Electricity Demand Forecast Review February 2008

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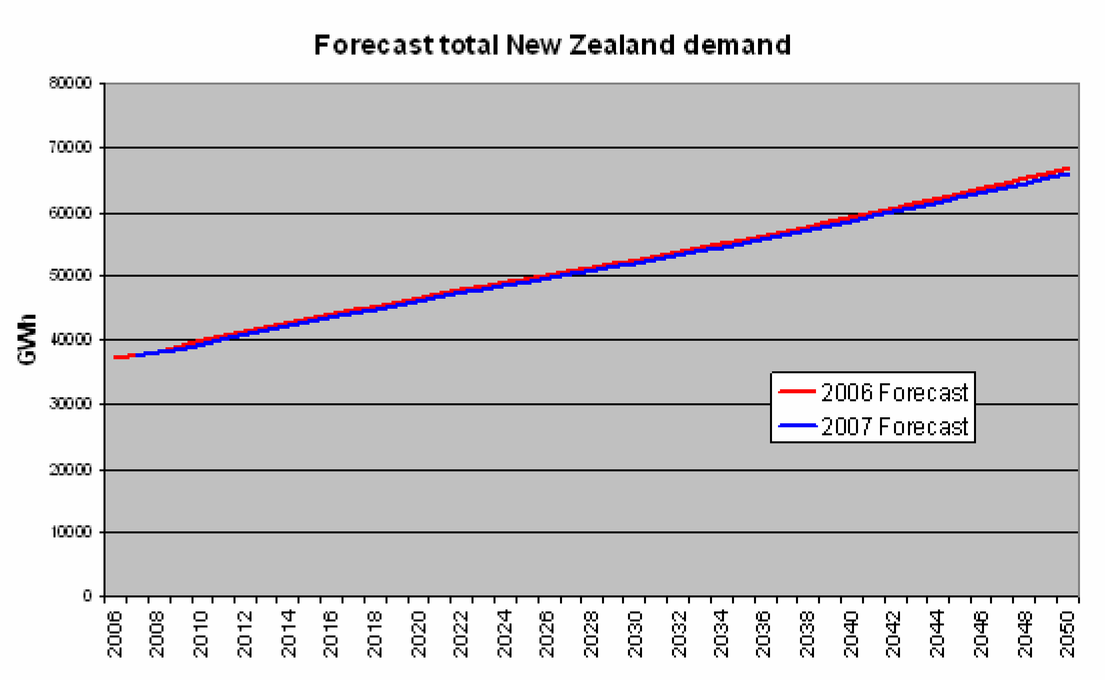
Executive summary

The Electricity Commission is required by Part F of the Electricity Governance Rules to prepare electrical energy demand forecasts. The forecasts are the starting point for decision-making about new investment in transmission, generation, and demand side response. They are included in the grid planning assumptions and are published in the Statement of Opportunities.

This paper discusses the Commission's most recent review of the demand forecasts which occurred in October/November 2007.

The following graph shows the revised 2007 national energy forecasts compared to the 2006 forecast.



The lower national forecast is primarily a result of the slightly lower GDP forecasts that were used as a driver for projecting future energy demand.

The forecast review resulted in a number of minor changes being made to the forecasting methodology The changes include an alteration to the weighting method used to transition between recent regional trends and the long term regional forecasts, and a change to the treatment of existing embedded generation with respect to projecting grid exit point level peak forecasts.

The review resulted in only reasonably small changes to the national level forecasts, however there have been more significant changes to some of the individual regional peak forecasts.

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1. Introduction and purpose of this report

1.1 Introduction

1.1.1 The Electricity Commission prepares long-term national, regional and grid exit point (GXP) demand forecasts as required by Part F of the Electricity Governance Rules. The forecasts form part of the grid planning assumptions 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.

1.1.2 The Commission published draft grid planning assumptions (GPAs) in May 2007. The draft GPAs included demand forecasts that had been prepared as part of the lead up to the intended publication of the Statement of Opportunities (SOO) in 2007. The Commission decided to delay the publication of the SOO until 2008. This paper discusses the review of the demand forecasts carried out in October/November 2007.

2. Review structure

2.1 Review process

2.1.1 The existing Electricity Commission models were used as the starting point for this year's review. 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 four main models. National level energy forecasts are produced using an econometric model that relates historical 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.

2.1.3 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.

2.1.4 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 draft 2006 GPAs, but lie outside the scope of this review.

3. Review of national energy models

3.1 Input series sources

3.1.1 Updated national level demand data was published by the Ministry of Economic Development in their June 2007 Energy Data File publication.

3.1.2 Revised national level statistics and projections were obtained from Statistics New Zealand publications and their INFOS data service.

3.1.3 National and regional GDP projections were obtained from NZIER.

3.1.4 GXP level meter data was sourced from the Centralised Dataset published by the Electricity Commission.

3.2 National level energy forecast

3.2.1 The national model uses the relationship between historical demand and key drivers (such as GDP and population) to forecast future demand based on forecasts of the key drivers. The forecasts 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.

3.2.2 Econometric model development has been carried out in MATLAB.

3.2.3 The forecasts are for energy consumption at grid exit points[1]. 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.

3.2.4 Electricity demand is modelled separately for three main sectors:

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

3.2.5 No significant changes were made to the econometric models used to forecast national demand as part of the 2007 review.

[1] Consistent with the GXP consumption metering points used for New Zealand Electricity Market administration and published in the Centralised Dataset

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. As part of the 2006 review, the model was amended to remove the temperature adjustment applied to the raw demand series.[2]

3.3.2 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. Data from 1974 onwards is available from the Energy Data File publication. The comparability of the earlier data and the Energy Data File data is uncertain. The Commission tested the impact of removing the 1972/73 data from the regression. There was little change in the results other than a small increase in forecast demand so the 1972/73 data previously included in the residential model has now been excluded pending confirmation and validation of the origin of the data.

3.3.3 The residential model continued to perform well using the updated data series, although the model statistics have deteriorated slightly as a result of shortening the series used for the regression analysis. The table below compares the results obtained in 2006 and 2007.

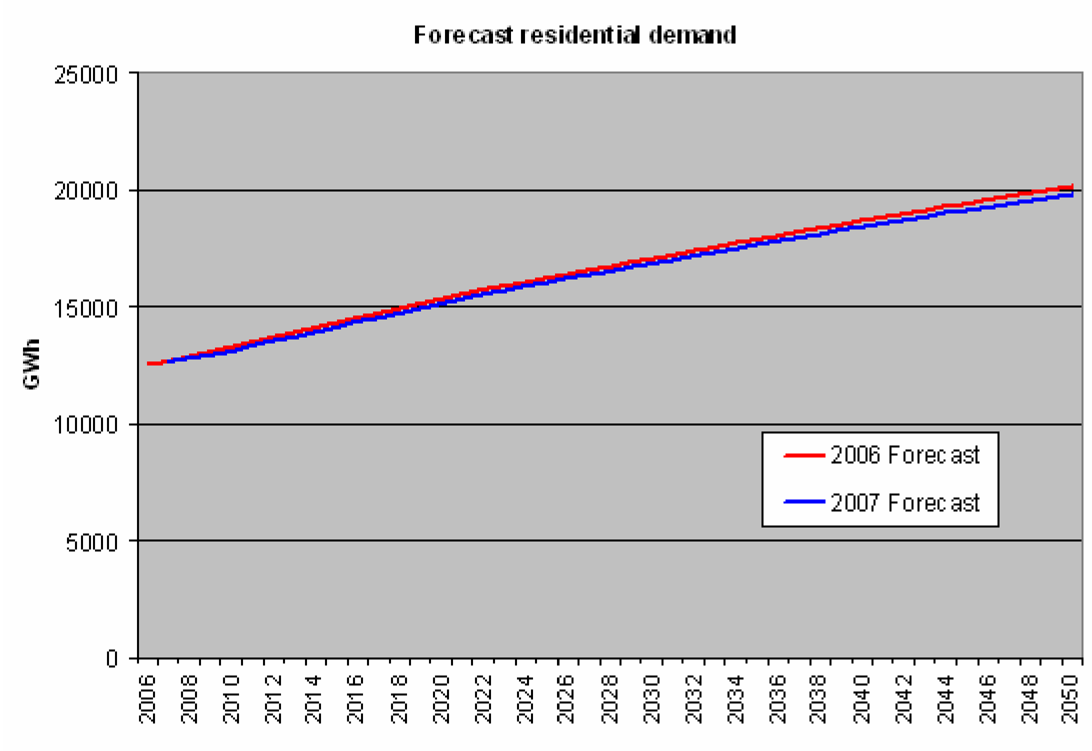
Table 1 Residential model regression statistics

	2006 Residential Model Results				**Updated 2007 Residential Model Results**			
	Variable	**coeff.**	**s.d.**	**t-stat**	**Variable**	**coeff.**	**s.d.**	**t-stat**
Coefficients, standard dev.s, and t-statistics	Constant	-3.446	0.32	-10.69	Constant	-3.533	0.41	-8.53
	log(GDP/Capita)	0.310	0.07	4.32	log(GDP/Capita)	0.275	0.08	3.52
	log(HH/Capita)	0.898	0.12	7.28	log(HH/Capita)	1.001	0.16	6.13
	log(Price)	-0.150	0.05	-3.10	log(Price)	-0.125	0.05	-2.28
$R^{\text{-squared}}$	0.9774				0.9713			
Adjusted $R^{\text{-squared}}$	0.9750				0.9682			
Durbin-Watson	1.3117 (dL = 1.27074 dU=1.65189)				1.3401 (dL = 1.25756 dU=1.6511)			

[2] 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.

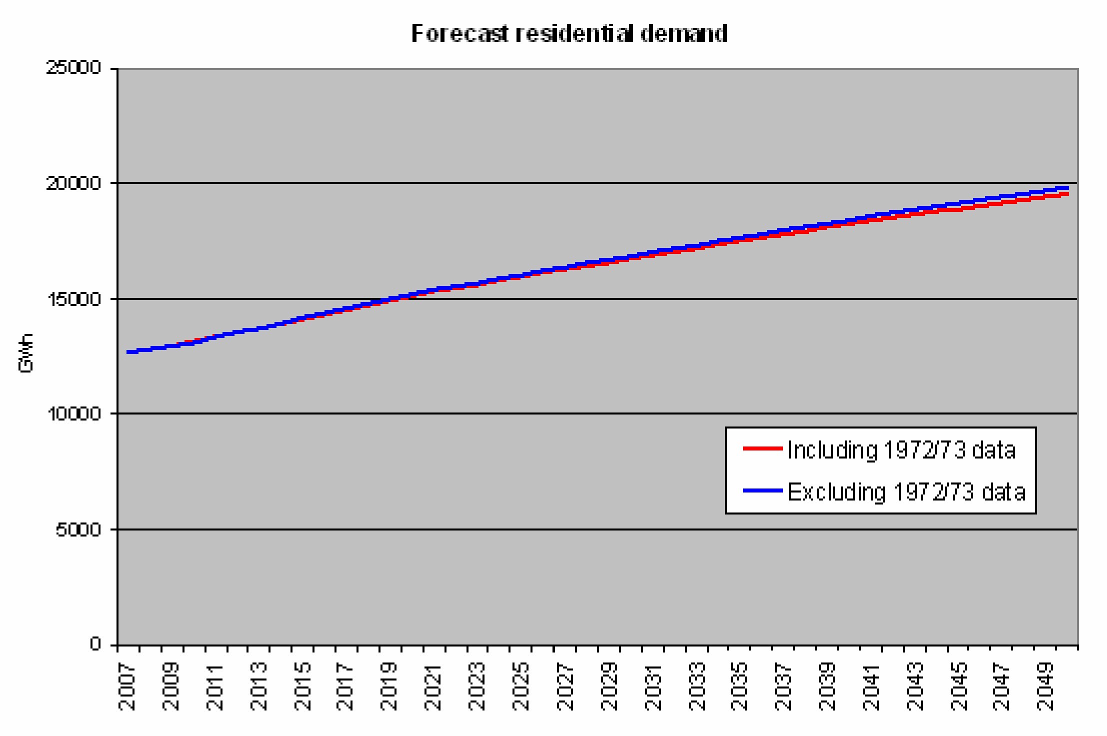
3.3.4 The following graph shows forecast residential demand based on the 2007 modelling compared to the results obtained in 2006. Note that the energy modelling discussed in this report is calculated and presented on a year-ending-March basis as a number of the key input series are only available in that form. This contrasts with the peak forecasts discussed later which are generally calculated and presented in a calendar year form.

Figure 1 : 2006 and 2007 residential demand forecasts



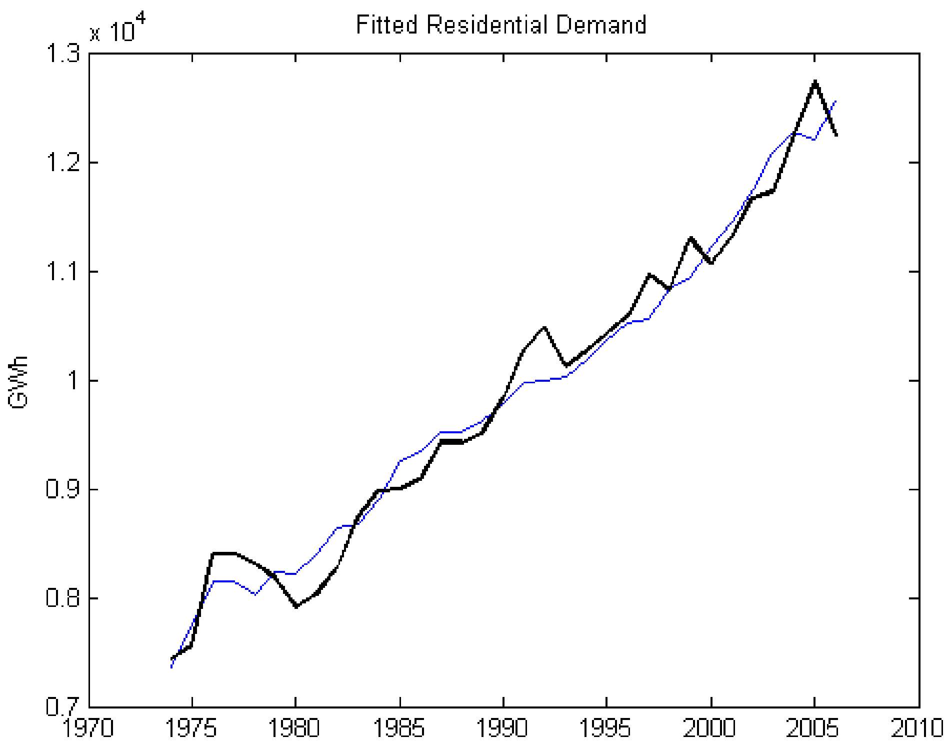
3.3.5 The sensitivity of the forecasts to the inclusion or exclusion of the 1972/73 data is shown in the following graph.

Figure 2 : Effect of excluding 1972/73 data from the residential model



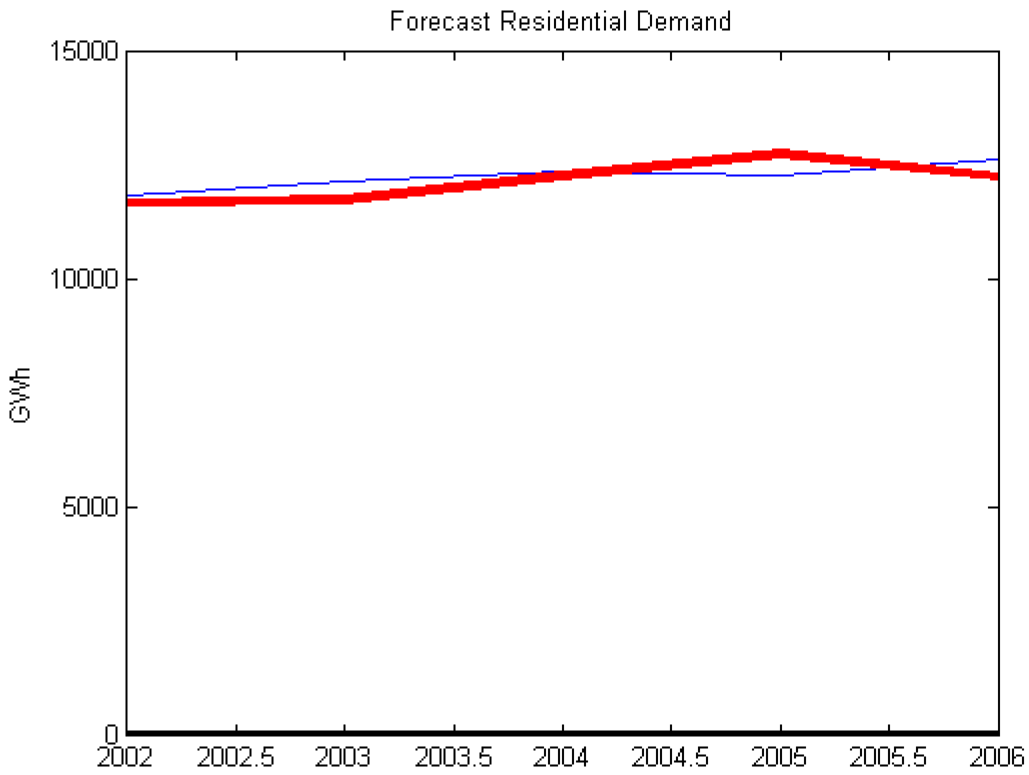
3.3.6 Fitted demand vs. actual residential demand is shown below (actual demand is in black and modelled demand is in blue).

Figure 3 : Fitted residential energy demand



3.3.7 The following graph shows the performance of the model when the historical data is truncated to 5 years ago, the model is re-estimated, and the resulting forecasts compared to actual demand for the past 5 years (actual demand is in red).

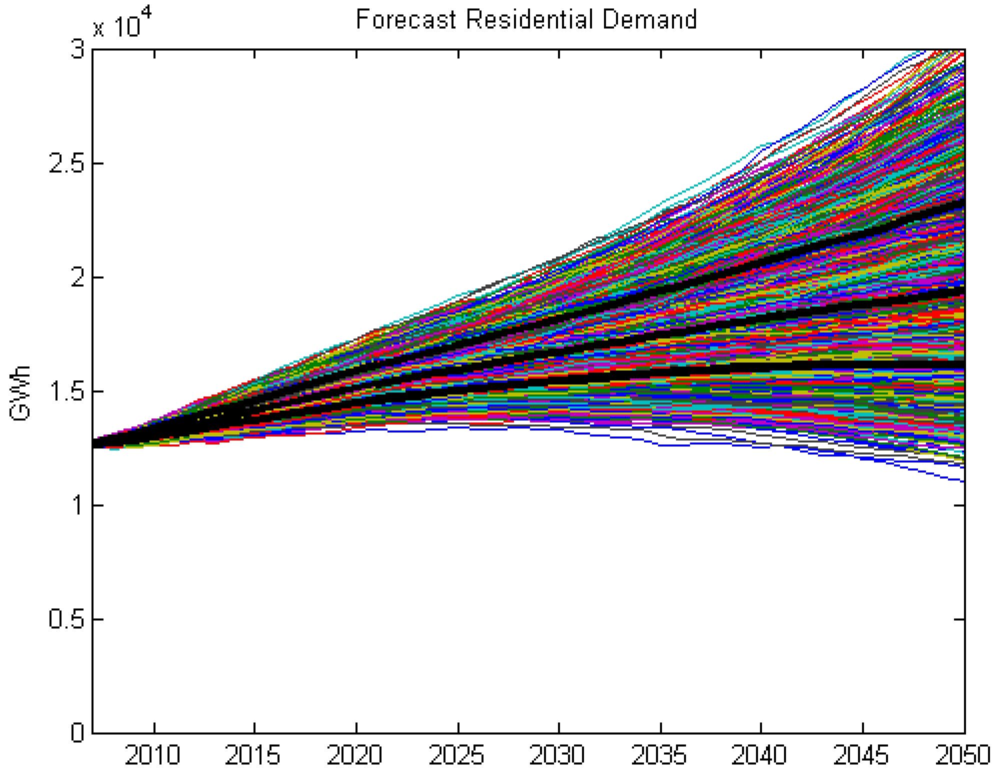
Figure 4 : Truncated residential model performance



3.3.8 The truncated version of the residential model predicted the past 5 year's actual demand reasonably well (recognising that the models are intended to predict long term trends rather than short term year-on-year movements).

3.3.9 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 more detail later). Total forecast uncertainty for residential demand is shown below, 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 5 : Residential model confidence limits



3.4 Commercial and industrial forecasts

3.4.1 The commercial and industrial model used by the Commission was changed significantly as a result of the 2006 review and industry consultation. A linear model relating GDP to demand growth was adopted and the time period covered by the historical data used in the model was shortened.

3.4.2 No changes have been made to the commercial and industrial model as a result of the 2007 review.

3.4.3 The following table shows the results for the 2006 and 2007 commercial and industrial models.

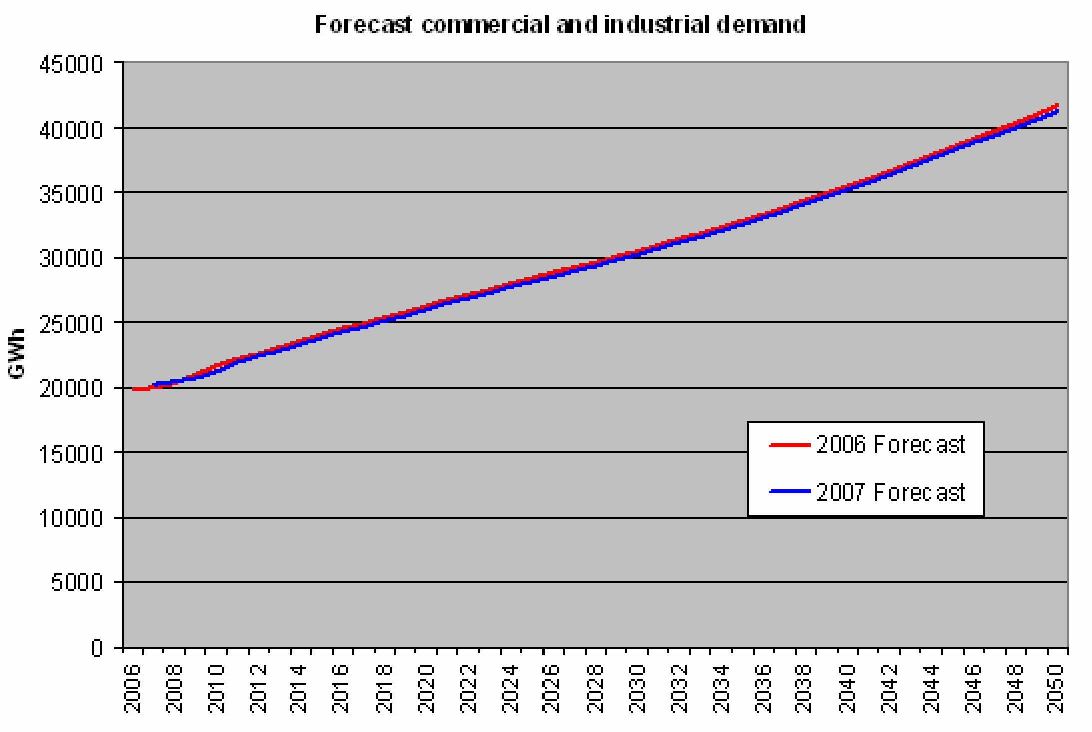
Table 2 Commercial and industrial model regression statistics

	2006 Commercial and Industrial Model				2007 Commercial and Industrial Model			
	Variable	**coeff.**	**s.d.**	**t-stat**	**Variable**	**coeff.**	**s.d.**	**t-stat**
Coefficients, standard dev.s, and t-statistics	Constant	1467.336	1101.62	1.33	Constant	1260.120	967.54	1.30
	GDP	0.145	0.01	12.32	GDP	0.148	0.01	14.56
	Shortage	-213.832	486.231	-0.44	Shortage	-210.151	457.93	-0.46
$R^{\text{-sqaured}}$	0.9042				0.9238			
Adjusted $R^{\text{-squared}}$	0.8923				0.9148			
Durbin-Watson	0.3518 (dL = 1.1004 dU=1.5367)				0.4031 (dL = 1.1246 dU=1.5385)			

3.4.4 The model statistics are relatively poor, reflecting the underlying nature of the series used to project future demand. See the **National energy demand forecast review (June 2006)** document for the background for the selection of this particular model.

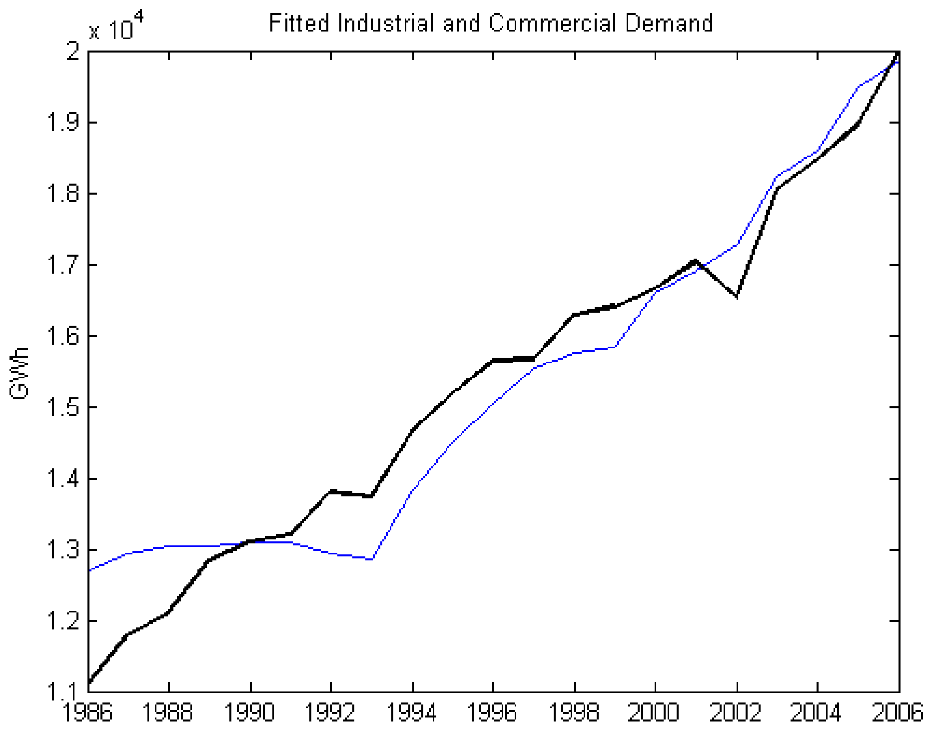
3.4.5 The following graph compares the 2006 and 2007 commercial and industrial forecasts (excluding the Tiwai point aluminium smelter which is handled separately in the heavy industrial forecast section below).

Figure 6 : 2006 and 2007 commercial and industrial energy demand forecasts



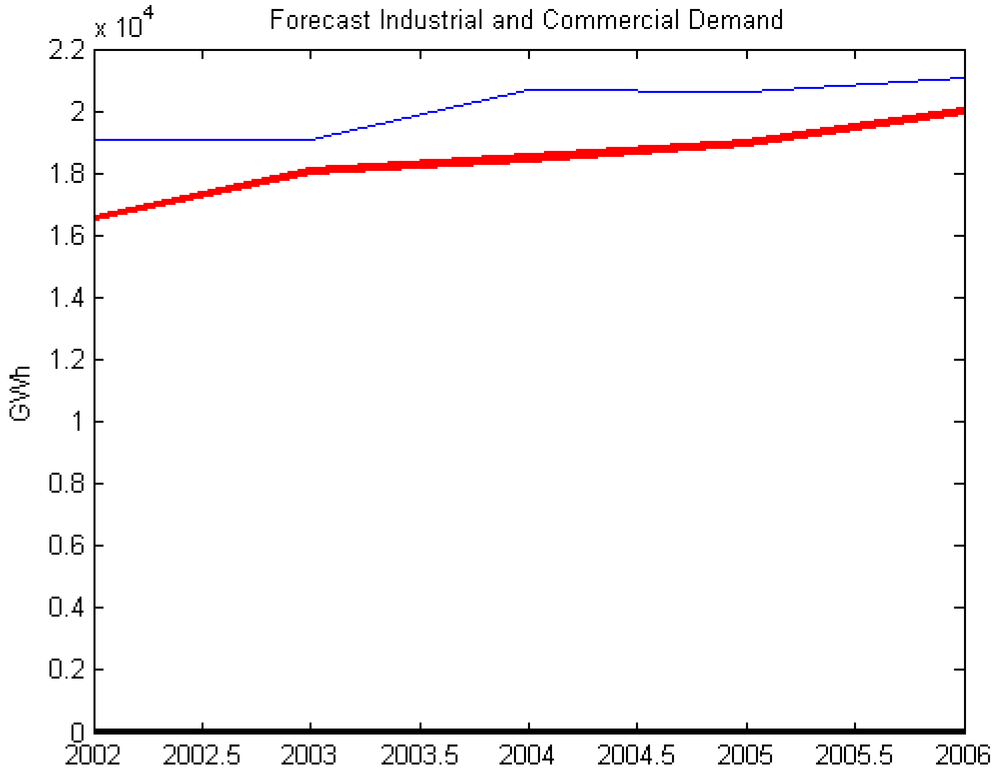
3.4.6 Fitted commercial and industrial demand vs. actual demand is shown below (actual demand is in black and modelled demand is in blue).

Figure 7 : Fitted commercial and industrial energy demand



3.4.7 The following graph shows the performance of the model when the historical data is truncated to 5 years ago, the model re-estimated, and the resulting forecasts compared to the actual demand over the past 5 years. Actual demand is in red.

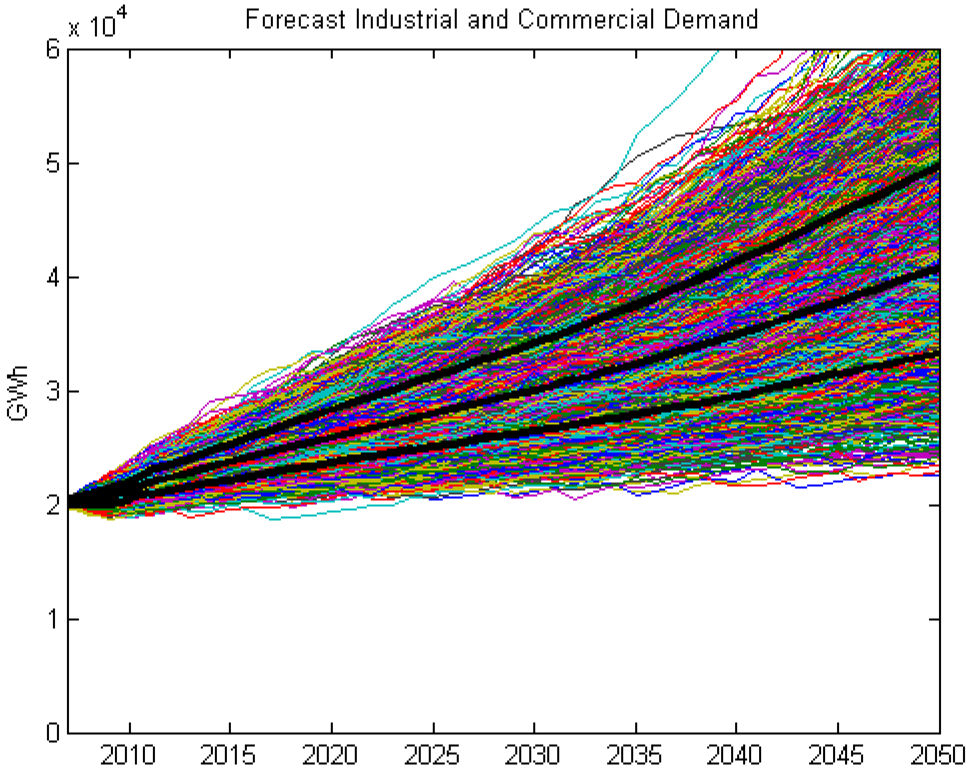
Figure 8 : Truncated commercial and industrial model performance



3.4.8 In this case the forecasts produced by the truncated version of the commercial and industrial model overestimated demand when compared to actual demand over the 2002-2006 period.

3.4.9 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

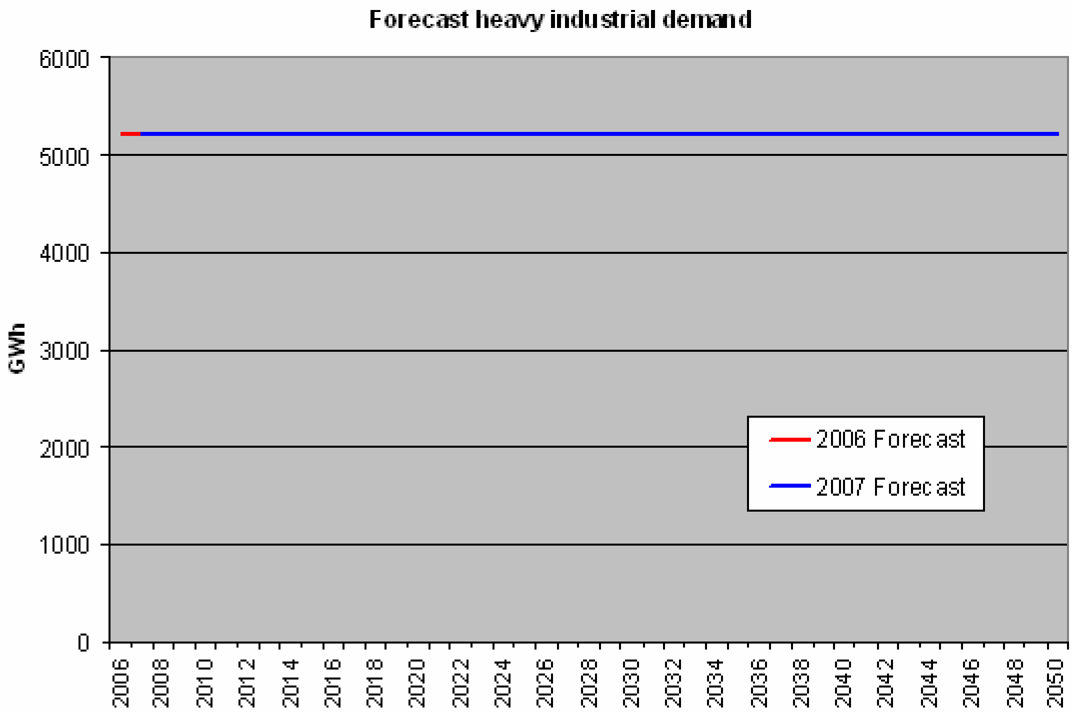


3.5 Heavy industrial forecasts

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). Tiwai Point future demand is assumed to remain constant – 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 2006 and 2007 forecasts. Forecast demand is based on the highest historical March year demand by the smelter. As this occurred in the year to 31 March 2005, the forecast is unchanged.

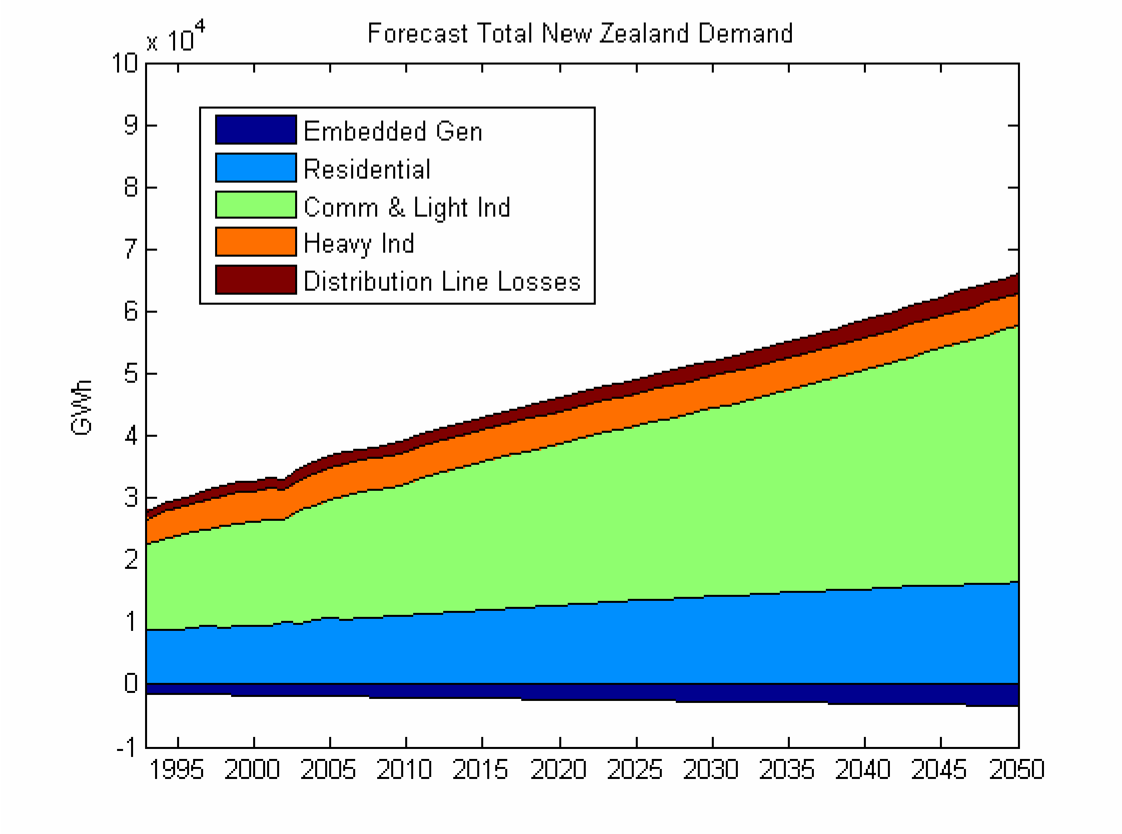
Figure 10 : 2006 and 2007 heavy industrial demand forecasts



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. The following graph shows the components of total forecast demand once the components forecasts outlined above are combined.

Figure 11 : Total forecast energy demand by component

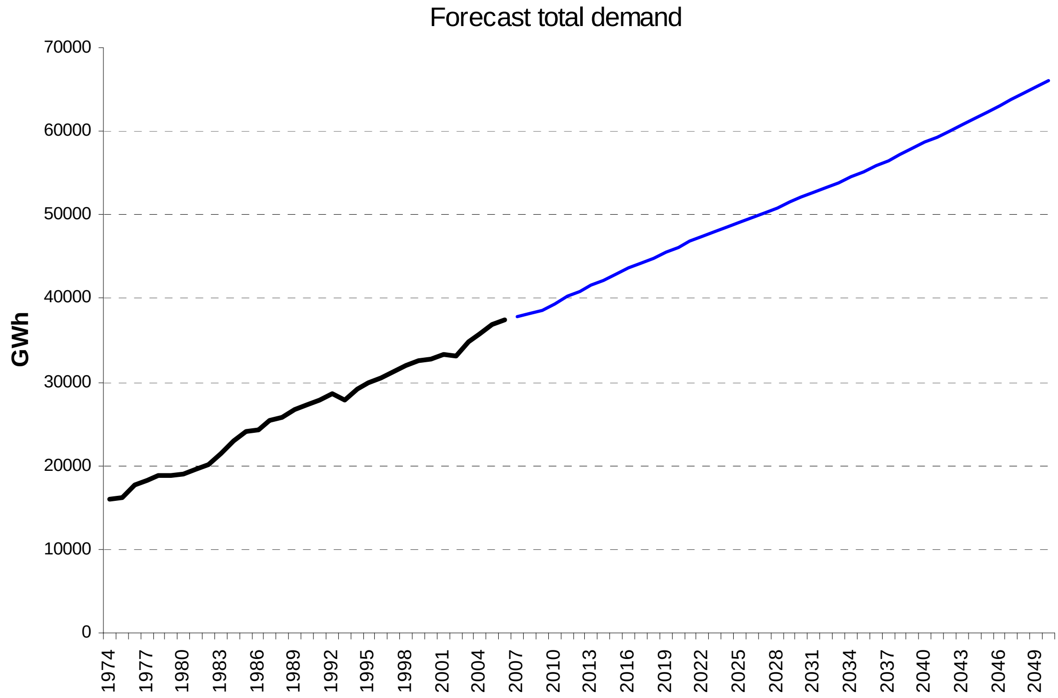


3.6.2 Embedded generation is assumed to remain at its current proportion of total generation (i.e. it will grow at the same rate as total demand). As embedded generation is roughly 5% of total generation this is equivalent to around 30-40 GWh of additional generating capacity each year (equivalent to roughly 10MW per year of wind generation going into local networks as opposed to being grid connected).

3.6.3 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).

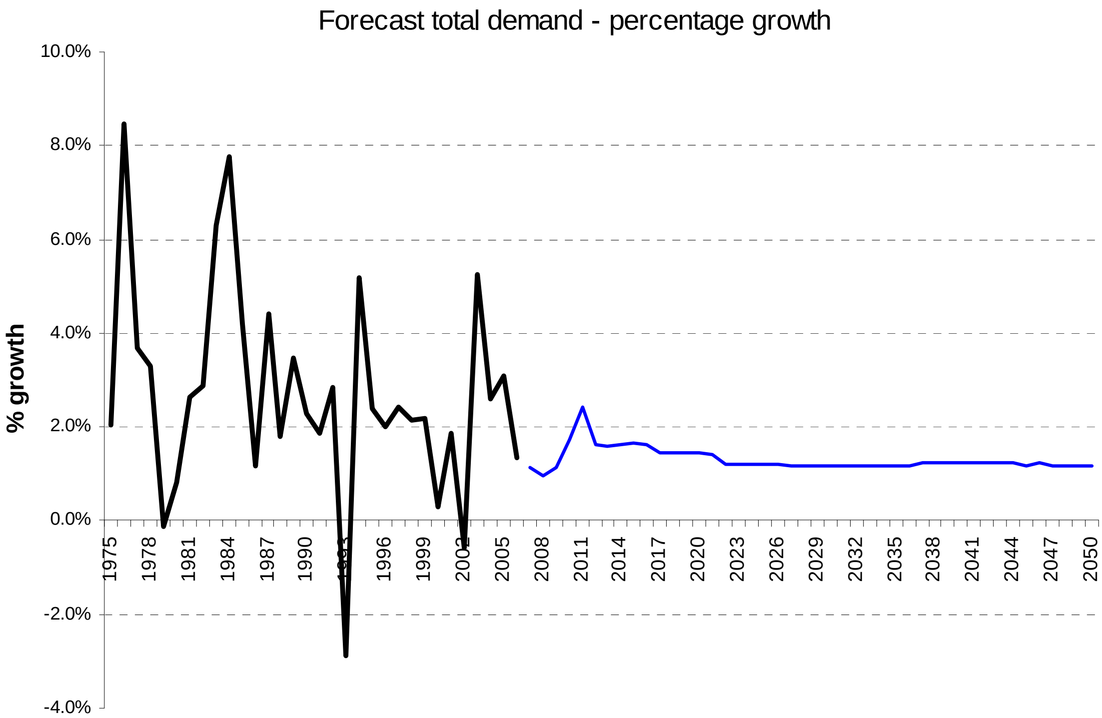
3.6.4 As demonstrated in the following graph, total national demand has increased in a linear manner since the early 1970's. Forecast growth is also expected to increase in a similar manner based on the mean forecasts of the key drivers of demand.

Figure 12 : Total historical and forecast energy demand



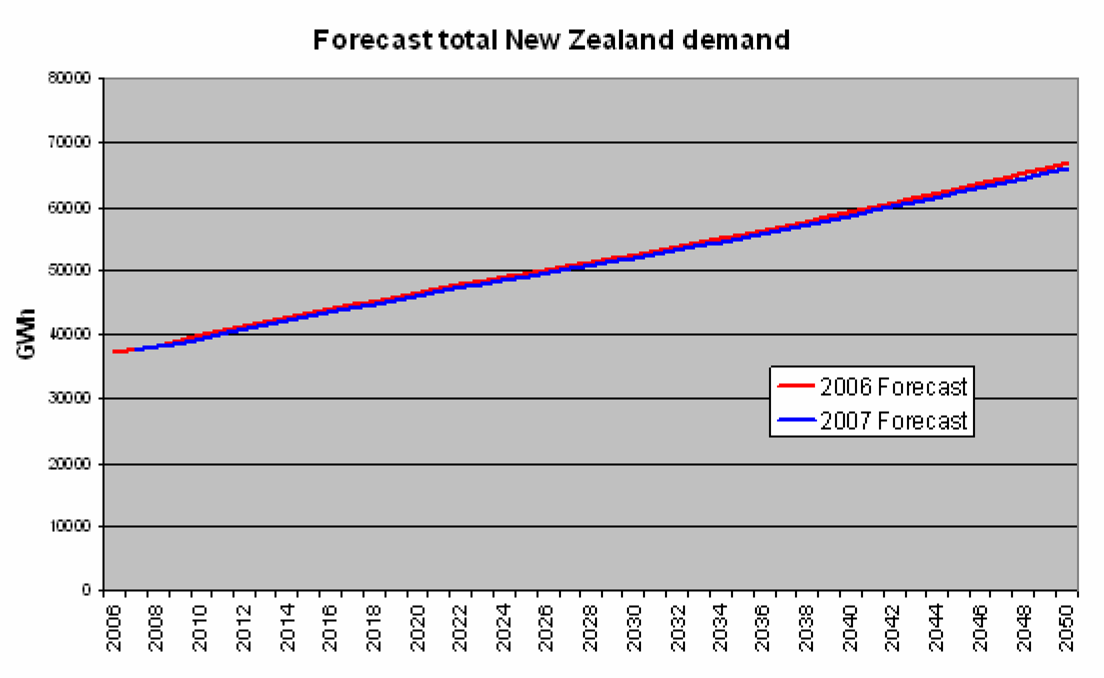
3.6.5 The graph below shows historical and forecast demand in percentage growth terms.

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



3.6.6 The following graph compares the 2007 and 2006 forecasts of total New Zealand demand.

Figure 14 : 2006 and 2007 total forecast energy demand



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 historical input series and the forecast input series respectively.

3.7.2 The historical input distributions are synthetic distributions based on the variation between the various inputs (reported GDP, population, households) and a 5 year moving average[3]. 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:

3.7.5 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 historical range. The third

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

component provides some year-on-year change caused by random external causes (such the international environment) and has been based on historical GDP variation.

3.7.6 Households : Uncertainty in households had been broken into two components - population uncertainty (kept consistent with the population variation below) and a household size component. Household size is varied based on a scale factor applied and phased in over the forecast period.

3.7.7 Population : Population variation is handled by applying a factor drawn from a distribution based on the various Statistics New Zealand population scenarios.

3.7.8 Price : Variation is based on a simple estimated distribution used to scale price in each forecast year.

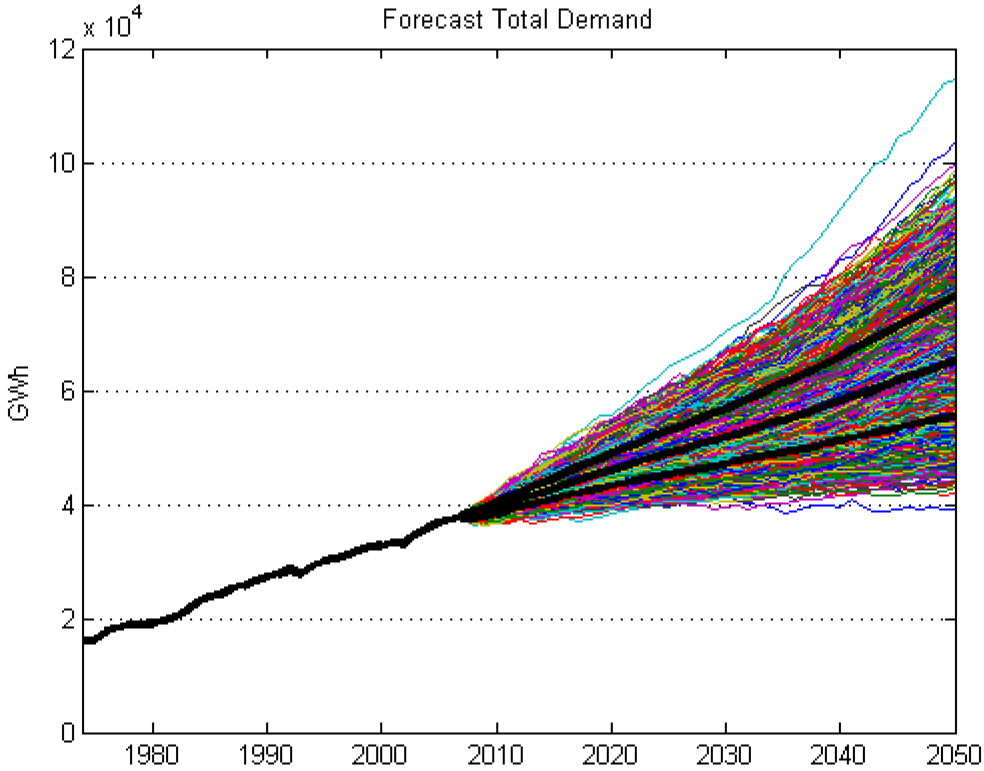
3.7.9 There are a wide range of other factors that will influence future demand growth. Two primary issues are future trends in energy intensity, and the balance between grid connected and embedded generation.

3.7.10 Energy intensity changes are reflected in the historical 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 historical 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.

3.7.11 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.

3.7.12 The following graph shows total forecast variation with 10% tail confidence limits and the median forecast shown in black.

Figure 15 : National energy forecast confidence limits



4. Regional modelling

4.1 Allocation of energy demand

4.1.1 A lack of consistent long-term historical 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.[4]

4.1.2 Residential allocation : Total national residential demand was allocated 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:

4.1.4 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).

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

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

4.1.7 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).

4.1.8 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.

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

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[4] A definition of the grouping of grid exit points to transmission regions can be found in the **ADMD2007PrudentPeakForecasts14_1_08.xls** spreadsheet.

4.1.10 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.

4.1.11 The allocation is based on the following formula:

4.1.12 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.

4.1.13 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.

4.1.14 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.

4.1.15 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

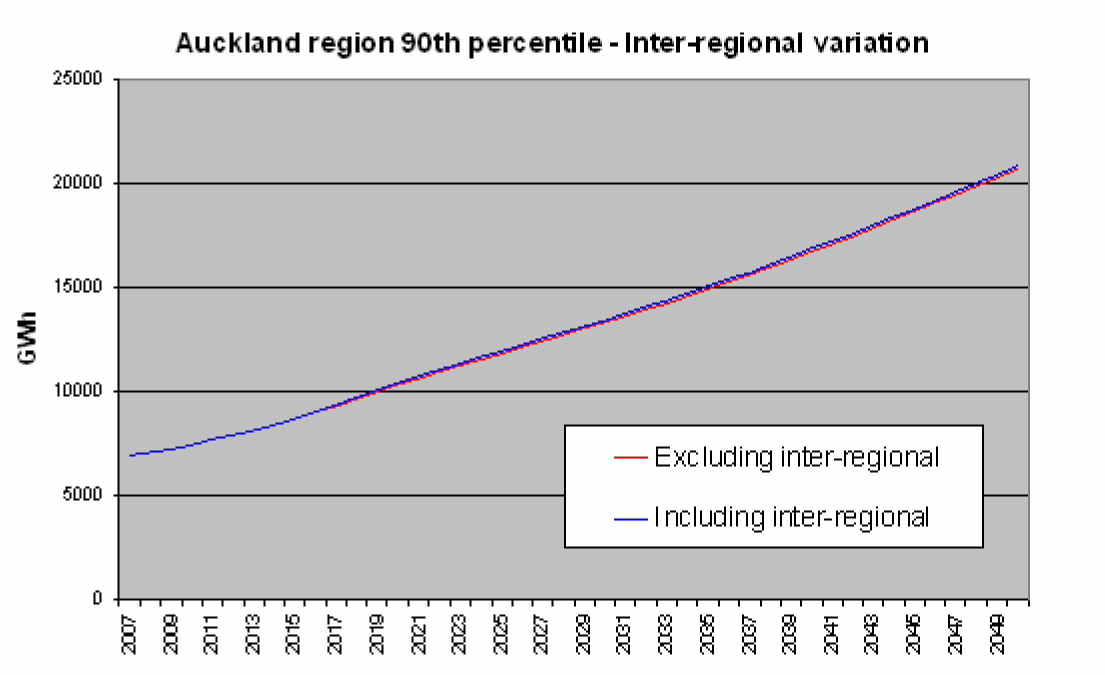
4.2.1 The 2006 forecast model allocated demand to the various regions using the same allocation profile in each Monte-Carlo run. Variation in the regional forecasts was therefore driven solely by the variation in the national level forecasts. In the 2007 model, variation from uncertainty in population movements between regions has been introduced.

4.2.2 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.

4.2.3 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.

4.2.4 The 2007 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. By way of illustration, the 2050 90th percentile demand forecast for the Auckland region was 20681 GWh excluding the inter-regional population modelling, and 20862 GWh when it was included, shown in the graph below.

Figure 16 : Impact of inter-regional uncertainty on Auckland confidence limits



4.2.5 Future work will focus on assessing whether the total forecast confidence limits are more sensitive to alternative inter-regional variation models.

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.

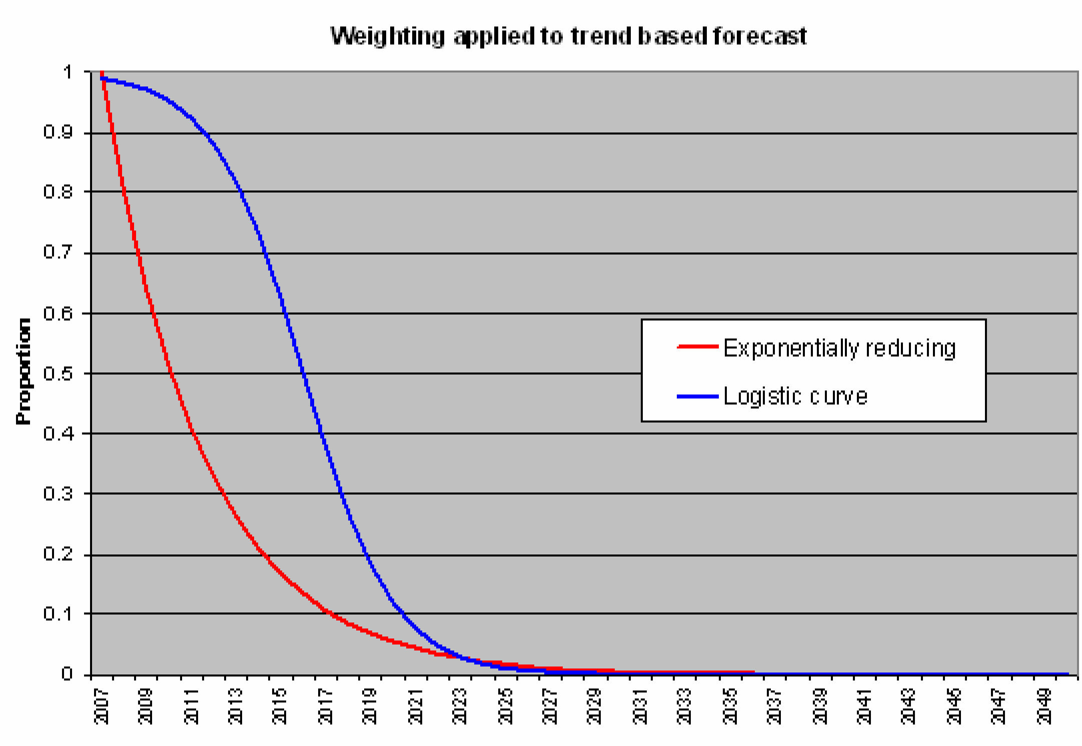
4.3.2 A hybrid approach has been used where forecasts are calculated based on a simple trend for each region using March year data from 1997. A weighting factor is then applied between the trend based forecasts, and the regional forecasts calculated using the mixed GDP/population based method outlined 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 weighting approach used has been amended as part of the 2007 review.

4.3.4 The 2006 forecasts used an exponentially reducing weighting. While this is fairly arbitrary in nature, the Commission's view is that this approach did not give enough weighting to the recent trend within each region for a sufficiently long period. A limitation of the exponential reduction approach is that if the trend weighting is set high to retain the recent trend forecasts for longer, it results in the driver based forecasts receiving insufficient weighting by the end of the modelling period.

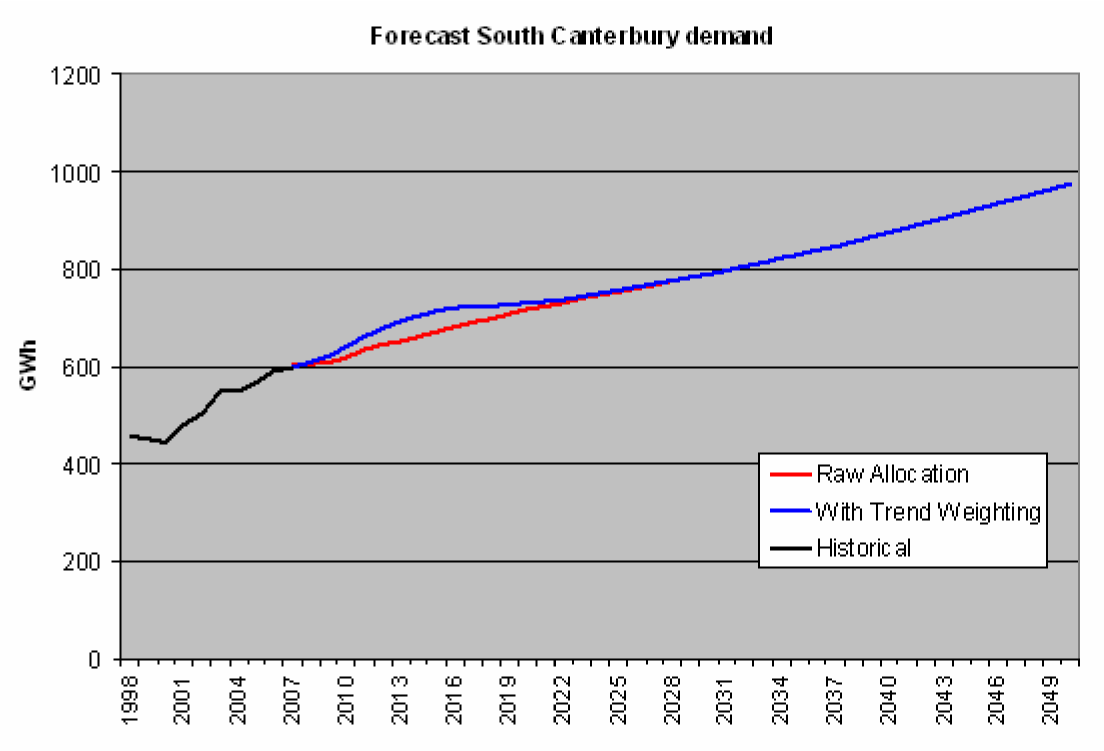
4.3.5 The 2007 forecasts use a logistic curve to determine the weighting in each year. As shown in the following graph, the weighting given to the trend stays higher for longer than the previous exponential approach, then drops away reasonably rapidly so that the longer term driver driven demand becomes dominant in the long term.

Figure 17 : Alternative trend weighting approaches



4.3.6 South Canterbury has seen very rapid growth since 2000 relative to the growth in the drivers used to forecast demand. The following graph shows forecast demand for South Canterbury with and without the trend adjustment to the regional forecast.

Figure 18 : South Canterbury energy demand with and without trend adjustment



4.3.7 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 results in the trend phasing out either somewhat-faster or somewhat-slower in each run compared to the mean case.

4.3.8 A possible future refinement in this approach is to exclude Tiwai from the calculation of the raw regional trend projections for the Otago/Southland region. Tiwai has seen a recent increase in demand that may have skewed the Otago/Southland future trend upwards past the point that would be expected if Tiwai demand were to stay constant. The 2007 forecast currently includes historical Tiwai growth in the trend calculation.

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 as part of the regional energy demand modelling in 2007 are listed in the following table.

Table 3 Step load adjustments to regional forecasts

Project	Date	MW	GWh	GXP	Region
Pike River coal mine Stage 1	2008	7	61	ATU1101	West Coast
Pike River coal mine Stage 2	2009	7	61	ATU1101	West Coast
Blackpoint irrigation Stage 1	2007	6	19	BPT1101	Otago/Southland
Blackpoint irrigation Stage 2	2008	4	18	BPT1101	Otago/Southland
Westland Dairy powder plant	2008	4	18	HKK0661	West Coast
Globe Progress gold mine	2008	4	35	RFT1101	West Coast
Hawera gas processing plant	2008	12	80	HWA0331	Taranaki

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

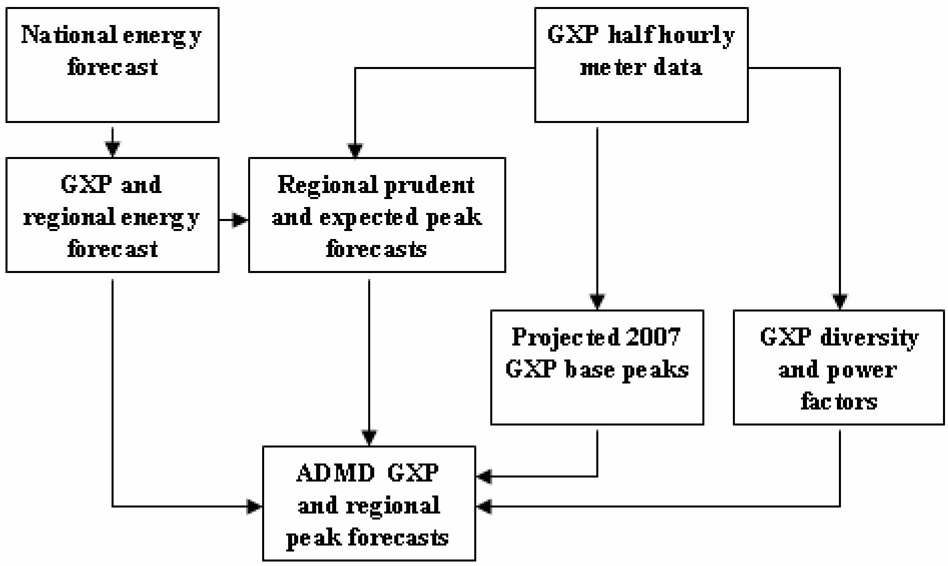
4.4.6 Appendix 2 contains tables with forecast annual energy demand by region.

5. Peak forecasts

5.1 Forecasting process

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

Figure 19 : Demand forecasting process flow diagram



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

5.2 Regional prudent peak forecasts

5.2.1 A detailed description of the methodology used to prepare the prudent and expected peak forecasts can be found in the **Regional peak demand forecast from 2007** document.

5.2.2 The prudent peaks forecasts are a projection of the half hourly peak demand by transmission region with a 10% chance of exceedance (i.e. there is a 10% chance of the regional forecast being exceeded in a given year).

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

- An exponential fitted curve is estimated for each region from historical peak meter data and mean expected peak demand projected for the next five years.
- Mean 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 historical 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 prudent peak forecasts feed into the calculation of the prudent After Diversity Maximum Demand (ADMD) peak forecasts below.

5.3 Projection of base peaks

5.3.1 The starting point for the projected peak load at each GXP is based on recent historical 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.[5]

5.3.2 Each individual GXP was assessed and the starting peak projected forward using either a year-on-year trend or a simple mean 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 historical meter data being of limited use. In these cases an estimated starting peak has been specified.

[5] 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.

5.4 Diversity and power factors

5.4.1 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 2006 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.

5.4.2 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.

5.5 ADMD peak forecasts

5.5.1 Calculation of the prudent ADMD peak forecasts consists of two primary steps:

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

5.5.2 The mean 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.

5.6 Direct connect customers

5.6.1 The Tiwai Point aluminium smelter peak demand has been projected at a constant level equivalent to its maximum historical peak, consistent with its treatment in the energy forecasts.

5.6.2 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.

5.7 Embedded generation

5.7.1 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).

5.7.2 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[6]. 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.

5.7.3 In the 2006 forecasts this step was carried out after the scaling of regional demand to the prudent peak forecasts. 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 6 below).

5.7.4 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.

5.8 Step load changes

5.8.1 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.

[6] 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 mean 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.

5.8.2 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.

5.8.3 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.

5.8.4 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.

5.9 Scaling to prudent peak forecasts

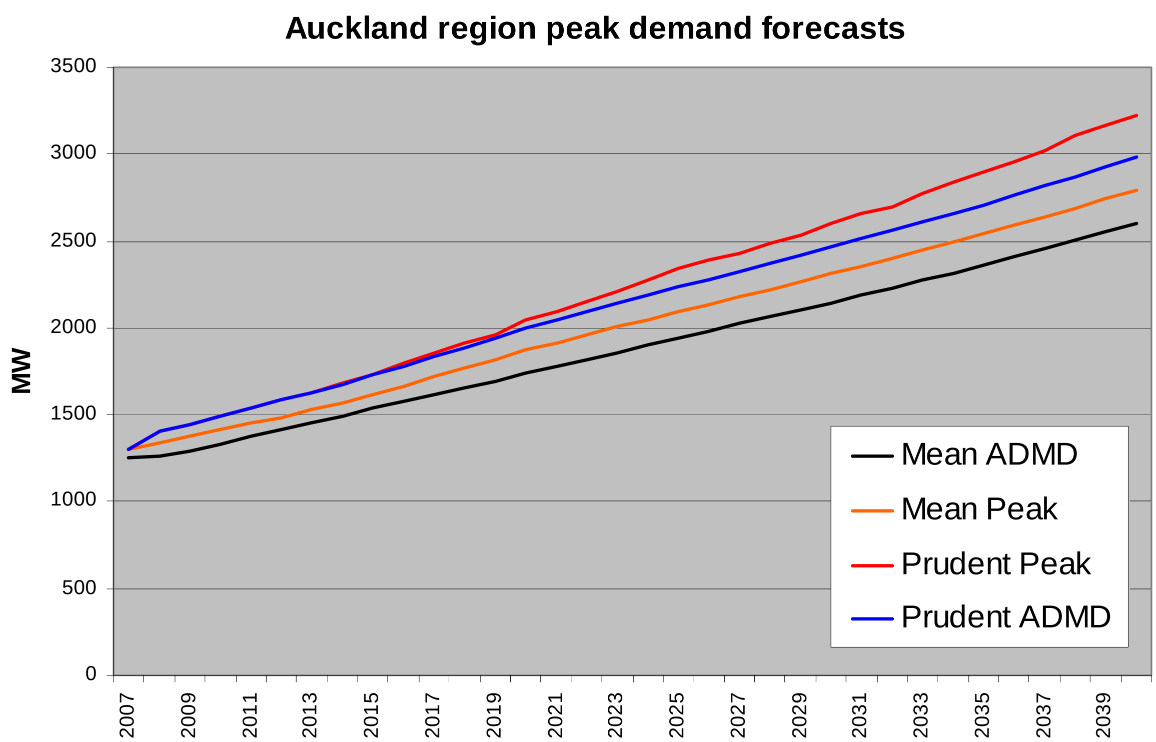
5.9.1 Once individual GXP forecast have been determined and any diversity factor changes made to adjust for new loads, a mean region peak forecast can be calculated by simply multiplying each individual GXP load by its associated regional diversity factor and summing across each region.

5.9.2 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.

5.9.3 The scaling applied to the mean ADMD peak forecasts is adjusted after the first 5 forecast years. After that point the mean 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.

5.9.4 The graph below contrasts the different types of peak forecasts produced as part of the demand forecasting. The example shown is for the Auckland region peak.

Figure 20 : Comparison of peak forecast types



5.9.5 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 Mean Peak is calculated as part of the prudent peak forecasting outlined above.

5.9.6 The Mean ADMD peak forecast is lower that the Mean 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 Prudent ADMD forecast matches the Prudent Peak forecast for the first 5 years then starts to differ once the mean growth rate is applied.

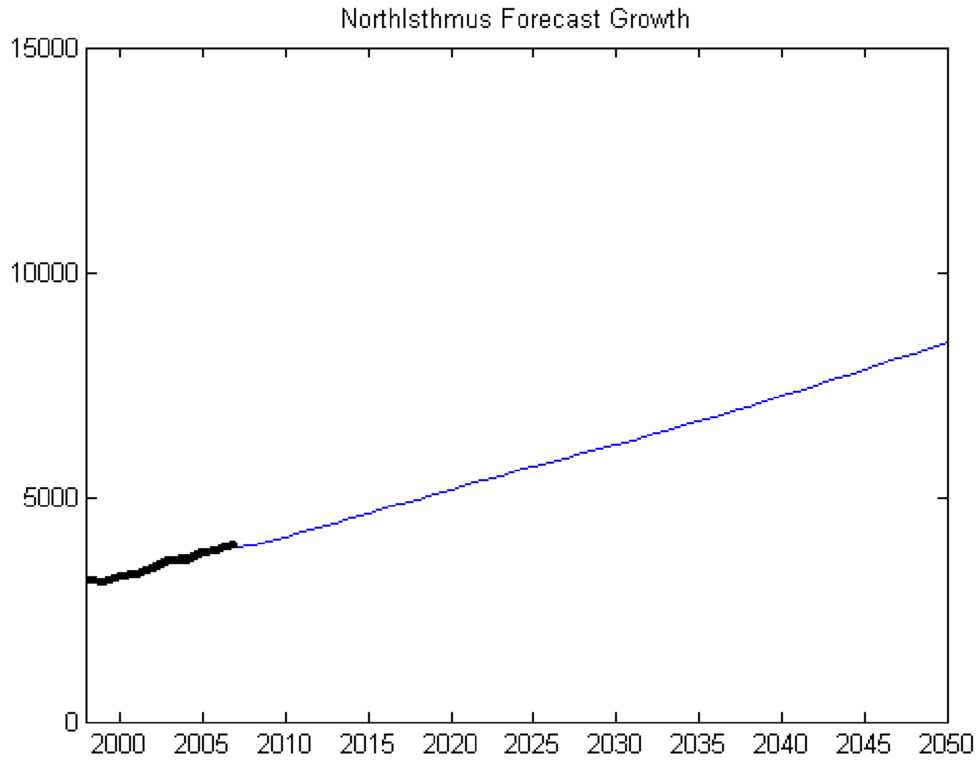
5.9.7 Appendix 3 contains tables with the prudent ADMD peak demand forecast by region. The figures included in the Appendix are the region loads at the time of the island peak. Typically these are slightly lower than the absolute region peak, but are usually used for system modelling unless region-specific issues are being assessed.

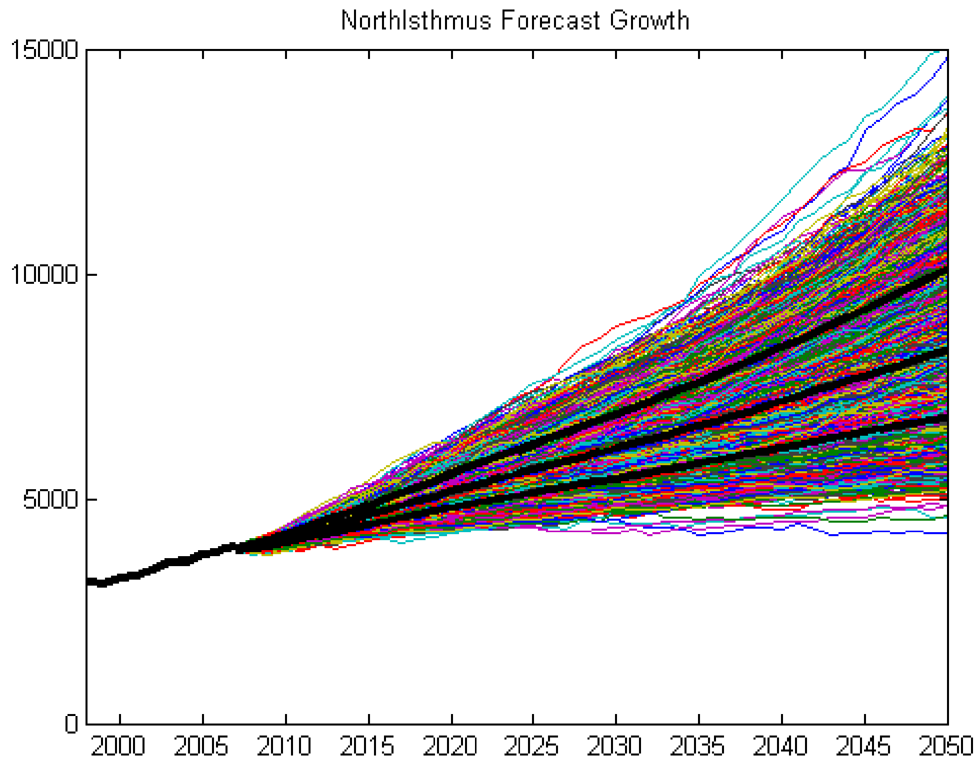
5.9.8 Appendix 4 contains graphs comparing the region level 2007 ADMD prudent peak forecast with the 2006 forecasts.

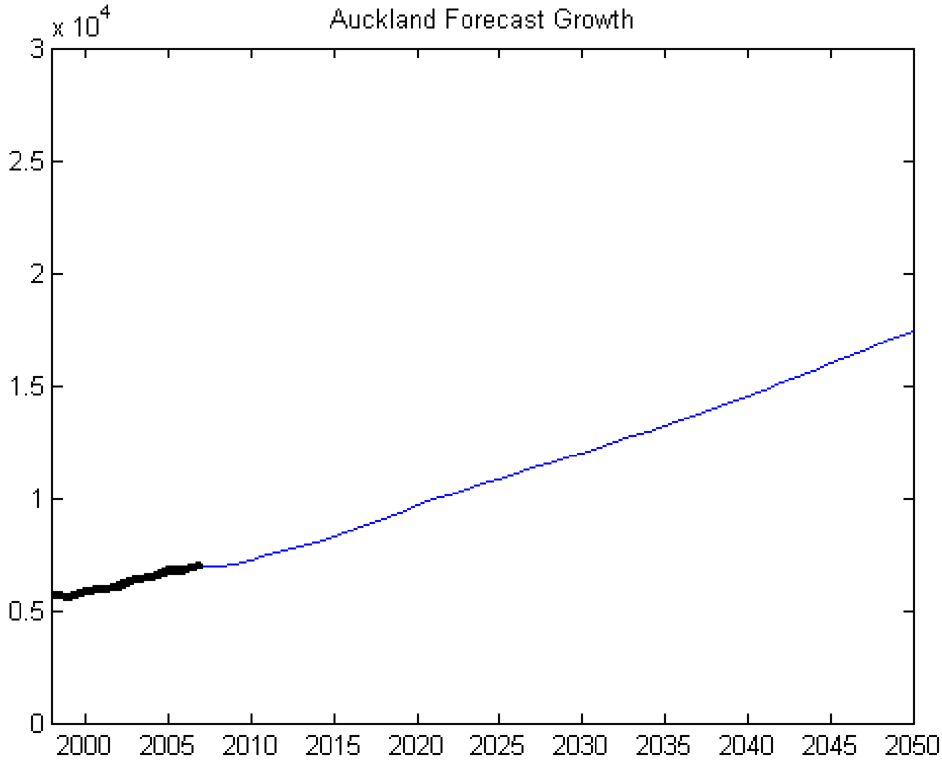
5.9.9 There are a number of significant changes in the projected regional peak forecasts compared to the 2006 forecasts. Brief notes on the primary causes of the changes are included in Appendix 4. Forecast Bay of Plenty and South Canterbury regional peak demand has been reduced significantly. Waikato and Hawkes Bay and Canterbury have also seen some levels of reduction. Nelson, Otago/Southland and the West Coast have all seen some increase, particularly in the short to medium term. Taranaki has also seen an increase (although at this stage no allowance has been made for possible changes associated with the recently announced re-commissioning of the Motunui methanol plant).

5.9.10 GXP level forecasts can be found in the **ADMD2007PrudentPeakForecasts14_1_08.xls** spreadsheet.

Appendix 1 Regional energy forecast graphs






Auckland Forecast Growth
x 10^4
3
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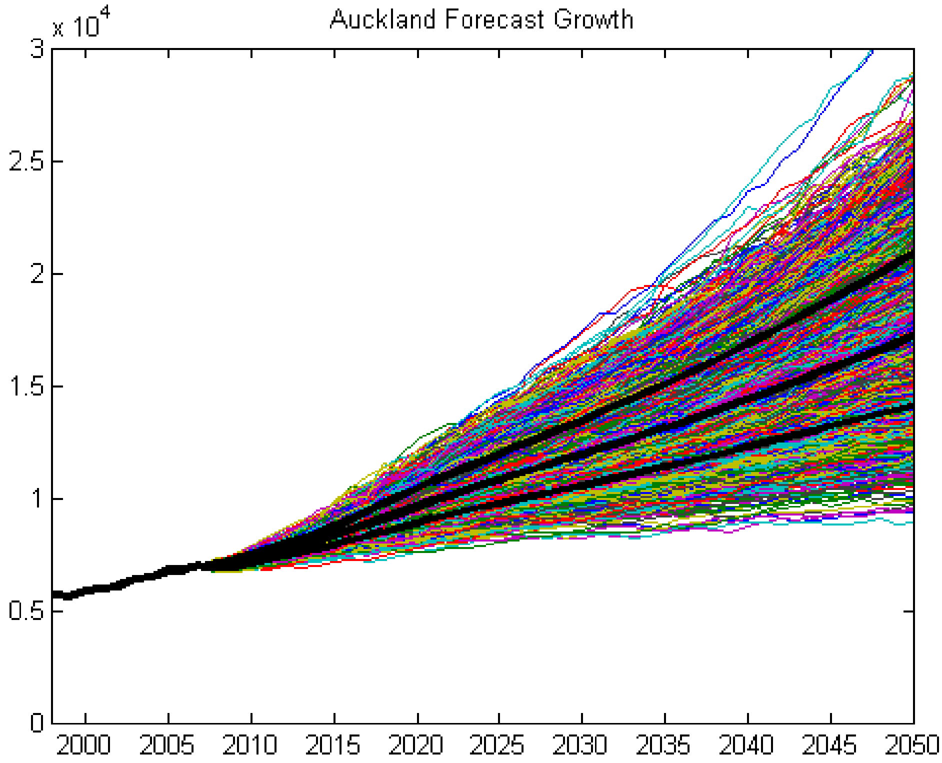
Auckland Forecast Growth
x 10^4
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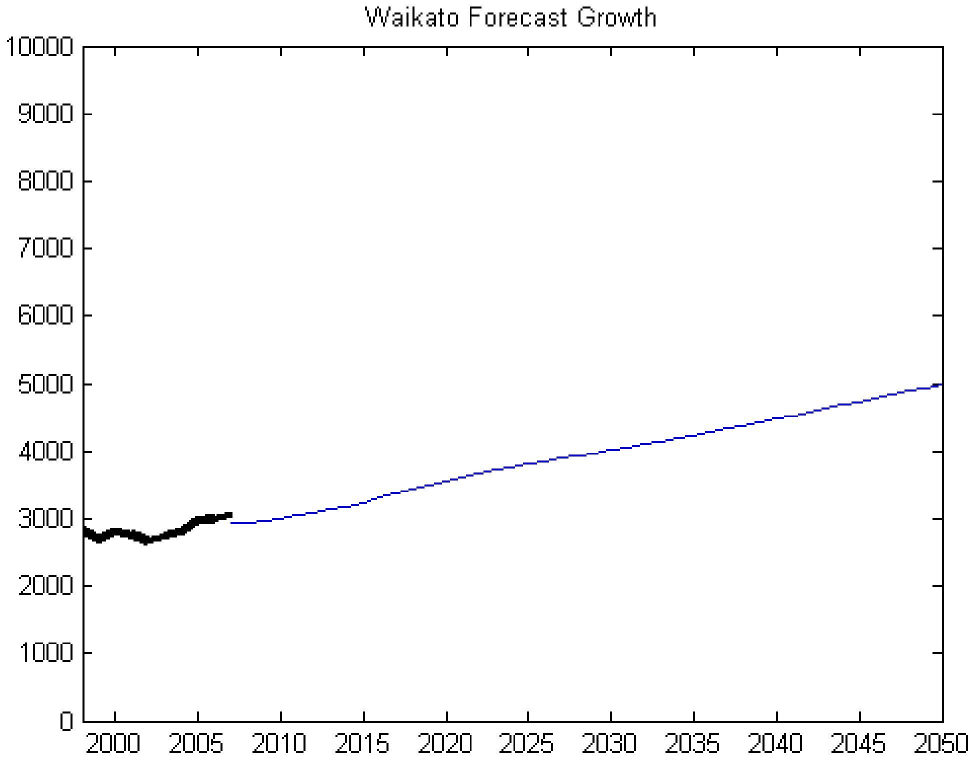
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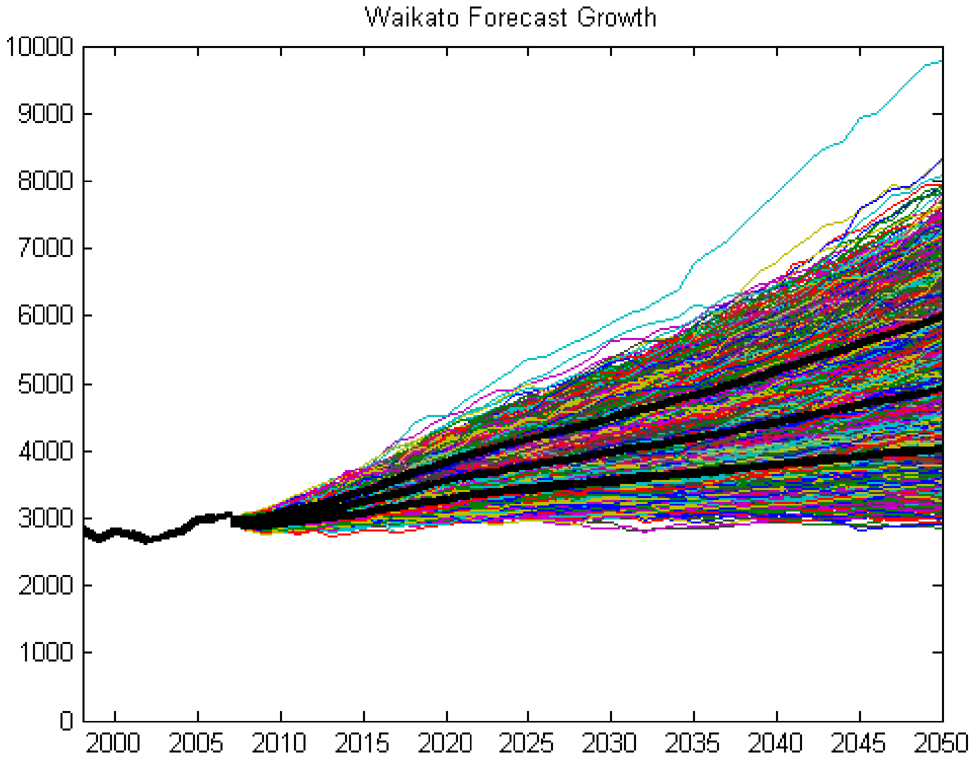
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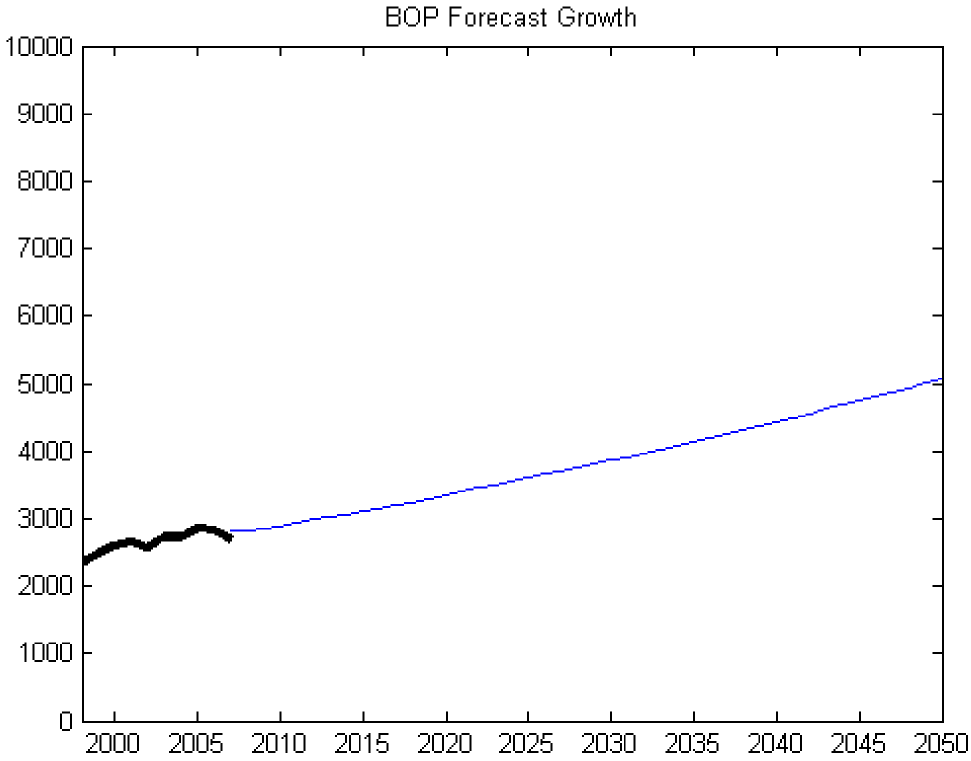
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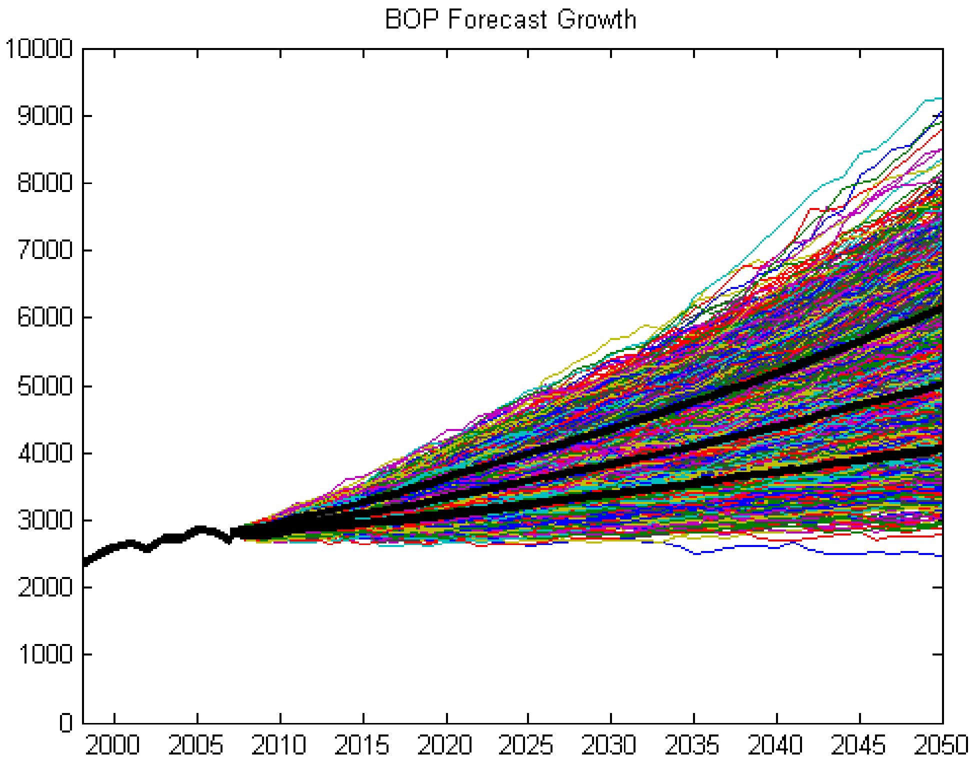
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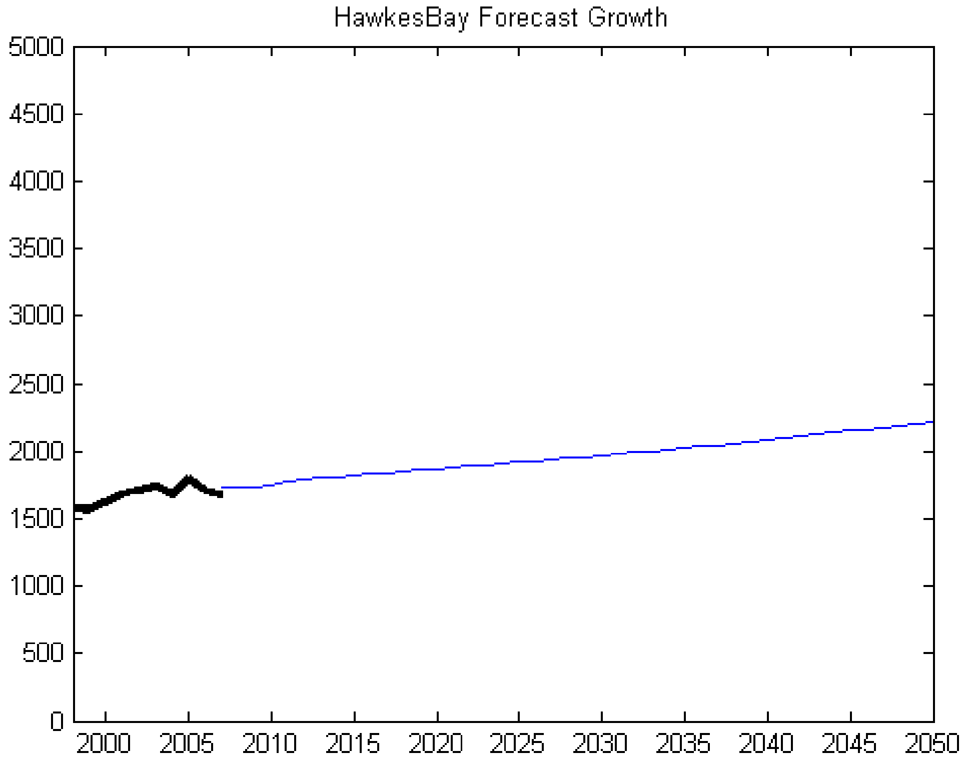
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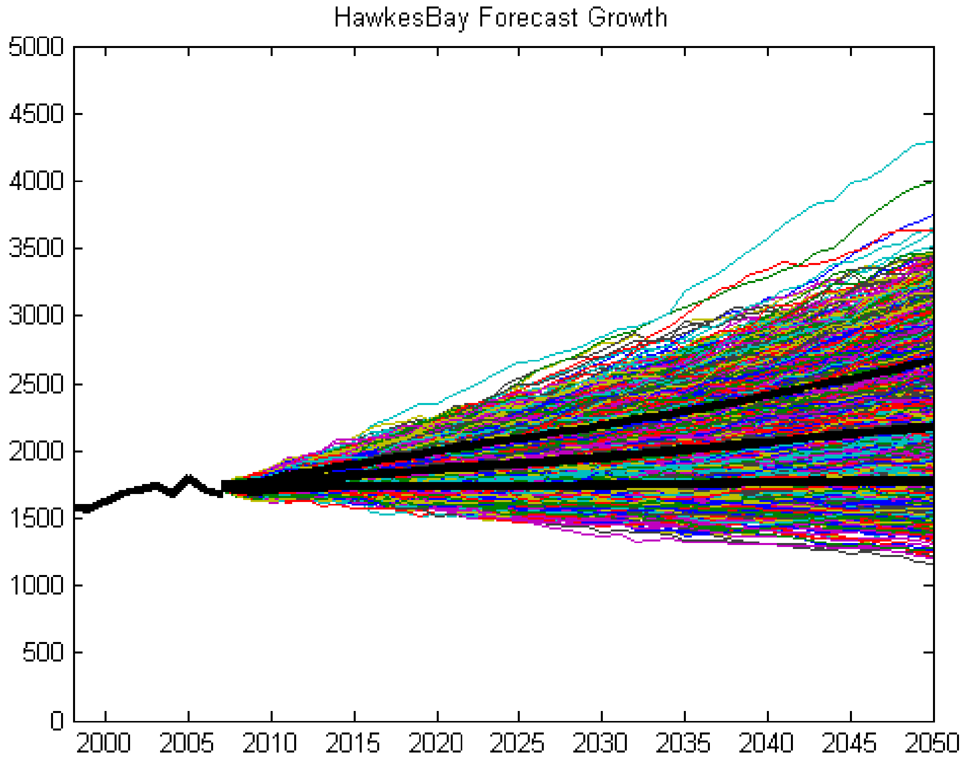
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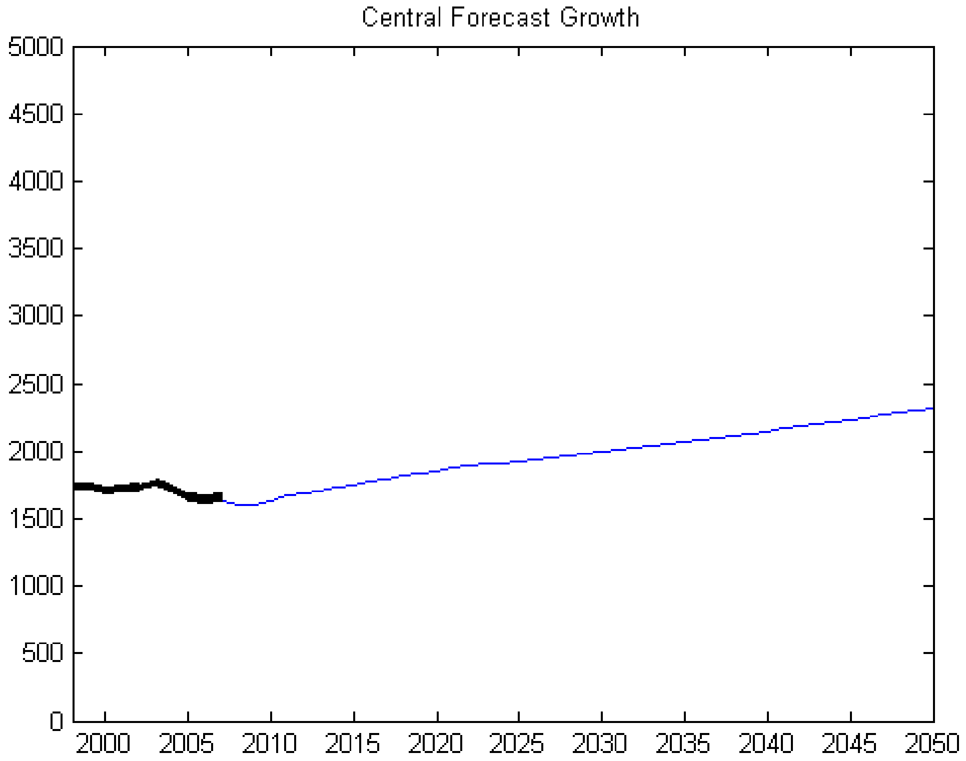
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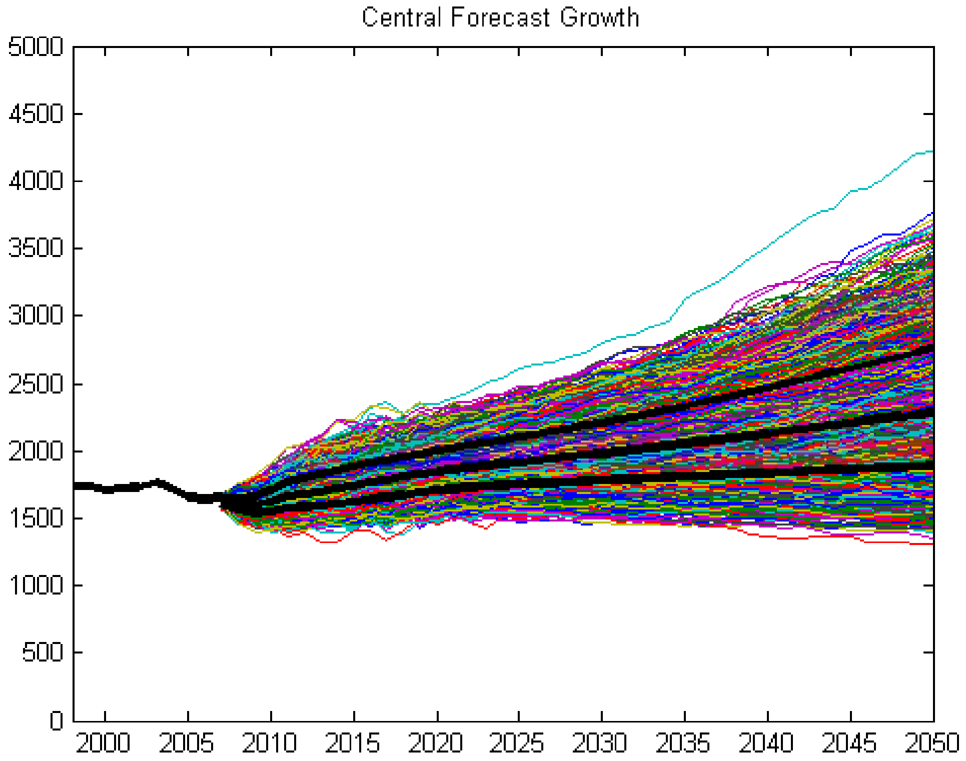
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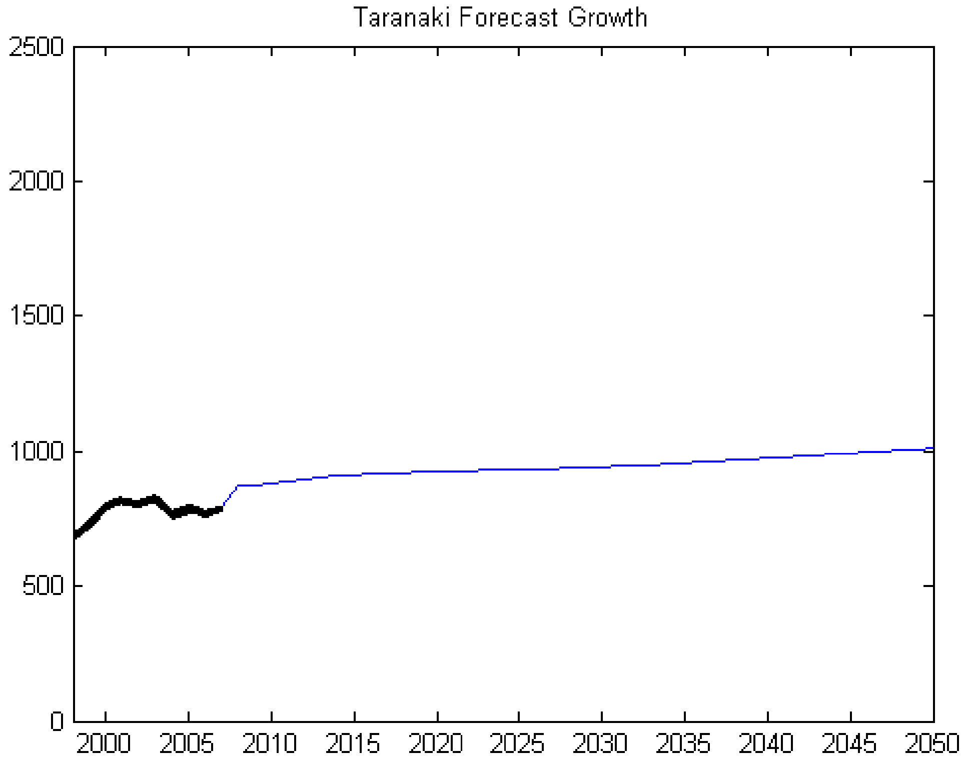
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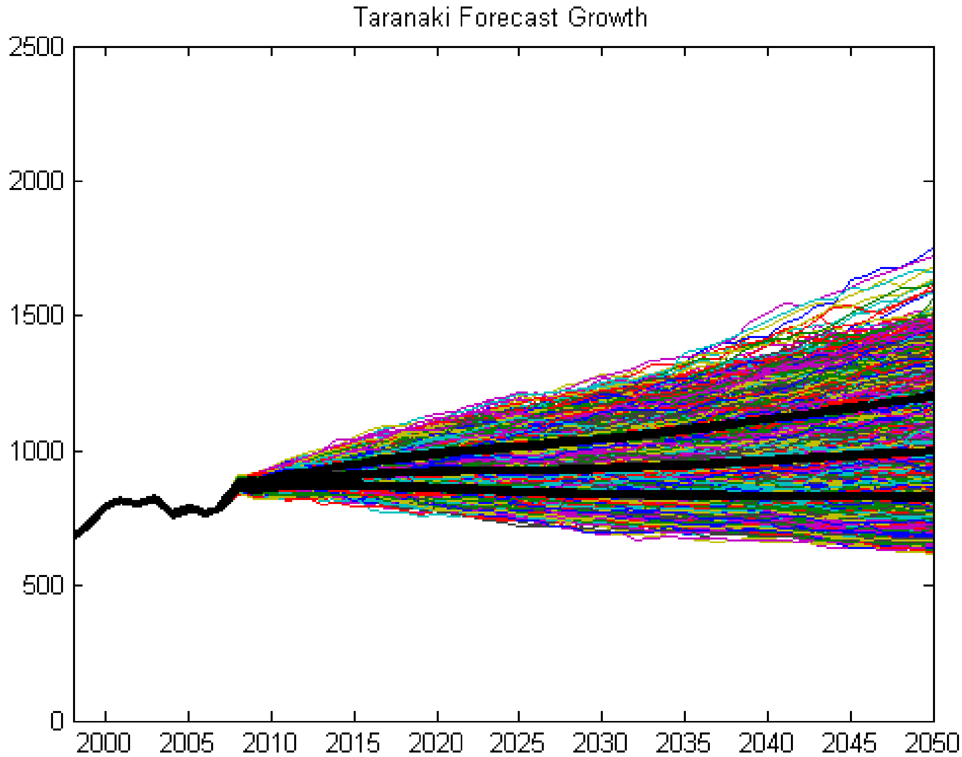
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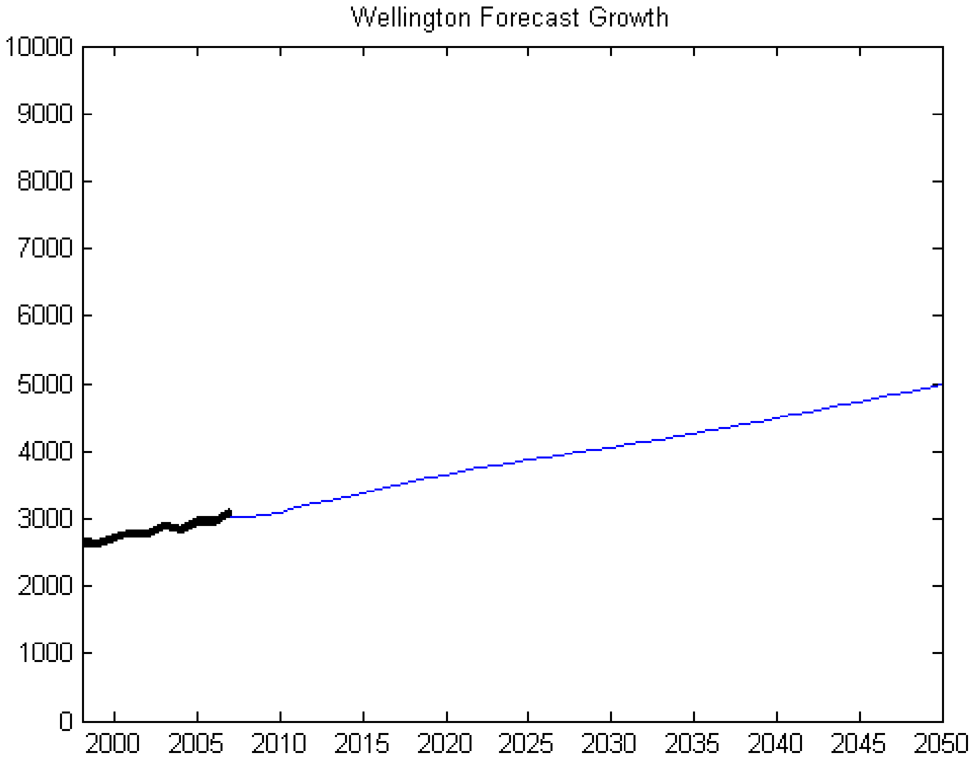
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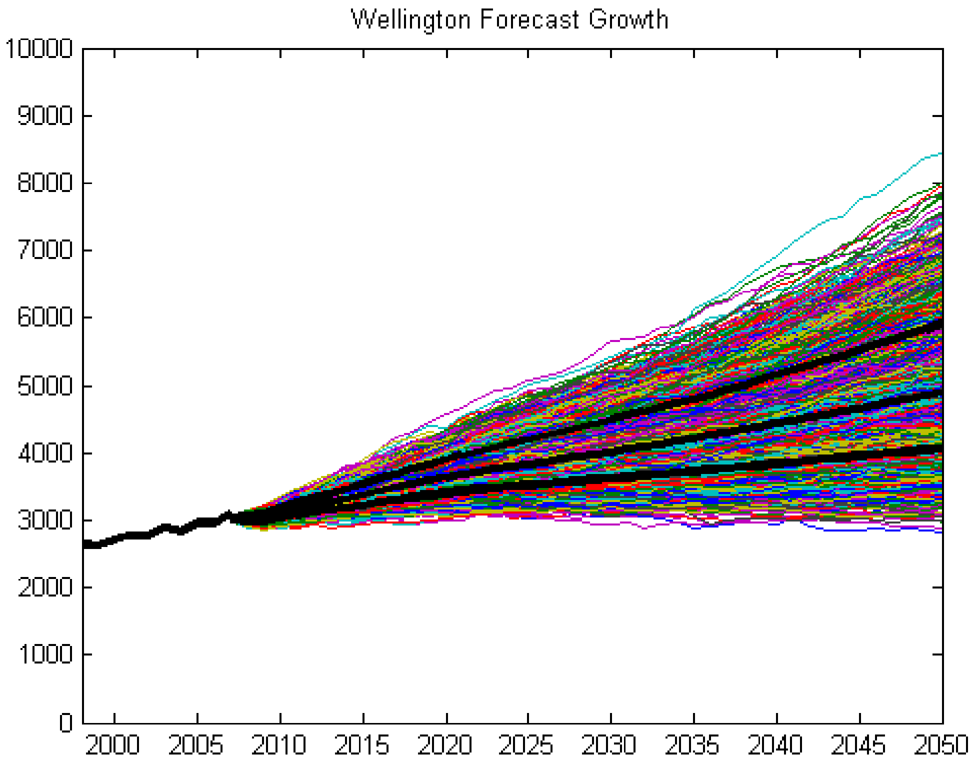
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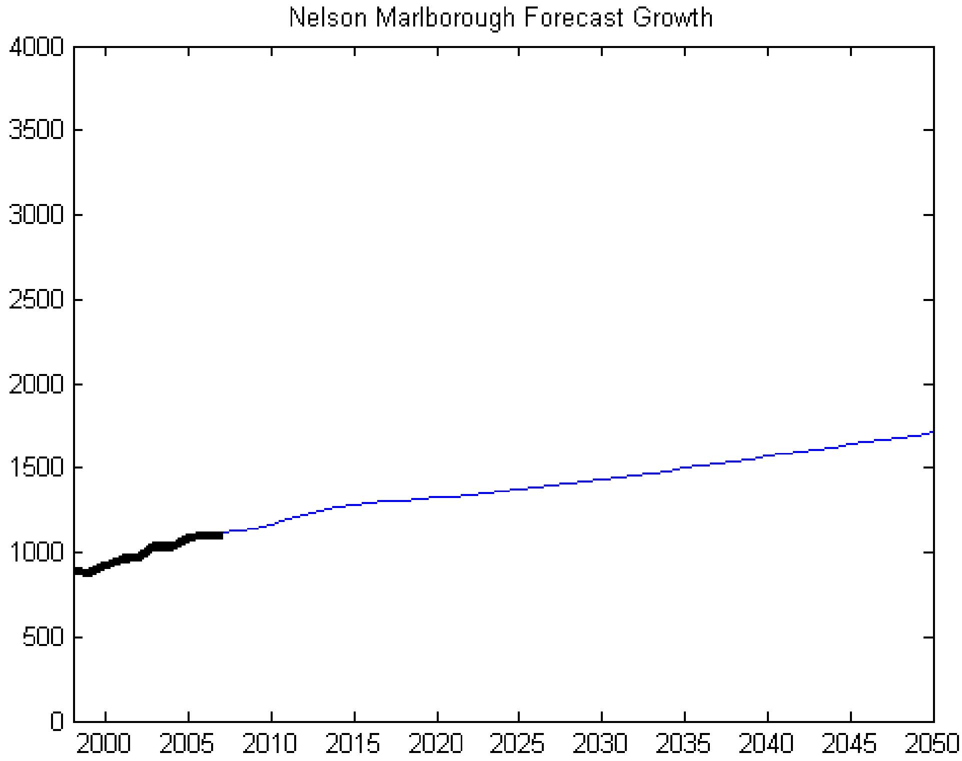
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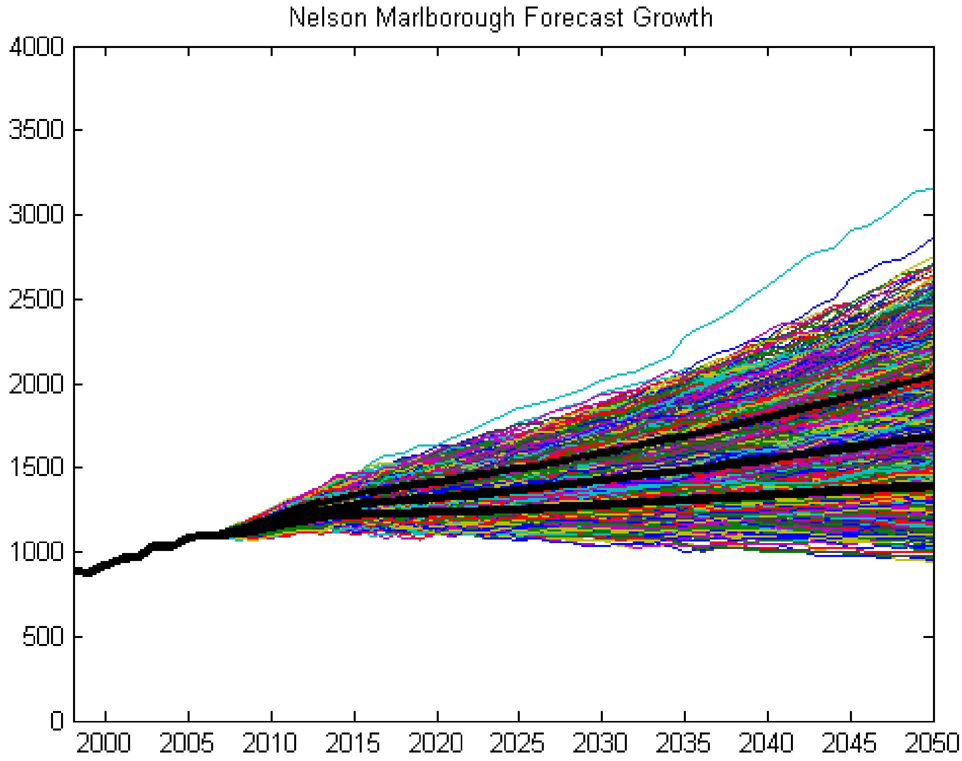
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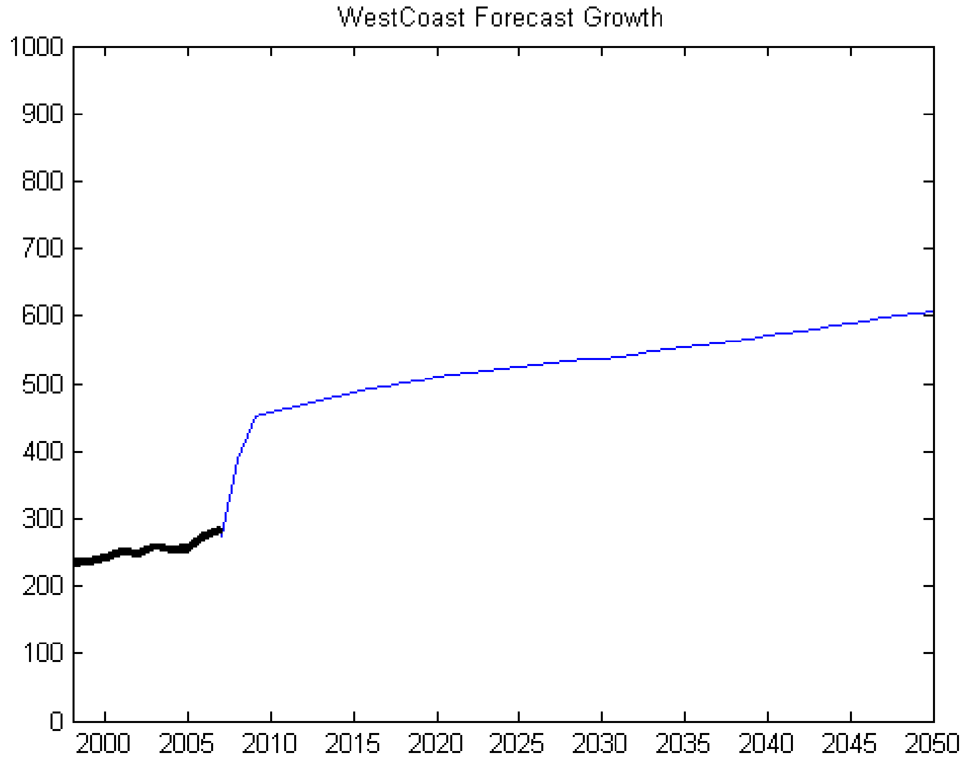
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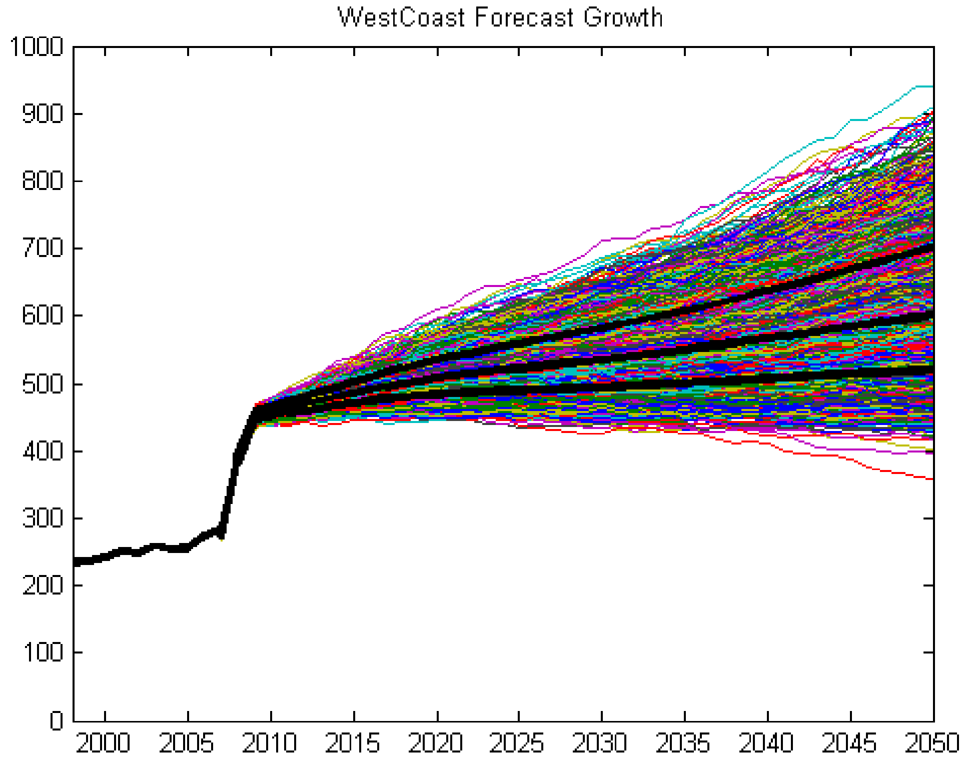
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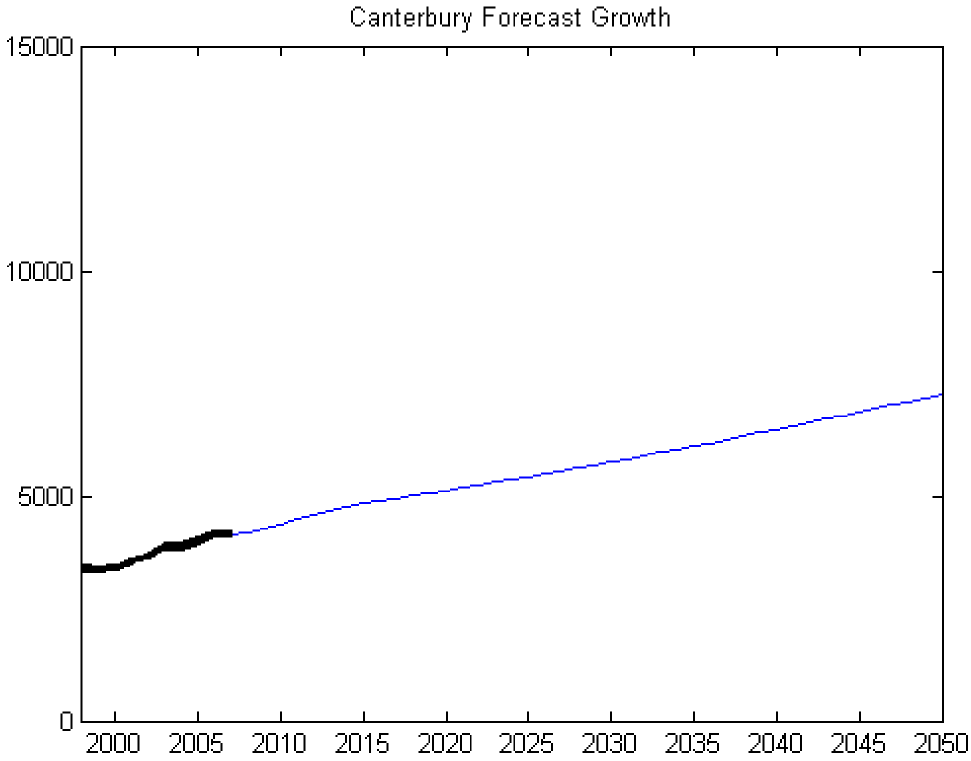
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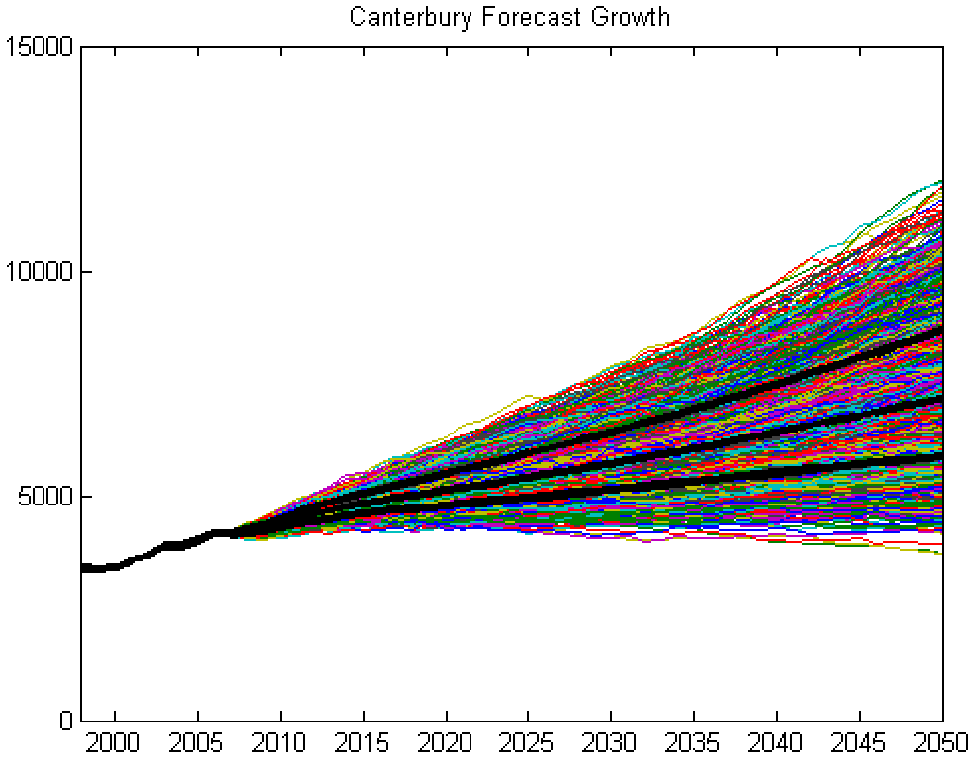
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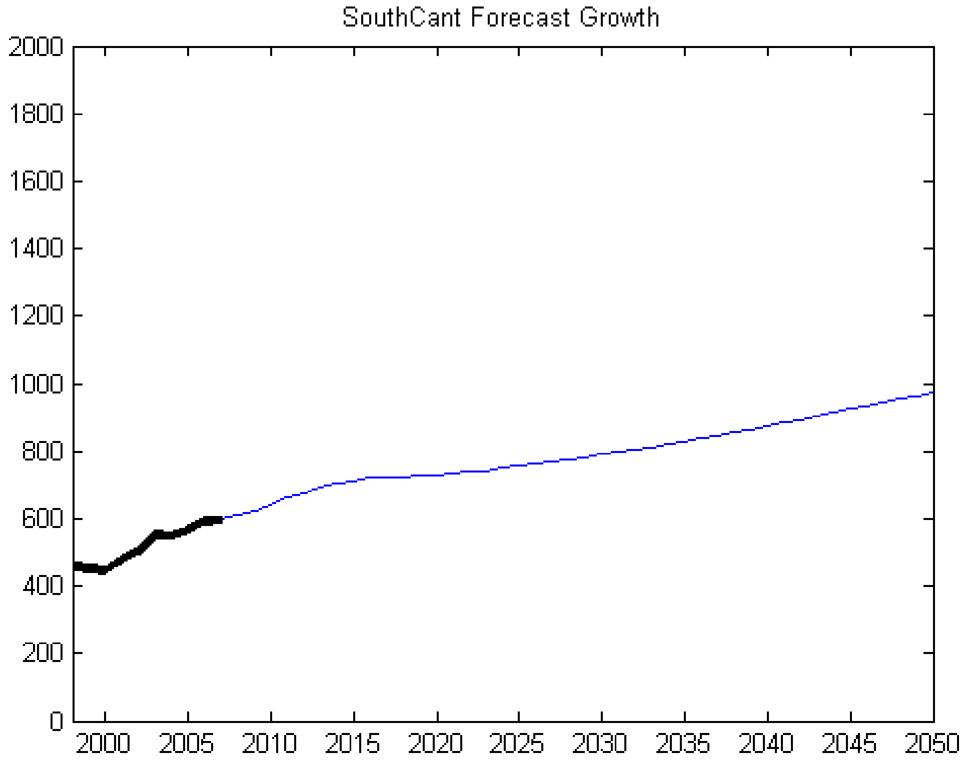
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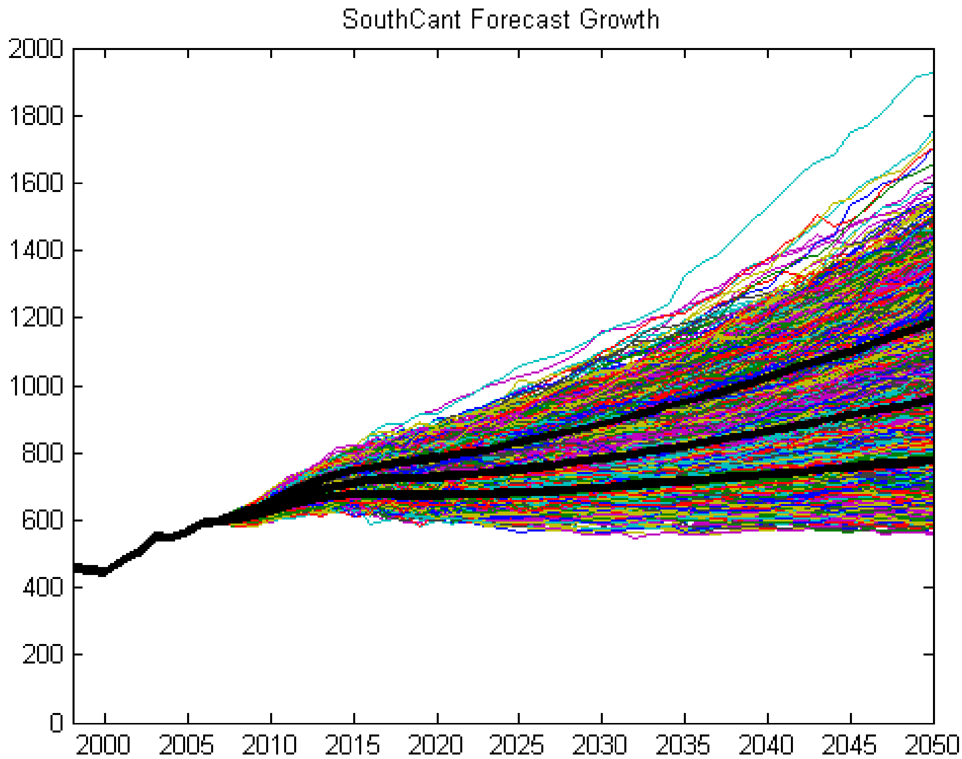
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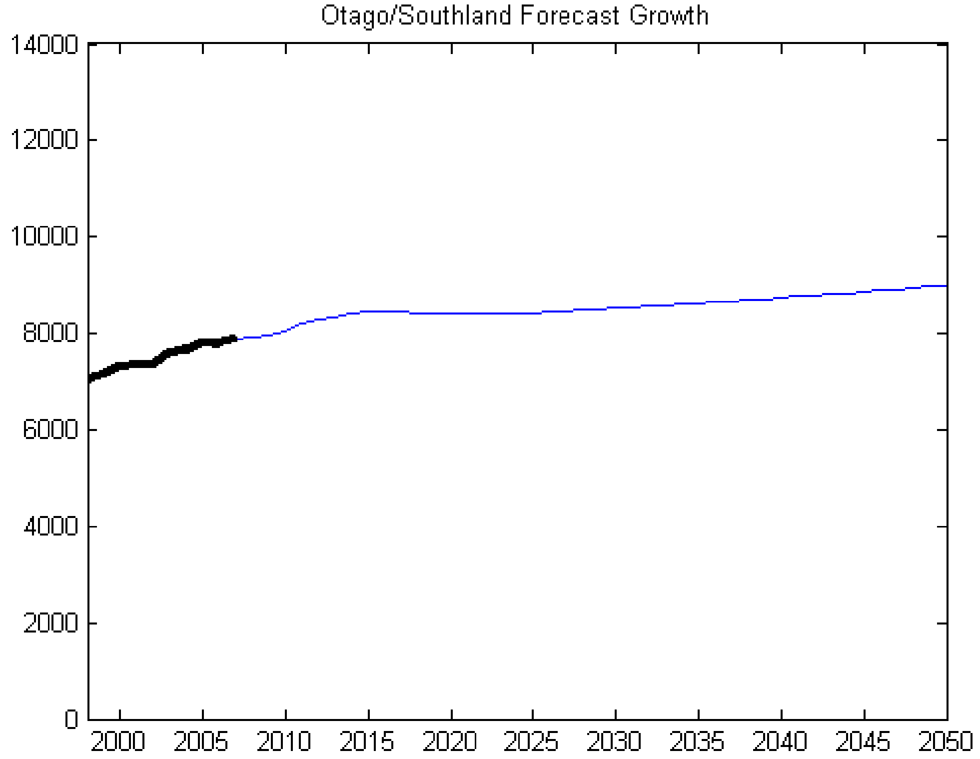
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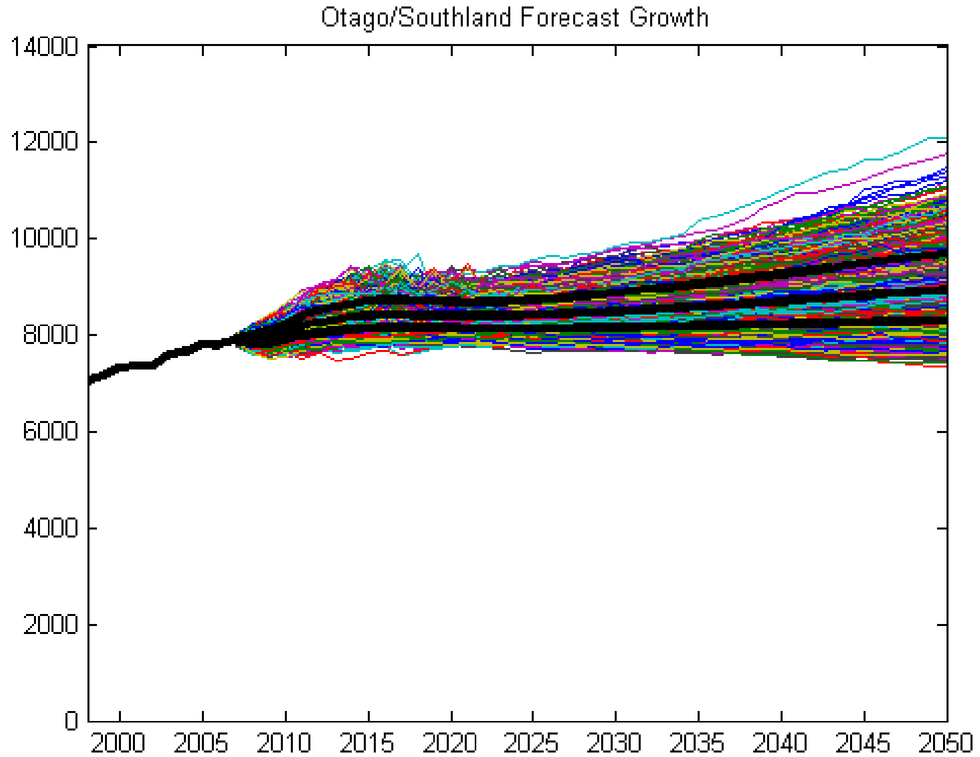
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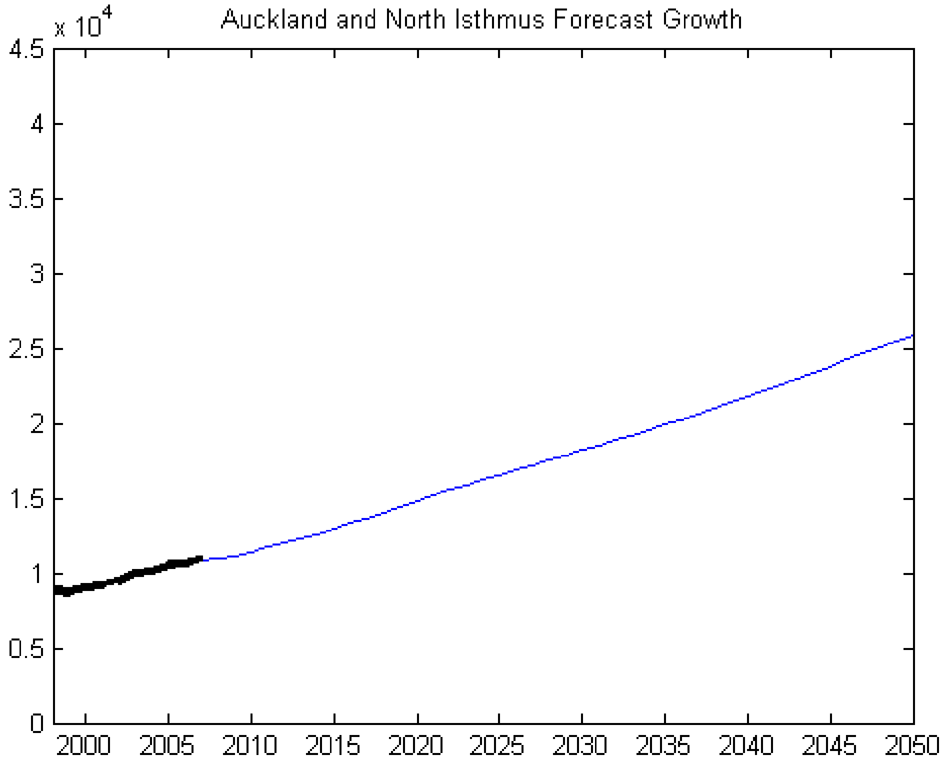
Auckland and North Isthmus Forecast Growth
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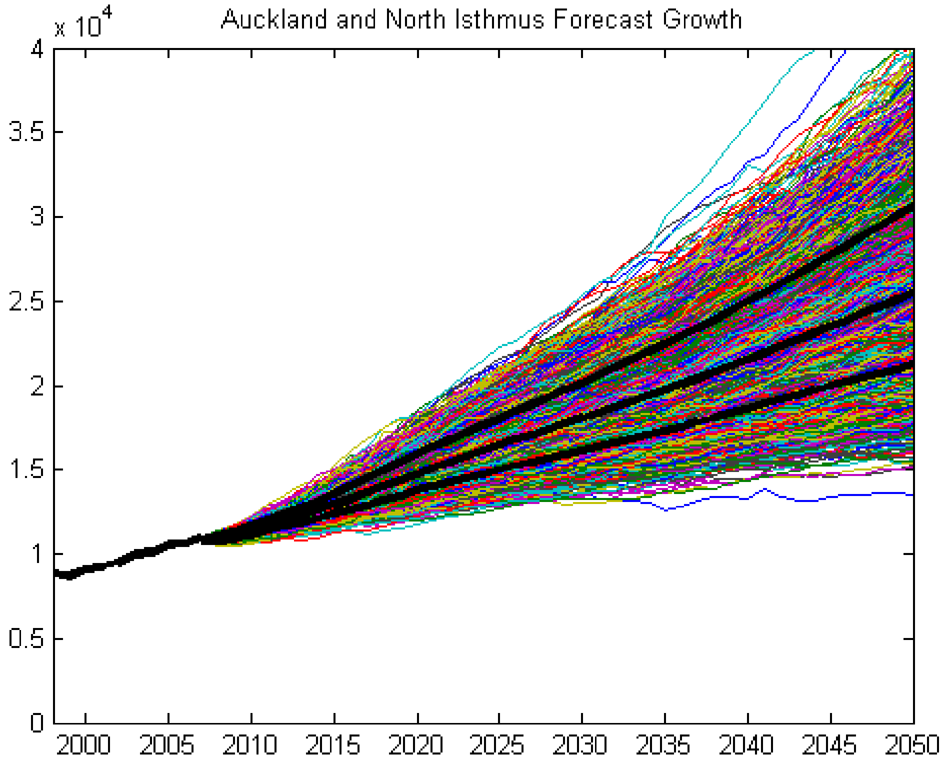
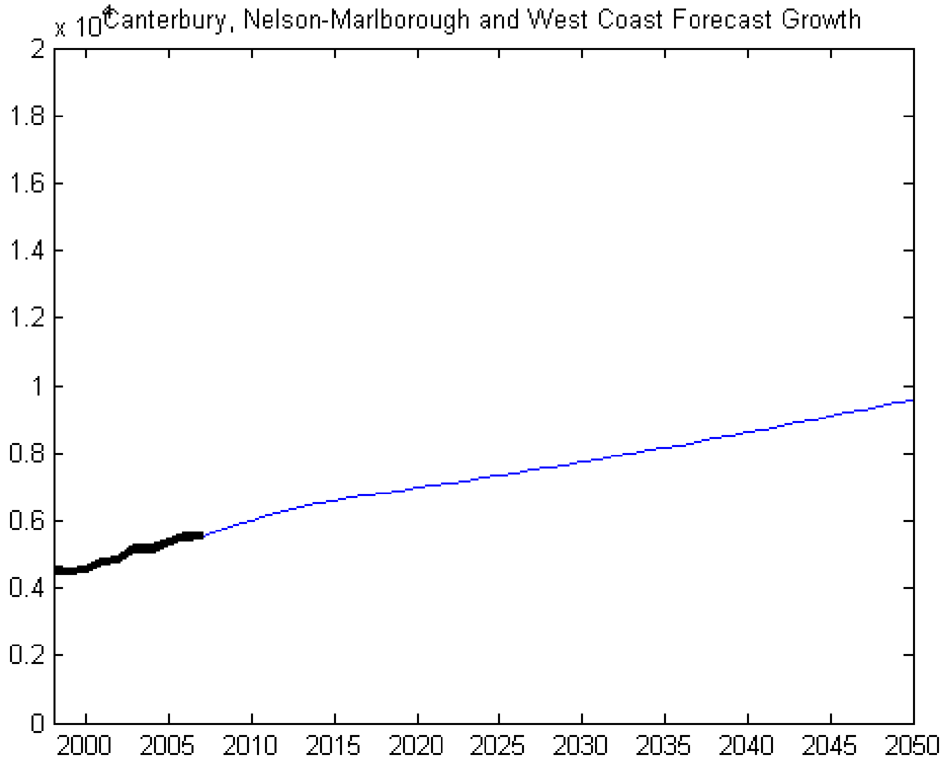
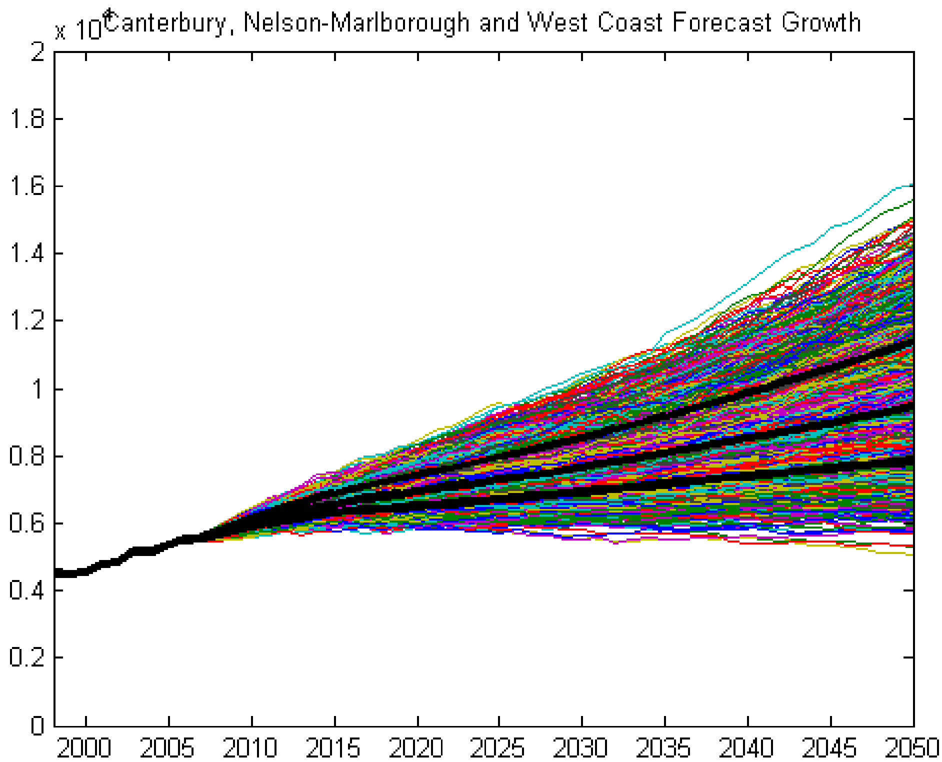
2030
2035
2040
2045
2050


Auckland and North Isthmus Forecast Growth
x 10^4
4
3.5
3
2.5
2
1.5
1
0.5
0
2000
2005
2010
2015
2020
2025
2030
2035
2040
2045
2050


x 10^4
Canterbury, Nelson-Marlborough and West Coast Forecast Growth
2
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
2000
2005
2010
2015
2020
2025
2030
2035
2040
2045
2050


x 10^4
Canterbury, Nelson-Marlborough and West Coast Forecast Growth
2
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
2000
2005
2010
2015
2020
2025
2030
2035
2040
2045
2050

Appendix 2 Regional energy forecasts

Regional Energy Demand Projections **March Years**

Figures in GWh

Year	North Isthmus	Auckland	Waikato	BOP	Hawkes Bay	Central	Taranaki	Wellington	Total North Island
2007	3897	6933	2953	2822	1736	1623	796	3019	23779
2008	3937	6995	2944	2825	1728	1607	872	3024	23931
2009	4002	7103	2955	2845	1730	1604	872	3049	24160
2010	4098	7268	2990	2888	1746	1624	879	3097	24592
2011	4223	7489	3048	2949	1773	1668	891	3168	25209
2012	4319	7663	3086	2988	1787	1688	896	3217	25645
2013	4416	7850	3129	3026	1799	1707	901	3267	26095
2014	4518	8060	3180	3066	1810	1729	907	3321	26591
2015	4627	8298	3239	3107	1822	1753	912	3379	27138
2016	4739	8562	3306	3152	1832	1776	916	3439	27722
2017	4845	8826	3371	3195	1840	1796	919	3494	28284
2018	4954	9102	3438	3242	1848	1816	921	3548	28867
2019	5064	9379	3504	3292	1857	1835	923	3602	29456
2020	5175	9653	3566	3346	1868	1855	925	3654	30041
2021	5285	9922	3625	3402	1880	1873	928	3704	30618
2022	5383	10161	3672	3452	1888	1887	928	3745	31116
2023	5481	10397	3718	3503	1897	1901	929	3785	31612
2024	5579	10632	3763	3554	1906	1915	930	3824	32104
2025	5679	10868	3806	3607	1916	1928	931	3864	32599
2026	5781	11106	3849	3659	1925	1941	932	3903	33096
2027	5877	11329	3890	3709	1935	1955	934	3942	33571
2028	5974	11554	3932	3760	1946	1968	936	3980	34050
2029	6072	11781	3973	3811	1956	1982	939	4019	34533
2030	6170	12010	4015	3863	1967	1996	941	4058	35019
2031	6270	12241	4057	3915	1977	2009	944	4097	35510
2032	6372	12480	4101	3968	1988	2024	946	4138	36018
2033	6475	12721	4145	4023	2000	2039	949	4179	36531
2034	6579	12965	4189	4078	2011	2053	952	4221	37049
2035	6684	13213	4234	4133	2022	2068	955	4263	37572
2036	6790	13463	4279	4189	2034	2083	958	4305	38100
2037	6902	13728	4328	4249	2047	2099	961	4351	38664
2038	7015	13996	4377	4309	2059	2116	965	4397	39235
2039	7129	14269	4426	4370	2072	2132	969	4444	39811
2040	7244	14544	4476	4432	2085	2149	972	4491	40393

Regional Energy Demand Projections **March Years**

Figures in GWh

Year	Nelson / Marlborough	West Coast	Canterbury	South Canterbury	Otago / Southland	Total South Island
2007	1111	273	4163	599	7894	14041
2008	1123	388	4203	609	7928	14251
2009	1141	452	4269	622	7971	14456
2010	1168	457	4366	640	8064	14696
2011	1202	464	4492	662	8204	15024
2012	1226	469	4583	678	8281	15237
2013	1247	475	4668	692	8346	15428
2014	1266	480	4750	704	8400	15601
2015	1282	486	4827	713	8437	15746
2016	1295	492	4897	719	8453	15856
2017	1301	497	4954	722	8443	15917
2018	1308	501	5009	724	8429	15971
2019	1315	505	5067	726	8414	16028
2020	1324	509	5129	729	8407	16098
2021	1333	513	5194	734	8406	16179
2022	1343	516	5251	738	8405	16252
2023	1352	519	5311	743	8409	16334
2024	1364	522	5373	749	8419	16426
2025	1374	524	5437	755	8431	16522
2026	1386	527	5503	761	8445	16622
2027	1397	530	5567	768	8462	16724
2028	1409	532	5631	775	8479	16828
2029	1421	535	5697	782	8498	16933
2030	1434	538	5763	790	8517	17040
2031	1446	541	5829	797	8536	17149
2032	1459	544	5898	805	8557	17262
2033	1472	547	5967	813	8578	17376
2034	1485	550	6036	821	8599	17491
2035	1498	553	6106	829	8620	17606
2036	1511	556	6177	837	8642	17723
2037	1525	560	6252	847	8666	17849
2038	1539	563	6328	856	8690	17976
2039	1553	567	6404	865	8715	18104
2040	1568	570	6480	875	8740	18232

Appendix 3 Regional peak forecasts

Regional Peak Projections* **Calendar years**

Figures in MW

Year	North Isthmus	Auckland	Waikato	BOP	Hawkes Bay	Central	Taranaki	Wellington	Total North Island
2007	783	1276	542	398	272	323	125	633	4352
2008	841	1377	562	441	277	334	137	655	4624
2009	869	1418	576	450	279	339	139	670	4740
2010	899	1468	587	459	284	347	140	686	4869
2011	930	1512	600	469	288	354	141	703	4996
2012	960	1558	613	476	292	361	143	719	5122
2013	982	1600	624	483	294	365	144	731	5222
2014	1005	1646	635	489	296	370	145	744	5330
2015	1029	1697	648	496	298	375	145	757	5444
2016	1052	1748	660	503	299	379	146	768	5554
2017	1075	1800	672	510	301	383	146	780	5667
2018	1098	1853	685	518	302	387	146	792	5781
2019	1122	1907	697	527	304	391	147	803	5896
2020	1145	1960	708	536	306	395	147	814	6010
2021	1166	2007	718	543	307	398	147	823	6109
2022	1188	2054	727	551	308	401	147	832	6208
2023	1209	2101	736	560	310	403	147	840	6306
2024	1230	2148	744	568	311	406	147	849	6403
2025	1252	2195	752	576	313	409	148	857	6502
2026	1273	2239	761	584	314	412	148	866	6597
2027	1294	2284	769	592	316	414	148	874	6692
2028	1315	2329	777	600	318	417	149	883	6787
2029	1336	2374	785	608	319	420	149	891	6883
2030	1358	2420	794	617	321	423	149	900	6982
2031	1380	2468	802	625	323	426	150	909	7083
2032	1402	2515	811	634	325	429	150	918	7184
2033	1425	2563	820	643	326	432	151	928	7287
2034	1447	2612	828	651	328	435	151	937	7389
2035	1470	2661	837	660	330	438	151	946	7494
2036	1494	2713	847	670	332	442	152	956	7605
2037	1518	2766	856	679	334	445	153	966	7717
2038	1543	2820	866	689	336	448	153	976	7831
2039	1568	2874	876	698	338	452	154	987	7946
2040	1593	2929	886	708	340	455	154	997	8063

*Region demand at Island peak

Regional Peak Projections* **Calendar years**

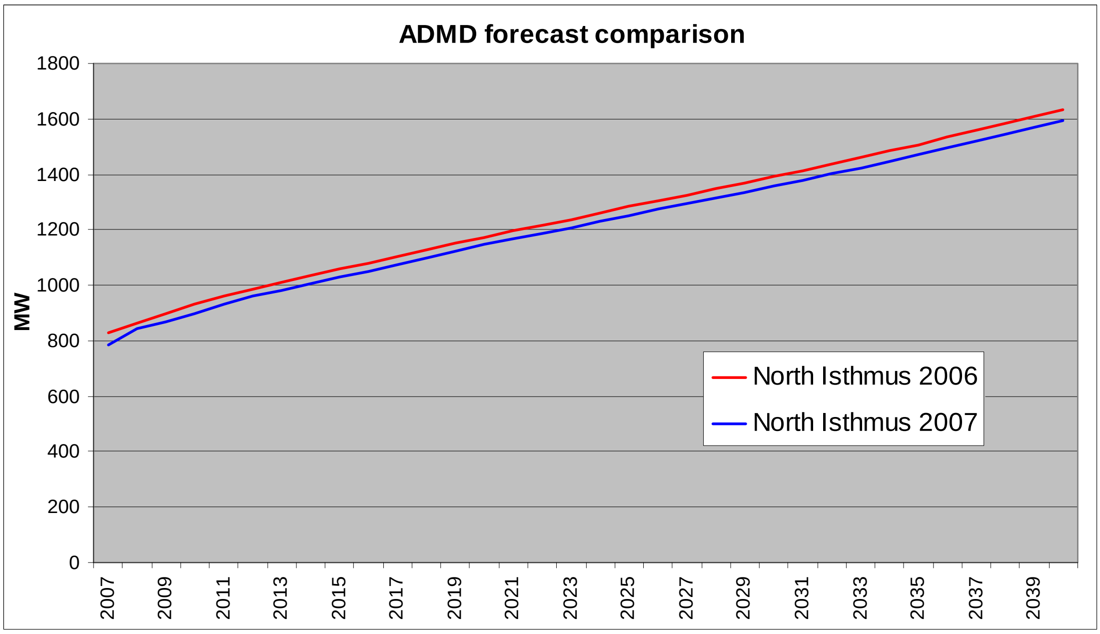
Figures in MW

Year	Nelson / Marlborough	West Coast	Canterbury	South Canterbury	Otago / Southland	Total South Island
2007	210	46	740	84	1100	2180
2008	216	69	781	92	1122	2280
2009	223	70	800	95	1148	2336
2010	232	72	824	99	1176	2402
2011	239	73	843	102	1199	2456
2012	246	74	864	105	1224	2513
2013	250	75	879	107	1232	2542
2014	253	75	893	108	1237	2566
2015	255	76	906	109	1240	2586
2016	257	76	917	110	1239	2598
2017	259	77	927	110	1237	2610
2018	260	77	938	110	1236	2621
2019	262	78	949	111	1235	2634
2020	264	78	961	111	1234	2648
2021	265	78	971	112	1233	2660
2022	267	78	982	113	1234	2674
2023	269	79	993	113	1235	2690
2024	271	79	1005	114	1236	2706
2025	273	79	1017	115	1238	2723
2026	276	80	1029	116	1240	2740
2027	278	80	1040	117	1243	2758
2028	280	80	1052	118	1245	2776
2029	283	80	1064	119	1248	2795
2030	285	81	1077	120	1251	2814
2031	288	81	1089	122	1254	2834
2032	290	81	1102	123	1257	2853
2033	293	82	1115	124	1261	2874
2034	295	82	1128	125	1264	2893
2035	298	82	1140	126	1267	2914
2036	301	83	1154	128	1271	2936
2037	303	83	1168	129	1274	2958
2038	306	83	1182	130	1278	2980
2039	309	84	1196	132	1282	3002
2040	312	84	1210	133	1286	3025

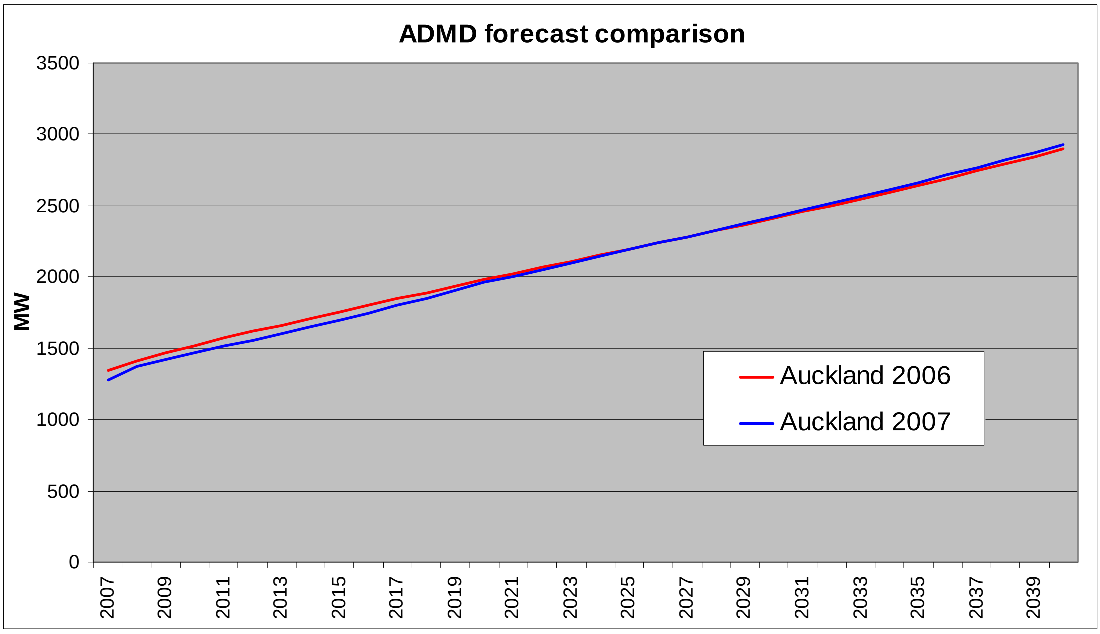
*Region demand at Island peak

Appendix 4 Comparison of 2006 and 2007 regional peak forecasts

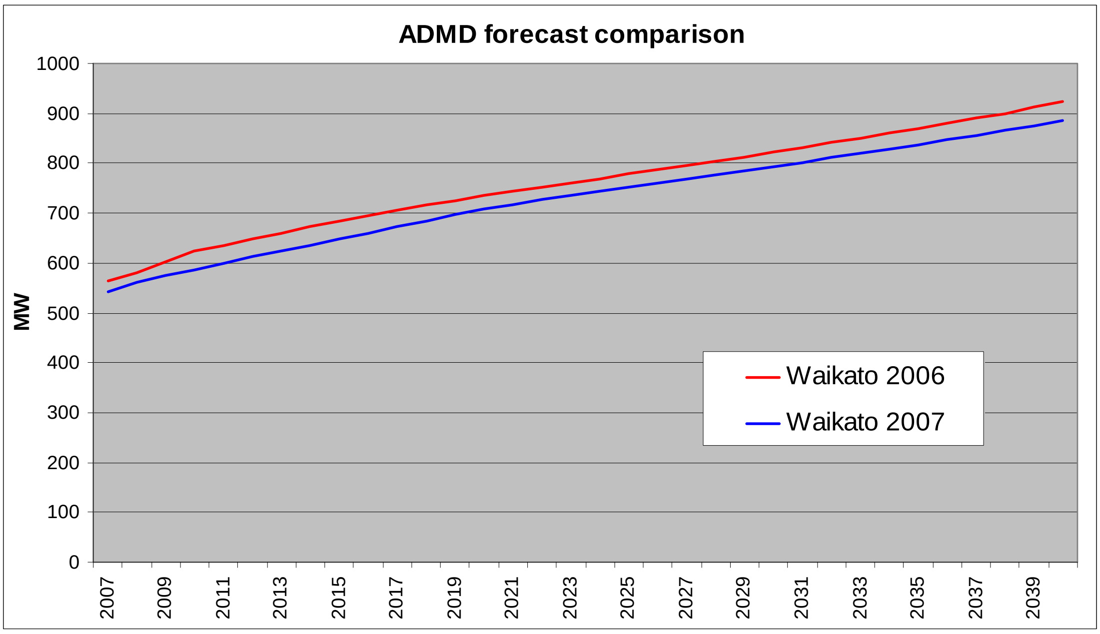
North Isthmus



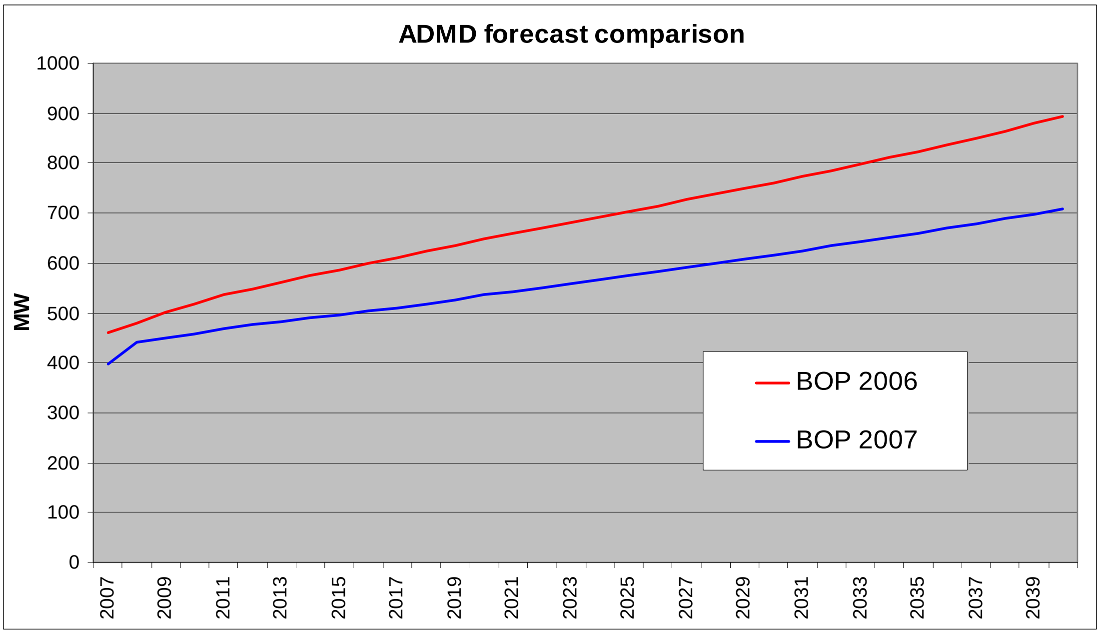
Auckland



Waikato

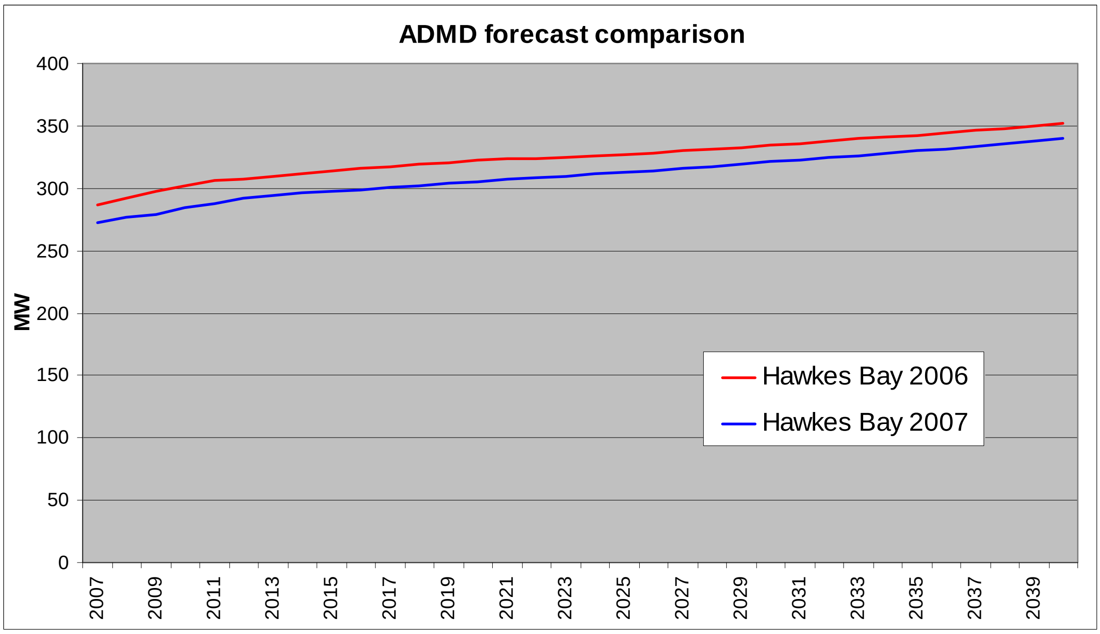


Bay of Plenty

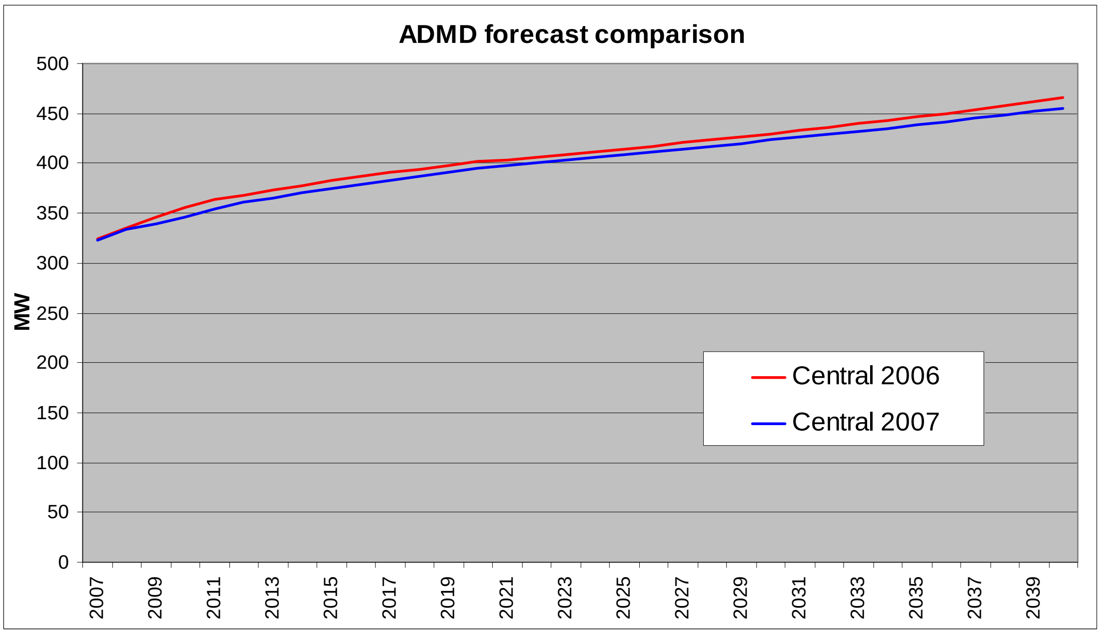


Note : the significantly lower Bay of Plenty forecast is a result of a reduction in the rate of growth in GDP forecast for the region compared to the 2006 projections, combined with a lower base peak starting point.

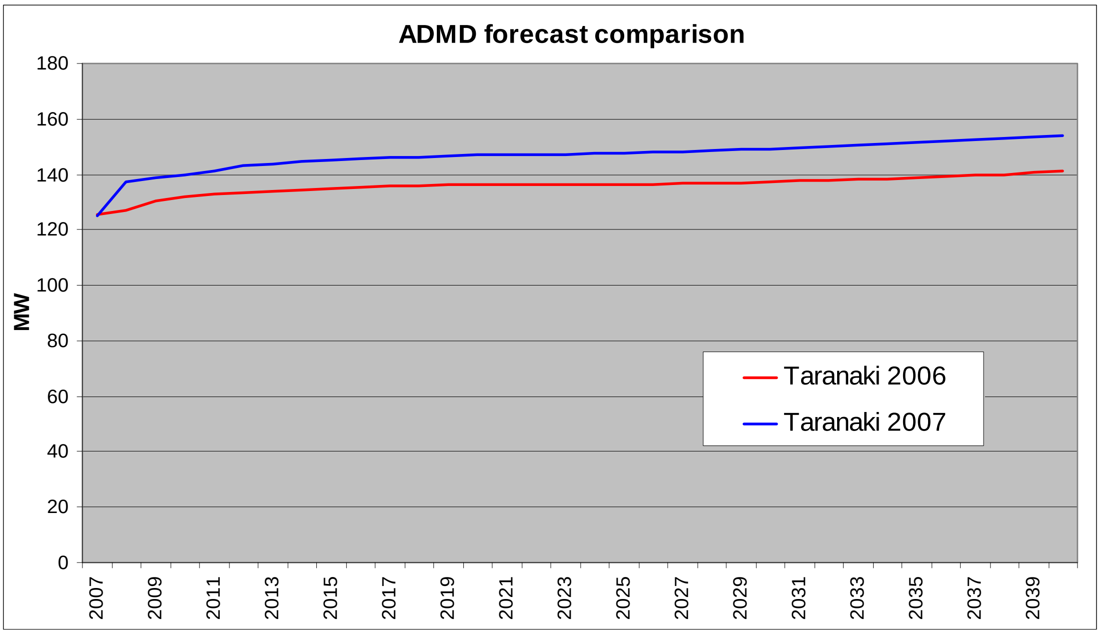
Hawkes Bay



Central

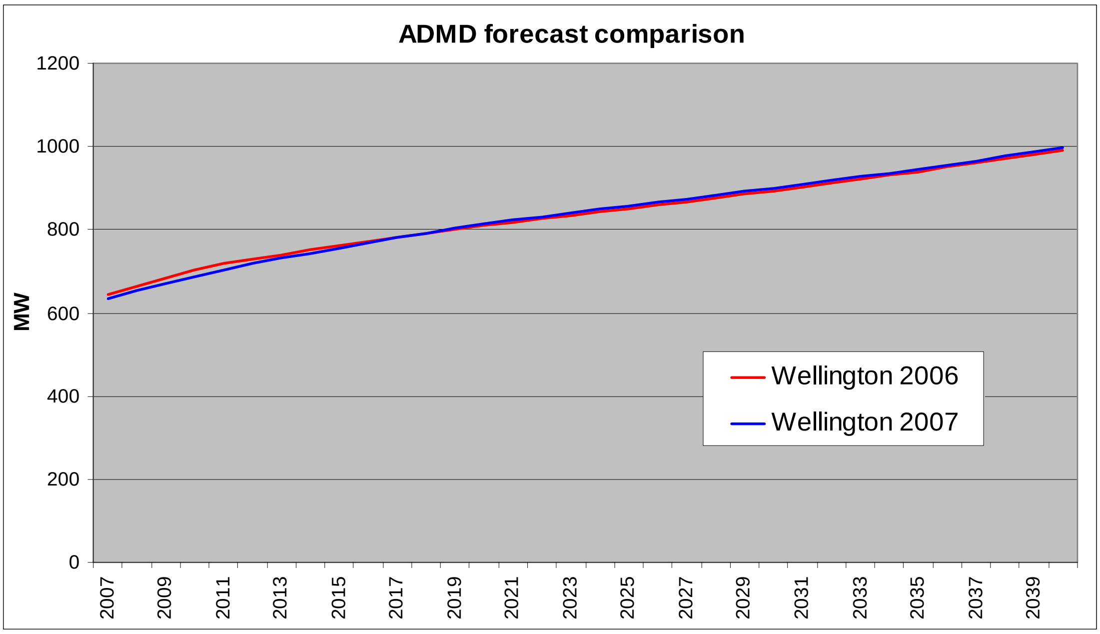


Taranaki

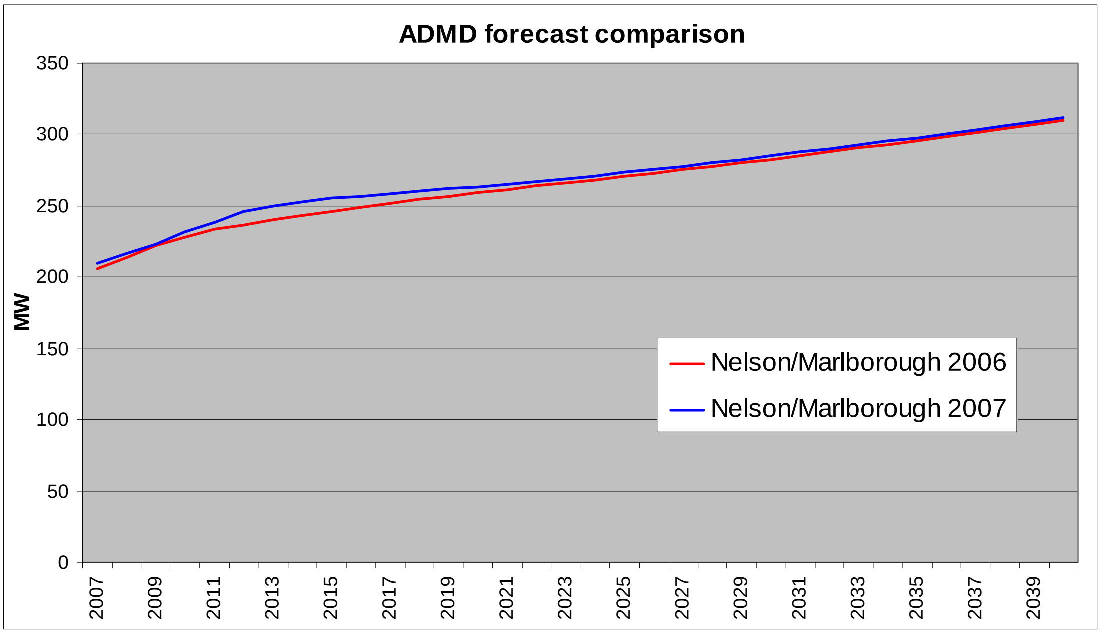


Note: Taranaki peak has increased primarily because of the addition of the new gas processing plant in Hawera

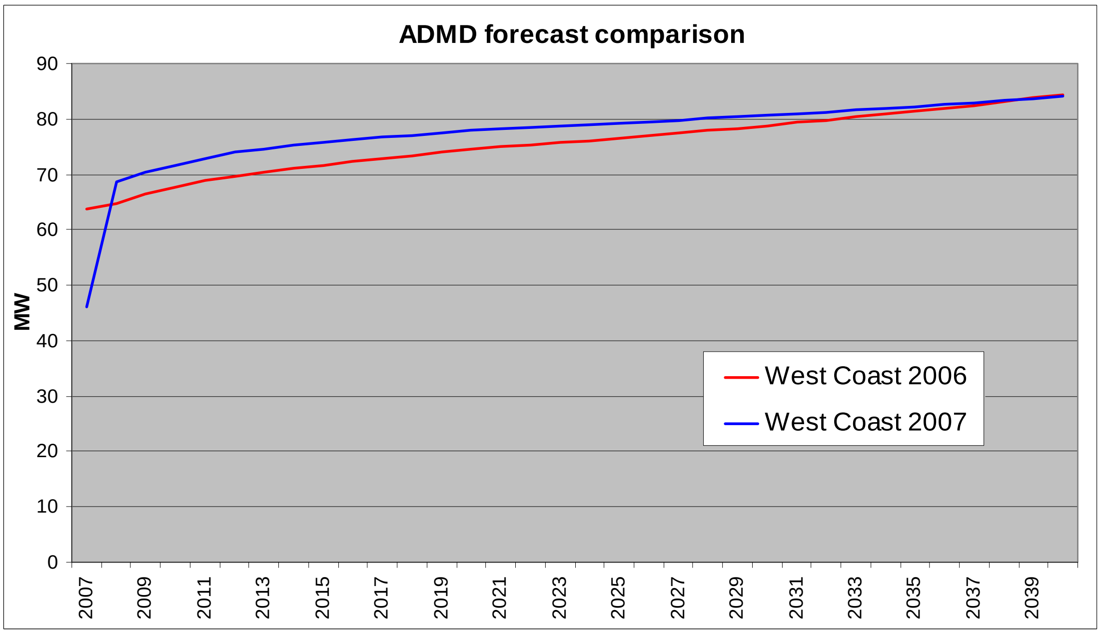
Wellington



Nelson/Marlborough

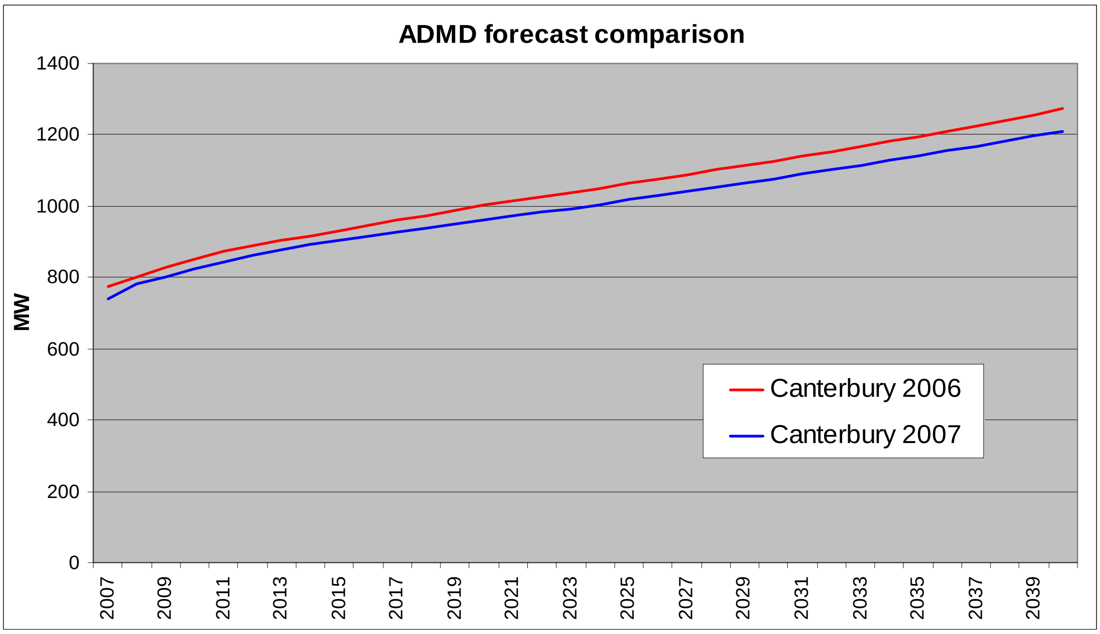


West Coast

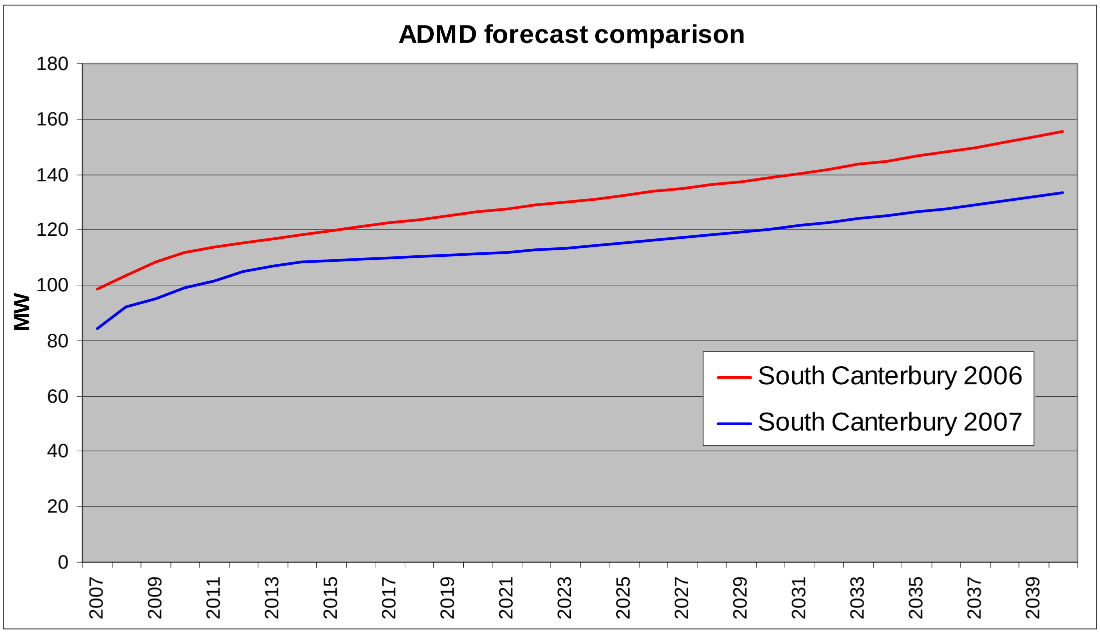


Note : New step loads introduced into West Coast are now expected later than was assumed in the 2006 forecasts, resulting in the lower starting point and the sudden jump. Long term growth rates are reduced, partly due to the revised treatment of embedded generation.

Canterbury

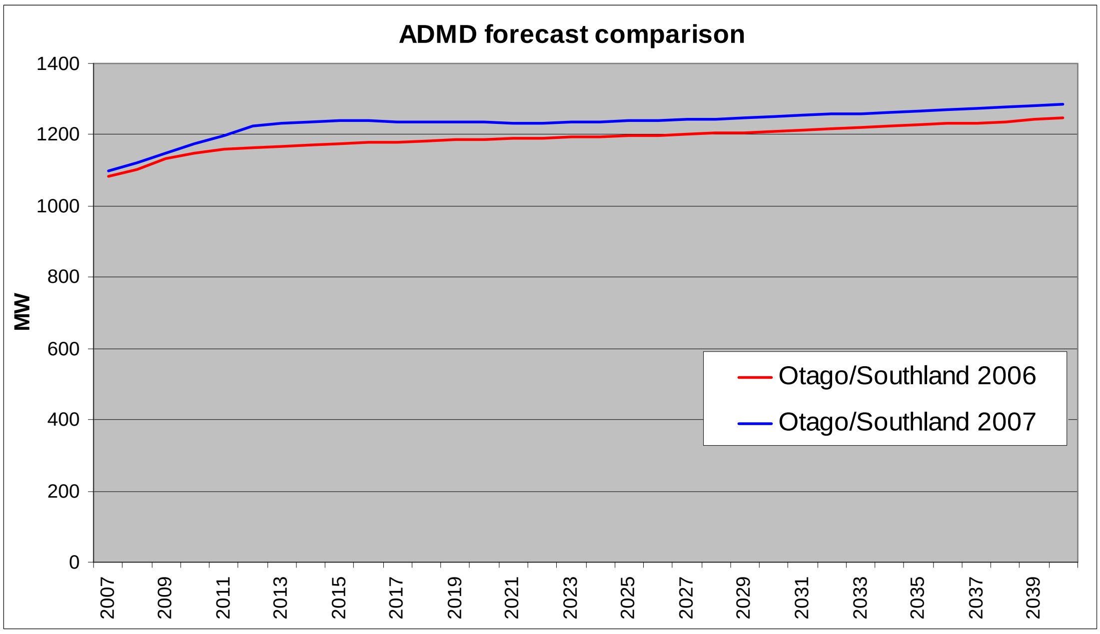


South Canterbury

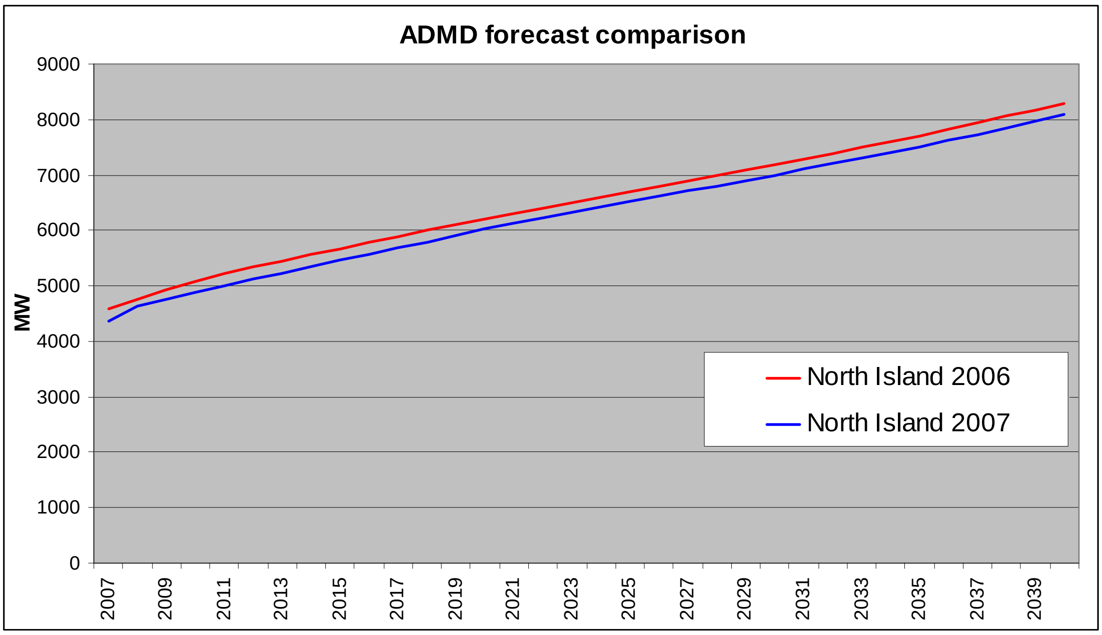


Note : the reduction in South Canterbury's region peak arises from a mix of slightly lower individual peak forecasts and changes in island diversity combined with a slightly lower prudent peak forecast.

Otago/Southland



North Island



South Island