MINISTRY OF BUSINESS, INNOVATION & EMPLOYMENT
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Energy Modelling Technical Guide

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New Zealand Government

Energy Modelling at MBIE

A core role of Energy and Building Trends is to project future energy supply and demand. The team uses econometric, financial and optimisation models to consider different future scenarios and sensitivities for the energy sector.

A key aspect of our work is the collation of robust assumptions about the future. Through observing historical relationships and extrapolating these into the future we can project future energy supply and demand. The most important assumptions are historical energy supply and demand figures. These are collected internally within the team and are published by the Ministry as New Zealand official energy statistics.

The Ministry's Energy Modelling capability has a long term focus, so we carefully note that we are not attempting to predict (or forecast) the future through these models, but rather "project" what might happen under the set of chosen assumptions if historical observed relationships continue to hold.

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1 Overview

The Ministry’s modelling system relies on a set of relationships based on observed past behaviour, engineering estimates, costs of technologies and the behaviours of market participants. Models are useful to help frame expectations of the future, but they do however have limitations. In particular:

- The future is uncertain and modelling cannot take into account the subtleties of commercial decision-making or barriers to investment.
- The models are based on what we have observed in the past. However, the relationship between energy demand and its key drivers may change in the future, particularly if there are unexpected changes in technology or external shocks.
- This modelling is of the energy sector only, not of the entire economy. The key drivers within this modelling are exogenous (for example GDP and oil price) meaning that secondary effects are not modelled, e.g. the potential link between the price of oil and GDP is not taken into account.

The Ministry’s current approach to energy modelling uses these distinct (but interrelated) models:

- the Ministry’s Supply and Demand Energy Model (SADEM);
- the Electricity Authority’s Generation Expansion Model (GEM);
- the Ministry’s Project Rank Model (PRM) for quantitative exemplar sampling;
- the Ministry’s electricity price indicator model;
- the Ministry’s oil and gas simulation model; and
- the Ministry of Transport (MOT) Vehicle Fleet Model (VFM);

These models are used to project future of energy supply and demand and energy sector greenhouse gas emissions.

Within this approach SADEM performs three key functions. Firstly, it projects energy demand for all sectors of the economy (with the exclusion of land transport) using econometric relationships with exogenous drivers (such as GDP and population) and relative price levels. Secondly, it provides a central hub, coordinating electricity supply information from GEM and land transport demand information from the VFM. Finally, SADEM calculates projections of energy sector greenhouse gas emissions by applying emission factors

The projections of on road transport energy demand from the VFM are ‘bottom-up’ forecasts. This ‘bottom-up’ modelling produces detailed fleet projections based on historical relationships of the fleet (turn-over, kilometres travelled, efficiency improvements, engine size and fuel switching) to economic growth, population change and fuel prices, and forecasts of these key exogenous variables. With the exception of using the same exogenous variables there is no real interactive feedback link between SADEM and the VFM meaning that the VFM essentially provides ‘plug and play’ projections of land transport demand to SADEM.

The Electricity Authority’s GEM optimisation model is the main model used to project the timing and type of new generation plant built. It also determines the operation of most existing plant and retirement years for existing thermal plant. However it only considers large scale generation (mostly transmission grid connected). Some demand is met by generation supply (using a simple growth assumption modelling approach) from directly within SADEM (mostly distributed generation). Solar PV is now modelled as an exogenous assumption into GEM. GEM requires fuel prices and adjusted electricity demand projections from SADEM as inputs.

The new build schedule produced by GEM is also used to calculate the wholesale electricity price indicator in a separate model. Future prices are calculated to cover the Long Run Marginal Cost (LRMC) of the newly installed plant.

The Project Rank Model (PRM) is used to help pre-process the GEM inputs to set earliest commissioning years for individual plants in GEM. This technique of GEM pre-processing is known as exemplar sampling.

There are two oil and gas models:

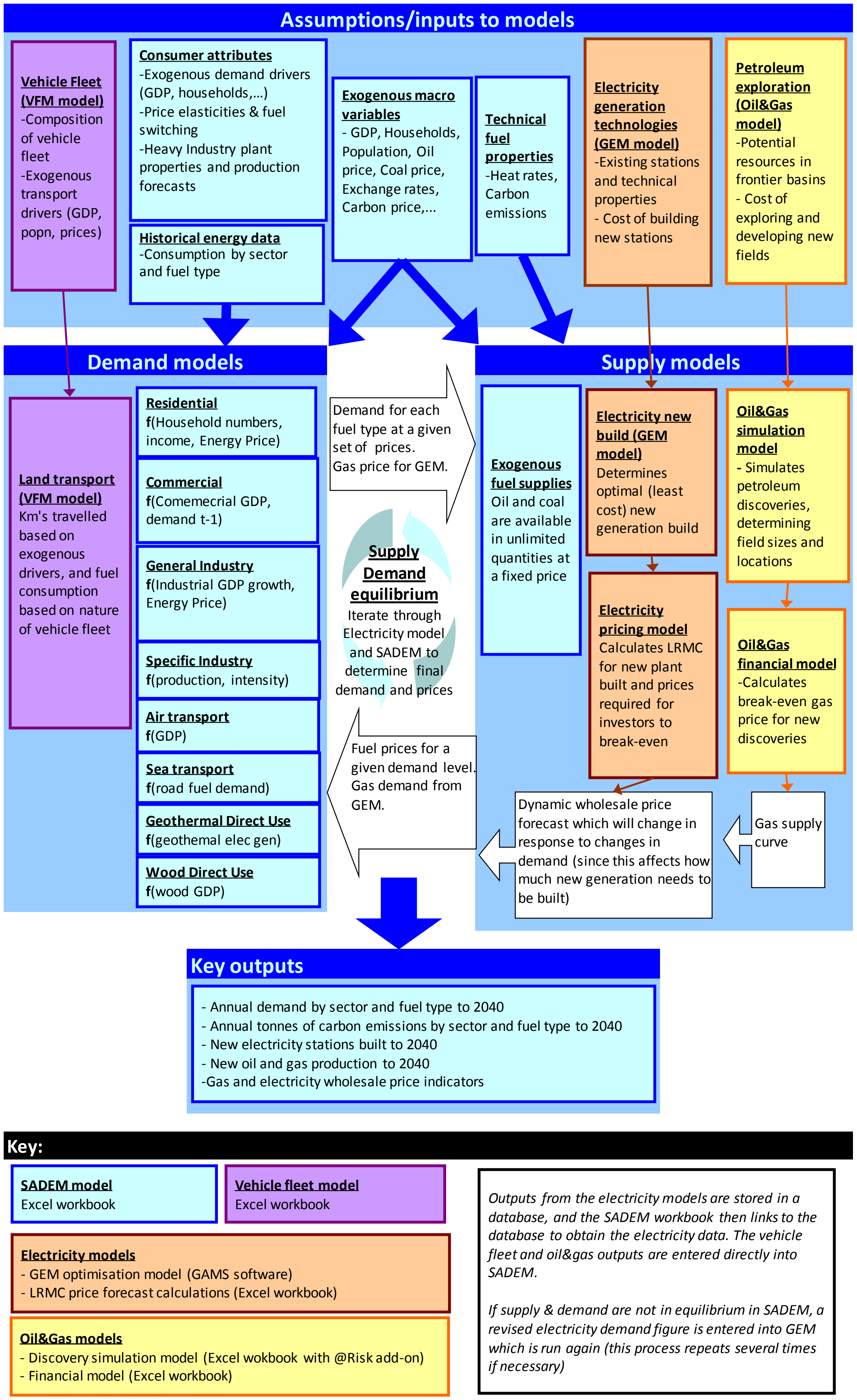
- a simulation model of future exploration activity which produces a probability distribution of future oil and gas discoveries, and a
- a financial model which determines whether these discoveries meet commercial thresholds.

The financial model is used to produce a gas supply curve based on the 'break-even[1]' gas price for each discovery. The gas supply curve feeds through to SADEM and the equilibrium gas price is determined where total demand intersects the supply curve.

The Ministry models peak electricity demand (MW) in house using Transpower's peak demand ensemble model. The Ministry commissioned a review by NZIER of Transpower's peak demand forecasting model. After amendment by Transpower the forecast model was judged fit-for-purpose in 2016.

The following diagram outlines the key interactions in the Ministry's energy modelling system. It is only intended to provide a high level picture of the system. In reality there are many more complex linkages within the system and the following technical document provides more detail around each of the sub-models and the linkages between them.

[1] Breakeven gas price is the price at which the Net Present Value (NPV) of the project equals zero.


Assumptions/inputs to models
Vehicle Fleet (VFM model)
-Composition of vehicle fleet
-Exogenous transport drivers (GDP, popn, prices)
Consumer attributes
-Exogenous demand drivers (GDP, households,...)
-Price elasticities & fuel switching
-Heavy Industry plant properties and production forecasts
Historical energy data
-Consumption by sector and fuel type
Exogenous macro variables
- GDP, Households, Population, Oil price, Coal price, Exchange rates, Carbon price,...
Technical fuel properties
-Heat rates, Carbon emissions
Electricity generation technologies (GEM model)
-Existing stations and technical properties
- Cost of building new stations
Petroleum exploration (Oil&Gas model)
-Potential resources in frontier basins
- Cost of exploring and developing new fields
Demand models
Land transport (VFM model)
Km's travelled based on exogenous drivers, and fuel consumption based on nature of vehicle fleet
Residential
f(Household numbers, income, Energy Price)
Commercial
f(Comemercial GDP, demand t-1)
General Industry
f(Industrial GDP growth, Energy Price)
Specific Industry
f(production, intensity)
Air transport
f(GDP)
Sea transport
f(road fuel demand)
Geothermal Direct Use
f(geothermal elec gen)
Wood Direct Use
f(wood GDP)
Demand for each fuel type at a given set of prices.
Gas price for GEM.
Supply Demand equilibrium
Iterate through Electricity model and SADEM to determine final demand and prices
Fuel prices for a given demand level.
Gas demand from GEM.
Supply models
Exogenous fuel supplies
Oil and coal are available in unlimited quantities at a fixed price
Electricity new build (GEM model)
Determines optimal (least cost) new generation build
Electricity pricing model
Calculates LRMC for new plant built and prices required for investors to break-even
Oil&Gas simulation model
- Simulates petroleum discoveries, determining field sizes and locations
Oil&Gas financial model
-Calculates break-even gas price for new discoveries
Dynamic wholesale price forecast which will change in response to changes in demand (since this affects how much new generation needs to be built)
Gas supply curve
Key outputs
- Annual demand by sector and fuel type to 2040
- Annual tonnes of carbon emissions by sector and fuel type to 2040
- New electricity stations built to 2040
- New oil and gas production to 2040
-Gas and electricity wholesale price indicators
Key:
SADEM model
Excel workbook
Vehicle fleet model
Excel workbook
Electricity models
- GEM optimisation model (GAMS software)
- LRMC price forecast calculations (Excel workbook)
Oil&Gas models
- Discovery simulation model (Excel wokbook with @Risk add-on)
- Financial model (Excel workbook)
Outputs from the electricity models are stored in a database, and the SADEM workbook then links to the database to obtain the electricity data. The vehicle fleet and oil&gas outputs are entered directly into SADEM.
If supply & demand are not in equilibrium in SADEM, a revised electricity demand figure is entered into GEM which is run again (this process repeats several times if necessary)

2 Key Modelling Assumptions

Within the energy sector modelling there are several key drivers and assumption sets which are discussed in the following section. All projections start with historic energy demand and supply data. Future energy demand and supply is modelled using this data, other exogenous inputs such as gross domestic product, and energy prices.

It is important to note that the modelling (including scenario development) does not include any macro-feedback loops (i.e. the effects of higher or lower energy consumption on GDP).

2.1 Historical demand and activity data

The energy demand models use historical energy data (for electricity and other fuels), as is published in the Ministry's regular energy data releases. To the extent possible, all projections are produced on the same basis as the historical data. That is, definitions of sectors and energy types are aligned across the historical and projection data. This is often challenging given the various international standards for reporting for energy statistics and greenhouse gas emissions.

One notable difference in definitions between the Energy in New Zealand and MBIE energy projections is with industrial and primary sector demand. For projections, the 'Industrial' and 'Agriculture Forestry and Fishing' sectors are summed into a larger aggregate 'Industrial' sector. These sectors have been combined to improve the accuracy of the total projection.

Revisions to historical energy data are made on an on-going basis as data quality improves. These changes impact on modelling results and explain some of the differences between results in older energy modelling publications.

It is important to note that the Ministry's published energy demand statistics are for consumer energy demand. That is the demand for energy at the point of sale or final consumption. For electricity (and other fuels), transmission and distribution losses are additional energy consumption.

2.2 Gross Domestic Product

Economic growth drives energy demand in the commercial and industrial sectors and impacts on residential demand as the population becomes wealthier. The high and low GDP scenarios used in the EDGS have been generated using the Treasury Fiscal Strategy Model (FSM).

The FSM projects future GDP primarily based on growth in the labour force and labour productivity growth. As a base case the FSM uses the 50th percentile Statistics New Zealand labour force projections which align with the 50th percentile population and household number used by MBIE in the EDGS central growth case. Statistics New Zealand P10 and P90 projections of the labour force were inputted into the FSM to increase and decrease GDP growth.

To give a wider range of GDP growth labour productivity growth was also varied. As a default, Treasury uses 1.5% per annum for future labour productivity growth in their long term projections. This is a highly uncertain assumption especially in the long run and so we have used the Treasury's high and low sensitivities of 2% and 1% per annum labour productivity growth from the Treasury report: Long-term Fiscal Projections: Reassessing Assumptions, Testing New Perspectives, combined with the Statistics New Zealand's 90th and 10th percentile labour force projections, respectively.[2]

Historic GDP data in the model is constant price (inflation adjusted or real) GDP in 1995/96 prices as published by Statistics New Zealand.

[2] Refer to the Treasury report: *Long-term Fiscal Projections: Reassessing Assumptions, Testing New Perspectives* (August 2012), available at http://www.treasury.govt.nz/government/longterm/externalpanel/pdfs/ltfep-s1-02.pdf.

GDP projections are broken down into commercial and industrial GDP projections using NZIER Quarterly Predictions to allocate GDP between those sectors. Specific sectoral projections are used to project general industrial (in the General Industry model) and commercial sector energy demands.

2.3 Exchange rates

Exchange rates are needed for converting price assumptions into New Zealand Dollars when they are sourced in a foreign currency. In SADEM, the US to NZ exchange rate is used in the calculation of liquid fuel prices (in New Zealand dollars) from projections of international crude oil prices in US dollars. In GEM, new generation investment capital costs are converted from their source currency to New Zealand dollars.

2.4 Emissions price

In the demand models the emissions price is added to the cost of each fuel. It increases the overall average effective energy cost (regardless of fuel type) which supresses overall energy demand and also drives fuel switching to lower emission fuels. In GEM, it affects the economics of new and existing fossil fuelled electricity generation, impacting on the electricity supply and price.

2.5 Population and household numbers

Population and household number projections are sourced from Statistics NZ. Household numbers are used to help project residential demand while population projections are used in the Transport demand modelling.

2.6 Crude oil price

Crude oil price projections are based on the Internationally Energy Agency's World Energy Outlook 2015 (WEO 2015). The WEO 2015 has a number of scenarios with different oil price projections. For the specific series use please consult the Electricity Demand and Generation Scenarios summary report.

2.7 Consumer energy prices

For the demand models, consumer energy prices are typically formed by taking a wholesale price for each individual fuel, and adding other costs, taxes and margins based on historical information for the three consumer types (residential, commercial and general industrial).

Wholesale prices are either exogenous inputs to the modelling system (e.g. the crude oil price), dynamic within the SADEM model (e.g. the gas price is dependent on gas demand), or an output of the iterative loop between SADEM and GEM (e.g. the wholesale electricity price). Electricity and gas wholesale prices are discussed later.

It is important to note that the following price calculation methodologies are not designed to give authoritative indications of future retail or consumer energy prices. These prices assumptions are simply a necessity that enables that ministry to consider the relative impacts of fuel switching. In this context, the absolute levels and accuracy of these assumptions is less important than the relevant movements in prices over time that they produce. In all three of the demand models, price is an important driver of changes in demand; however there are other factors which are overwhelmingly more significant, such as economic and household growth.

2.7.1 Consumer Electricity Prices

A consumer price is built up by taking the following approach (note that the carbon price is implicit within the wholesale electricity price):

Consumer Electricity Price = Lines Cost + Wholesale Cost + Retail Cost + Profit Margin + GST (if applicable)

Wholesale cost is a direct output of the GEM/SADEM iteration process. Lines costs are a fixed input assumption based on the Ministry's electricity price data for the most recent data year. The retail cost assumption is built up from assuming: a cost to serve, metering costs, and a profile effect.

*Retail Cost = Cost to serve + meter costs + profile effect *(wholesale price)*

The profit margin is calculated as a percentage of the total pre-GST consumer price. The calculation is as follows:

Profit margin = (lines cost + cost to serve + meter costs + profile effect cost + wholesale price)/(1/ Profit margin factor-1).

The retail electricity price assumptions and projections are not published due to uncertainties around the cost components. They are used for internal modelling purposes only.

2.7.2 Consumer Gas Prices

As with consumer electricity prices, consumer gas prices are built up from wholesale prices. Gas prices are treated in a simpler fashion than electricity prices, with fewer breakdowns of the price components. The following approach is used (in $/GJ – net CV or lower heating value):

Consumer Gas Price = Wholesale Cost + Carbon Cost + Constant

The carbon cost is simply an additional cost in $/GJ which adds around $0.06/GJ for every $1/tonne charge on Carbon Dioxide (equivalent) – So a $17/tonne CO2 charge adds around $1/GJ to the consumer cost of gas.

The constant is simply based on the historic difference between the pre carbon consumer gas prices and the wholesale price.

The consumer gas price assumptions and projections are not published due to uncertainties around the cost components. They are used for internal modelling purposes only.

2.7.3 LPG Prices

Consumer LPG prices are calculated using a similar approach to that taken for consumer natural gas prices (in $/GJ – net CV or lower heating value):

Consumer LPG Price = Wholesale Cost + Carbon Cost + Constant

For LPG wholesale prices are based off a simple oil price regression, where:

$$\text{Wholesale Cost (USD/netGJ)} = \big(\text{Oil Price (USD/bbl)}\big)\text{b}_0, \text{ where } \text{b}_0 = 0.19$$

The margin applied to calculate retail prices is based off the historical relationship between wholesale and retail prices.

LPG has a marginally higher carbon cost per GJ than natural gas so a $16/tonne CO2 charge adds around $1/GJ to the consumer cost of LPG.

Like for natural gas the constant is simply based on the historical relationship between wholesale and retail prices

Historical commercial retail prices were sourced from an LPG price index provided by Statistics NZ, while a residential price indicator was supplied from the MED's annual LPG survey. As no price information is available for general industry prices are assumed equal to the commercial estimate.

The consumer LPG price assumptions and projections are not published due to uncertainties around the cost components. They are used for internal modelling purposes only.

2.7.4 Consumer coal prices

The Ministry commissioned Covec to provide an updated set of coal price projections for use as assumptions in modelling (updated January 2014). This includes a series for General Industry, existing coal generation (at Huntly), and new sub-bituminous coal or lignite generation. Covec's price projections exclude the cost of carbon. For each of the coal price projections a final consumer price is calculated as follows:

Consumer coal price = Covec Cost + Carbon Cost

Coal has a relatively high carbon concentration so only requires a \$10.40 per tonne CO_2 charge to add \$1/GJ (net CV/LHV) to the consumer cost of coal.

2.7.5 Retail petrol and diesel prices

These prices are built up from the US\$/bbl oil price to include direct taxes and levies, wharfage costs, freight costs (including an uplift component in the face of higher fuel prices), insurance and a quality premium (see below for descriptions).

The following formulae are used to calculate retail prices for petrol or diesel:

$$\text{Price}_{(t)}\ (\text{c/l}) = (\text{Spot}_{US,t} * \text{MOPS} + \text{QP} + \text{Freight}_{(t)}) * (1 + \text{IL})/\text{Exchange}_{(t)} / 1.5897 + (\text{IM} + \text{T\&L} + \text{W}),$$

$$\text{Freight}_{(t)} = \text{Freight}_{(base)} * (1 + (\text{Spot}_{US,t} - \text{Spot}_{US,base})) * \text{FA}$$

***Table 1 - Components of retail fuel prices*[3]**

Variable	Petrol	Diesel	Description	Units
Importers Margin (IM)	25.53	31.34	The amount available to cover domestic transportation, distribution, retailing costs and profit margins - based on the annual average from MED's weekly petrol and diesel importers margins monitoring	c/l
Taxes and Levies (T&L)	67.28	0.53	Summarised in table 2 below	c/l
Wharfage (W)	0.45	0.45	Covers the cost of landing the fuel	c/l
Freight(base)	5.14	5.80	Cost of international transportation of crude oil	USD/bbl
Quality Premium (QP)	3.12	0.56	Premium added to the pricing benchmark to reflect the higher quality of New Zealand specification petrol relative to the Singapore benchmark price	USD/bbl
Crude WTI to MOPS [4]	1.13	1.19	Scalar applied to the West Texas Intermediates price (from the NYMEX) to convert to the Mean of Platts Singapore price	USD/bbl
Insurance Loss (IL)	0.32%	0.32%	Scalar for the cost of insurance and losses during shipping	%
Freight Adjustment (FA)	15.0%	15.0%	Scales the international freight fuel cost for increasing/decreasing oil prices. This is set at 15% reflecting the amount tied to the underlying fuel costs	%
$Freight_{(t)}$	*	*	Freight price to New Zealand ports	USD/bbl
$Spot_{US,t}$	*	*	Spot price for Crude Oil West Texas Intermediate at time t	USD/bbl
$Spot_{US,base}$			Spot price for Crude Oil, West Texas Intermediate in the first year of modelling	USD/bbl

** Values in table with asterisk vary by year.*

Taxes and levies are made up of the following categories, information for which is updated annually from the current Energy in New Zealand:

Table 2 - Summary of Petrol and Diesel Taxes

Taxes	Petrol	Diesel
National Land Transport Fund (NLTMF)	59.52[5]	
Local Authority Petroleum Tax (LAPT)	0.66	0.33
Petroleum or Energy Fuel Monitoring Levy (PFML)	0.2	0.2
Accident Compensation Corporation Levy (ACC)	6.90	
Total	**67.28**	**0.53**

2.7.6 Wholesale diesel and fuel oil prices

The wholesale diesel price is calculated by deducting a mark-up figure from the retail price calculated above. This mark-up is set at 4.5 c/l; the long-term annual average retail margin.

[3] All prices in real 2014 terms

[4] Based on regression of WTI and MOPS Jan 2009 – 2014 data. MOPS is the acronym for Mean of Platts Singapore

The wholesale fuel oil price is calculated based on a scalar applied to the spot crude oil price and converted from US$/bbl to NZ$/GJ. The current scalar is set at 120% based on comparing historical fuel oil prices to crude oil prices.

2.8 Wind cost update

The wind capital costs, along with all other plant costs, are available in the generation cost assumptions file released with the latest modelling publication.

Since the 2011 PB generation cost update, there have been some movements in the cost of wind generation.[6] A key source for wind cost information is Bloomberg New Energy Finance (BNEF).[7] The BNEF's *Sustainable Energy in America Factbook 2014* (February 2014)[8] shows that the capex wind turbine price index has moved considerably lower since 2011.[9] The figure for the first half of 2011 was 1.39 USD/W while the figure for the first half of 2014 was $1.04 USD/W. This is a fall of 25% in capex costs. BNEF stated in February 2013[10] that research in Australia shows that since 2011, the cost of wind generation has fallen by 10%.

The Ministry has revised down the wind costs from the *2011 NZ Generation Data Update.* In addition, the long run NZD/EUR exchange rate used was 0.64 and wind turbine costs are denominated in EUR. For the *Global Low Carbon* scenario wind costs have been further reduced by 10% from the *Mixed Renewables* scenario.

3 Consumer Energy Demand models

3.1 Introduction to Consumer Energy Demand modelling

Consumer energy demand, is energy used by final consumers. It excludes energy used for transformation (e.g. electricity generation) and that used for non-energy purposes.

Examples of consumer energy include:

- burning coal or gas for heat,
- burning of petrol in an internal combustion engine to drive a car
- using solar thermal energy directly to heat water
- using geothermal steam directly to heat water for a prawn farm
- all demand for electricity.

It is important to note that, in the case of electricity demand, it is not the fuel input that went into making the electricity that we are interested in, when we are projecting future consumer energy demand. The following are examples of energy use that is not consumer energy demand:

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[6] The wind costs in the PB generation cost update are set out in http://www.med.govt.nz/sectors-industries/energy/energy-modelling/technical-papers/2011-nz-generation-data-update

[7] Refer to http://about.newenergyfinance.com/about/.

[8] Refer to http://about.bnef.com/white-papers/sustainable-energy-in-america-2014-factbook/.

[9] Refer to figure 49 of that document on page 38. The relevant figures to apply in the New Zealand context are those for the "old models" of wind turbine. The more expensive new models are designed for lower wind conditions than those prevalent in New Zealand.

[10] Refer to the media release titled *Renewable energy now cheaper than new fossil fuels in Australia* (7 February 2013) available athttp://about.newenergyfinance.com/about/press-releases/renewable-energy-now-cheaper-than-new-fossil-fuels-in-australia/.

- Any burning of fossil fuels to make electricity
- Solar photovoltaic generation and other renewable electricity generation.

SADEM builds up total energy supply by summing consumer energy demand with energy demand for transformation (e.g. electricity generation) and that used for non-energy purposes. See section 4.

Consumer energy demand is modelled using a range of techniques. This includes econometrics, simple growth and naïve (i.e. no change) projections, all of which rely on making good input assumptions. The following is a list of the different components of energy demand which we model independently from each other and aggregate up to get total energy demand:

1. Residential
2. Commercial
3. General Industry
4. Specific Industry
5. Road transport
6. Rail transport
7. Air transport
8. Sea transport

Note that 'Industrial' demand is spilt into two categories; 'general industry' and 'specific industry'. This is because some industrial demand (a few large scale energy users) are projected forward based on assumptions about their future production, rather than using general econometric techniques.

The following is a list of the demand modelling techniques used:

1. **Two stage** - Two stage econometric models
2. **Production** - Production based models for Specific Industry
3. **VFM** – relies on the Vehicle Fleet Model
4. **Other –** has its own model (which may be dependent on another model)
5. **Simple** - Simple growth rates or set to no change
6. **Flat household** – growth rate is equal to the projected growth in households

Note that not all fuel types are included in every model due to data limitations.

The following table shows for each of the energy demand categories, which technique is used for each fuel type:

Table 3 – Modelling technique applied to energy demand category

	Residential	Commercial	General Industry	Specific Industry	Road Transport	Rail Transport	Air Transport	Sea Transport
Electricity	Other	Two stage	Two stage	Production	VFM	Other	N/A	N/A
Gas	Flat household	Two stage	Two stage	Production	Naïve	N/A	N/A	N/A
LPG	Flat household	Two stage	Two stage	N/A	Naïve	N/A	N/A	N/A
Diesel*	Flat household	Two stage	Two stage	N/A	VFM	Other	N/A	Other
Coal	Simple	Simple	Two stage	Production	Simple	N/A	N/A	N/A
Fuel Oil	N/A	Simple	Two stage	Production	N/A	N/A	N/A	Other
Petrol*	Flat household	Simple	Simple	N/A	Simple	N/A	N/A	N/A
Solar	Simple	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Biogas	N/A	Simple	N/A	N/A	N/A	N/A	N/A	N/A
Geothermal	Other	Other	Other	N/A	N/A	N/A	N/A	N/A
Wood	Other	Other	Other	N/A	N/A	N/A	N/A	N/A
Aviation Fuels	N/A	N/A	N/A	N/A	N/A	N/A	Other	N/A

In the following section we explain the demand models for each sector. The VFM is discussed in more detail in section 8.1.1 below.

3.2 The Two Stage models for Commercial and General Industrial Demand

Early in 2011 MED undertook a review of its demand models. The following documents, which are available on the MED website, outline the review process and results:

- Review of MED's demand forecasting methodology
- SADEM model review (by NZIER)

Several changes were recommended and implemented in 2011. Note that of the parameter values in the review document will differ to those quoted in this technical document since new energy and price data has been received since the review, and the projections will also be different due to more recent GDP projections being used.

The following sections describe the new projection method which can be considered in a in a two-stage process:

1. Project the total effective energy demand for each sector;
2. Project the demand for individual fuels in each sector by calculating their market share of the effective energy demand.

For the Industrial sector, demand has been spilt, and is projected using two different techniques. This section outlines the methodology used in the General Industry model, which excludes energy use by a small number of very large industrial energy users. See section 3.3 for details on the Specific Industry Model.

Stage one projection of effective energy

The first step is to project 'effective' energy demand which is the net petajoules (PJ) of energy consumed (net PJ of fuel consumed takes into consideration the 'efficiency' of each fuel). The effective demand forecast is based on econometric relationships with exogenous drivers. The demand review identified the 'best-fit' models for each sector, which resulted in a slightly different approach for each.

Commercial effective energy demand:

The commercial sector covers trade, hospitality, communications services, business/financial services, and public services.

The demand review recommended that commercial energy forecasts should be based on a weighted average forecast from two alternative models:

(C1) Log Commercial Demand = $\beta_{1,C1}$*(log Commercial sector GDP) +

$\beta_{2,C1}$*(log Demand t-1) + Constant

Where $\beta_{1,C1}$= 0.3816

$\beta_{2,C1}$= 0.5568

Constant = -2.7415

Log = natural logarithm

Total effective energy demand for C1 is then equal to exponential (Log Commercial Demand).

(C2) Annual Commercial Demand % growth = $\beta_{1,C2}$*(annual % growth in Commercial sector GDP)

Where $\beta_{1,C2}$= 0.71

Total effective energy demand for C2 (for time period t) is then equal to (Annual Commercial Demand % growth)$_t$ * (Commercial Demand)$_{t-1}$.

A 50/50 weighting was applied to C1 and C2. C1 includes an autoregressive parameter to help address autocorrelation in the model, otherwise both models have the same explanatory variable (Commercial sector GDP). The models have different transformations of the raw data, and although both models are statistically robust (with statistically significant diagnostic statistics) they both provide different forecast trajectories, hence the reason for including both models.

The commercial sector was the only sector where price was not a significant explanatory variable. The energy intensity of the Commercial sector is considerably less than the Industrial sector. In 2010 Commercial energy costs (excluding transport) were estimated at around $18 for every $1000 of GDP (1.8%) while General Industrial sector costs were $72 (7.2%).

General Industrial effective energy demand:

The industrial sector includes agriculture, forestry, fishing, mining, manufacturing, and construction, but excludes a small number of large specific industrial energy users which are discussed in section 2.5.

The demand review recommended the following model which has been used :

(I1) Annual Industrial Demand % growth = $\beta_{1,I}$*(annual % growth in Industrial sector GDP) + $\beta_{2,I}$*(annual % growth in Industrial sector Aggregate Price)

Where $\beta_{1,I}= 0.63$

$\beta_{2,I}= -0.07$

Total effective energy demand (for time period t) is then equal to (Annual Industrial Demand % growth)$_t$ * (Industrial Demand)$_{t-1}$.

3.2.1 Stage two forecasts for individual fuels

In stage two we calculate how the effective energy demand forecast from stage one is broken down into demand for the alternative fuels. This is where we introduce the prices for each fuel type and allow for switching between fuels based on relative fuel prices.

The following equations show how the final fuel forecasts are produced for the Residential model. The Commercial and General Industry approach is the same.

Equations 1a to 1c describe the price ratio calculations.

(1a) $\text{Price\%}\Delta\text{\_Elec\_Gas}_t = (\text{Price\_Gas}_t/\text{Price\_Elec}_t) / (\text{Price\_Gas}_{t-1}/\text{Price\_Elec}_{t-1}) - 1$

(1b) $\text{Price\%}\Delta\text{\_Elec\_LPG}_t = (\text{Price\_LPG}_t/\text{Price\_Elec}_t) / (\text{Price\_LPG}_{t-1}/\text{Price\_Elec}_{t-1}) - 1$

(1c) $\text{Price\%}\Delta\text{\_Gas\_LPG}_t = (\text{Price\_LPG}_t/\text{Price\_Gas}_t) / (\text{Price\_LPG}_{t-1}/\text{Price\_Gas}_{t-1}) - 1$

Equations 2a-2c describe the fuel switching calculations.

(2a) $\text{Demand}\Delta\text{\_Elec}_t = \text{Demand\_Elec}_{t-1} * \text{Price\%}\Delta\text{\_Elec\_Gas}_t * \beta_{E,G} + \text{Demand\_Elec}_{t-1} * \text{Price\%}\Delta\text{\_Elec\_LPG}_t * \beta_{E,L}$

(2b) $\text{Demand}\Delta\text{\_Gas}_t = \text{Demand\_Gas}_{t-1} * \text{Price\%}\Delta\text{\_Gas\_LPG}_t * \beta_{G,L} - (\text{Demand\_Elec}_{t-1} * \text{Price\%}\Delta\text{\_Elec\_Gas}_t * \beta_{E,G})$

(2c) $\text{Demand}\Delta\text{\_LPG}_t = -1 * (\text{Demand\_Elec}_{t-1} * \text{Price\%}\Delta\text{\_Elec\_LPG}_t * \beta_{E,L} + \text{Demand\_Gas}_{t-1} * \text{Price\%}\Delta\text{\_Gas\_LPG}_t * \beta_{G,L})$

Where $\beta_{E,G}$ is the elasticity parameter for substitution between electricity and gas demand (0.01), $\beta_{E,L}$ is the electricity vs LPG elasticity parameter (0.00) and $\beta_{G,L}$ is the gas vs LPG elasticity parameter (0.04). Note that the sum across 2a-2c will always be zero.

The final forecast for residential electricity, gas and LPG is then:

(3a) $Demand\_Elec_t = S1\_Energy\_Forecast_t * Mkt\_share_{E,t-1} + Demand\Delta\_Elec_t$

(3b) $Demand\_Gas_t = S1\_Energy\_Forecast_t * Mkt\_share_{G,t-1} + Demand\Delta\_Gas_t$

(3c) $Demand\_LPG_t = S1\_Energy\_Forecast_t * Mkt\_share_{L,t-1} + Demand\Delta\_LPG_t$

Where $S1\_Energy\_Forecast_t$ is the stage one econometric forecast for effective energy.

3.2.2 Estimating the cross elasticity parameters in the Stage two forecasts

The elasticity values (the β's in equations 2a-2c) have been estimated using a 'least squared error' approach. An initial forecast was produced with all elasticities set at 0. The model errors from this initial forecast were then minimised by adjusting the elasticity parameter values. This was done using a linear least squares optimisation in *Matlab*[11].

The least squares optimisation produced the following results.

Table 4 - Market share cross/price elasticities

Residential

	Elect	Gas	Coal	Diesel	LPG
Elect		0.01	-	-	-
Gas			-	-	0.04
Coal				-	-
Diesel					-
LPG					

Commercial

	Elect	Gas	Coal	Diesel	FuelOil	LPG
Elect		0.04	-	0.001	-	0.01
Gas			-	-	-	-
Coal				-	-	-
Diesel					-	-
FuelOil						-
LPG						

General Industry

	Elect	Gas	Coal	Diesel	FuelOil	LPG
Elect		-	0.09	-	-	-
Gas			0.12	-	-	-
Coal				-	0.11	0.13
Diesel					-	-
FuelOil						-
LPG						

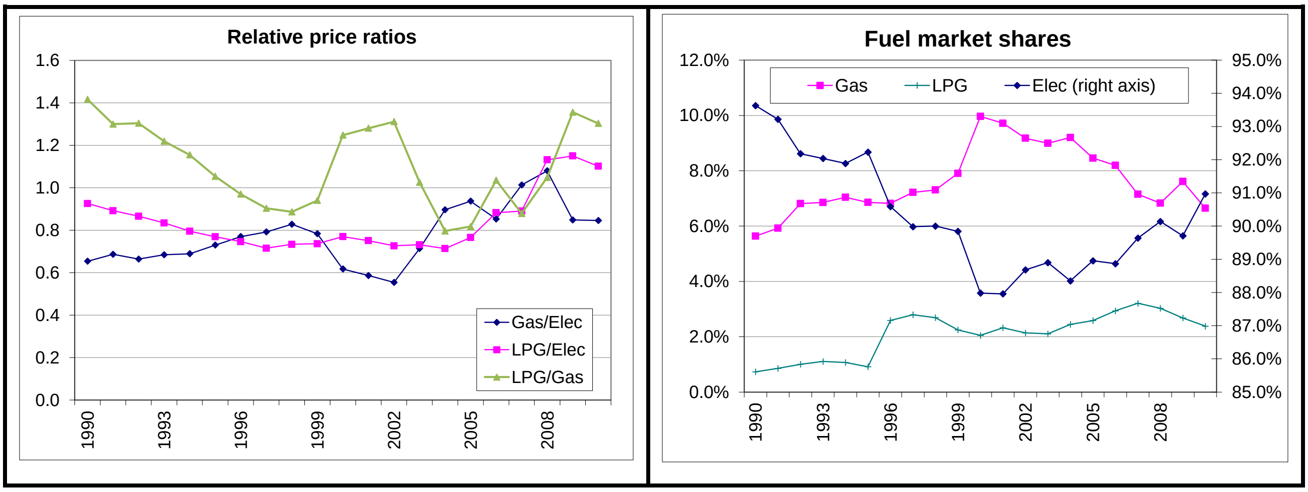
[11] An additional non-linear optimisation was also performed in Excel with additional constraints. This tended to give similar results in terms of the parameter estimates. The MATLAB approach was retained for simplicity.

A cross elasticity of 0 means that the fuels cannot be substituted. An elasticity value of 0.01 means that a 100% increase in the price of fuel B relative to fuel A results in a 1% increase in the demand for fuel A (and an equal decrease in fuel B demand in absolute terms)[12].

The optimised parameter values reflect patterns in the historical data. There is potential for these patterns to change over time and it is possible that historic trends do not reflect current elasticity. However the parameters estimated above do appear to reflect realistic fuel switching potential and so have been used.

The relationship between relative fuel prices and market shares can be illustrated in the following charts for the Residential sector. Between 2002 and 2008 the price of gas rose relative to the electricity price. This is consistent with an increase in the electricity market share over the same period, and a fall in the gas market share.

Figure 1 - Residential price ratios and market share trends



3.3 Residential demand forecasting

The residential sector covers households' use of energy but excludes motor-vehicle use (which is included under transport demand).

Electricity demand forecasts

Two models were used. R1 is used for all EDGS scenarios except the Global Low Carbon scenario. Residential electricity demand in the Tiwai Off and High Grid scenario differ because they have different household growth assumptions. R2 is used for the Global Low Carbon scenario.

(R1) $\quad LN(\text{electricity demand per household}_t) =$

$\beta_{1,R} * LN(\text{electricity demand per household}_{t-1}) + \beta_{2,R} * LN(\text{Affordability})$

$+ \beta_{3,R} * LN(\text{Heating Degree Days})$

Where $\quad \beta_{1,R} = 0.62$

$\beta_{2,R} = -0.09$

$\beta_{3,R} = 0.05$

[12] Note that the elasticities are defined with respect to the fuels on the vertical axis, so the 0.01 for residential elec/gas is the percent change in electricity demand from a 100% percentage change in the relative price between these fuels (price gas / price electricity). The resulting percent change in gas will be a negative sign, but will be a much higher percentage since electricity demand (PJ) is much higher than gas.

This model for residential demand has some theoretical appeal, reflecting a consumption function which is based on income, price. Affordability is represented by electricity costs divided by GDP per household. The lagged demand explanatory variable allows the model to capture recent unexplained downward trends in electricity demand per household. Heating degree days allows us to capture warmer temperatures effects on electricity demand.

(R2) electricity demand per household_t =electricity demand per household_{2014}

Total effective energy demand is then equal to (Demand per Household) * (number of households).

The team have explored many different types of models for forecasting residential electricity demand. Based on the range of models considered R1 performed the best under testing and R2 was a reasonable option for the Global Low Carbon scenario. Recent downward trends in electricity demand per household were difficult to explain with existing data. The team will continue to explore new data sources to better explain these recent trends.

3.4 Specific Industry Models

In New Zealand a relatively small number of industrial users consume a considerable proportion of total energy demand. As such, these large energy consumers are best modelled based on an assessment of expected production levels, rather than by applying generic econometric relationships with external variables such as GDP or population.

The specific industry sub-model covers[13] production of:

- Steel;
- Aluminium;
- Urea;
- Methanol; and
- Oil Products

Each large user is modelled individually within the specific industry sub model. Total energy demand for each of the categories is calculated as future production (FP) multiplied by the intensity factor (IF).

Future production from each of the specific large industrial consumers is based on known or expected future production levels and capacity upgrades (as of 2011). The intensity factor is energy consumption per unit of production. For each large user an IF has been established based on historical data. Known and proposed upgrades or energy efficiency improvements can be built in to the IF forecasts.

Total energy demand for each large user is allocated across each energy source based on the historical market share of the fuels.

As the specific industry model deals with commercially sensitive information on individual companies, the actual forecast parameters used in SADEM cannot be disclosed in this document. As a made-up example, consider a widget factory that produces 2.5 million tonnes of widgets per annum and uses 1.5PJ of gas, 1PJ of electricity and 0.5PJ of coal per annum to produce the widgets.

The widget factory uses 1.5+1+0.5 = 3 PJ of consumer energy per annum. If this widget factory was included in the specific industry sub model, its energy intensity factor (IF) would be calculated as 3/2.5 = 1.2PJ/tonne.

The specific industry sub-model would then require a forecast of future production by the widget factory. In this example, we might have been informed by the widget factory that they were expanding their plant and would increase production by 20% from current levels and in the future produce 3 million tonnes of widgets per annum.

Total energy demand would then be calculated by multiplying 1.2 PJ/tonne by 3 million tonne/annum to get 3.6PJ/annum. This 3.6 PJ is then shared out by the historic fuel shares. So for gas: 1.5/3 = 50%* 3.6 = 1.8 PJ/annum of gas. For electricity: 1/3 = 33.3%*3.6 = 1.2 PJ/annum of electricity. For coal: 0.5/3 = 16.7%*3.6 = 0.6 PJ/annum of coal.

3.4.1 Aluminium (NZAS);

For the EDGS publication, aluminium production at Tiwai Point is the most significant Specific Industry. Tiwai Point used over 13% of New Zealand's total electricity supply in 2013.

The base assumption sees the smelter continue operating at 572 MW for the entire projection period. We also consider when the plant closes and has zero demand from 2017

3.5 Transport Demand models

Transport demand includes road, rail, sea, and air transport. Walking, cycling and animal based transport modes are not included.

Oil is the dominant fuel source for transport purposes with around 98% of its energy demand being for oil products, predominantly petrol and diesel. Electricity is used for some rail and in 2011 for a small number of electric cars and trolley buses. Within the transport sector, around 90% of energy demand is for road transport with the remaining 10% split between rail, domestic marine and domestic aviation.

While transport accounts for the majority of oil product use, there are also a range of non-transport uses of these fuels. These include stationary applications, such as fuel burned in generators, fuel used for heating, gardening equipment etc; and mobile applications off-road. Transport energy does not include that used by motorised vehicles in off-road situations such as on farm or at construction sites; fuel known to be delivered for these purposes is recorded under the various economic sector titles. Pragmatically it is hard to differentiate the amount of fuel sold at service stations between its final end-uses (e.g. petrol taken home for lawn mowing) and thus all of such fuel and energy is allocated to transport.

The Ministry's energy statistics identify consumer energy by fuel and by end-use sector. Transport energy is recorded as the sum of fuel sold directly to transport sector participants and all fuel sold at retail service stations and truck stops. Sea transport energy is inferred as the sale of fuel oil to the transport sector and air transport energy is inferred as the total of jet fuel and aviation gasoline not used for international civil aviation.

3.5.1 Road

The projections of road transport energy demand from the VFM are 'bottom-up' forecasts. This 'bottom-up' modelling produces detailed fleet projections based on historical relationships of the fleet (turn-over, kilometres travelled, efficiency improvements, engine size and fuel switching) to economic growth, population change and fuel prices, and forecasts of these key exogenous variables.

VFM essentially provides 'plug and play' projections of road transport demand to SADEM. For more details refer to section 7, of this document.

3.5.2 Rail

Information on the energy use by New Zealand railways is derived from information provided by KiwiRail (and its predecessors). This data is utilised to calculate the greenhouse gas emissions from rail, published each year in the Ministry publication, New Zealand Energy Greenhouse Gas Emissions[14].

These emissions result from the combustion of diesel used to power diesel-electric locomotives. The amount of fuel used has been relatively flat since 1995 however our *Reference Scenario* projection allows for this demand to increase in line with the forecast growth in heavy commercial vehicle diesel demand from VFM, such that the ratio of energy demand for rail to diesel demand for heavy commercial vehicles remains constant:

i.e. $\quad \text{Energy}_{\text{rail}} \sim f$ (historical data, HCV diesel demand VFEM output)

Indeed, KiwiRail intends to expand its operation in the future but they are also purchasing new locomotives which may be expected to provide some energy efficiency improvement. The total energy demand of rail (just over 2PJ in 2010) contributes less than 1% of New Zealand's total transport energy demand.

3.5.3 Air Transport

The air transport model is based on a linear relationship of historical energy demand and economic activity (GDP), adjusted for fuel price changes using price elasticities. Put simply, demand in the current period is the previous demand multiplied by the long-term growth rate adjusted for any changes in the price of crude oil.

The complete calculations are as follows:

Equation 1: $\text{Energy Demand}_{(t)} = \text{Demand}_{(t-1)} * (\text{Base Growth}_{(t)} + \Delta\text{Oil Price} * \text{FPS} * \text{WAPE})$, where

Equation 2: $\text{Base Growth (\%)} = \text{Demand Growth}_{(1990-t-1)} * \text{GDP \%}_{(t)} / \text{Average GDP \%}_{(1990-t-1)}$

Equation 3: Weighted Average Price Elasticity (WAPE) = -1.52 * 60% + -.7 * 40%

WAPE = -1.19

3.5.4 Sea Transport

Domestic sea transport covers demand for fuel oil for coastal shipping and ferries. The vast majority of fuel oil demand for coastal (domestic) shipping in New Zealand is for the transfer of oil products around New Zealand. Forecast domestic fuel oil demand is therefore a function of oil product demand.

3.6 Geothermal Direct Use model

Direct use of geothermal energy in New Zealand is relatively small at present with it accounting for less than 11 PJ of New Zealand's total Consumer Energy demand of around 540 PJ.

The largest geothermal direct user in New Zealand is the Kawerau pulp and paper mill. It uses geothermal fluids to generate clean process steam for paper drying, a source of heat in evaporators, and timber drying. Kawerau accounts for over half of all the direct use energy demand in New Zealand.

Other users of geothermal energy direct-use in New Zealand include: residential users, commercial users (e.g. tourism), agricultural users (e.g. frost protection for crops), and other industrial users.

Historic geothermal direct use data from the Energy in New Zealand is organised into four sectoral groupings:

1. Residential
2. Commercial

[14] http://www.med.govt.nz/sectors-industries/energy/energy-modelling/publications/energy-greenhouse-gas-emissions

3. Industrial – Kawerau
4. Industrial – Non-Kawerau

Historic geothermal information in the Energy in New Zealand is based on information collated by the Geothermal Energy Association of New Zealand at a user/locality level.

In 2010, residential and commercial demand accounted for 0.3PJ, and 2.3PJ respectively. In the forecast, demand for these sectors is held at current levels for the entire forecast period. Kawerau is also assumed to continue at its current level of direct geothermal energy demand.

The remaining unallocated industrial (including primary sector) demand can be forecast in one of three ways in SADEM:

1. Linear growth – based on the historic annual growth rates
2. Directly linked to growth in geothermal electricity generation
3. Based on general industry forecast

Option 2 has been used. With more exploration and development of geothermal resources for electricity generation it is expected new resources for direct use will also be utilised at the same rate. This has been observed in recent years.

3.7 Wood demand model

Very limited historic information is available on the direct use of wood or biomass as an energy source. In the Energy in New Zealand, we estimate a historic time series of wood energy consumption by scaling (assuming a constant energy intensity over time) the results of the 2008 EECA heat plant database by the production of wood products (e.g. pulp and paper products or panel products) as reported in statistics released by the Ministry of Agriculture and Forestry.

The assumptions made to estimate the wood processing sector statistics are valid, as by far the largest industrial user of wood energy for heat is the wood processing sector and their demand is readily forecasted.

The forecast of industrial wood consumption is derived in a similar manner to the historic information. Rather than attempt to forecast future quantities of wood products, we use NZIER forecasts of GDP output by the Wood Processing sector.

In SADEM an ensemble model is used combining a Log-linear forecast and a Growth-linear forecast with equal weighting in the Reference Scenario.

The log-linear equation used:

$$\textit{Wood Energy Demand} = 2.042x - 12.20$$

Where ‘x’ is the GDP ($000) of the wood processing sector.

The growth-linear equation used:

$$\textit{Wood Energy Demand Growth} = 1.111z$$

Where ‘z’ is the GDP growth (%) of the wood processing sector.

3.8 Liquid Biofuels model

The liquid biofuels model has been developed based on the assumed economics of biofuels production. This approach sees increasing rates of local production and consumption triggered once biofuels become cost competitive with petrol and diesel. Both so-called ‘first generation’ and ‘second generation’ (that is, production techniques sourcing biomass from a range of sources including algae, woody residues and purpose-grown short rotation energy crops) are included in the model.

This model draws on analysis completed by Scion and data from the Ministry for Primary Industries. It is however, important to consider that methods for biofuels production are still being developed and therefore timing and levels of production are highly uncertain.

Forecast levels of ‘first generation’ biodiesel from tallow, canola and recycled waste oil) and bio-ethanol (from whey and imports) are calculated assuming a continuation of historical levels with an inclusion of known/expected expansion. This sees first generation biodiesel produce approximately 4 million litres by 2015 and approximately 8 million litres of bio-ethanol (one third of which is expected to be imported).

Wood was identified as the most likely feedstock for large scale biofuel production. Two second generation technologies that use a wood based feedstock were considered. Fischer Tropsch, a relatively well explored technology, which requires a large amount of feedstock. Secondly, catalytic pyrolysis, a more recent technology that requires less feedstock and so is less location tied. From a build-up of feedstock, labour, energy, capital, other costs and margin, provided by Scion, a breakeven price for each technology was estimated. This was $1.71 and $1.89 for Fischer Tropsch and Catalytic pyrolysis, respectively. The analysis assumed that Fischer Tropsch plants would be energy self-sufficient and catalytic pyrolysis plants would be nearly energy self-sufficient.

In the Reference Scenario it has been assumed that once biofuels become cost competitive one large-scale Fischer Tropsch plant producing 135 million litres per year is feasible in New Zealand. This was assumed after taking into suitable regional availability of feedstock. For catalytic pyrolysis five plants with a capacity to produce 60 million litres per year were assumed.

Quantities of imported biofuels are also included within the modelling based on the historical rate of uptake.

4 Modelling Solar PV and Battery systems

MBIE has vastly improved the way we model the uptake of Solar PV systems since the Draft EDGS 2015. We now consider an economic decision by the consumer between a Solar PV system with batteries and that without batteries to the variable component of the price in each network regions. Much of our work has been informed by discussions with experts from the Green Grid.[15]

We used NIWA hourly Global Irradiance data for towns in New Zealand and combined this with a household electricity demand profile, electricity prices in each network region, buy back rates, and Solar PV system costs and battery costs, to determine where Solar PV was economic around New Zealand.

Solar Irradiance data • NIWA hourly Global Irradiance data for 28 towns around New Zealand for the year 2014	**Household electricity demand profile** • Average hourly demand profile for households by season • Average annual electricity demand by electricity network reporting region
Solar PV system specifications • 3 KW system • 30 degree tilt • North facing	**Battery specifications** • 6.4 kWh Tesla Powerwall battery • 87% battery efficiency

Hourly Solar PV generation and consumption profiles are modelled from this information. This allows us to estimate Solar PV capacity factors by network reporting region. Combining this with the demand profile information we are able to calculate onsite consumption and excess Solar that is feed back into the network.

We assume that when the household has a battery they try to maximise onsite consumption of Solar PV in the following hierarchy

- If Solar PV is being generated the consumer uses it first before drawing electricity from the network.
- If Solar PV generation is higher than demand in any hour, the excess Solar PV is fed into the battery.
- Any excess Solar PV that cannot be stored is fed back into the grid i.e. if the consumer does not have a battery then they have no choice but to feed it back into the grid
- The battery is only charged from the network when hourly demand is less than the daily average, and this amount is constrained by their hourly demand profile e.g. their network demand will not be higher than their hourly peak demand profile if they did not have Solar PV.

4.1 Solar PV and battery financial assumptions

The table below outlines the financial assumptions used for the EDGS Mixed Renewables and Tiwai Off scenario, which are the same. The table following this outlines how the costs differ across the other scenarios.

15 http://www.epecentre.ac.nz/greengrid/

		Base case/Tiwai Off		
	Unit	**2015**	**2020**	**2035**
Solar system size	KW	3	3	3
Battery system size	KWh	6.4	6.4	6.4
Exchange rate	USD per NZD	0.67	0.6	0.6
Discount rate	per year	4.14%	5.13%	5.13%
Capital costs		**NZD**	**NZD**	**NZD**
Total Solar PV system cost	Per KW	3,333	3,292	3,292
Inverter replacement	Per KW Per 15 years	400	318	253
Battery	Per KWh	700	667	500
Battery installation	Per 10 years	746	746	746
Operational costs				
Operation and Maintenance	Per KW per year	30	28	27
System operation				
Panel degredation	Per year	0.8%	0.8%	0.8%
Solar system life	Years	25	25	25
Battery system life	Years	10	10	10
Inverter life	Years	15	15	15
Financing				
Solar system loan length	Years	25	25	25
Inverter replacement loan length	Years	15	15	15
Battery system loan length	Years	10	10	10
Debt servicing rate		4.14%	5.13%	5.13%
Revenue				
Buy back rate	c/KWh	9.0	9.0	9.0

		High Grid			Globla Low Carbon			Disruptive		
		2015	**2020**	**2035**	**2015**	**2020**	**2035**	**2015**	**2020**	**2035**
Capital costs		**NZD**	**NZD**	**NZD**	**NZD**	**NZD**	**NZD**	**NZD**	**NZD**	**NZD**
Total Solar PV system cost	Per KW	3,333	3,333	3,333	3,333	3,292	3,158	3,333	3,292	3,158
Inverter replacement	Per KW Per 15 years	400	400	400	400	318	195	400	239	98
Battery	Per KWh	700	700	700	700	500	333	700	333	167
Battery installation	Per 10 years	746	746	746	746	746	746	746	746	746
Operational costs										
Operation and Maintenance	Per KW per year	30	30	30	30	28	27	30	28	27

4.2 **Solar PV purchase decision**

The consumer considers upfront capital costs and operating and maintenance costs of Solar PV system with and without batteries. These costs start at current levels but fall at different rates depending on the scenario e.g. battery costs are assumed to fall at a much faster rate in the EDGS Disruptive scenario. The consumer also considers the buy-back rate of Solar PV injected back into the network, as well as considering day/night prices and their ability to shift Solar PV generation across the day with a battery.

The consumer has a choice between a Solar PV system with batteries and one without batteries, and chooses the one with the lowest Long-run Marginal Cost (LRMC). The relevant equations are outlined below.

LRMC equation for a Solar PV system

$$LRMC = \frac{-C - \left(\frac{O\&M_1}{(1+i)^1} + \cdots + \frac{O\&M_T}{(1+i)^T}\right) + \left(\frac{BB_1 \times Surplus_1}{(1+i)^1} + \cdots + \frac{BB_T \times Surplus_T}{(1+i)^T}\right)}{\left(\frac{OnsiteS_1}{(1+i)^1} + \cdots + \frac{OnsiteS_T}{(1+i)^T}\right)}$$

LRMC equation for a Solar PV system with a battery

$$LRMC = \frac{-C - \left(\frac{O\&M_1}{(1+i)^1} + \cdots + \frac{O\&M_T}{(1+i)^T}\right) - \left(\frac{Pop_1 \times OnsiteN_1}{(1+i)^1} + \cdots + \frac{Pop_T \times OnsiteN_T}{(1+i)^T}\right) + \left(\frac{BB_1 \times Surplus_1}{(1+i)^1} + \cdots + \frac{BB_T \times Surplus_T}{(1+i)^T}\right)}{\left(\frac{OnsiteS_1 + OnsiteN_1}{(1+i)^1} + \cdots + \frac{OnsiteS_T + OnsiteN_T}{(1+i)^T}\right)}$$

T = Lifetime

i = discount rate

C = initial capital cost (NZD)

O&M =Operating and maintenance cost for period t

P =Variable component of the electricity price (c/kWh)

Pop =Offpeak variable component of the electricity price per unit (c/kWh)

OnsiteS = The amount of household demand met by solar generation (kWh)

OnisteN = The amount of household demand met by stored electricity from the network (kWh)

OnsiteS + OnsiteN = the total amount of electricity met either by direct use of solar PV, storage of excess solar, or storage of electricity from the network

BB =The buyback rate per unit of electricity (c/kWh)

Surplus = The amount of solar generation exported to the electricity network

A system is considered to be economic if the LRMC of the system is lower than the variable component of the price. The variable component differs between regions and is based on prices from the Quarterly Survey of Domestic Electricity Prices (QSDEP) as at 15 August 2015 and estimated variable components of the price.

If a system is economic it does not mean that it will be taken up by the consumer. Uptake rates were informed by Solar PV preference information collected by the Green-Grid. This information was combined with the savings per year to determine the uptake of Solar PV in each region given the Solar PV system is economic. [16]

[16] http://www.epecentre.ac.nz/research/papers.shtml

4.3 **Commercial Solar PV systems**

Commercial Solar PV uptake is model in the way as that described in the sections above with the following differences:

- 10 kW system
- Commercial businesses undersize their panels and are able to consume 100%
- Since commercial Solar PV systems are undersized then systems do not have batteries
- An initial electricity variable component price of 12 c/kWh

Under these assumptions Commercial Solar PV does not become economic in any year across all of the EDGS scenarios.

It is unlikely that there will be zero uptake of Solar PV by Commercial businesses and we have assumed 1% of commercial businesses will have Solar PV by 2050 across all EDGS scenarios.

5 SADEM - the hub

SADEM stands for Supply and Demand Energy Model; however it is not really one model, but a collection of models and a central hub for pulling information together. In SADEM we pull information together on total energy supply, greenhouse gas emissions and energy intensity. The following section gives an overview of how these important results are pulled together.

5.1 **Energy Supply**

Energy supply or total energy use is the amount of primary energy used in New Zealand. Primary energy is energy that does not need to been transformed into a secondary energy type through a transformation process in New Zealand. Electricity, and domestically refined petrol and diesel are all secondary energy types as they have been transformed into another energy type in New Zealand.

Electricity can be generated from any primary energy source. For us to estimate energy supply we need to know how much energy was consumed in making the unit of electricity that was demanded by a consumer. See section 6.3 for information on how we calculate electricity demand.

Similarly domestically refined petrol and diesel begin their lives as crude oil, and so it is the crude oil, not the petrol or diesel in that case that is supplied as primary energy to New Zealand. In the case of petrol and diesel we also import refined product so that imported portion is counted as primary energy supply.

In the case of national greenhouse gas accounting it is important to consider the total energy supplied, not just the final consumer energy demand. For example, electricity has no emission at the point source of use, however electricity is generated from gas and coal which have emissions so these fuel input emissions also need to be calculated.

To determine a national gas supply and demand balance and calculate a break even gas price (see section 2.7.2) we need to know total gas use (not just consumer demand), including use for electricity, and non-energy uses such as methanol.

Energy supply is of particular importance for non-renewable energy resources for which there are finite supplies and on-going fuel costs.

SADEM works as the hub to pull all energy supply information together. SADEM uses the following formula to estimate energy supply:

Energy Supply = Consumer Energy Demand of all fuels excluding electricity
+ fuel input to electricity supply and other transformation activities
+ fuel used for non-energy uses (such as methanol manufacturing)

+ any other transformation losses not already accounted for.

5.2 Greenhouse Gas Emissions

Greenhouse Gas Emissions are calculated by multiplying forecast fuel demand by an emissions factor.

The emission factors employed in these calculations are the same as those used for National Inventory reporting and in the New Zealand Energy Greenhouse Emissions report.

Emission factors currently in this model are as follows (these are updated annually as required):

Table 5 – Emissions factors used in modelling

		Energy		LHV Emissions Factors - kt CO_2/Net PJ			
		Grouping	**Detail**	**CO_2**	**CH_4**	**N_2O**	**CO_2-e**
Manufacturing & Construction	Total	Coal	Average	94.99	0.0007	0.0016	95.49
		Liquid Fuels	Diesel	73.49	0.0028	0.0028	74.38
		Liquid Fuels	Petrol	70.62	0.0038	0.0006	70.90
		Gas	Gas	58.64	0.0014	0.0001	58.70
		Liquid Fuels	LPG	62.38	0.0011	0.0006	62.59
		Liquid Fuels	FuelOil	76.37	0.0030	0.0003	76.54
		Wood	Wood	-	0.0179	0.0048	1.87
Other Sectors	Primary	Coal	Coal	94.99	0.0101	0.0014	95.66
		Liquid Fuels	Diesel	73.49	0.0030	0.0030	74.45
		Liquid Fuels	FuelOil	76.37	0.0030	0.0003	76.54
		Gas	Gas	58.64	0.0014	0.0001	58.70
		Liquid Fuels	Petrol	70.62	0.0176	0.0014	71.48
	Commercial	Coal	Coal	96.20	0.0101	0.0014	96.88
		Liquid Fuels	Diesel	73.49	0.0007	0.0004	73.63
		Liquid Fuels	FuelOil	76.37	0.0014	0.0003	76.50
		Gas	Gas	58.64	0.0012	0.0023	59.35
		Liquid Fuels	LPG	62.38	0.0011	0.0006	62.59
		Liquid Fuels	Petrol	70.62	0.0007	0.0004	70.76
		Biogas	Biogas	-	0.0014	0.0026	0.82
	Residential	Coal	Coal	97.56	0.3037	0.0014	105.57
		Liquid Fuels	Diesel	73.49	0.0007	0.0002	73.57

		Liquid Fuels	FuelOil	76.37	0.0014	0.0002	76.47
		Gas	Gas	58.64	0.0010	0.0001	58.69
		Liquid Fuels	LPG	62.38	0.0011	0.0006	62.59
		Liquid Fuels	Petrol	70.62	0.0007	0.0002	70.70
		Wood	Wood	-	0.3585	0.0048	10.39
Transport	Land	Liquid Fuels	Petrol	70.62	0.0198	0.0015	71.58
		Liquid Fuels	Diesel	73.49	0.0041	0.0039	74.77
		Gas	Gas	58.64	0.6272	0.0001	74.35
		Liquid Fuels	LPG	62.38	0.0309	0.0006	63.34
	Sea	Liquid Fuels	Fuel Oil	76.37	0.0070	0.0020	77.15
	Air	Liquid Fuels	Aviation	72.28	0.0020	0.0020	72.93

Table 6 – Emissions factors by fuel and activity used in modelling

		Energy		LHV Emissions Factors - kt CO_2/Net PJ			
		Grouping	**Detail**	**CO_2**	**CH_4**	**N_2O**	**CO_2-e**
Transformation Industries	Main Activity Electricity	Coal	Sub-bit	95.08	0.0007	0.0016	95.60
		Coal	Lignite	99.25	0.0007	0.0016	99.77
		Gas		58.66	0.0060	0.0001	58.82
		Liquid Fuels	Diesel	73.50	0.0009	0.0004	73.64
		Liquid Fuels	Fuel Oil	-	0.0009	0.0004	0.14
		Biogas		76.47	0.0009	0.0003	76.58
	Main Activity Cogen	Gas		58.66	0.0030	0.0001	58.76
	Petroleum Refining	Refinery Gas		67.38	0.0014	0.0001	67.44
		Gas		58.66	0.0014	0.0001	58.72
		Asphalt		79.54	0.0030	0.0003	79.70
		Fuel Oil		76.11	0.0030	0.0003	76.27

CO_2-e is calculated using the following formula which accounts for the different greenhouse gas potentials[17] of the individual gasses: $CO_2\text{-e} = CO_2 + 21*CH_4 + 310*N_20$

5.2.1 Fugitive Emissions

Fugitive emissions are those which arise from the production, processing, transmission, storage and use of fuels and include the categories: Gas Transmission and Distribution, Gas/Oil Flaring, Gas Processing, Coal Mining, Oil Transportation and Geothermal electricity generation.

- Fugitive emissions from geothermal electricity generation are calculated by multiplying the electricity generated (in TWh) from geothermal by the emission factors as follow:

	CO_2	**CH_4**
Fugitive Geothermal (kt CO_2/TWh)	90.6	0.921

- Gas processing emissions are calculated based on the amount of gas forecast to be processed at the Kapuni Treatment Station (which is simply assumed to be the amount of gas forecast to be produced from the Kapuni gas field)'.
- Gas transmission and distribution emissions are calculated as the total amount of gas distributed to consumers multiplied by a scalar representing the proportion of gas lost in distribution (1.46%) multiplied by an emissions factor.

For the remainder, emissions are forecast to continue at current levels.

5.3 Energy Intensity

'Energy intensity' is the ratio of energy use to Gross Domestic Product (GDP). Changes in energy intensity are caused by:

- energy efficiency improvements;
- energy conservation; and

[17] The global warming potential is a relative measure of how much heat a greenhouse gas traps in the atmosphere. It compares the amount of heat trapped by a certain mass of the gas in question to the amount of heat trapped by the same mass of carbon dioxide.

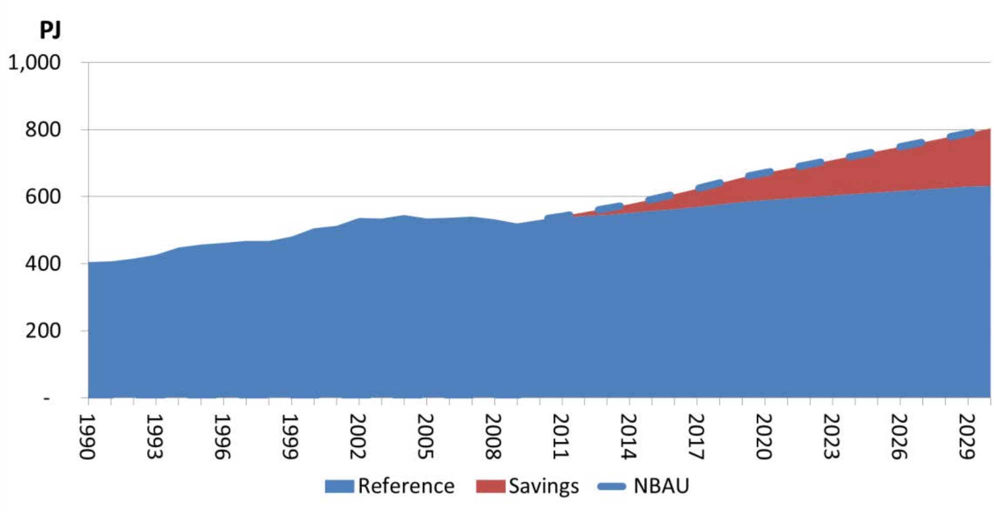
- structural changes in the economy (i.e. movements towards or away from energy intensive sectors).

The impact of existing energy efficiency programmes in the residential[18], commercial and industrial sectors is reflected in regression coefficients used to forecast demand. In addition, forecasts incorporate on-going expansion of energy efficiency programmes. The commercial and general industry models also allow for fuel switching based on relative fuel prices. If there is a shift in consumption towards energy sources with greater effective energy (for example moving from coal to gas) this results in an efficiency gain, which is reflected in the energy intensity forecasts. As all fuel prices increase, consumption will reduce. For more information on the effect of price on the consumer energy forecasts, see section 3.2. Residential electricity demand and other fuel demand have been modelled separately using different functions and residential fuel switching is not captured in this method.

In the specific industry model energy intensity improvements can be explicitly accounted for, for all five individual plants based on available information on plant upgrades etc. For more information see section 3.3. The other energy intensity improvements come from the projections of energy demand from land transport. As discussed in section 8.1.2, future fleet size, makeup and choice of fuel (including Electric Vehicles and Plug-in Electric Vehicles) influence energy intensity improvements within the energy forecasts of this model.

The impact of energy intensity improvements on energy demand can be can be assessed by comparing energy demand forecasts with a 'naïve business as usual' (NBAU) where energy intensity is held constant, i.e. there is no further improvement in energy efficiency or conservation and no structural change in the economy.

Figure 2 – Economy wide energy savings



The energy 'savings' in the figure above represent energy savings across the economy from all programmes and actions to improve energy efficiency and reduce consumption. The impact of individual programmes and actions cannot be isolated using such a top-down approach – programme specific modelling is required in such cases.

[18] In one of our modelled scenarios we make explicit assumptions about a higher rate of electricity energy efficiency and assume a flat per household electricity demand throughout the modelled scenario.

6 Electricity Demand, Supply and Prices

6.1 Introduction

Electricity demand is a key input required for projecting future electricity supply. However there are many ways to define and measure electricity demand.

The demand modelled in SADEM is the consumer energy demand as discussed in section 3.1. This is the final energy consumption or the demand at point of sale, which excludes transmission and distribution losses. A portion of consumer energy demand is met from distributed on-site generation, rather than grid connected generation.

Electricity supply or generation is modelled predominantly using the Generation Expansion Model (GEM). The GEM optimisation model is the main tool used to model the operation of existing plant, produce a projection of new generation plant built over the projection period and the expected fuel demand's from existing and new thermal generators. GEM requires thermal fuel prices, gas availability, carbon prices and appropriately scaled electricity energy demand projections by island as key inputs from SADEM.

The first thing to note is that while electricity demand is a key input to GEM, it is not the same type of electricity demand as is the key output of the SADEM consumer demand models.

Around 10% of all existing generation is modelled within SADEM, rather than GEM to simplify the supply projections. Almost all distributed (local distribution network – rather than transmission connected) generation is excluded from GEM.

We convert SADEM demand into GEM input demand by taking away the portion of the generation projected outside of GEM from SADEM demand and adding distribution network lines losses. GEM input demand $(\mathrm{Demand}_{\mathrm{GEM}})$ is then used as an input to GEM and is also used to calculate peak electricity demand as an input to GEM[19].

GEM produces generation supply and fuel information for its portion of supply and demand. This generation is added to the generation not included in GEM (which is mainly distributed and onsite generation) to make a projection of total electricity supply.

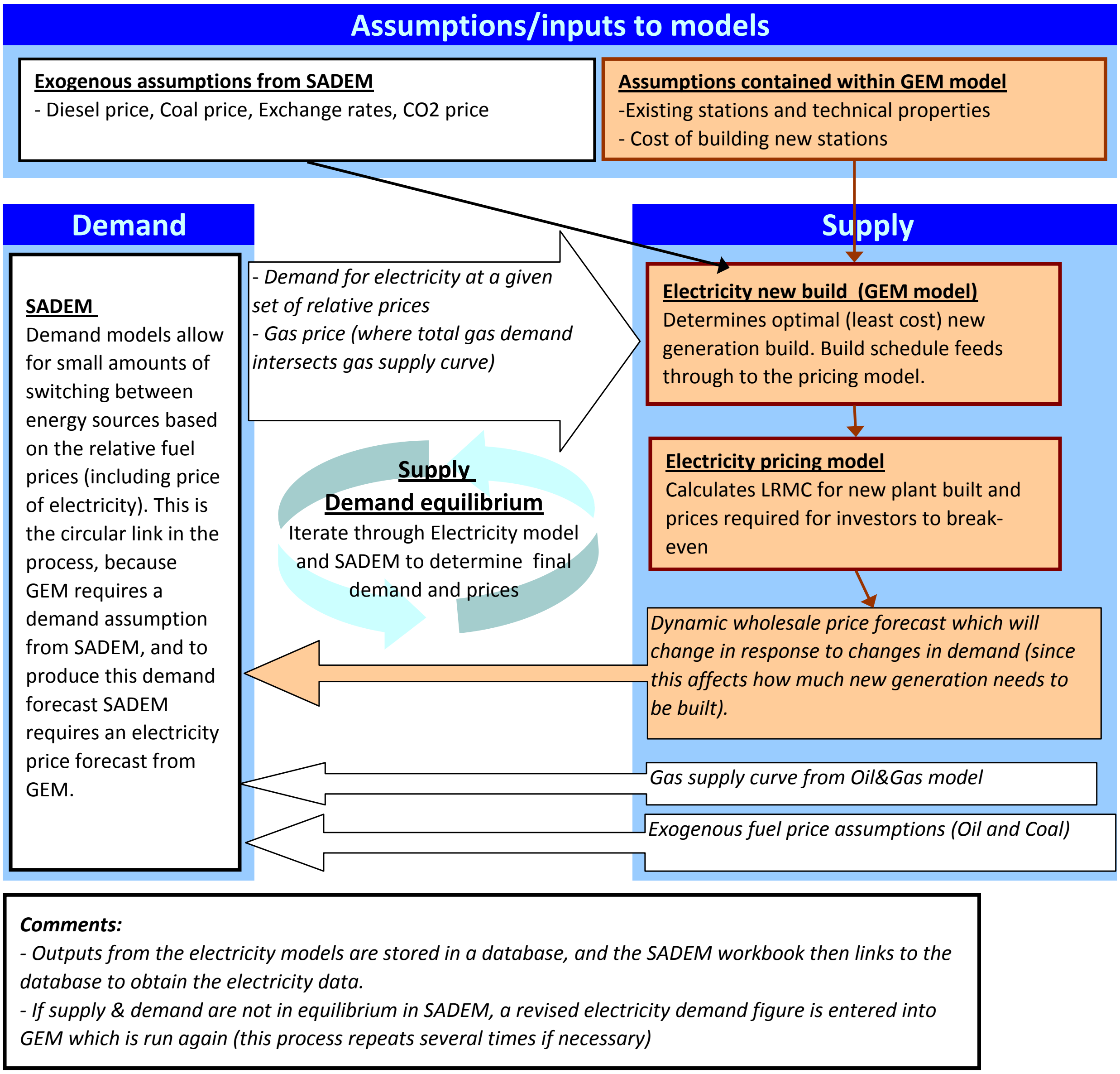
6.2 Iterating between SADEM and GEM

The GEM[20] optimisation model produces a projection of new generation plant built over the next 30 years and the expected gas demand from existing and new thermal generators. A separate pricing model then determines the wholesale price indicator based on the LRMC (long run marginal cost) of each new plant built. These models operate independently of SADEM however data is exchanged between all the models in a dynamic loop. Figure 2 outlines the nature of these linkages.

19 Peak electricity demand is discussed further in section 5.3.2

20 'Generation Expansion Model'.

Figure 3 - Interactions between SADEM and Electricity models



GEM requires inputs of fuel prices and electricity demand forecasts from SADEM. The demand forecasts in SADEM are based on relative fuel prices, including electricity prices. However the electricity price forecast is produced from the GEM build schedule which is, in turn, affected by the demand from SADEM. This produces a loop which becomes an iterative process to determine an equilibrium between the electricity supply produced by GEM and the demand for electricity produced by SADEM.

6.3 Electricity demand relationships

6.3.1 Adjusting consumer demand for use in GEM

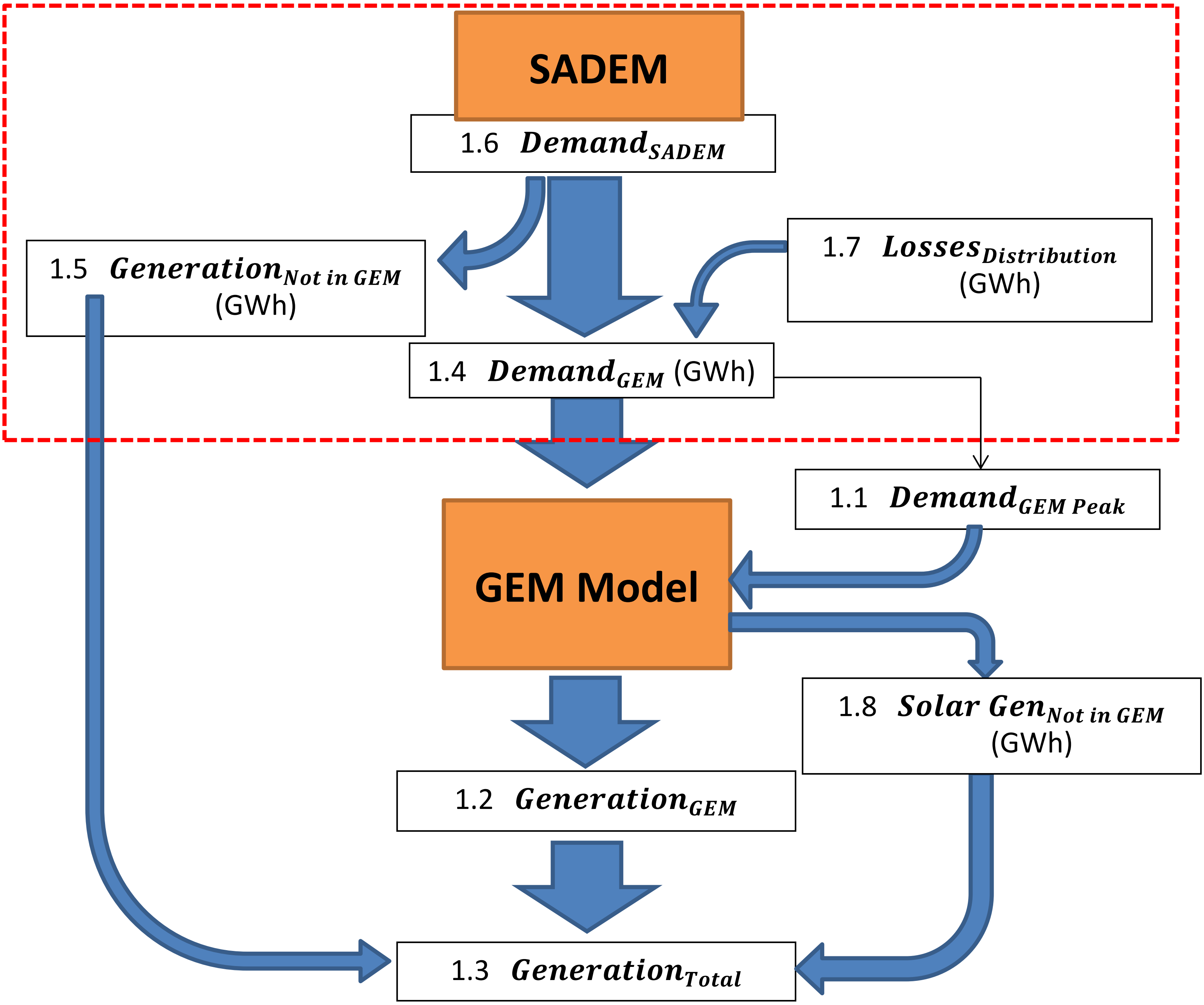
GEM input demand is close to – but not equal to – GXP level demand. GEM input demand is a function of the plant set included in the GEM model. The following points explain how generators are included in GEM:

a) For existing generation - the Ministry has removed most embedded or distributed network generation from the GEM model. However some distributed wind generation remains in the model as its intermittence impacts on grid demand.

b) For new generation - the GEM plant input list includes a number of smaller plants that could potentially be distributed rather than GXP connected generation.

The key point to take away from points a) and b) is that there is no simple relationship between SADEM demand, GXP demand, GEM demand and that some assumptions must be made to get from SADEM demand to GEM demand.

The following figure illustrates the flow of demand data from SADEM to GEM.



We have taken the following approach (illustrated by looking at portion of the diagram on the previous page which is surrounded by a red dotted line box):

$$\boldsymbol{Demand_{GEM\ Input}} = \boldsymbol{Demand_{SADEM}} - \boldsymbol{Generation_{Not\ in\ GEM}} + \boldsymbol{Losses_{Distribution}}$$

Where:

$\boldsymbol{Demand_{GEM\ Input}}$ = Electricity energy demand used to create demand scalar as GEM input.

$\boldsymbol{Demand_{SADEM}}$ = Final Total Consumer Energy demand for electricity

$\boldsymbol{Generation}_{Not\ in\ GEM}$ = Total amount of generation modelled outside of GEM, excludes modelled solar generation

$\boldsymbol{Solar\ Gen}_{Not\ in\ GEM}$ = Solar generation and battery load shift modelled outside of GEM and SADEM.

$\boldsymbol{Losses}_{Distribution}$ = Total losses from the 29 local distribution networks (currently ~1700 GWh/annum)

A key input to this calculation is $\boldsymbol{Generation}_{Not\ in\ GEM}$. This is highly dependent on what plants are included in the GEM plant input list.

Almost all distributed generation is excluded from GEM. Assumptions made about the growth of this non-GEM generation are very important for the EDGS (see section 6.4). If new demand is met by distributed generation rather than large scale grid connected generation, then the need to invest in the core transmission grid will be impacted.

Over the projection period it is assumed growth rate can be either:

a) A manual input (e.g. 1% per annum)

b) Linked to the growth of consumer energy demand in a sector/industry or nationally

c) Linked to the historic rate of increase in distribution generation for the particular fuel type

d) Based off the growth rate coming out of the current GEM/SADEM iteration for that individual fuel type

New embedded solar generation and solar with battery operation are modelled outside of SADEM; see Section 4. This modelling captures the seasonal and time of day pattern of both solar generation and battery load shifting, defined here as $\boldsymbol{Solar\ Gen}_{Not\ in\ GEM}$. $\boldsymbol{Solar\ Gen}_{Not\ in\ GEM}$ is subtracted from $\boldsymbol{Demand}_{GEM\ Input}$ at the start of the GEM modelling in a way that takes account of the seasonal and daily time of generation and load shifting. This is explained in more detail in Section 6.3.2.

$\boldsymbol{Losses}_{Distribution}$ are less important, but still have an impact. For the EDGS these are calculated by assuming a constant amount of SADEM demand that is GXP level direct connected demand (assumed to be 8004 GWh/annum), and the remaining SADEM demand is a proxy for demand that is met from distribution networks. In reality, onsite and distributed generation mean that this relationship does not hold in its entirely, however, it is a good approximation (5.5% of demand starting at ~32000 GWh in 2012 produces a reasonable proxy for distribution losses which start at around 1,750 GWh /annum in 2012).

Due to the way GEM operates, rather than simply entering a new national energy demand projection into the model with each iteration, it takes a base demand file, which is built into GEM and is unrelated to SADEM, and scales that by the ratio between it (the base demand file) and the $\boldsymbol{Demand}_{GEM\ Input}$ coming out of SADEM.

Now that readers will have basic understanding of the $\boldsymbol{Demand}_{SADEM}$ to $\boldsymbol{Demand}_{GEM\ Input}$ relationship, an additional complexity must be considered. For the EDGS, some existing plants are modelled as both generation in GEM and SADEM.

This applies to all plants that are predominantly onsite generators, but which have some capacity available to meet GXP demand requirements. For the draft EDGS 2015 this includes:

- Whareroa (Hawera) (Fonterra dairy plant)
- Kapuni (Pulp and paper plant)
- Kinleith (Pulp and paper plant)

The entire capacity of these plants is projected within SADEM. Only the portion available to meet grid demand is also projected within GEM, and its utilisation is restricted based on how the plants have historically operated and injected into the grid. For example, Whareroa's grid injection is inversely correlated to demand for electricity at the Fonterra dairy factory onsite.

As far as modelling outputs are concerned, the SADEM projection is the authoritative projection for these plants. To avoid an imbalance between $\boldsymbol{Demand}_{GEM\ Input}$ and $\boldsymbol{Generation}_{in\ GEM}$, a rough adjustment is made for these plants, to $\boldsymbol{Demand}_{GEM\ Input}$. This adjustment takes the generation from the last iteration for the plants concerned and adds it to $\boldsymbol{Demand}_{GEM\ Input}$ so that there is sufficient additional demand that can be met by the plants concerned.

To avoid double counting the generation from these plants is removed from the $\boldsymbol{Generation}_{in\ GEM}$ which is an output of GEM that goes into SADEM. The only reason for allowing these plants to exist in GEM (as well as SADEM) is to reflect the fact that these plants can meet GXP level demand, in particular at peak demand periods.

Ideally these plant would be projected entirely within GEM to simplify the modelling process. However this cannot occur as these plants produce a large portion of their generation for onsite consumption. This onsite consumption is included in SADEM demand, but has no real impact on GXP demand, or the derived $\boldsymbol{Demand}_{GEM\ Input}$. So if these plants were allowed to generate to their full capacity in GEM, this would be an oversupply of generation relative to the derived $\boldsymbol{Demand}_{GEM\ Input}$.

6.3.2 Disruptive technology and demand and peak demand in GEM

In the GEM model we have captured the supply of electricity from Solar PV generation and release of stored electricity from Solar PV systems with batteries. We have also captured in the GEM model the demand for electricity from charging batteries associated with Solar PV systems as well as charging from electricity vehicles. The demand and supply of these technologies have been captured when it occurs over the year based on the GEM annual electricity demand profile.

Energy demand in GEM is shaped into an annual demand profile. It is divided into four quarter with a demand shape for each quarter defined by nine load blocks. Below shows how these load blocks are defined.

The half hourly demand in each quarter shown in Figure 4 is ordered from the highest to lowest as showing Figure 5 to create a load duration curve. The load duration curve is divided in to 9 load blocks as shown in Figure 6. These load blocks define the electricity demand in each quarter that must be met in the GEM model.

Figure 4 – Historic hourly demand for one quarter (3 months)

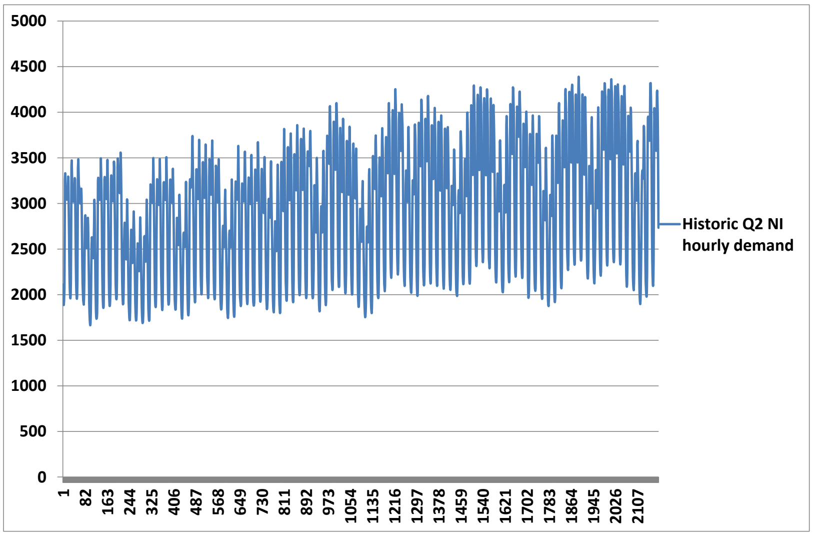


Figure 5 – Load duration curve for a historic quarter

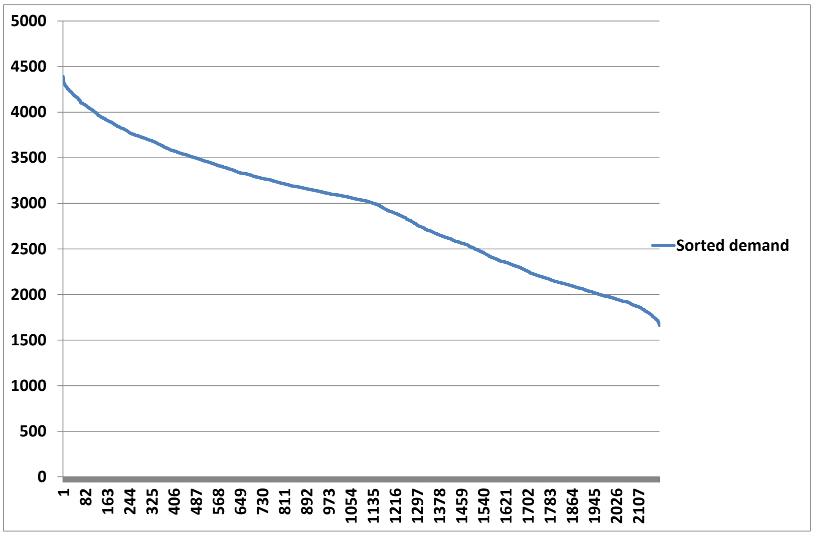
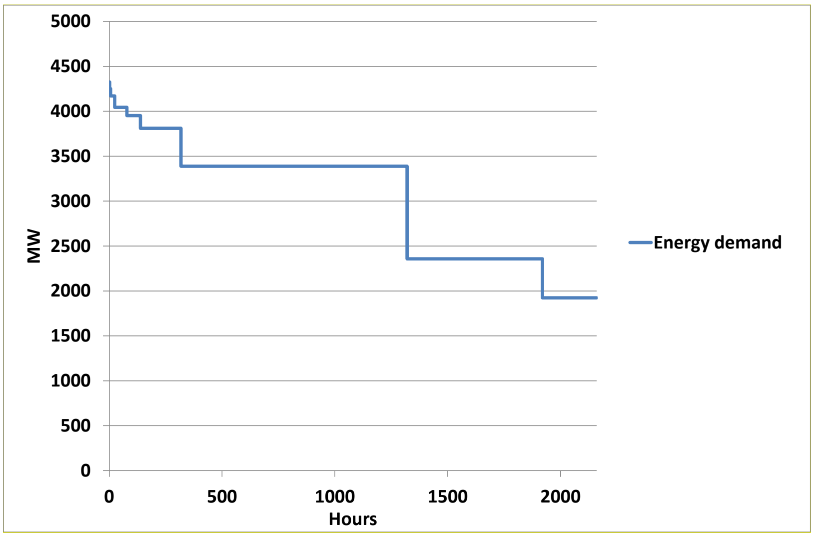


Figure 6 – Load blocks for a quarter



Residential Solar PV systems with and without batteries

The Solar PV and Battery uptake model, described in section *Modelling Solar PV and Battery systems*, provides an annual hourly time series for the following:

- Hourly solar generation for a 3kW system over a year
- Hourly battery charging for a 6.4 KWh battery operating with a solar PV panel over a year
- Hourly battery discharge for a 6.4 kWh battery operating with a solar PV panel over a year

Generation from a single solar PV system without a battery is allocated into the GEM load blocks. The solar generation by load block for a single system is then multiplied by the number of solar systems in each year and this generation is subtracted from the demand load blocks in GEM in the initial data processing step, before the model solve begins. Since these solar PV systems are embedded the generation they produce are subtracted from GEM demand to get the correct level of grid demand before the GEM model solves.

The net effect on GEM energy demand of a solar PV system with a battery is more complicated as the battery charging and discharging must be considered. The net effect on demand in any period is calculated as follows for a solar and battery system:

Net effect of solar PV & battery system = solar generation + battery discharge – battery charging

As with the solar PV system without a battery, the net effect of a single solar PV & battery system on demand is calculated on an hourly basis and then allocated to the load blocks defined in GEM. This net effect for a single solar & battery system in each load block is then multiplied by the number of solar with battery systems in each year and subtracted for the GEM demand by load block prior to the model solve.

Once this adjustment has been made the generation required to be met in the GEM solve from existing and new generation capacity is reduced by the amount of Solar PV generation and battery discharges, and increased by battery charging, in the periods that these occur.

Electricity demand from electric vehicles

The electricity demand for electric vehicle charging in each year is allocated to load blocks in GEM based on assumptions made about the time electric vehicles will be charged. Total EV energy demand is allocated by hour of the day based on the following assumptions:

- 80% of charging occurs between 11pm and 5am
- 10% of charging occurs between 5pm and 11pm
- 10% of charging occurs during the day evenly allocated between 9am and 5pm

The impact of disruptive technology on GEM demand

Figure 7 and 8 show how solar PV, batteries and electric vehicles impact GEM in the *Disruptive* scenario in 2040. The green line in Figure 7 and 8 shows GEM demand before any adjustments have been made for Solar PV & battery systems and electric vehicle demand. The red line shows the electric vehicle demand allocated to load blocks, the blue line shows the demand met by solar PV and batteries. The Black line shows the GEM demand after adjusting for Solar PV & battery system supply and demand, and electric vehicle demand.

Figure 7 - North Island Q3 2040 Disruptive scenario

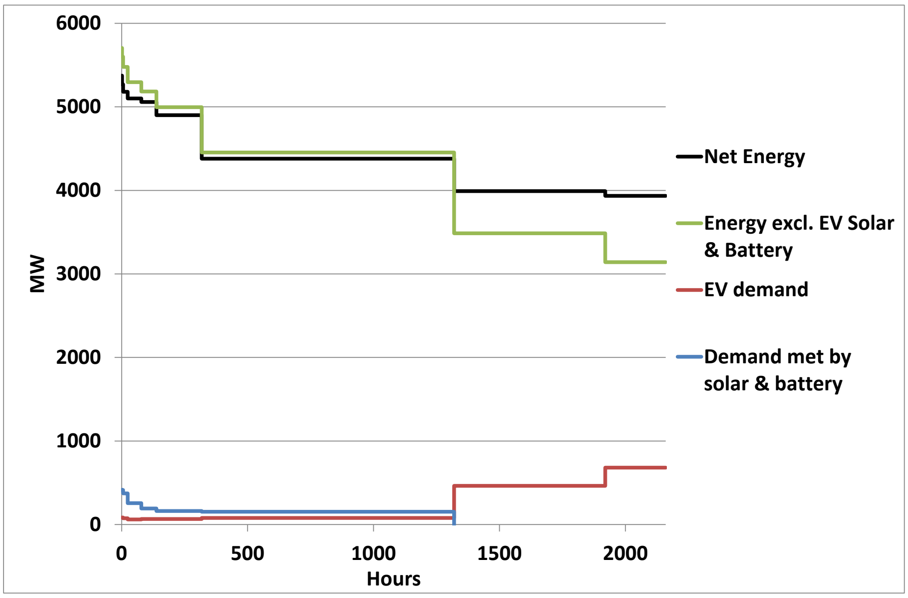
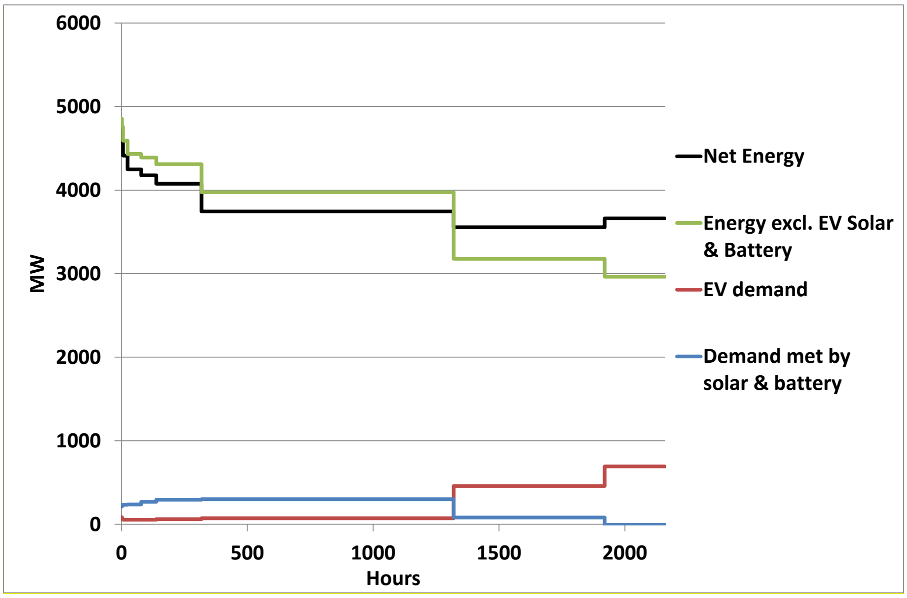


Figure 8 - North Island demand Q4 Disruptive scenario 2040.



6.3.3 Peak demand forecasting

Transpower's peak demand ensemble model was employed to forecast national and North Island peak demand. Theses peak demand forecasts were used directly in the *Mixed Renewable* scenario in the EDGS 2016 modelling.

More information about Transpower's peak demand ensemble model can be found on the Transpower website at https://www.transpower.co.nz/.../PeakDemandForecasts20Feb-2015.pdf

The ensemble model consists of four component models. These are a long-term trend model, a short-term trend model, an econometric model and an MBIE total energy model. The MBIE model component uses the total consumer energy in the *Mixed Renewables* scenario as well as high and low variations. These are driven by the GDP assumptions in section 2.2. The distributions of the four component models are combined equally to form the ensemble distribution. The p50 modelled demand forecast for the ensemble is then determined.

National and North Island peak demand ratios are determined using the modelled peak demand forecasts and the *Mixed Renewables* scenario energy demand forecasts out to 2050. For each of the other scenarios the forecast electricity energy demand (in GWh) was multiplied by the ratio of energy demand to peak demand to determine a peak demand forecast.

Further complexity is added to the calculation of peak demand in scenarios with high solar, high solar with battery uptake and/or high electric vehicle uptake where these technologies are expected to change the ratio between peak and energy demand.

In this case the following formula is used to calculate peak demand in any given year:

Peak demand ratio$_t$ * ($\boldsymbol{Demand_{GEM\ Inputs}}$- Transport electricity demand$_t$) + Peak transport demand$_t$ – Peak solar generation & battery delta$_t$

Peak demand ratio$_t$ = Modelled peak demand$_t$ / ($\boldsymbol{Demand_{GEM\ Input}}$[21] / hours in the year)

Transport electricity demand$_t$ = electricity demand used to charge electric vehicles in year t

Peak transport demand$_t$ = Transport demand in highest 1.5 hours of demand in quarter 3 divided by 1.5 in year t. See section 6.3.2 for details of how transport demand is allocated by load block.

Peak solar generation and battery delta$_t$ = net effect of solar and batteries in highest 1.5 hours of demand in quarter 3 divided by 1.5 in year t. See section 6.3.2 for details of how transport demand is allocated by load block.

This formula is used on a national and a North Island level to calculate the annual national and North Island peak demand for each year of the modelled period. The national and North Island peak demand is used to define a national and North Island peak demand constraint in the GEM model.

6.3.4 GEM overview

The generation expansion model (GEM) has been developed by Phil Bishop at the Electricity Authority (EA) and can be downloaded at https://github.com/ElectricityAuthority/gem/.

GEM determines the new generation plant that needs to be built over the next 30 years in order to meet demand growth and retirement of existing plant. It determines:

- what technology gets built (wind / hydro / geothermal / thermal baseload / thermal peakers),
- when it gets built,
- how much gets built (MW), and
- where it gets built (North Island / South Island).

GEM has inputs of both energy demand (GWh) and peak demand (MW) growth and so the new generation built must be sufficient to meet both energy and peak requirements. Accordingly, when GEM chooses what plant is built, it is choosing between plant which is primarily for baseload operation (e.g. geothermal, wind, combined cycle gas turbine (CCGT)) or plant that is designed primarily for meeting peak demand and/or supply shortfalls such as dry years or windless days (e.g. open cycle gas turbine (OCGT)).

[21] Mixed Renewables $Demand_{GEM\ Input}$ in year t.

In making the decision to build new plant, GEM samples from a list of possible new generation projects and then calculates the total cost of supply from building each combination of new plant (capital and operating costs). GEM iterates through until it finds the lowest cost combination of new plant to meet the various model constraints (the key constraint being energy and peak demand growth).

It is important to note that GEM is purely a cost minimisation model, and so determines the likelihood of investment based purely on the lowest cost option. Other commercial objectives will also influence investment decisions (such as individual market participants managing their portfolio risk) however these are not modelled in GEM. The model user can apply some discretion by preventing the build of certain projects until a certain year, or even 'forcing in' a project in a certain year. These modelling decisions are made based on observations of the electricity market and the discussions and consultations forming part of the EDGS process.

In some of the scenarios modelled in the EDGS 2016 some small diesel reciprocating generators are built in the early years in the GEM solve. The decision to build these plants in our modelling is the least cost option to meet the dry hydro year energy requirements. At time of publication we are unaware of any generators or distributors planning to build plant by the start of 2018, but if a capacity shortfall does indeed eventuate, we assume that the market will find some way of addressing this, if not from new build, through demand response measures, or even from mothballed plant being recommissioned (eg. Huntly 3).

Demand side response is included in the new generator list and the amount of additional demand side response that is available to the model in the early years is limited in the assumptions. We may see a higher level of demand side response in a dry hydro year than is available in the GEM model and hence some or all of the need for the additional reciprocating diesel peakers could be avoided.

GEM also models the HVDC transmission link between the North and South Island, so when making new build decisions (and the location) will consider the transmission capacity (MW) available between the islands.

There are many more layers of detail in the GEM model which go beyond the scope of this document. The EA's website[22] and the GEM *github.com* site[23] have more information about the model.

6.3.5 GEM assumptions

The key assumptions are:

- the list of all possible new generation plant that could be built;
- the capital costs and operating costs associated with each plant;
- technical operating specifications for each plant (such as heat rate for thermal plant, expected capacity factors for wind farms);
- fuel availability and cost; and
- carbon emissions cost.

For the EDGS 2016 generation plant assumptions have been sourced from the report by Parsons Brinkerhoff (PB): '2011 NZ Generation Data Update'. Some project costs (for projects expected to be more likely built over the next few years) have been adjusted to reflect short/medium term exchange rate expectations.

[22] http://reports.ea.govt.nz/emiGEM.htm

[23] https://github.com/ElectricityAuthority/gem/

Gas availability (PJ pa) is an assumption that comes from SADEM. It is estimated by subtracting non-electricity usage from the total gas production (refer also to section 7 for details of the gas supply modelling).

The gas price also comes directly from SADEM. It is determined where total gas demand intersects the supply curve (again, refer to the separate gas modelling section for more details).

Other assumptions that come from SADEM are the diesel price, coal price, carbon price and exchange rate.

6.3.6 GEM outputs

There are a wide range of outputs produced after a GEM model run. The key outputs which feed through to SADEM are:

- new generation build and retirements (MW);
- expected gas consumption (PJ per annum); and
- expected annual generation (GWh).

For the EDGS 2016 we solve GEM to determine new plant build decisions stochastically with a 80% weighting on an average of all hydro years and 20% weighting on the dry hydro year (defined as 1932). Generation plant operation is dispatched over 10 hydro years and the expected gas consumption and annual generation are calculated by taking the average across the hydro years.

6.4 Residual generation supply modelled in SADEM

6.4.1 Overview

Almost all distributed generation is excluded from GEM. However, assumptions made about the growth of this non-GEM generation are important. If new demand is met by distributed generation rather than large scale grid connected generation, then the need to invest in the core transmission grid will be impacted.

For the residual generation modelled in SADEM, a very simple modelling approach is taken. The last year of historic data for generation and fuel input is used as a basis for growth in SADEM generation. Growth can either be:

a) A manual input (e.g. 1% per annum)

b) Linked to the growth of consumer energy demand in a sector/industry or nationally

c) Linked to the historic rate of increase in distribution generation for the particular fuel type

d) Based off the growth rate coming out of the current GEM/SADEM iteration for that individual fuel type.

6.5 Electricity price indicator

6.5.1 Background

The price indicator reflects the long run marginal cost (LRMC) of new generation. The LRMC is the revenue per unit of electricity generated that a new investment must earn, on average, so that the net present value (NPV) equals zero. A discount rate of 8% (post tax, real) is used to discount the cashflows[24].

[24] An LRMC tool is also available on the Ministry's website which can be used to compare the LRMC's of different technologies under varying assumptions such as exchange rates, fuel costs, etc.

6.5.2 Method

GEM v2.0 has a module which calculates the Long Run Marginal Cost (LRMC) of each new plant. GEM also calculates the MWh dispatched by each plant in each quarter. The dispatch data is broken down into 9 load blocks in each quarter.

The LRMC and dispatch data are then fed into a price optimisation model, or linear program (LP). The LP finds the market prices required in each load block so that new plant, on average, obtain market prices which are greater than or equal to the LRMC. The following section describes all the equations in more detail.

This methodology does not consider short term dynamics of the electricity spot market where offers are largely based on SRMC as opposed to LRMC. The methodology is based on the premise that investors are unlikely to build new generation unless they anticipate prices at or above LRMC when their plant is running in the future. If prices do not move towards LRMC then future investment will be delayed, resulting in a supply short-fall if demand keeps rising. This will eventually drive up wholesale prices (as more expensive thermal generation would be need to be dispatched) and as prices rise towards LRMC then these new plant will be built. The electricity price indicator can be considered as the marginal cost of new generation under a set of scenario assumptions. However, it should not be used as an electricity price forecast, particularly in the short term, as it does not take account of short term dynamics in the electricity market.

6.5.3 Price optimisation equations

The Price Optimisation Model (POM) is written in GAMS and is solved using a linear program (LP). The 'objective function' of the POM is to minimise total revenue subject to various constraints. The GAMS equations are explained below.

Objective function:

Minimise $\sum_{g}\sum_{y}\sum_{t}\sum_{lb}\sum_{hy}\{P_{y,t,lb,hy}*Gen_{g,y,t,lb,hy}\}$

where *g* = the set of generation plant (Otahuhu B, West Wind,…);

y = the set of forecast years (2011 to 2040);

t = the set of quarters (1 to 4);

lb = the set of load blocks (1 to 9);

hy = set of hydro years (1998 to 2007);

P = the price variable the LP is solving for in year *y*, quarter *t*, etc...;

Gen = MWh of generation dispatched by plant *g* in year *y*, quarter *t*, etc... (this is output data from GEM).

The first set of terms in the above equation represents the dimensions of the sum, so in this case all dimensions are being summed which results in a single summed value.

Constraints:

(C1) $Ann\_rev\_new_{y,k}$ >= $LRMC\_rev\_new_{y,k}$

Where $Ann\_rev\_new_{y,k} = \sum_{g=new}\sum_{t}\sum_{lb}\sum_{hy}\{P_{y,t,lb,hy}*Gen_{g,k,y,t,lb,hy}\}$

$LRMC\_rev\_new_{y,k} = \sum_{g=new}\sum_{t}\sum_{lb}\sum_{hy}\{LRMC_{g}*Gen_{g,k,y,t,lb,hy}\}$

$LRMC_g$ = the LRMC of each new plant built

k = the set of technologies (wind, CCGT, hydro, ...)

Note that the constraint is applied by technology and year. For example, in 2015, all the new windfarms built from 2011 to 2015 must, in 2015, earn collectively at least as much as LRMC_rev_new(wind,2015). This approach reduces the impact of an individual plant's LRMC on the price (similar to the previous approach where a weighted average LRMC was calculated for each technology).

(C2) $P_{y,t,lb=1,hy} >= P_{y,t,lb=2,hy}$;

$P_{y,t,lb=2,hy} >= P_{y,t,lb=3,hy}$;

and so on until lb = 9.

These constraints ensure that prices in a high peak block are greater than or equal to prices in a lower peak block.

(C3) $10{,}000 >= P_{y,t,lb,hy}$;

$2{,}500 >= P_{y,t,lb=4,hy}$;

$SRMC\_Whiri_y >= P_{y,t,lb=7,hy}$;

$SRMC\_Whiri_y >= P_{y,t,lb=7,hy}$;

These constraints provide some maximum prices. Note that a maximum price for a specified load block also applies to all other blocks that sit below it (because of the constraints in C2).

Figure 9 - LRMC of new generation

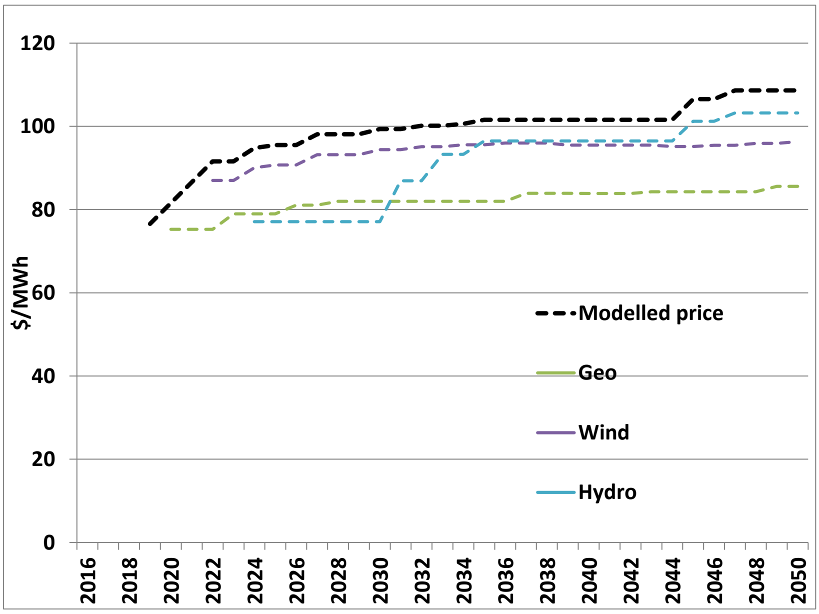


Figure 9 displays the installed capacity weighed average LRMC of new wind, geothermal and hydro that are built in the Mixed Renewables Scenario. Plant that are already committed or that are included in the modelled build schedule as an exogenous assumption are not included in the average LRMCs shown above.

The electricity price indicator is based on scaled LRMCs. The LRMCs are scaled to reflect the price capture of the technology type. Wind plant operate inflexibly and tend to capture prices that are on average lower than average wholesale prices, therefore the LRMC of wind has been scaled up to reflect the average annual electricity price required to meet the LRMC of new wind. The Mixed Renewables scenario electricity price indicator is shown as a dotted black line.

We can see from the chart that geothermal LRMC initially sets the price followed by new build wind and hydro. Wind sets the level of the electricity price indicator from 2022, when the first modelled wind plant build in the EDGS 2016 Mixed Renewables Scenario occurs.

Optimised prices are produced for each hydro year, load block and quarterly time period. The price across the hydro years, load blocks and quarters is averaged to provide an annual average price forecast.

7 Gas Supply and Prices

7.1 Background

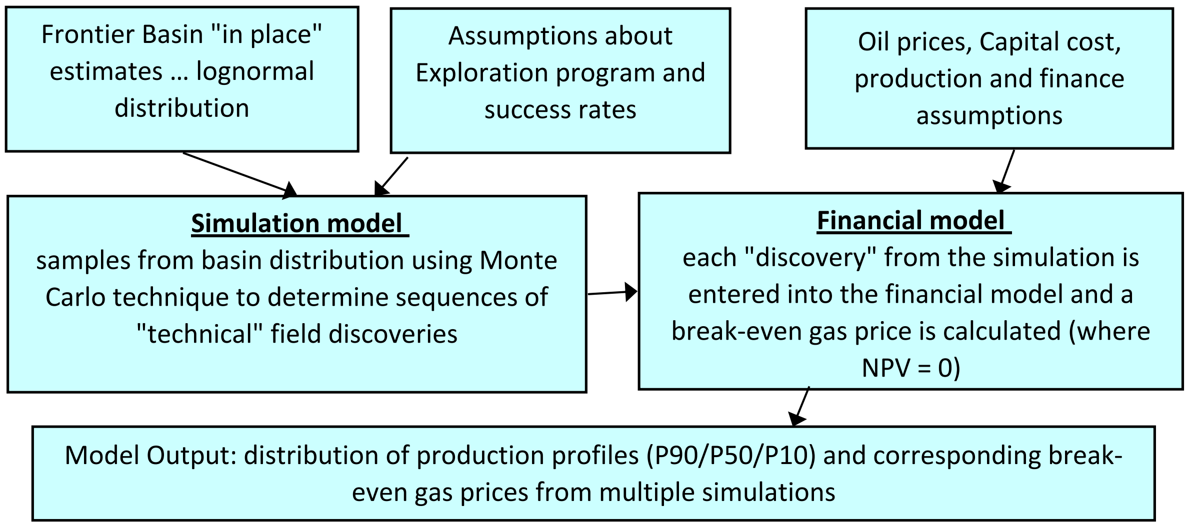
The following sources provide information about the potential size of the national petroleum resource, as well as to assess the competitiveness and effectiveness of the current royalty approach:

- Production and Cost Estimates for New Zealand's Petroleum Resources – Mike Adams Reservoir Engineering (updated 2014)
- Potential Undiscovered Oil and Gas Resources of New Zealand - GNS Science (updated 2015)
- Evaluation of the Petroleum Tax and Licensing Regime of New Zealand – AUPEC 2009

7.2 Overview of modelling process

A ***simulation model*** has been developed to assess New Zealand's potential undiscovered technical petroleum (oil and gas) resource and a ***financial model*** to calculate the commercial viability of the technical resource.

Figure 10 Overview of modelling process



7.3 Simulation model

The first step in the modelling process is to estimate, for each frontier basin, the technical Oil Initially in Place (**OIIP**) and technical Gas Initially in Place (**GIIP**) for the entire basin. The GNS report provides OIIP and GIIP assumptions, with the uncertainty in the estimates reflected by assuming a *lognormal* distribution. Table 7 shows the basin OIIP and GIIP estimates at the P90, P50 and P10 levels, as well as the truncated minimum and maximum values.

Table 7 - Technical in place resource estimates

	Tki Onsh	Tki Offsh	Canty Near	Canty Far	GSB	Northland	Tki Deep	Raukum	Pegasus
Giip (tcf)									
Min	0.4	0.7	0.2	0.1	0.5	0.4	0.6	0.2	0.3
90%	0.9	1.5	0.7	0.4	1.6	1.0	1.6	0.7	1.0
50%	2.2	3.5	2.6	1.6	6.9	2.8	5.0	3.3	4.5
10%	5.3	8.1	10.1	6.8	29.4	8.0	12.3	15.9	13.5
Max	10.8	16.2	30.3	22.4	95.9	18.6	12.3	57.1	13.5
Oiip (mmbbl)									
Min	46	103	60	14	84	44	47	25	10
90%	90	238	156	53	244	125	156	81	43
50%	207	663	508	267	907	445	683	348	248
10%	475	1850	1650	1363	3375	1588	2158	1488	750
Max	934	4271	4313	5138	9852	4474	2158	4866	750

The simulation model samples from these basin distributions using a Monte Carlo technique. The sampling process is run several hundred times, with each sample referred to as an 'iteration'. Each 'iteration' is a hypothetical future in which NZ has a certain quantity of petroleum resources.

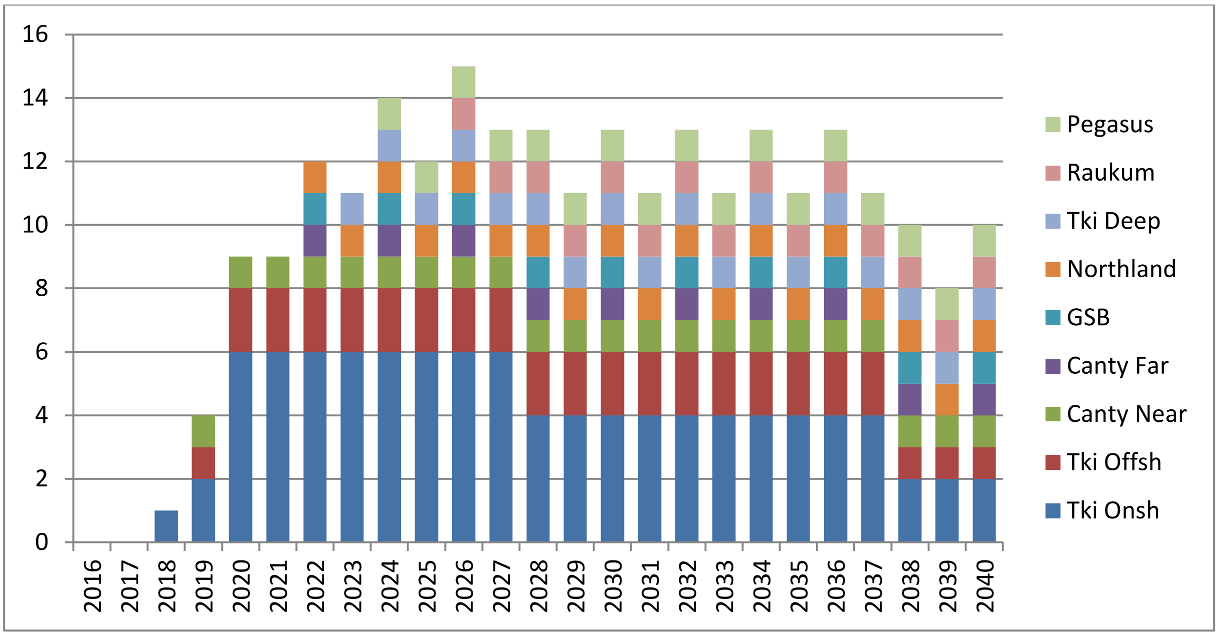
The next step in the modelling process is to determine the likely size and number of gas and oil fields that are contained within each basin. It is assumed that the distribution of fields follows 'Zipf's law', where the second largest field is half the size of the largest field, the third largest field is one third of the largest, and so on. Once the basin size and the largest field size are known, then the remaining field sizes can be calculated. Table 8 below shows the largest field assumptions for each basin and for each basin probability level.

Table 8 - Maximum field size for each probability level

	Tki Onsh	Tki Offsh	Canty Near	Canty Far	GSB	Northland	Tki Deep	Raukum	Pegasus
Max gas field size (tcf)									
Min	0.23	0.50	0.08	0.07	0.23	0.38	0.45	0.15	0.21
90%	0.42	0.75	0.28	0.23	0.67	0.75	1.13	0.53	0.75
50%	0.80	1.50	1.20	1.00	3.00	1.50	2.25	2.25	2.25
10%	1.50	2.75	3.30	3.00	9.00	3.00	6.00	6.00	2.25
Max	2.62	4.68	8.70	7.91	22.50	6.33	13.29	16.29	6.11
Max oil field size (mmbbl)									
Min	23	100	63	50	150	65	60	44	14
90%	38	133	125	100	225	120	120	100	31
50%	80	300	250	200	450	200	300	300	150
10%	140	600	550	600	1200	500	1000	600	200
Max	258	1137	1031	1125	2400	1000	2370	1500	900

The next step, for each iteration, is to determine how many of these potential fields will be discovered and when they will be discovered. This requires hypothetical exploration wells to be drilled and assumptions made regarding the success of the wells. Figure 11 and Table 9 outline the exploration and success rate assumptions.

Figure 11 - Exploration wells drilled each year



The probability of success for each of the basins is shown in Table 9. The probability of a *technical* success is assumed lower for frontier basins when compared to the established Taranaki region[25]. The probability rates are based on historical well success rates in Taranaki. They were discussed and agreed on in consultation with Michael Adams Reservoir Engineering.

[25] However, the model does allow the technical success rates to slowly increase in the frontier basins if there is a successful discovery (in a given iteration).

Table 9 - Probability of a technical success

Taranaki Onshore	Taranaki Offshore	Canty Near	Canty Far	GSB	Northland	Taranaki Deepwater	Pegasus
Success rate (for finding oil or gas)							
40%	20%	15%	15%	15%	10%	10%	10%
Probability of gas (if there is a success)							
50%	48%	65%	65%	67%	48%	50%	50%

The model randomly selects a number between 0 and 100 when an exploration well is drilled. If the random number is less than the assumed success rate then the well is a success, otherwise it is a failure. For example, a random number of 17 in Offshore Taranaki is deemed a success. If there is a technical success, the model then selects another random number to determine whether the discovery is primarily oil or gas prone. Another random number is then generated to determine what sized field is discovered (ie. is it the largest, fourth largest, smallest, etc)[26].

The random numbers are generated for each hypothetical exploration well drilled. This results in a sequence of discoveries and failures for each single model iteration. These technical successes and failures are stored for each iteration in a database, which contains the following information:

- Technical field size (tcf gas or mmbbl oil) by basin
- Discovery year
- Number of exploration well failures

The exploration assumptions used in the draft EDGS reflect three sensitivities. A 'low case', 'mid case' and 'high case' trajectory. The average number of successful well drills per year over the projection timeline for each case is given below.

a) High case – average of 17 well drills

b) Mid case – average of 10 well drills

7.4 Financial model method

The commercial viability of each technical discovery was assessed using the financial model. The financial model is a discounted cashflow model, which includes all the relevant income and costs an oil company would expect in the course of exploring, developing, and operating an oil or gas field.

Every gas field discovered and stored in the database is fed into the financial model and a break even gas price and production profile are calculated. The break even gas price is the average price required in order for the project to attain a net present value (NPV) of zero. Note that gas prone fields also produce some oil condensate which is sold at a given price (refer to Financial Model assumptions in the appendices).

Every oil field was also fed into the financial model and an NPV was calculated using an exogenous oil price assumption (same price as in Reference Scenario).

7.5 Gas model results – Mixed Renewables Scenario

The modelling found that between 2015 and 2050 there were, on average, around 48 fields discovered across all of the eight basins modelled, and almost half of them were gas-prone fields. Results from each of the model iterations are stored in the database. The database was used to

[26] The model assumes that the largest field will be found before the third discovery.

produce the P50 gas production/price curves and P50 oil production curves used (the P50 results represent the 50th percentile from the data).

Figure 12 shows the potential P50 production volumes if all economic[27] gas fields were developed when they were discovered. The production volumes are also broken down into tranches which reflect the relevant breakeven gas prices (note that the prices exclude any carbon cost pass through).

Figure 12 - Potential P50 production profiles and break even gas prices for new discoveries (Mixed Renewables scenario, prices exclude carbon cost)

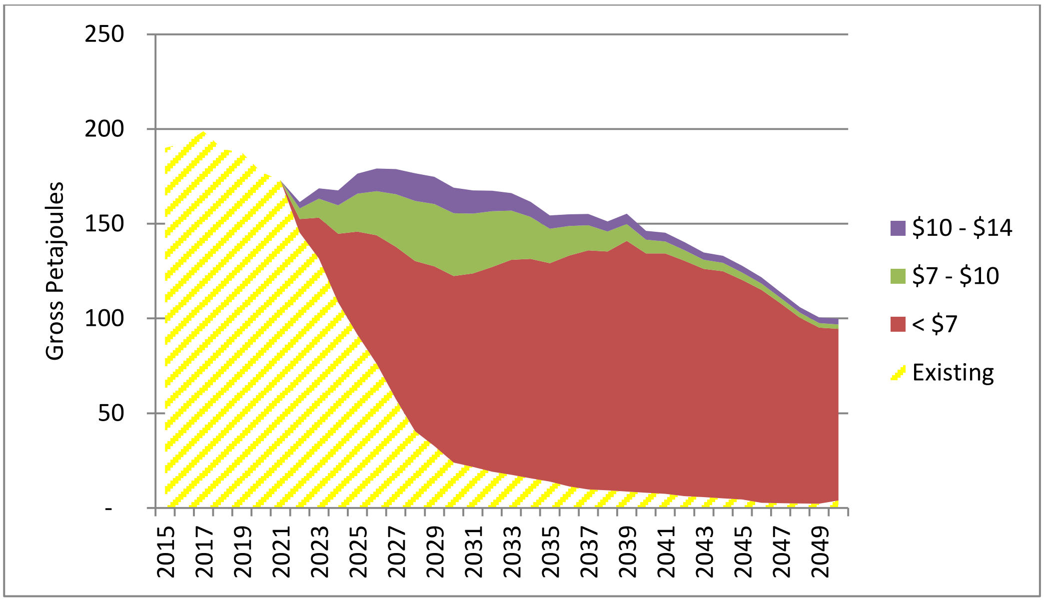
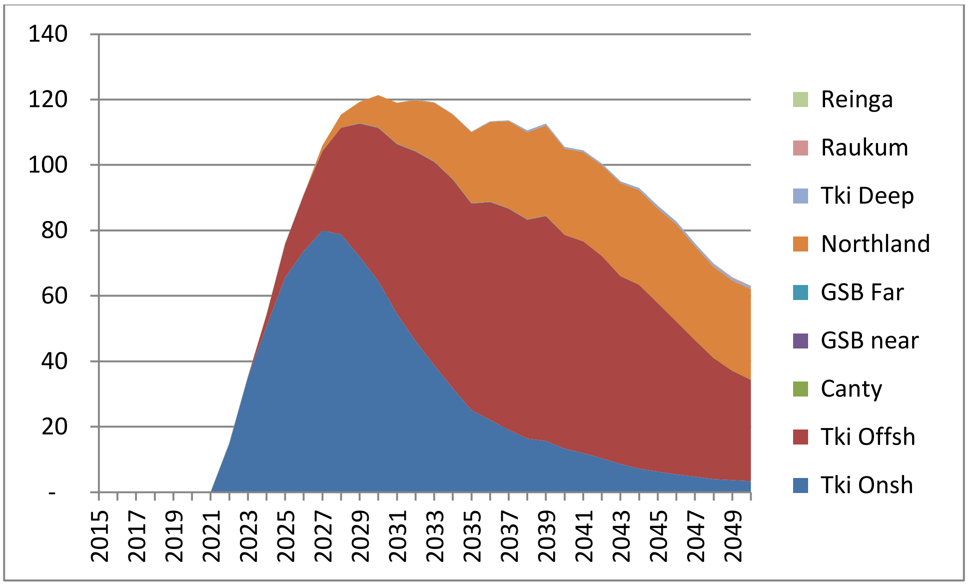


Figure 13 - Potential P50 gas production from each basin (mid oil price, mid carbon price, mid exploration used in the Mixed Renewables scenario, <13 13/GJ)



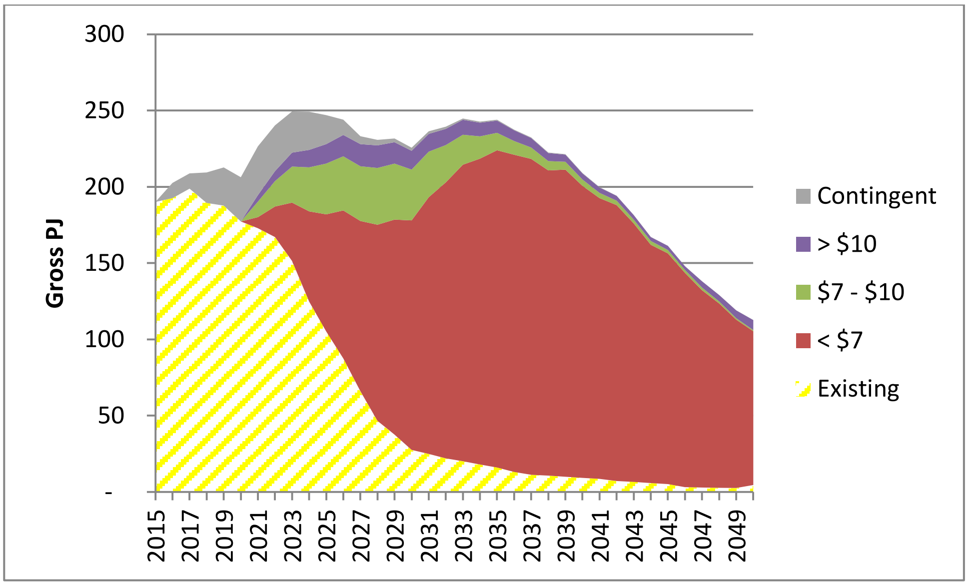
With the exploration assumptions we have, Figure 13 shows that from 2020 we could start to see some production from the onshore Taranaki basin. Further discoveries could come from Taranaki offshore and Northland frontier basins., and by 2030 up to one third of the total production from new discoveries could come from frontier basins. Most of the Offshore and Onshore Taranaki fields

[27] A potentially economic gas field has been defined in this case as a field with a break even price less than $13/GJ (excluding emissions price).

are in the $7 (or lower) price tranche, while most of the $8+ tranches are composed of frontier basins.

7.6 Gas model results – Oil price sensitivity

Figure 14 - Potential P50 production profile by break even gas price (high oil price, low carbon price, high exploration used in the High Grid Scenario)[28]



The gas supply curves are significantly affected by different input assumptions for oil price, carbon price and exploration rate. Figure 14 shows the gas supply curves based on a high-oil price, low carbon price and high exploration rate are shown, which is used in the EDGS *High Grid* scenario. New gas fields are assumed to have oil condensate also, and so the price this condensate sells for affects the economics of gas field developments. A low oil price will result in fewer gas fields meeting commercial thresholds (or in other words, the break-even gas price increases) which results in lower potential production volumes, at a $13 price cap. The inverse occurs in a low oil price case.

Based on this logic we can take the view that a high oil price will typically be associated with a lower long run gas price in New Zealand, as gas field operator may be willing to sell gas at a discount in order to extract the highly valuable oil condensate as quickly as possible.

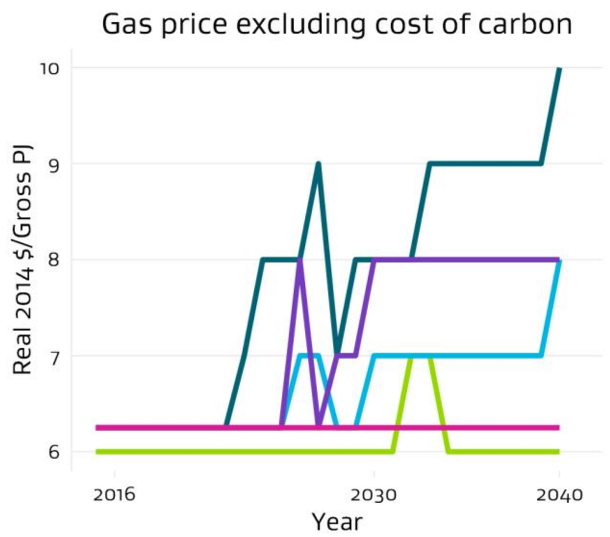
Note that this only holds if the NZ gas market remains disjointed from the international gas (LNG) market. If NZ were to import or export gas then NZ's domestic gas prices would more than likely become indexed to the oil price[29].

In the EDGS it is not always the case that higher oil prices are associated with lower gas prices. The gas price projections under each scenario reflect the availability and cost of gas supplies, but also the rate at which supplies are used. In the *Mixed Renewables* scenario where the input gas supply curves (Figure 13) have more abundant low cost gas supply than in gas supply curves used in the Global Low Carbon Emissions, we see higher gas prices in the *Mixed Renewables* Scenario than in the *Global Low Carbon scenario*, from 2035. This occurs as there is more demand for gas in the period 2013 – 2035 in the *Mixed Renewables* scenario, and the lower cost supplies of gas are used up more quickly.

[28] Excludes carbon cost.

[29] Unless we were exporting gas from a remote offshore location, far from NZ's current pipeline infrastructure, such as Great South Basin or, potentially, Canterbury.

Figure 15 - Gas price projections excluding carbon cost



8 Road Transport Demand

On-road transport energy demand is that used by New Zealand's motor vehicle fleet including light private passenger vehicles (LPV's are cars and SUVs with less than 9 seating positions), light commercial vehicles (LCV's are vans, utility, small trucks <3.5t), heavy commercial vehicles (HCV's are trucks >3.5K), and buses, motorcycles, mopeds.

The Vehicle Fleet Model (VFM) is a MoT operated model used to project future vehicle travel, vehicle fleet, fuel demand and greenhouse gas emissions.

This model forecasts transport energy use by combining forecasts of:

1. total travel by vehicle types (i.e. LPV, LCV, HCV, etc.), with
2. Projections of the vehicle size and fleet composition within each class required to meet the total travel by class in 1, and
3. Projections of future fuel consumption rates of vehicles of each size and class.

$$\text{Energy}_{\text{Transport}} = \sum_{\textit{fuels, vehicle classes \& size, road type and condition}} \text{VKT}_{\text{average}} \times \text{vehicles} \times \text{fuel factors}$$

A schematic of the modelling process is shown in the appendix.

8.1 Historical data and forecasts

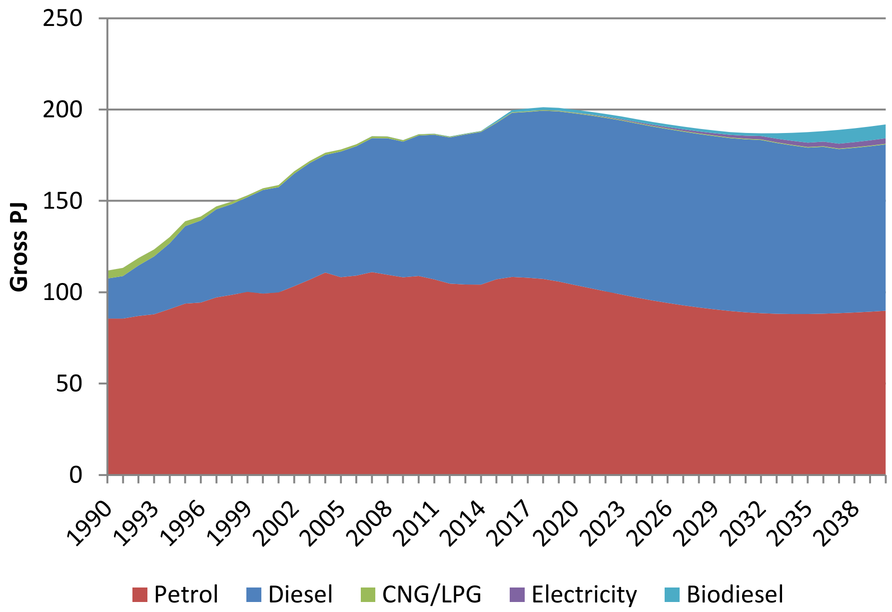
The New Zealand Energy in New Zealand[30] provides a time series of consumption of liquid fuels, showing transport accounting for the majority of petrol and a large proportion of diesel consumption.

Statistics and dynamics of the vehicle fleet are discussed in depth in the Ministry of Transport's annual publication 'The New Zealand Vehicle Fleet'[31]. Key statistics used for modelling are:

- Historical fleet data including vehicle numbers by vehicle type, size, fuel, the year of manufacture, origin (new or used import)
- Annual travel data as vehicle kilometres travelled (VKT) by vehicle type, size, fuel, the year of manufacture, origin (new or used import)
- The vehicles entering the fleet each year including both new vehicles and used imports by vehicle type, size, fuel, the year of manufacture, origin (new or used import)

Historical road transport data and forecast data are plotted together in Figure 16.

Figure 16 - Road transport energy demand - by fuel type for Mixed Renewables



Note the strong growth in diesel demand throughout and the dwindling level of CNG/LPG after the peak demand in the 1980s (when governments actively encouraged these alternatives). The growth in diesel followed earlier deregulation of the freight industry and the (almost total) move away from gasoline powered trucks and light commercial vehicles.

It is also worth making note of the plateau reached in petrol demand over the last 4 years – a period of higher fuel prices and the recession over 2008-09. Petrol demand reached a peak at in 2004, which it reached again in 2007, but it has fallen ever since.

Issues have arisen in the past because of a lack of information as to the final end-user of a proportion of our diesel but a new survey of fuel distributors has shed additional light as to the amount of this fuel used off-road. In 2014 the Ministry's Energy in New Zealand 2013 balance table shows an estimate of 34PJ of diesel used off road with 81.8PJ used in transport.

30 http://www.med.govt.nz/sectors-industries/energy/energy-modelling/publications/energy-data-file

31 www.transport.govt.nz/research/newzealandvehiclefleetstatistics/

Forecast CNG/LPG demand for transport is assumed to remain at current levels for the entire forecast period.

Transport modelling for the EDGS 2016 was done as a joint exercise between the Ministry of Business, Innovation and Employment and the Ministry of Transport[32].

In the Global low carbon emissions scenario we did consider high hybrid vehicle uptake, in the Disruptive scenario we consider high EV uptake.

Vehicle Fleet Model (VFM)

The VFM projects travel (VKT) and the future vehicle fleet for the projection period to 2040. Detailed discussion of the component models is included in the following sections.

8.1.1 Travel demand

One of the key projections made in modelling on-road transport energy demand is that of the future vehicle kilometres travelled.

Estimates of historical travel by vehicle type (measured as 'vehicle kilometres travelled' or 'VKT') are made from information gathered through the vehicle warrant/certificate of fitness process (WoF/CoF) which records odometer readings from vehicles. This allows a breakdown by vehicle type, vehicle age (year of manufacture), fuel (petrol, diesel, and electric) and size (light vehicles by engine-cc band, heavy vehicles by gross vehicle mass class).

Travel demand

Light Fleet

$$\text{VKT}_{\text{year}} = \text{population}_{\text{year}} * \text{VKT/capita}_{\text{year}}$$

where,

$$\text{VKT/ capita}_{\text{year}} \sim f\,(\text{GDP/capita}_{\text{year}}, \text{fuel price}_{\text{year}}, \text{vehicle price}_{\text{year}}, \text{Saturation level, historical data})$$

Heavy Fleet

$$\text{VKT}_{\text{year}} \sim f\,(\text{GDP}_{\text{year}}, \text{fuel price}_{\text{year}}, \text{historical data})$$

Light fleet travel

Projections of travel by the light fleet are based on a forecast of travel per capita (i.e. VKT/capita) multiplied by population. Future travel per capita is based on the historical relationship between travel per capita, GDP per capita and the cost of fuel and vehicles. The model assumes that travel per capita is capped by a manually set maximum saturation level.

In recent years per capita travel has flattened. This is due in part to higher fuel prices and the recession. It is unclear whether this suggests a saturation level has been reached. Similar flattening in travel demand has been observed in the US, UK and Europe and a range of influences have been

[32] The VFEM transport model used to forecast EV numbers in the EDGS scenarios is different to the model used by MoT to forecast EV uptake for the 2021 EV target. The MBIE EDGS scenarios focus on modelling long term transport fuel demand using MoT's *Vehicle Fleet Emissions Model*. The percentage of EVs entering the fleet in this model is defined every 5 years. Given the 5 yearly time steps in EV uptake assumptions there is uncertainty in the exact number of EVs each year in the EDGS results. It is the longer term increase in electricity demand that is important in the EDGS modelling. The MoT model used to forecast EV uptake for the 2021 EV target, models annual EV uptake on a yearly basis and is thus more suitable for determining the number of EV in the New Zealand fleet in a certain year.

suggested – including: mode switching (which in New Zealand's case may be from road to air travel in line with the strong growth in inter-city flying), some replacement of domestic travel with international travel and demographic changes. Despite this uncertainty, our model assumes that saturation has not yet been reached and sets this at 10,000kms per capita – well above current levels.

Heavy fleet travel

Heavy fleet VKT is projected based on the historical relationship with GDP and, to a lesser extent, diesel price – historically heavy fleet travel has been shown to very be inelastic to the price of diesel (for the range of prices experienced). Also heavy fleet travel has been seen to grow independently of population in the previous decade. Population is therefore not included as an explanatory variable.

8.1.2 Fleet size and composition

Fleet Size

The light and heavy fleet is broken down further by vehicle type, size, fuel, year of manufacture, and origin (new or used import). For projection purposes, the existing fleet is modified to take account of new vehicle purchases and vehicle disposals. This split is necessary as travel by various vehicle types is likely to grow at differing rates. With this split, the appropriate fuel consumption factor can be applied to each vehicle type to derive total on-road transport energy consumption.

Fleet size:

Model for light vehicles

$$\text{Fleet size}_{\text{year}} = \text{population}_{\text{year}} * \text{vehicles per capita}_{\text{year}}$$

where for LCV and M/C vehicles per capita $_{\text{year}}$ ~ f(year, saturation level, historical data)

and for LPV vehicles per capita $_{\text{year}}$ ~ f(year, historical data, constant after 2020)

Model for LCV, HCV and Buses

$$\text{Fleet size}_{\text{year}} = \text{population}_{\text{year}} * \text{vehicles per capita}_{\text{year}}$$

Light fleet

Light Passenger vehicles and light commercial vehicles are projected separately.

The size of the light fleet is projected based on a projection of vehicles ownership per capita multiplied by population projections (from Statistics New Zealand). With the effects of the recent recession on the availability of finance, and the demand for new and (newly imported) used imports, and the decreasing availability of used imports, the size of the Light Passenger Fleet, consisting mostly of privately owned vehicles, has decreased over the past two years.

Our model assumes the decreasing trend continues to a minimum of 584 vehicles/1000 people in 2012, recovers to a level of 600 LPVs per thousand people in 2020 and is constant after that.

A tanner model of the form R(t) = S/[1+ A exp(-t/T)] is used to predict the size of the Light Commercial Fleet where R is the rate of vehicle ownership (vehicles per capita). It is assumed that R increases to the saturation level S – assumed at 0.089 (89 LCV's per thousand people). T is found via a least squares fit to historical data.

The projection of total light vehicles is further broken down into its component parts based on the following assumptions:

- The share of LPV sales of hybrid and electric vehicles increases from current levels of 2.4 %.
- Electric Vehicles (EVs) contribute 20% of new LPV sales by 2030 in the EDGS *Mixed Renewables* scenario.
- Hybrid vehicles continue recent growth reaching 15% of new LPV sales by 2030 in the *Mixed Renewables* scenario.
- Used import shares lag new by 5 years.

Heavy fleet

The size of the heavy fleet is similarly projected based on a projection of vehicles per capita multiplied by population, although the heavy fleet model includes an additional GDP factor to allow growth of the heavy fleet as economic activity increases:

R(t) = S/[1+ AG^g exp(-t/T)]

Where the G = the GDP/capita from the previous year, which allows for the time taken for the effect of changes in GDP to filter through the economy.

Fleet Composition

Vehicles enter the New Zealand fleet as either new vehicles or used imports. Projections of future vehicles entering the fleet are made with a simple model that grows the vehicle purchase rate along with GDP growth.

Armed with projections of yearly fleet totals, the number of new and used-import vehicles entering the fleet each year, the market share of these vehicles by vehicle size and a base year (2009) fleet breakdown; the model then determines detailed fleets for each year. This step effectively estimates the number and distribution (size and age) of vehicles scrapped each year that give the required fleet size.

i.e. Vehicles disposed $_t$ = Vehicles year $_{t-1}$ + Vehicles added $_t$ – Vehicles year $_t$

The profile of vehicle disposals is based on historical data and an assumption that the scrapping profile by vehicle age will continue.

The draft 2015 EDGS included an update to the VFM that reflected the purchase of a larger number of more fuel efficient vehicles. This trend was projected to continue through the modelled period.

8.1.3 Fuel factors

The last step for the VFM is to cross multiply forecast VKTs for each vehicle type by the appropriate fuel consumption rate (in litres per km), or 'fuel factor'. This allows calculation of energy use by vehicle type, which sums to total on-road transport energy consumption.

The vehicle registration process in New Zealand records test cycle fuel factors for light vehicles and these are now used to estimate fuel use factors. To adjust test cycle fuel factors to reflect real world driving conditions, information on the VKT split by road type and traffic condition is used, although this does not capture all factors affecting actual fuel consumption – factors such as driving style, hills, road surface etc are beyond the scope of VFM.

There is little publicly available data on fuel use factors for the heavy fleet and these are known to vary greatly by loading factor and drive cycle. The factors used are, on average, around 3 times greater than for the light fleet.

Forecast fuel factors also take into account future road growth and traffic conditions based on regional data on current road types, traffic conditions and the relativity between regional and national population growth.

The projected fuel factors include an efficiency improvement within each class of 0.75% per year to 2025 from when we assume all efficiency gains have been made. This cumulative improvement of 11% over 15 years is conservative in that it is much lower than what has been achieved in Europe over recent years where a higher rate of improvement has been legislated. However there is no guarantee that the most efficient vehicles will be popular here as they will often be sold here at a premium price (as has been seen with some hybrid models).

9 Outputs

9.1 Electricity Demand and Generation Scenarios

Independent demand and generation scenarios are a key reference point for preparing and assessing major grid investment proposals by Transpower. Transpower are required to use the Electricity Demand and Generation Scenarios (EDGS) when developing major capital expenditure proposals.

For further information see: http://www.med.govt.nz/sectors-industries/energy/energy-modelling/modelling/electricity-demand-and-generation-scenarios.

9.2 Energy Outlook

The most recent Energy Outlook published was Energy Outlook: Electricity Insight (http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/modelling/new-zealands-energy-outlook/electricity-insight). This publication is an annual series presenting long-term energy supply and demand projections used to support decision making both within and external to government and to fulfil international reporting obligations.

9.3 Short to medium-term projection of greenhouse gas emissions

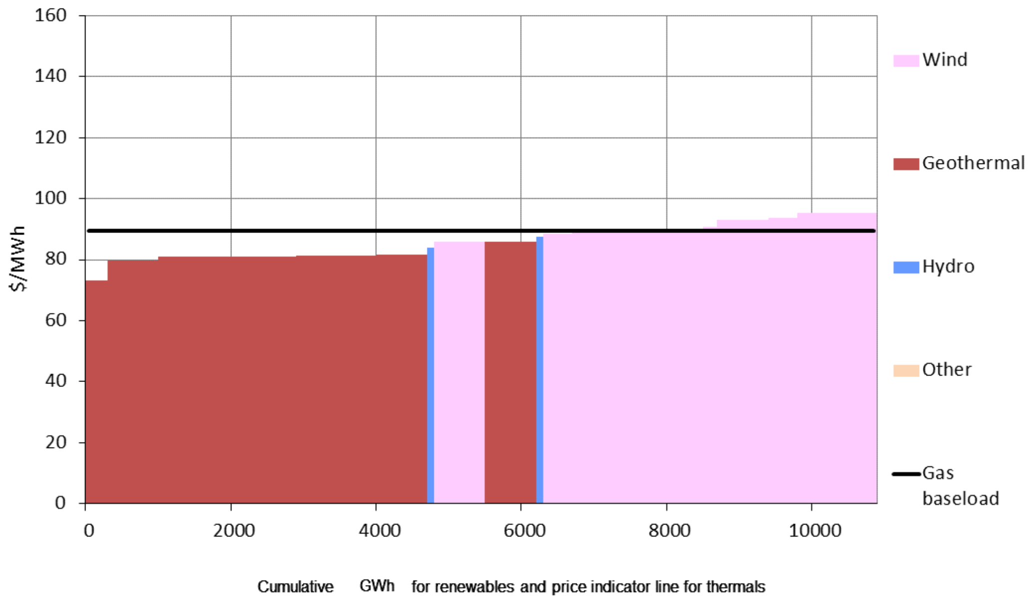
These projections are provided to the Ministry for the Environment who each year lead a whole-of-government process that produces a ‘net position’ report assessing the Crown’s liability under the Kyoto Protocol.

10 Appendices

10.1 Electricity LRMC webtool

The following is an example LRMC chart from the webtool available on the Ministry’s website. Users can enter their own assumptions around fuel prices, carbon price, exchange rates and capital costs to see how the LRMC responds.

Figure 17 - LRMC of potential new generation plant (gas $7/GJ, carbon $38/t)



10.2 **VFM Schematic**