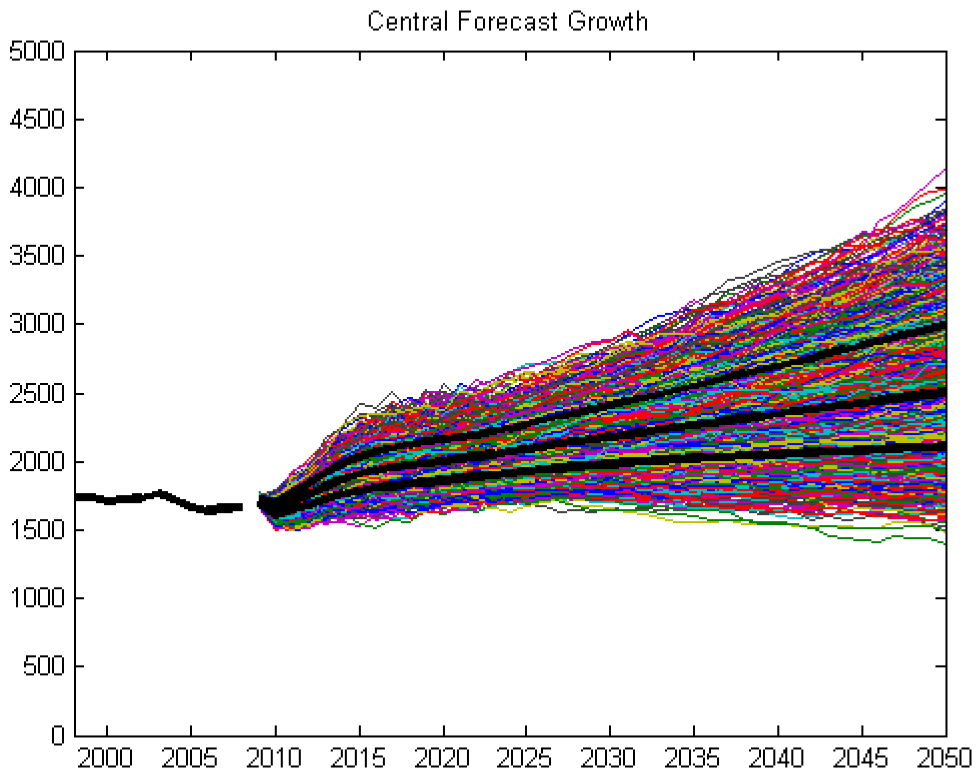

BOP Forecast Growth


Hawkes Bay
3,000
2,500
2,000
1,500
1,000
500
0
Annual GWh
1998
2001
2004
2007
2010
2013
2016
2019
2022
2025
2028
2031
2034
2037
2040
2043
2046
2049
March Year
2009 update
2008 SOO
Actual

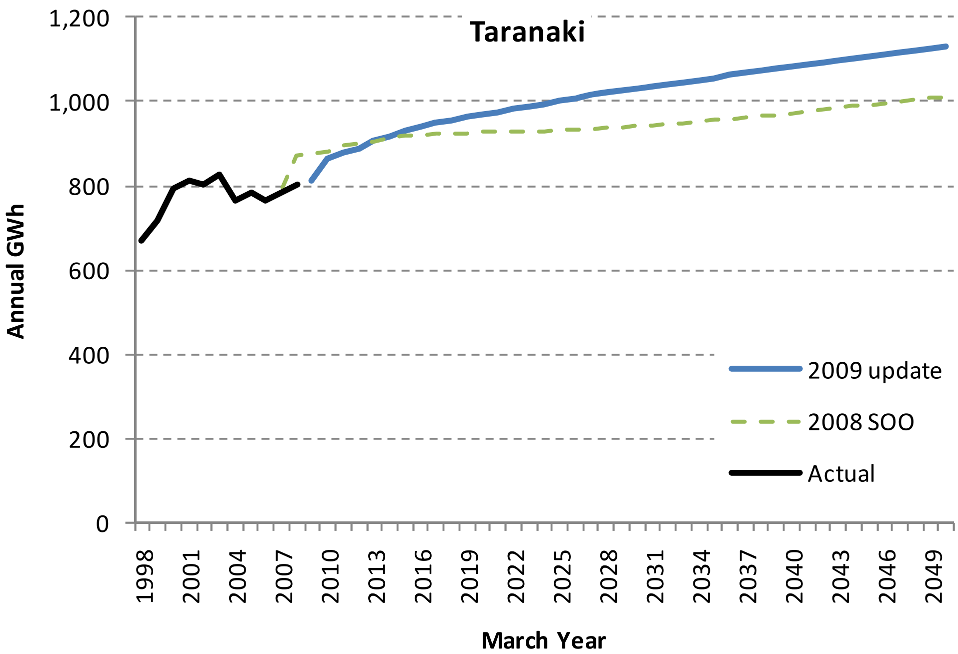

HawkesBay Forecast Growth
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
2000
2005
2010
2015
2020
2025
2030
2035
2040
2045
2050

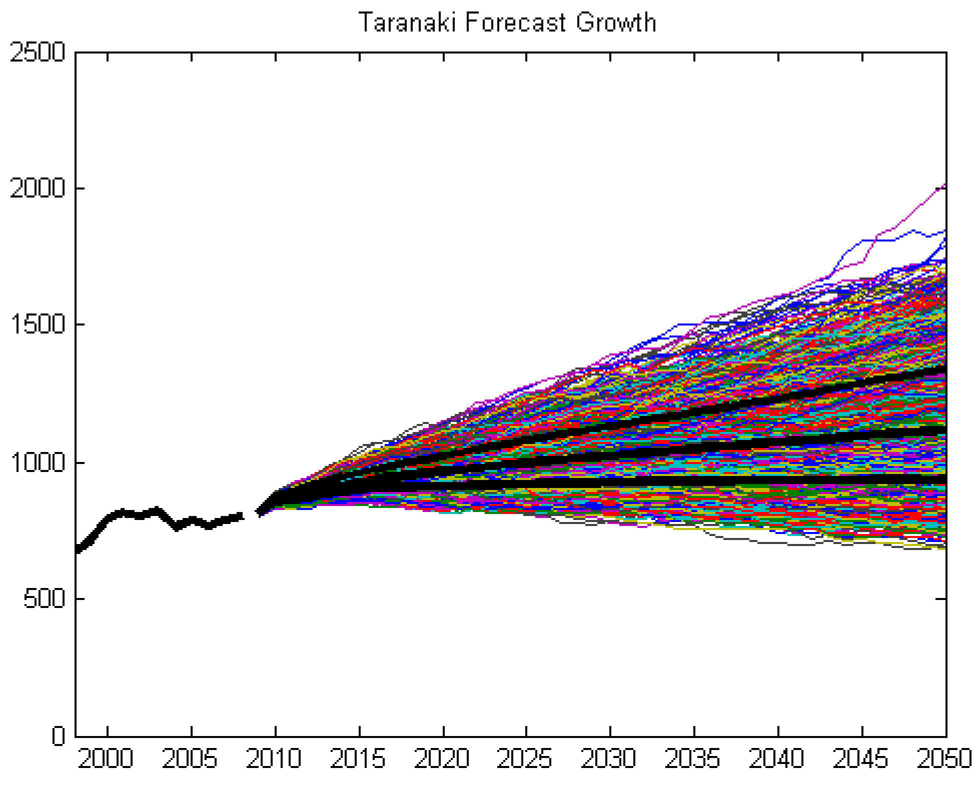


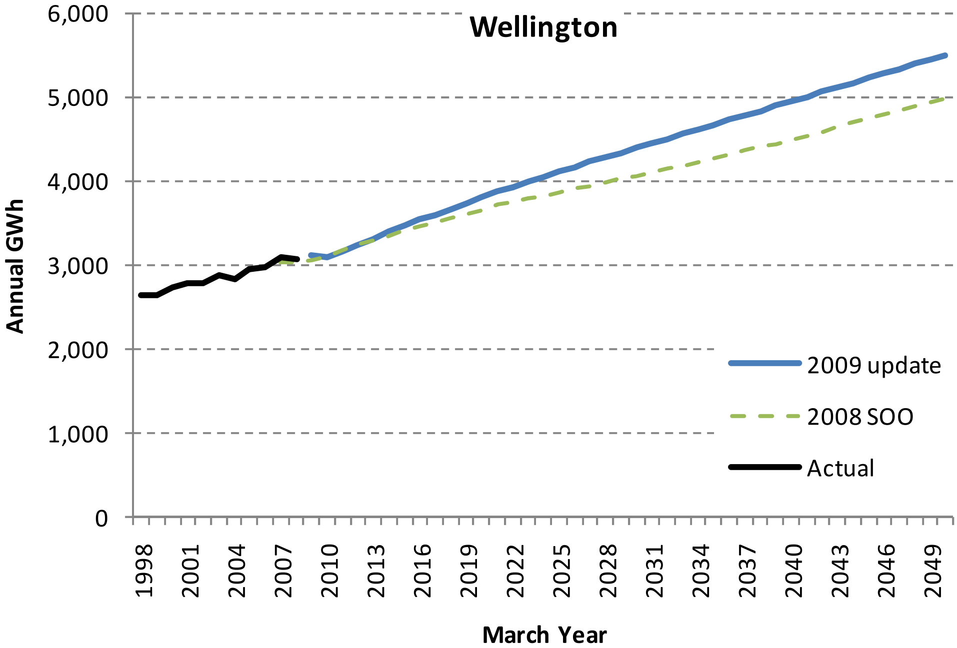
Central
3,000
2,500
2,000
1,500
1,000
500
0
Annual GWh
1998
2001
2004
2007
2010
2013
2016
2019
2022
2025
2028
2031
2034
2037
2040
2043
2046
2049
March Year
2009 update
2008 SOO
Actual

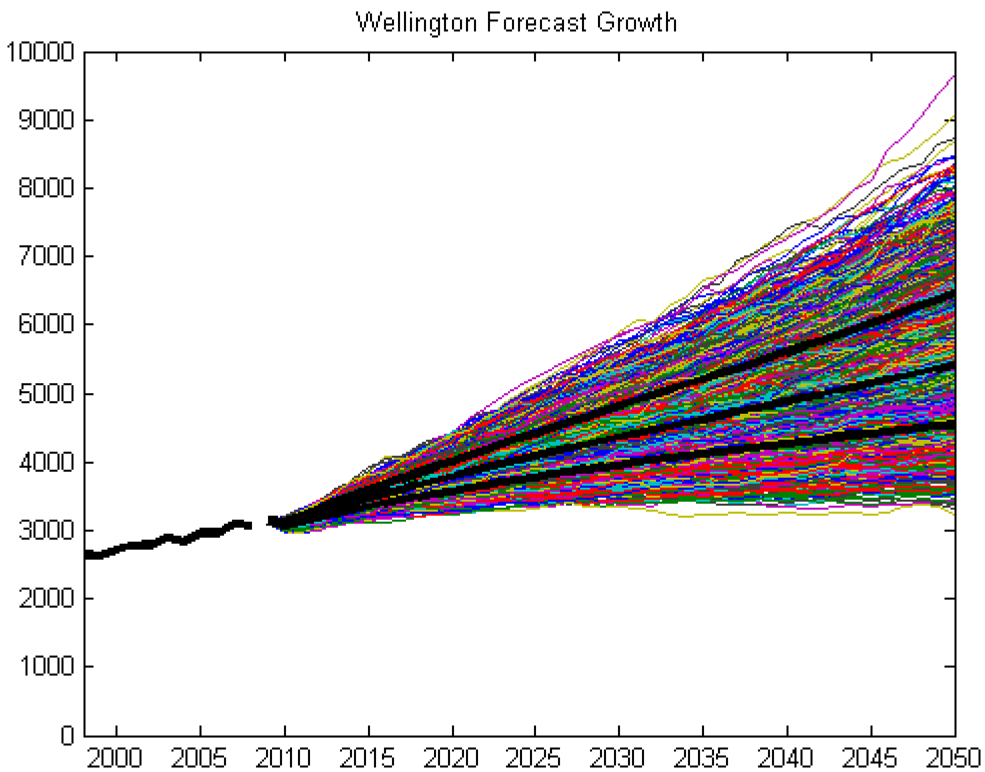


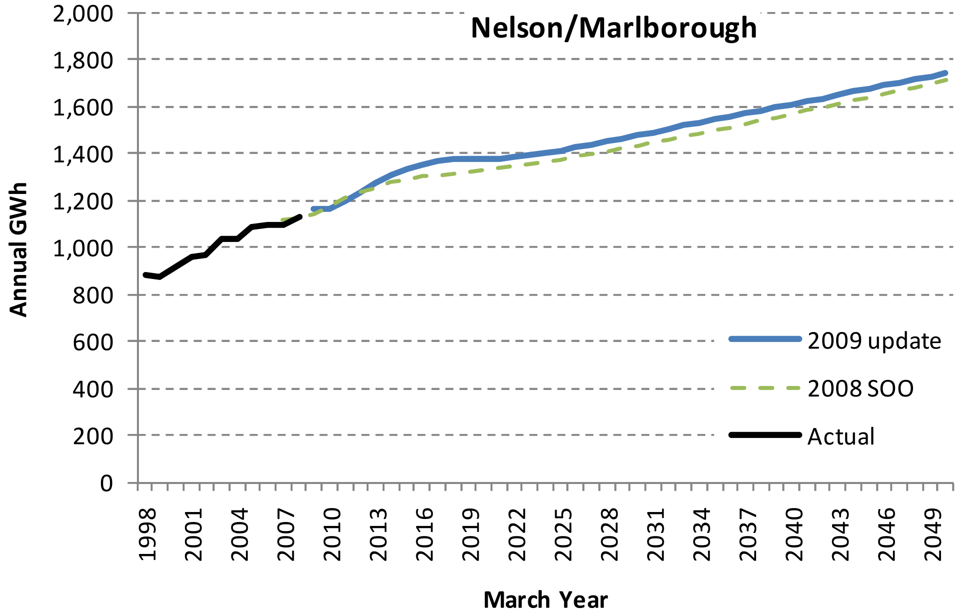
Central Forecast Growth
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
2000
2005
2010
2015
2020
2025
2030
2035
2040
2045
2050

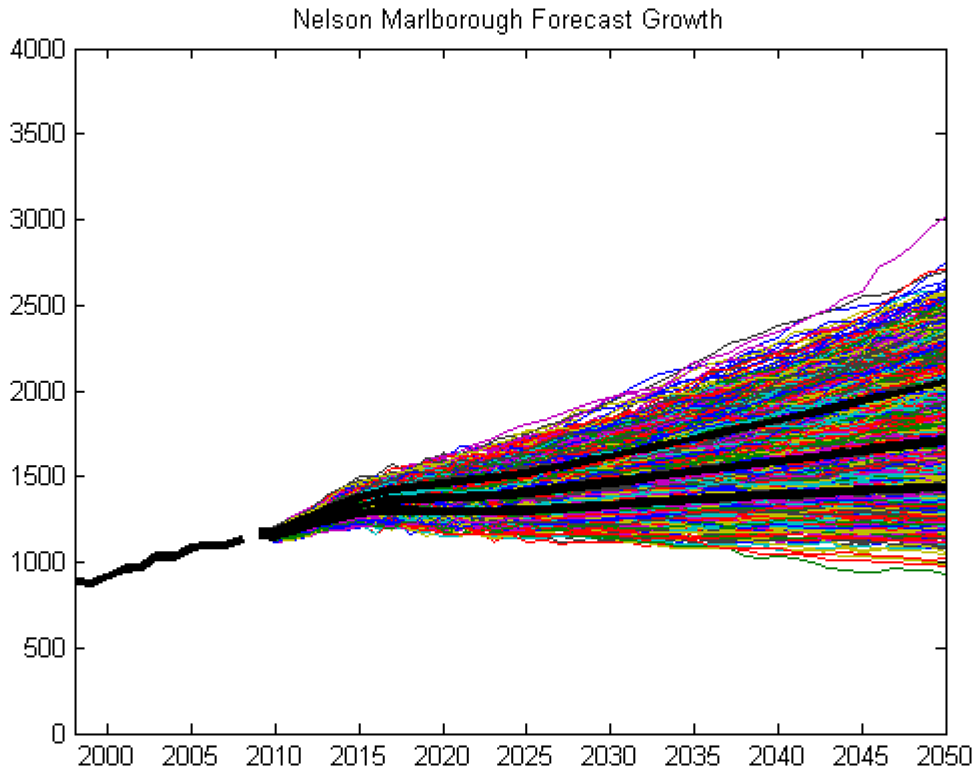

Taranaki
Annual GWh
1,200
1,000
800
600
400
200
0
1998
2001
2004
2007
2010
2013
2016
2019
2022
2025
2028
2031
2034
2037
2040
2043
2046
2049
March Year
2009 update
2008 SOO
Actual

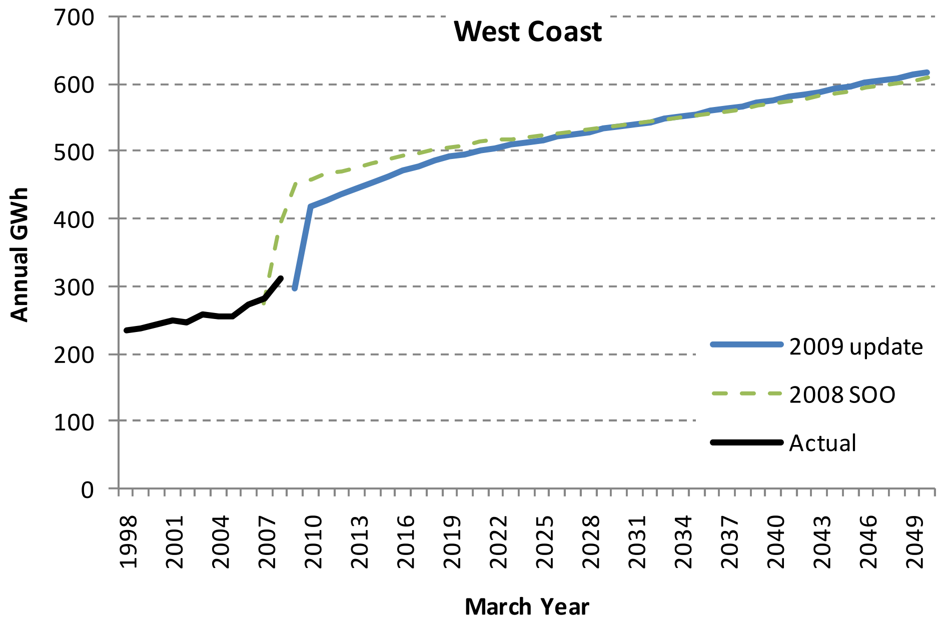

Taranaki Forecast Growth
2500
2000
1500
1000
500
0
2000
2005
2010
2015
2020
2025
2030
2035
2040
2045
2050


Wellington
Annual GWh
March Year
2009 update
2008 SOO
Actual


Wellington Forecast Growth


Nelson/Marlborough
Annual GWh
2,000
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
1998
2001
2004
2007
2010
2013
2016
2019
2022
2025
2028
2031
2034
2037
2040
2043
2046
2049
March Year
2009 update
2008 SOO
Actual


Nelson Marlborough Forecast Growth
4000
3500
3000
2500
2000
1500
1000
500
0
2000
2005
2010
2015
2020
2025
2030
2035
2040
2045
2050


West Coast
Annual GWh
March Year
2009 update
2008 SOO
Actual
0
100
200
300
400
500
600
700
1998
2001
2004
2007
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2013
2016
2019
2022
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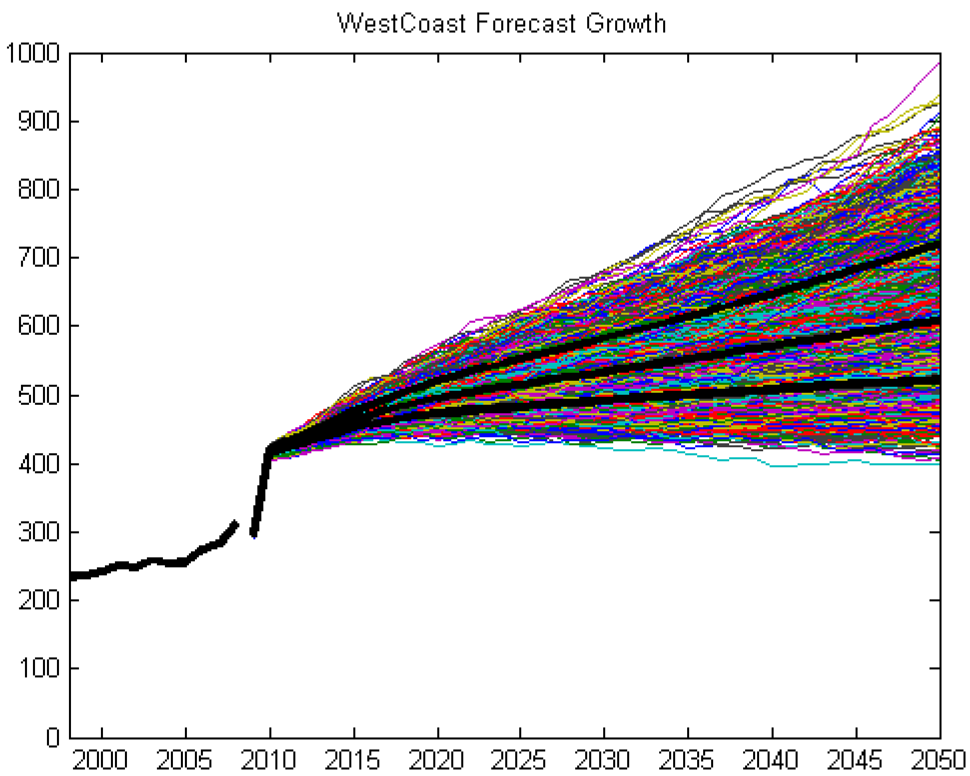
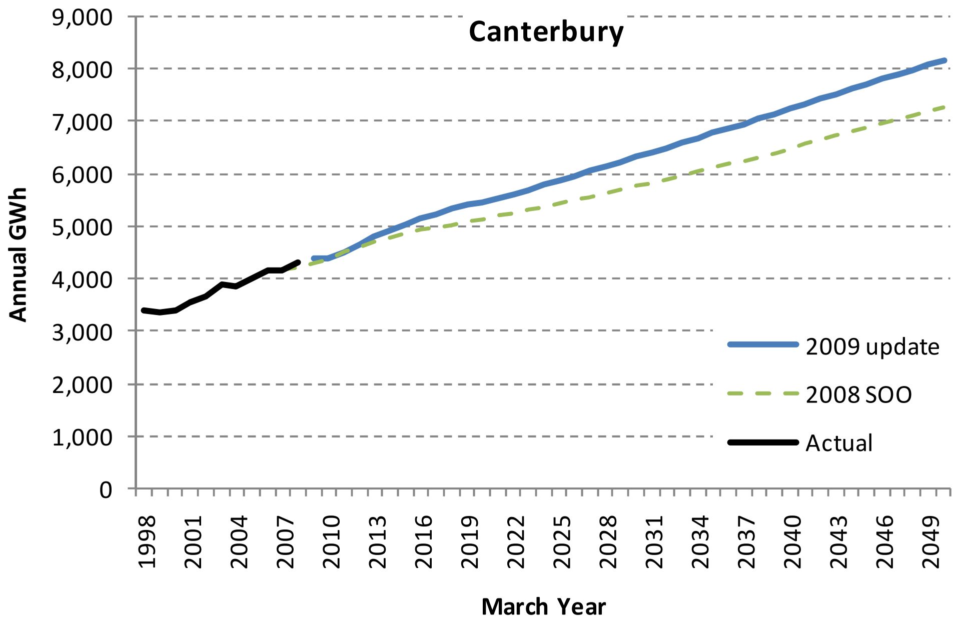
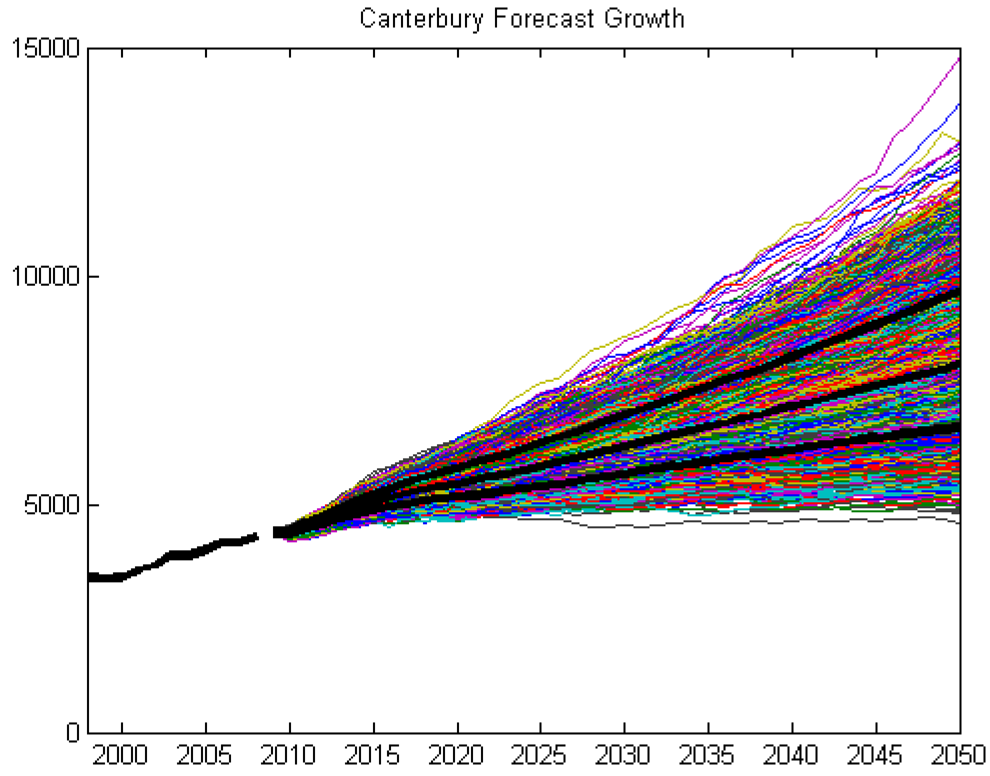
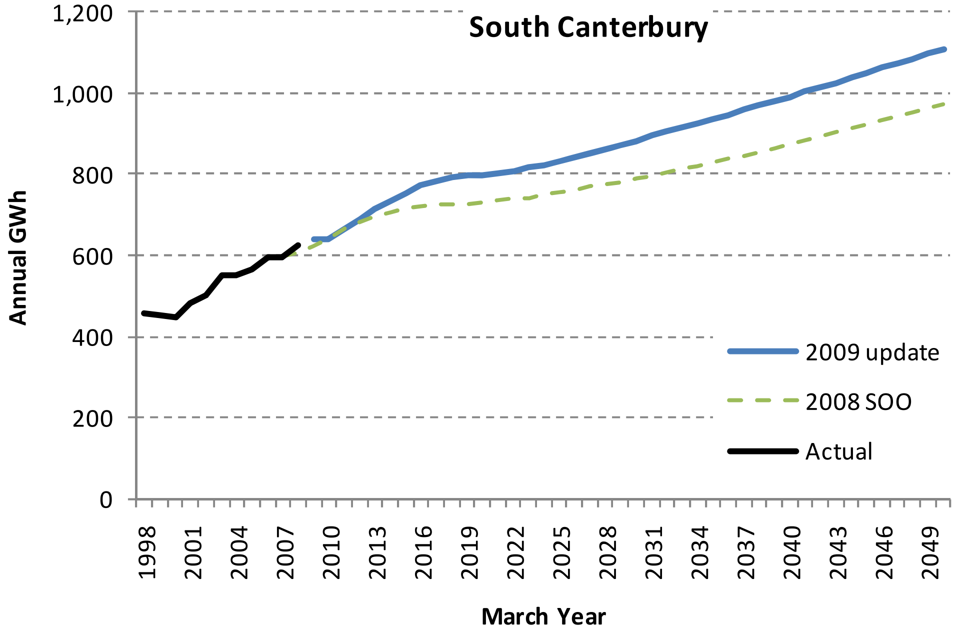
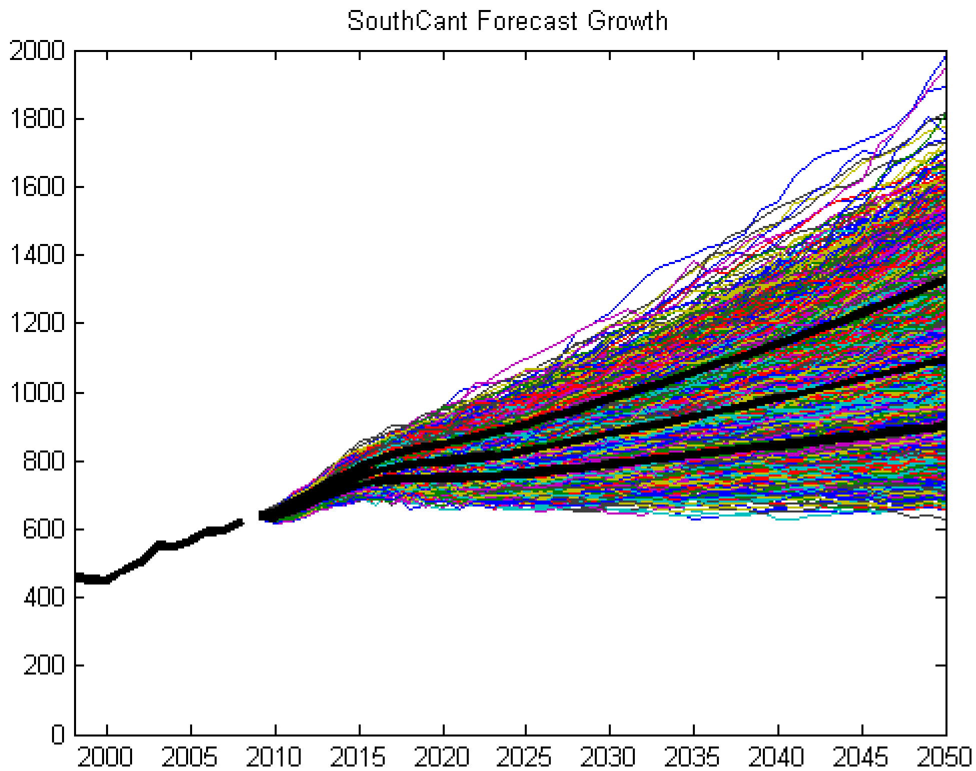
2040
2043
2046
2049

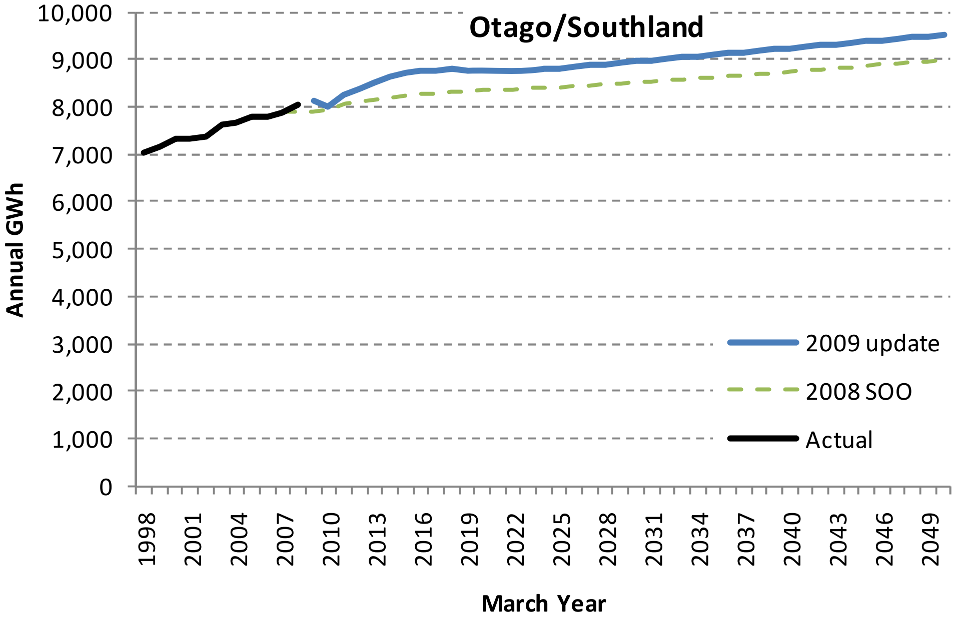

WestCoast Forecast Growth
0
100
200
300
400
500
600
700
800
900
1000
2000
2005
2010
2015
2020
2025
2030
2035
2040
2045
2050

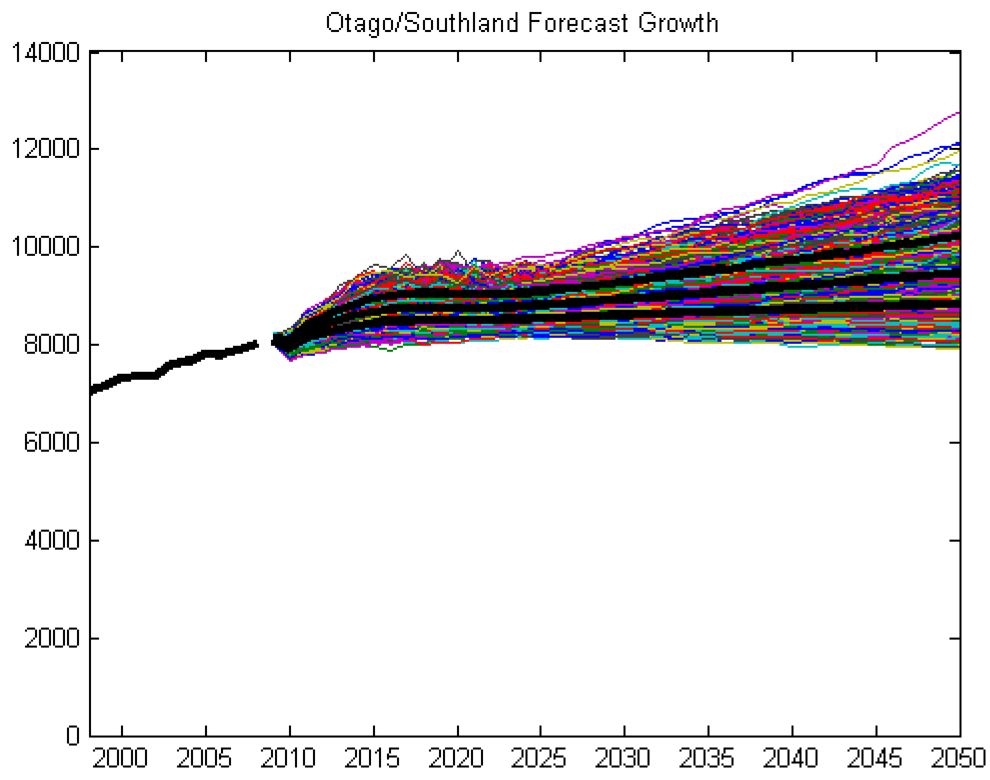

Canterbury
Annual GWh
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
1998
2001
2004
2007
2010
2013
2016
2019
2022
2025
2028
2031
2034
2037
2040
2043
2046
2049
March Year
2009 update
2008 SOO
Actual


Canterbury Forecast Growth
15000
10000
5000
0
2000
2005
2010
2015
2020
2025
2030
2035
2040
2045
2050


South Canterbury
Annual GWh
March Year
1,200
1,000
800
600
400
200
0
1998
2001
2004
2007
2010
2013
2016
2019
2022
2025
2028
2031
2034
2037
2040
2043
2046
2049
2009 update
2008 SOO
Actual


SouthCant Forecast Growth
2000
1800
1600
1400
1200
1000
800
600
400
200
0
2000
2005
2010
2015
2020
2025
2030
2035
2040
2045
2050


Otago/Southland
Annual GWh
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
2009 update
2008 SOO
Actual
1998
2001
2004
2007
2010
2013
2016
2019
2022
2025
2028
2031
2034
2037
2040
2043
2046
2049
March Year


Otago/Southland Forecast Growth
14000
12000
10000
8000
6000
4000
2000
0
2000
2005
2010
2015
2020
2025
2030
2035
2040
2045
2050

Appendix 2 Peak Demand Forecasts

2.1 Peak demand and ADMD Tables

Table 7: Prudent and Expected Peak Demand Projections (MW)

	National		North Island		South Island	
Year	**Expected Peak**	**Prudent Peak**	**Expected Peak**	**Prudent Peak**	**Expected Peak**	**Prudent Peak**
2009	6729	6882	4502	4627	2257	2288
2010	6870	7059	4602	4750	2299	2349
2011	7009	7247	4704	4873	2338	2406
2012	7170	7455	4823	5051	2382	2474
2013	7326	7715	4940	5213	2424	2546
2014	7473	7838	5055	5320	2460	2575
2015	7615	8014	5170	5485	2490	2614
2016	7734	8190	5273	5613	2511	2641
2017	7858	8346	5386	5730	2529	2665
2018	7975	8487	5495	5862	2543	2681
2019	8091	8629	5605	6013	2555	2697
2020	8210	8752	5716	6146	2569	2723
2021	8326	8924	5826	6283	2583	2726
2022	8446	9060	5935	6405	2599	2751
2023	8565	9224	6042	6537	2617	2786
2024	8688	9415	6152	6680	2636	2803
2025	8813	9561	6261	6826	2656	2824
2026	8935	9679	6368	6978	2677	2860
2027	9053	9850	6471	7069	2697	2889
2028	9177	10004	6578	7194	2719	2908
2029	9300	10189	6685	7350	2741	2949
2030	9425	10314	6793	7536	2762	2965
2031	9560	10462	6909	7632	2787	3000
2032	9690	10692	7022	7826	2810	3040
2033	9820	10821	7134	7940	2832	3077
2034	9953	11086	7250	8096	2855	3111
2035	10087	11198	7366	8224	2878	3151
2036	10223	11382	7485	8404	2901	3161
2037	10361	11586	7605	8510	2925	3211
2038	10500	11714	7726	8660	2948	3242
2039	10642	11911	7850	8865	2972	3285
2040	10784	12091	7975	9023	2996	3301

Table 8: Regional ADMD Peak Demand Projections – North Island (MW)

Year	North Isthmus	Auckland	Waikato	BOP	Hawkes Bay	Central	Taranaki	Wellington	Total North Island
2009	879	1430	575	450	280	330	142	677	4762
2010	908	1469	587	458	283	335	145	692	4876
2011	939	1518	601	465	288	342	147	709	5010
2012	970	1571	615	476	297	353	149	732	5164
2013	1009	1623	633	487	306	363	154	751	5326
2014	1032	1674	646	497	315	373	156	768	5461
2015	1056	1725	659	507	319	379	158	784	5587
2016	1078	1774	671	515	322	382	159	798	5701
2017	1101	1829	684	525	325	386	160	813	5825
2018	1123	1885	697	535	328	389	161	828	5945
2019	1144	1940	710	546	330	392	162	842	6066
2020	1167	1996	723	556	333	395	163	856	6188
2021	1189	2051	735	567	335	398	163	869	6308
2022	1212	2105	747	578	338	401	164	883	6429
2023	1236	2158	759	588	341	405	165	896	6547
2024	1260	2211	770	598	343	409	166	909	6667
2025	1285	2265	782	609	346	412	167	922	6787
2026	1309	2317	793	618	349	416	168	935	6905
2027	1333	2368	803	628	352	419	169	947	7018
2028	1358	2420	814	638	355	423	169	959	7136
2029	1384	2473	824	647	357	426	170	972	7254
2030	1409	2527	835	657	360	430	171	984	7373
2031	1437	2583	846	668	363	433	172	998	7501
2032	1464	2639	857	679	366	437	173	1010	7625
2033	1491	2694	868	689	369	440	174	1023	7748
2034	1518	2752	879	700	372	444	175	1035	7876
2035	1546	2810	890	711	375	447	176	1048	8004
2036	1575	2870	902	722	378	451	176	1061	8134
2037	1604	2931	913	733	381	455	177	1074	8267
2038	1633	2992	925	745	383	458	178	1087	8401
2039	1662	3056	936	756	386	462	179	1100	8537
2040	1692	3119	948	768	389	465	180	1113	8675

*Region demand at Island peak

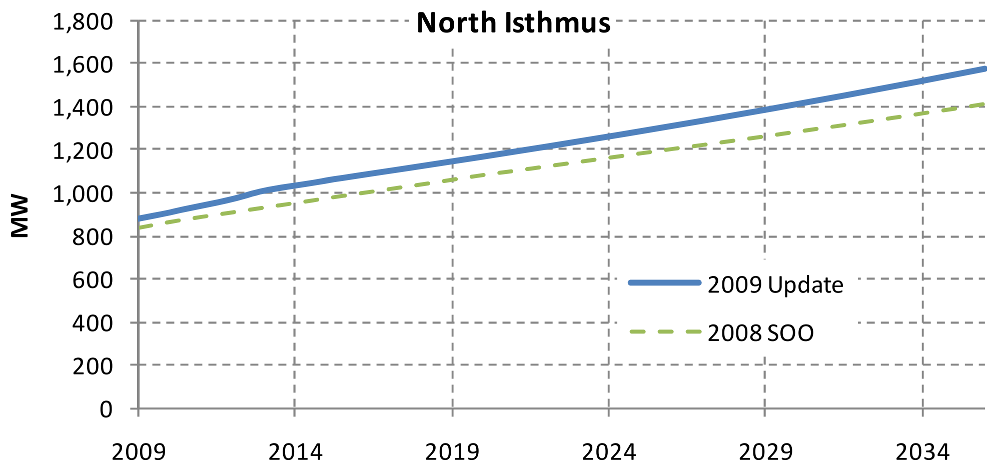
Table 9: Regional ADMD Projections – South Island (MW)

Year	Nelson / Marlborough	West Coast	Canterbury	South Canterbury	Otago / Southland	Total South Island
2009	225	60	799	96	1134	2314
2010	232	60	817	103	1151	2363
2011	240	61	842	107	1175	2425
2012	250	76	868	112	1199	2505
2013	258	77	894	117	1221	2567
2014	264	78	918	120	1236	2615
2015	268	79	938	122	1244	2650
2016	270	80	954	124	1247	2674
2017	272	80	970	125	1248	2695
2018	273	81	984	126	1248	2711
2019	273	81	997	127	1248	2726
2020	274	82	1011	127	1248	2742
2021	275	82	1024	128	1248	2758
2022	277	82	1039	129	1250	2777
2023	278	83	1053	130	1252	2797
2024	281	83	1069	132	1255	2820
2025	283	84	1085	133	1259	2844
2026	285	84	1101	135	1263	2868
2027	288	84	1117	136	1266	2891
2028	290	85	1133	138	1270	2916
2029	293	85	1150	139	1275	2941
2030	295	85	1167	141	1279	2967
2031	298	86	1185	143	1284	2995
2032	301	86	1202	144	1288	3021
2033	304	87	1219	146	1292	3047
2034	307	87	1236	148	1297	3074
2035	309	87	1253	149	1301	3101
2036	312	88	1271	151	1306	3128
2037	315	88	1288	153	1310	3155
2038	318	89	1306	155	1315	3182
2039	321	89	1324	156	1320	3210
2040	324	89	1342	158	1324	3238

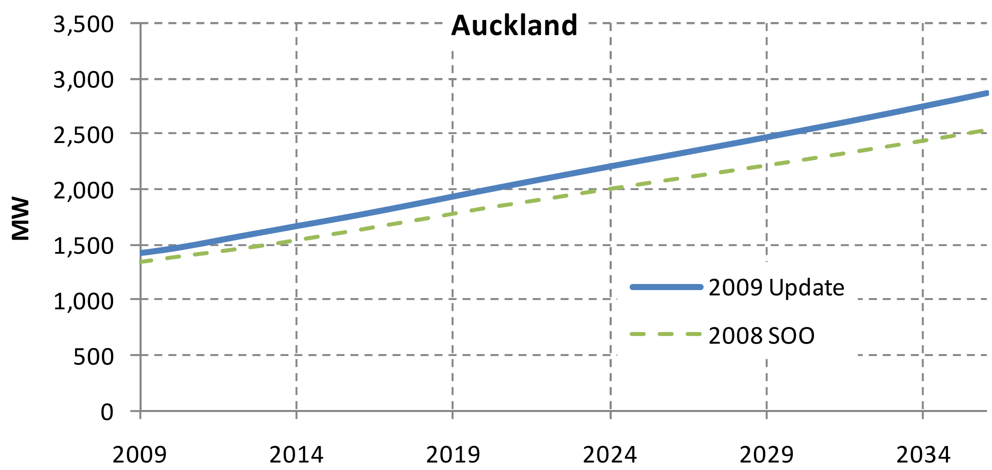
*Region demand at Island peak

2.2 ADMD figures

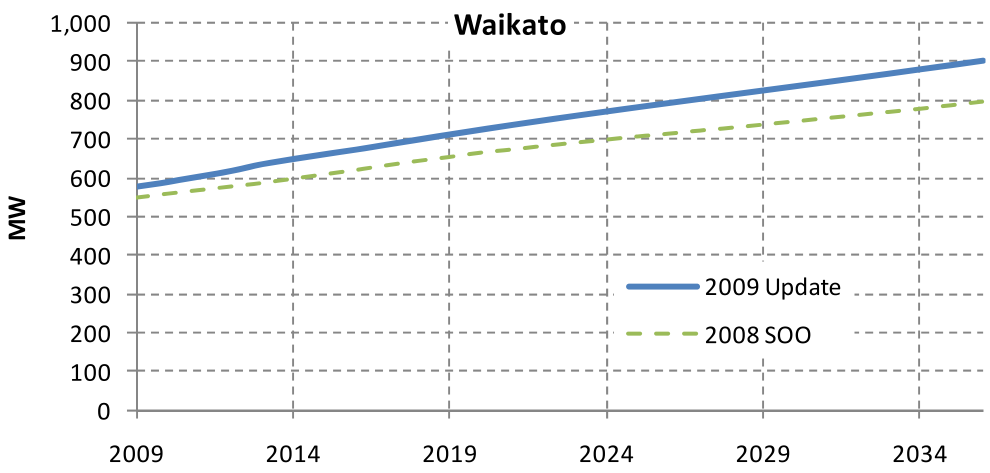
North Isthmus ADMD forecast



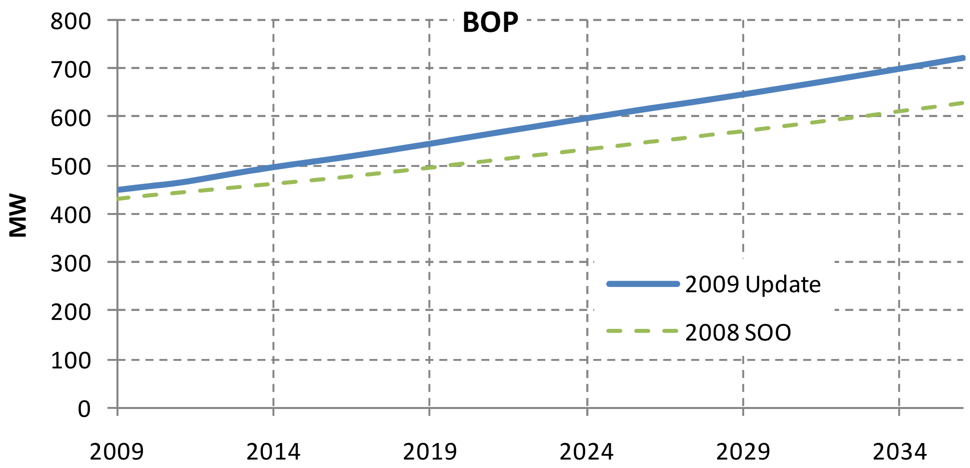
Auckland ADMD forecast



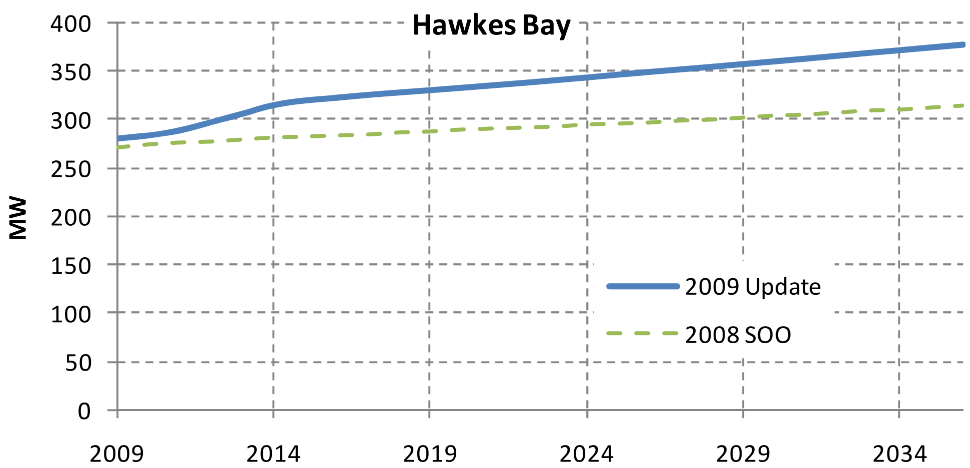
Waikato ADMD forecast



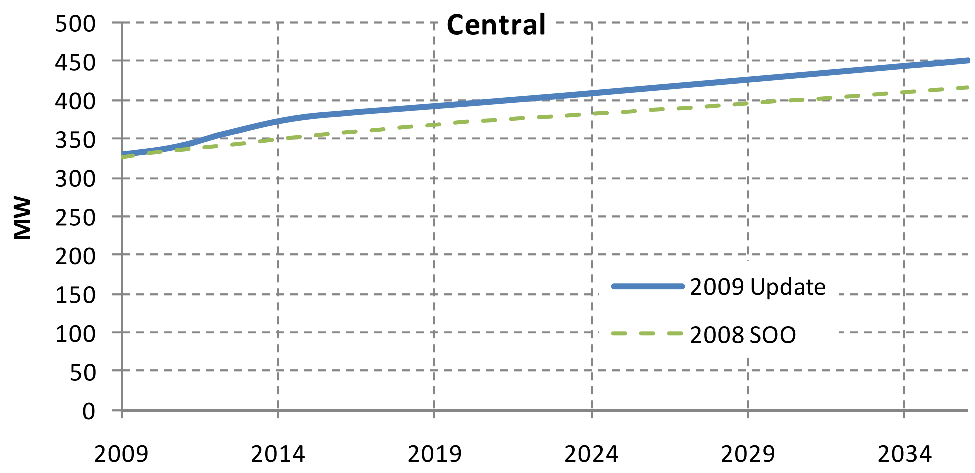
Bay of Plenty ADMD forecast



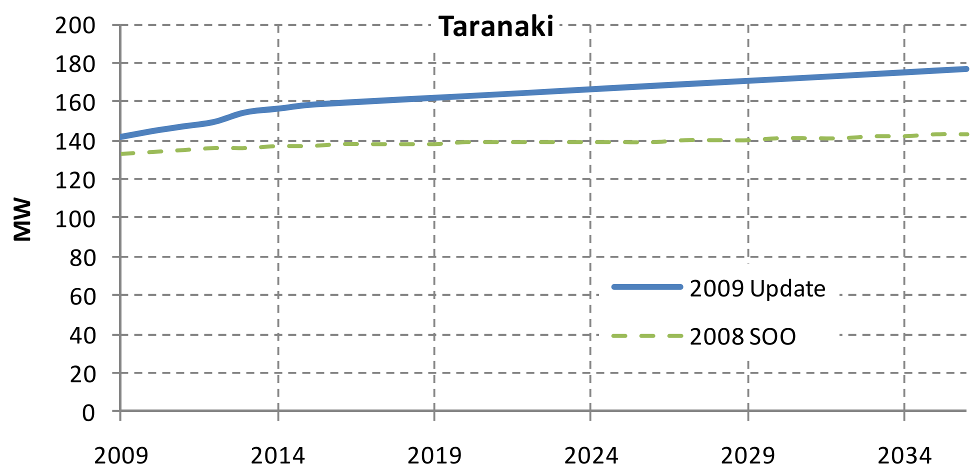
Hawkes Bay ADMD forecast



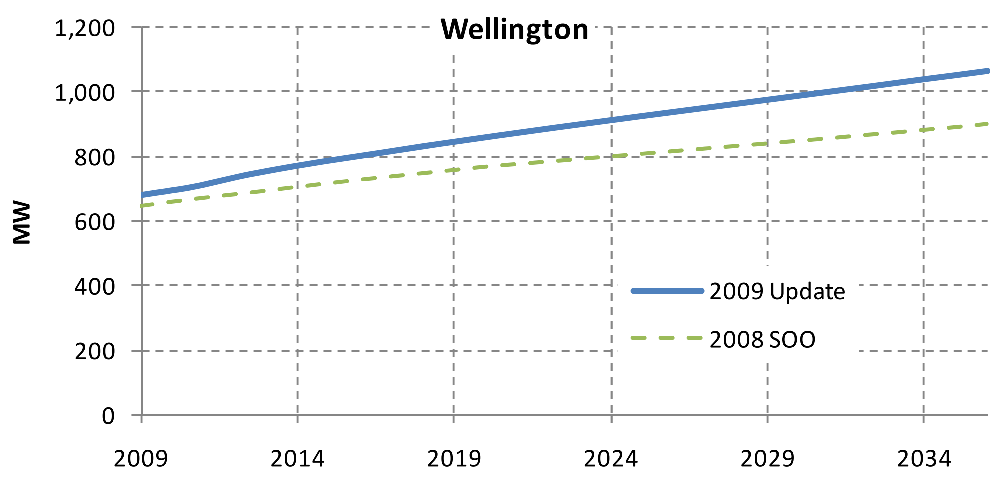
Central ADMD forecast



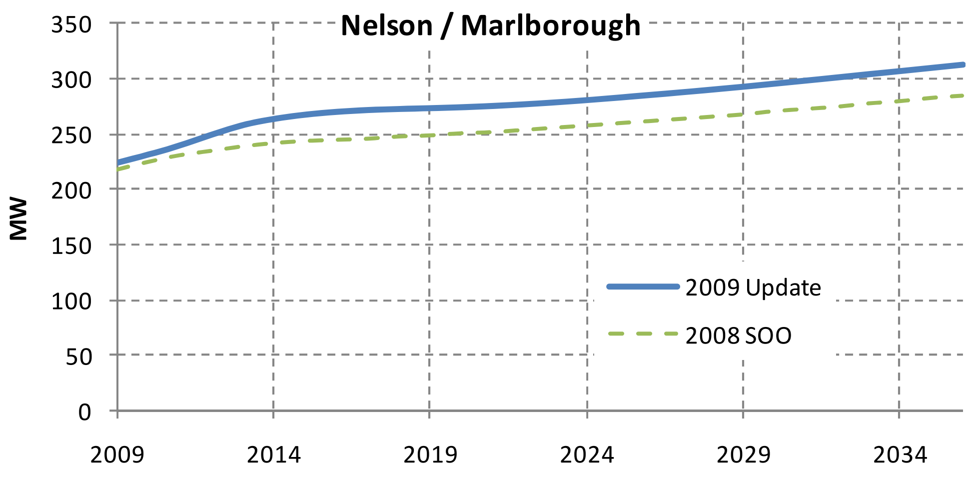
Taranaki ADMD forecast



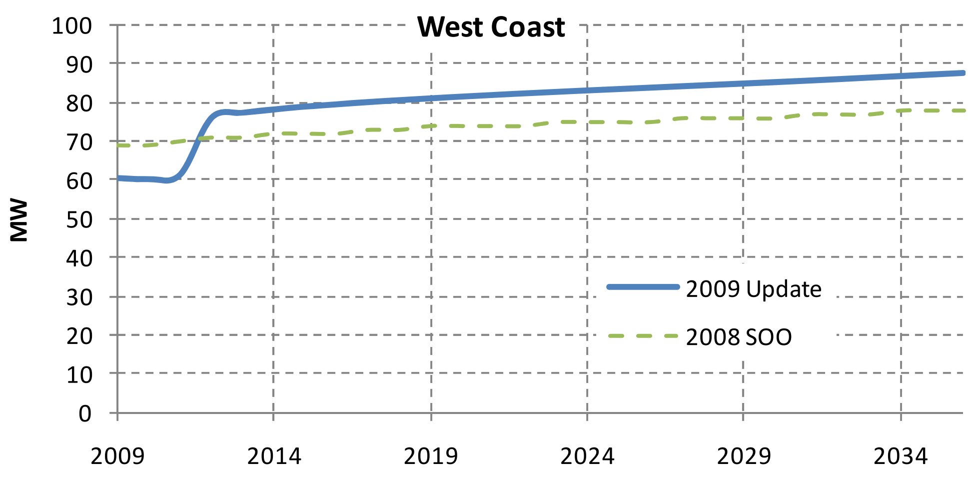
Wellington ADMD forecast



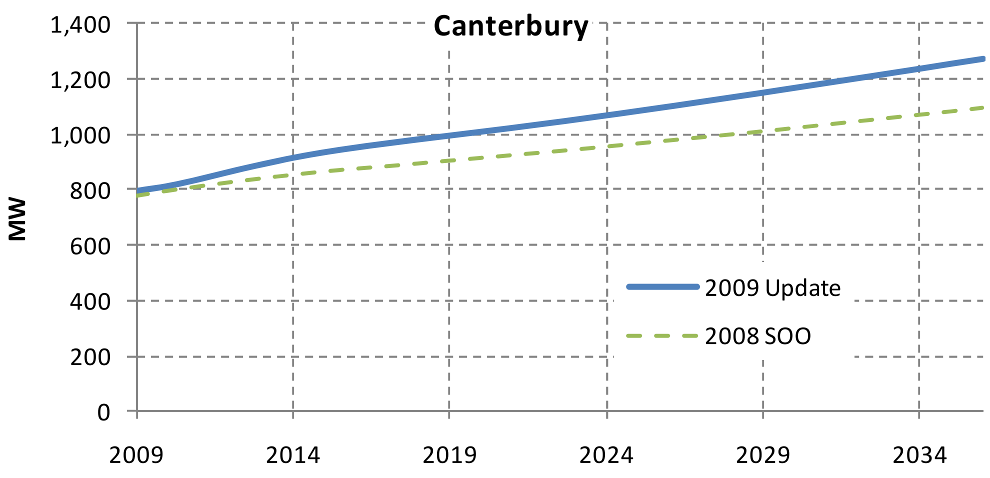
Nelson/Marlborough ADMD forecast



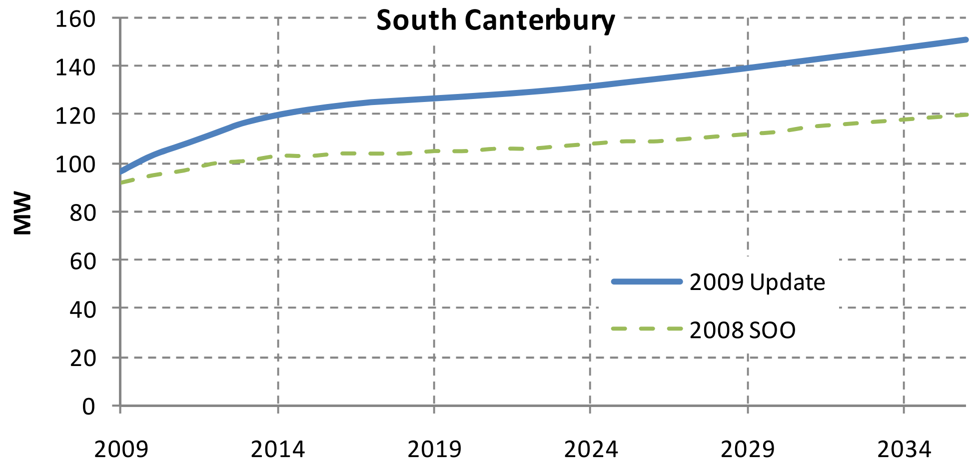
West Coast ADMD forecast



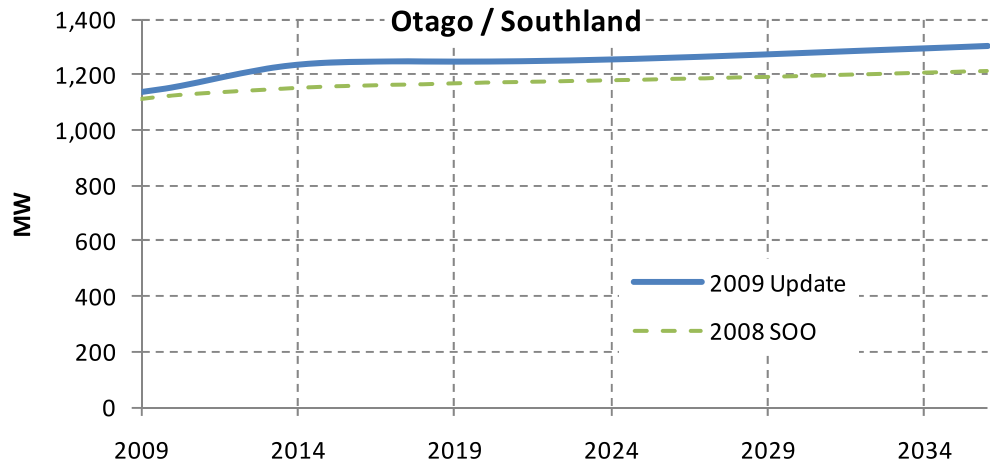
Canterbury ADMD forecast



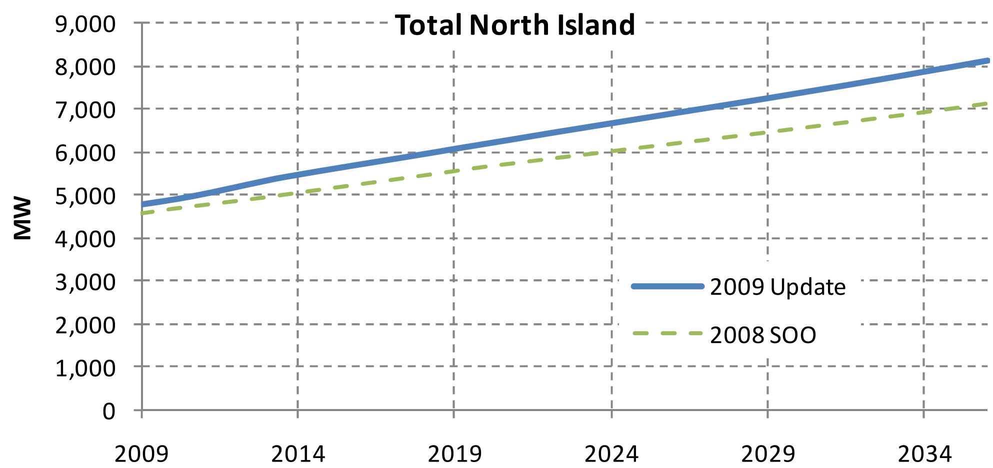
South Canterbury ADMD forecast



Otago/Southland ADMD forecast



North Island ADMD forecast



South Island ADMD forecast