Electricity Allocation Factor Modelling

2020

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Definitions

The following key terms, abbreviations and acronyms are used in this report.

3h	Three-hour modelling resolution
AB	Allocative Baseline
Base case	The modelled scenarios that assume medium demand growth per annum
D-N	Day-night modelling resolution
EAF	Electricity Allocation Factor
EDB	Electricity distribution (lines) business
EITE	Emission-Intensive Trade-Exposed
EMarket	Energy Link's electricity market model
ETS	Emissions Trading Scheme
FPO	Fixed price option (under the ETS)
GIP	Grid injection point (where a generator connects to the grid)
GXP	Grid exit point (where demand is supplied from the grid)
HVDC	High voltage direct current – refers to the inter-island link
ICCC	Interim Climate Change Committee
I-Gen	Energy Link's generation build model
LA	Level of Assistance
LCOE	Levelised cost of electricity
LRMC	Long run marginal cost
Ministry	Ministry for the Environment
NZU	New Zealand Unit (under the ETS)
PPI	Producer Price Index
SRMC	Short run marginal cost
TCC	Taranaki Combined Cycle Power Station
TPM	Transmission Pricing Methodology

Contents

1 Introduction

The Ministry for the Environment ("the Ministry") is reviewing the Electricity Allocation Factor (EAF).

The EAF is used to calculate free allocations of NZUs to eligible activities that are emissions-intensive and trade-exposed (EITE). The EAF is included in clause 6 of the Climate Change (Eligible Industrial Activities) Regulations 2010 and currently its value is 0.537 tCO_2/MWh. This number is a key parameter used in calculating the free allocation of approximately 2.9 million NZUs to EITE industries, currently valued at around $70 million per annum.

In November 2019, the Ministry released an issues paper (Ministry for the Environment, 2019) relating to modelling that would be required to determine if the EAF should be revised[1]. The issues paper includes background information and modelling parameters recommended in a report produced by Energy Link earlier in 2019 (Energy Link Ltd, 2019). It also called for submissions on the modelling parameters, and a range of submissions were received.

The Ministry subsequently engaged Energy Link in 2020 to undertake the EAF modelling using the recommended parameters, but taking into account feedback from submitters. This report describes the modelling methodology which has been in use since 2008 (the 'current methodology'), the modelling parameters actually used, considers feedback from submitters, and presents the various EAF values arising from the modelling, along with a final recommendation for the value of the EAF.

The methodology is based on modelling a range of possible scenarios for how the electricity market will evolve in future, and an EAF can be calculated for each scenario. However, under the current methodology, the final EAF that is used in the free allocations of NZUs is a weighted average of the EAFs calculated for the scenario. Depending on context, EAF could refer to the EAF from a particular scenario, or it could refer to the final EAF that is used in the free allocations.

Readers are referred to our earlier report (Energy Link Ltd, 2019) for details on the EAF and the modelling methodology, but these are also summarised in section 3.

The current methodology relies on being able to formulate and forecast a counterfactual scenario for the electricity market in which there is no explicit price on carbon, never was an explicit price on carbon, and no expectation of there ever being a price on carbon that is relevant to electricity generation. Over time, the counterfactual scenario becomes progressively more uncertain in respect of the make-up and costs of the generation fleet. In addition to using the current methodology for calculating the EAF, the Ministry and some EITE firms wished to explore alternative methodologies that make more use of historical data rather than forecast data, with and without a counterfactual.

[1] The issues paper can be found at https://www.mfe.govt.nz/sites/default/files/media/Climate%20Change/modelling-eaf-issues-paper.pdf

Section 3 describes the methodologies used to calculate the EAF using the current approach, and also two alternative methodologies that either do not follow the current approach, or partially follow it (with a counterfactual scenario).

Section 4 briefly describes Energy Link's two market models used for the EAF modelling, the I-Gen model which calculates what new plant is built and when in each modelled scenario, and the EMarket model of the New Zealand electricity spot market.

Section 5 describes the key input parameters and works through the matters raised in submissions to the Ministry on the inputs.

Section 6 lists out all of the results from the various approaches to calculating the EAF, including a range of calculations intended to test the sensitivity of the EAF to various inputs and assumptions.

Section 7 includes our recommendation on the new value of the EAF using the current methodology and discusses the pros and cons of the alternative methodologies.

Section 8 is an Appendix which shows how the definition of the EAF causes the value of the EAF to be sensitive to various factors.

Finally, section 9 is a list of references to reports that are relevant to the 2019 recalculation of the EAF.

2 Summary

The EAF is a key parameter used in the calculation of the number of NZUs that are allocated free each year to EITEs. Its current value is 0.537 and it has units of '\$/MWh per \$/tCO_2' although this is usually shortened to 'tCO_2/MWh'. The EAF represents the amount that electricity prices are expected to change for a unit change in the price of NZUs.

This should not be confused with physical emissions, which average around 100 g/kWh of electricity generation over a typical year, equating to 0.1 tCO_2/MWh. The EAF is a measure of the price impact of the ETS, not of the underlying emissions or emission intensity. It is a function of the marginal impact of carbon prices on spot prices.

In 2008, 2011 and again in 2020, electricity market modelling was used to calculate forecast electricity spot market price scenarios for the next several years, along with prices calculated for a counterfactual scenario in which there is no price put on carbon for emissions from electricity generation. Counterfactual scenarios must be developed from 2009, the year before the ETS included electricity generators, through to 2019, and then forecast over the modelled period, which is now the six years from 2020 to 2025.

The EAF is the difference between the average prices from the market and counterfactual scenarios, divided by the forecast carbon price:

$$EAF = \frac{Average\ spot\ price\ with\ carbon\ charge - Average\ spot\ price\ without\ carbon\ charge}{Carbon\ charge}$$

All scenarios run for this report used hydro inflows dating back to 1932, and the prices averaged across all inflow years.

The modelling undertaken for this report was based on three electricity demand growth scenarios over the modelled period 2020 to 2025 inclusive, from 0.3% per annum (low demand), 0.5% per annum (medium demand) and up to 0.8% per annum (high demand).

Counterfactual scenarios were also run for the period, on the assumption that there never was an explicit price on carbon, and nor is there any expectation of there ever being a carbon price relevant to electricity. The three counterfactual scenarios started with a modelled counterfactual plant mix that was determined by modelling the counterfactual from 2009 to 2019.

Each demand growth market scenario was run with three sets of carbon prices from low to high, giving a total of nine market scenarios for the period. These were then compared to their respective counterfactual scenarios to calculate a set of nine individual scenario EAF values, each the average over the six years in the modelled period.

The final EAF recommended for use in calculating free allocations of NZUs, is the weighted average of the nine individual scenario EAFs. In 2011 the EAF calculations used average North Is prices to calculate a final EAF value of 0.537 tCO_2/MWh; the equivalent value obtained from the modelling this year is 0.472 tCO_2/MWh. This value is a weighted average across the nine individual EAFs which assigns a probability of 50% to medium demand scenarios, 20% to high demand scenarios, and 30% to low demand scenarios. Low demand is given a lower probability than high demand, because high demand is based on higher uptake of EVs, and electrification of industry, which will take some time to gain momentum.

The recommended EAF value of 0.472 is 12.1% lower than the current value of 0.537, which is largely the result of not including scenarios in which it is assumed that large thermal generation is retired between now and 2025. If, however, a large thermal plant is actually retired, or another significant event such as the closure of the Tiwai aluminium smelter occurs before 2025, then the EAF will need to be recalculated.

The following table shows the weighted average EAF values, including a set which is included for comparison, calculated using equally weighted demand scenarios.

The table also shows EAFs calculated for regional groupings other than the North Is, including all GXPs and South Is GXPs, and for three individual GXPs that are often used as key reference points on the grid: Benmore in the centre of the South Is, Haywards in Upper Hutt, and Otahuhu in Auckland. It is not proposed to move to regional EAFs, but the figures are provided to show that the impact of the ETS on electricity does vary around the country, by virtue of the spot pricing system that is used for electricity in New Zealand.

Table 1 – Weighted Average EAFs

GXP Grouping	Probability-weighted EAF: Evenly Weighted	Probability-weighted EAF: Med Demand 50%; Low 30%; High 20%	Relative to Current EAF = 0.537: Evenly Weighted	Relative to Current EAF = 0.537: Med Demand 50%; Low 30%; High 20%
North Is GXPs	**0.475**	**0.472**	**-11.5%**	**-12.1%**
South Is GXPs	0.524	0.517	-2.5%	-3.8%
All GXPs	0.492	0.488	-8.4%	-9.1%
Otahuhu	0.536	0.533	-0.2%	-0.8%
Haywards	0.457	0.453	-14.9%	-15.7%
Benmore	0.494	0.488	-8.0%	-9.2%

A range of other scenarios were run, and compared to the 'base case' scenario (medium demand growth and medium carbon prices), to test the sensitivity of the EAF to various factors:

- retirement of the 377 MW Taranaki Combined Cycle gas-fired generator (TCC) in 2021;
- lower financing costs for building renewable generation, leading to an additional 300 MW of windfarm capacity being built over and above the new generation built in the base case; and
- the effect of climate change on inflows into the hydro lakes.

The sensitivity results are shown in the following table.

Table 2 – Sensitivity Analysis for North Is GXPs

Assumption	EAF versus Base Case
TCC retires end of 2021	52%
Lower interest rates - 300 MW additional windfarms	-21%
Inflows 2004 - 2019 only	16%

Assuming that TCC retires at the end of 2021 increases the EAF by 52% relative to the base case, because a lag in building new plant to replace it reduces the gap between supply and demand.

If lower renewables costs prompted a higher rate of build of new plant, to the tune of an additional 300 MW of windfarms, this would lower the base case EAF by 21%.

The current EAF methodology uses averaging of prices over all historical inflows back to 1932, but if only inflows from 2004 were used, in an attempt to capture the impact of climate change on inflows, then the EAF would increase by 16% relative to the base case.

The current EAF is an average over a range of scenarios, as is the recommended new value of 0.472, but an EAF can be also calculated for the individual inflow years in each scenario. Table 3 shows the individual EAFs for a series of six years in the base case, over which inflows varied widely; the EAFs for individual years also varied significantly from year to year. Looking ahead, one cannot predict inflows, so it does not make sense to use forward-looking EAFs for individual years, but this does illustrate the degree of volatility in EAFs that could result from alternative methodologies that are backward-looking and which would result in annual updates to the EAF.

Table 3 – EAFs for Individual Inflow Years in the Base Case

Inflow Year	EAF versus Base Case
2007	34%
2008	181%
2009	-53%
2010	3%
2011	-46%
2012	97%

Two backward-looking alternative methodologies were modelled, one using a "back-cast" of the actual market. Carbon costs are then removed from generator offers into the spot market and the model rerun, to produce counterfactual prices without carbon. This produced EAFs that varied between 0.312 and 0.557 for the four years from 2016 to 2019. This alternative methodology would be applied each year, and it has the advantage of not requiring a counterfactual scenario dating back to 2009, which obviously becomes increasingly uncertain over time. However, its disadvantage is that it would produce EAFs that vary widely from year-to-year, introducing significant volatility into the annual free allocations of NZUs, as illustrated in the following table where these EAFs were calculated for four recent years.

Table 4 – Annual EAFs Using Back-cast With and Without Carbon, All GXPs

Year	Back-cast Without Carbon	Back-cast With Carbon	EAF	Running Average EAF
2016	$53.2	$56.6	**0.427**	**0.427**
2017	$78.9	$82.8	**0.312**	**0.369**
2018	$104.5	$112.3	**0.410**	**0.383**
2019	$98.3	$111.8	**0.557**	**0.426**

The second alternative method uses a "back-cast" of the counterfactual scenario for the base case, which is then compared to actual market prices. This produced EAFs that varied between -0.109 and 1.898 depending on the year (from 2016 to 2019) and the gas prices assumed in the back-cast. A negative EAF implies that prices would be lower without the ETS. This wide range suggests that this alternative methodology could be unstable, and it also gas the disadvantage that it relies on a counterfactual scenario dating back to 2009.

3 Methodology

The Climate Change Response Act 2002 established the framework for the ETS, and it also allows for the allocation of free NZUs to EITE industries. The allocation to an industry is given by

$$\text{Allocation} = \text{Production} \times \text{Allocative Baseline (AB)} \times \text{Level of Assistance (LA)} \qquad (1)$$

and the AB for any industry using electricity is partly based on the EAF, so when the EAF changes, then all such ABs will also change. As most industrial and agricultural processes require electricity, a change in the EAF will impact the majority of the ABs[2].

The EAF is a single figure that expresses the amount by which electricity prices change with the carbon price, and has underlying units of '\$/MWh per \$/tCO_2' although this is usually shortened to 'tCO_2/MWh'. This is perhaps an unfortunate unit to use for the EAF, because it is easy to confuse with physical emissions, which average around 100 g/kWh of electricity generation over a typical year, equating to 0.1 tCO_2/MWh. The EAF, on the other hand, is a measure of the price impact of the ETS, not of the underlying emissions or emission intensity, and it is a function of the marginal[3] impact of carbon prices on spot prices.

The definition of the EAF can be traced back to the Stationary Energy and Industrial Process Technical Advisory Group in 2008, and was stated by Concept Consulting in 2011[4] to be:

$$EAF = \frac{Electricity\ purchase\ cost\ with\ carbon\ charge - Electricity\ purchase\ cost\ without\ carbon\ charge}{Carbon\ charge} \quad (2)$$

where the purchase costs of electricity are in \$/MWh and the carbon charge is specified in \$/tonne CO_2.

Concept Consulting noted that "the intent of the EAF is to establish the price difference between the 'with CO_2' factual and the likely 'without CO_2' counterfactual. To establish such a counterfactual requires a modelling approach which 'turns the clock-back' and projects a schedule of generation build and retirement from before 2010 (the date of introduction of the ETS) for a world where there has never been a cost of CO_2, and no expectation of such a cost."

The approach recommended by Concept Consulting Ltd and used in 2011, was to model the period of interest (2012 to 2017 in 2011 and 2020 to 2025 in this report) both with and without a carbon charge, with electricity prices being the key outcome of the modelling. In this report we refer to scenarios with the ETS as 'market scenarios' and to the scenarios without the ETS as 'counterfactual scenarios'.

This requires modelling of two separate worlds which potentially develop in quite different ways. But just because there is no carbon charge, and "no expectation of a carbon charge" in the counterfactual scenarios, does not mean that there is no climate change. If New Zealand did not have an ETS, nor any expectation of ever having an ETS (or equivalent explicit carbon charge such as a carbon tax), we nevertheless live in a world where climate change is happening and, as a result, there is huge investment offshore in renewables because of the demand induced by climate change, thus bringing the cost of renewables down over time. There are also domestic carbon-reduction policies which are not based on the ETS. Because of this, the counterfactual is not isolated from the transition to renewables, it just happens at a much lower rate.

[2] Refer to section 2 of our earlier report (Energy Link Ltd, 2019).
[3] Because spot prices reflect the marginal cost to spot purchasers.
[4] Refer to section 2.1 of our earlier report (Energy Link Ltd, 2019) and to section 8 for the reference to Concept Consulting's report.

3.1 The Carbon Charge

The denominator of equation (2) on page 6 is the carbon charge, so the choice of the carbon charge value is a key determinant of the EAF in any given scenario that is modelled.

In the real world, not all generators have the same carbon charge at the same time. In practice, if one analyses market data including the offers made by generators into the electricity spot market, it is difficult, if not impossible, to find a statistically significant relationship between the offer prices and the NZU price prevailing at the time, even when the cost of carbon has risen rapidly in past years. One reason for this is that carbon is just one cost of owning and operating a generator, and not the most significant.

A lot of thermal generation is also offered into the market at a price close to zero, including all generation at one station, for a variety of possible reasons.

While it is possible to recognise that different generators may have different carbon costs in the modelled scenarios, this is substantially more difficult than assuming all generators face the same carbon costs at the same time. The assumption implicit in the modelling undertaken in 2011 was that all generators would factor the same carbon charge into their respective offers to generate into the spot market, and that this would also be used as the carbon charge in the denominator. For the sake of consistency alone, therefore, we have used the same approach throughout.

3.2 Modelling Methodology

In (Energy Link Ltd, 2019) we noted that “calculating a new EAF is about as difficult a modelling exercise as one can get in terms of the electricity market and price forecasting”. This is partly because of the sensitivity of the EAF to the terms in the numerator of (2), as fully described in section 8. It is also partly because equation (2) has three terms, and each term is uncertain when looking forward over the modelled period out to 2025:

1. electricity purchase cost with carbon charge: this is given by a forecast of average wholesale electricity prices with the ETS;
2. electricity purchase cost without carbon charge: this is given by a forecast of average wholesale electricity prices without the ETS, and no expectation of ever having an ETS;
3. carbon charge: this is the forecast of average carbon prices over the period.

All of the modelling starts from the present day, which sets the starting point for the plant mix, carbon price, and other variables for the market scenarios (number 1 in the list above) but the starting point for the counterfactuals cannot be assumed to be the same as for the market scenarios because the ETS is in its ninth year of operation and is almost certain to have had an influence on the decisions made by electricity market participants on whether to retire or build new plant, and which type of new plant is built.

Hence the first step in the modelling is to run a forecast of the counterfactual starting from 2009 through to the end of 2019 to determine the starting point for the future counterfactual scenarios that must be modelled.

The ETS took effect in stages from January 2010[5] and the first date on which electricity generators could assume their full obligations under the ETS was July 2010, so 2009 is the last year in which generators had no obligations under the ETS. However, ETS design was underway in 2007, and prior to 2007 there were also proposals for a carbon tax. From 2003, a number of new generation projects were awarded tradeable units under the 'Projects to Reduce Emissions' scheme[6], which was discontinued in 2005[7] by which time 41 projects were approved[8]. Five of these projects were windfarms that were actually built or extended: Genesis Energy's Hau Nui extension; Meridian Energy's The Apiti and White Hills wind farms; the 2nd and 3rd stages of TrustPower's Tararua wind farm; New Zealand Windfarms Te Rere Hau wind farm.

In 2002 the government announced its intention to implement a carbon tax[9] of $15 per tonne, to be introduced in April 2007, but subsequently scrapped this proposal in favour of implementing the ETS.

Arguably then, even before 2009 there was an expectation of a carbon cost relating to electricity, even if the details were far from settled, which suggests that the counterfactual should ideally be started from the early 2000s. However, this would require the creation of an alternative history for the electricity spanning 20 years, a period four times as long as the forecast period out to 2025. To rationalise the amount of work required to determine the counterfactual plant mix in 2019, we have instead undertaken alternative build modelling from 2009 to verify manual adjustments to the actual build from 2000 through to 2019.

When the EAF was calculated in 2011, a contact group was formed to review the modelling results. In its conclusion, this group listed a number of "lessons from the first two EAF determination exercises":

- the purpose of each scenario, and how the scenario fits into the overall EAF methodology, should be clearly stated;
- assumptions ideally should be sourced from independent verifiable sources;
- assumptions consistent with each other;
- simplicity and attention to the key variables of interest should be a focus;
- the build model should be allowed to select the optimum build as far as possible without external adjustments;
- consistency across multiple time horizons is important.

In preparing background material (Energy Link Ltd, 2019) and recommending various input parameters, we took note of the above lessons, and recommended a modelling approach different to that employed in 2011.

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[5] See https://www.mfe.govt.nz/sites/default/files/media/Climate%20Change/A%20Guide%20to%20the%20New%20Zealand%20Emissions%20Trading%20Scheme.pdf
[6] These units could be traded internationally under the general auspices of the Kyoto Protocol.
[7] See http://motu-www.motu.org.nz/wpapers/17_06.pdf
[8] See https://www.mfe.govt.nz/more/cabinet-papers-and-related-material-search/briefing-notes/briefing-incoming-ministers-all
[9] See https://www.beehive.govt.nz/release/government-adds-detail-2002-carbon-tax-policy

The modelling in 2011 canvassed a wide range of possible futures including retirement of major thermal generators. If retirements are not signalled well in advance, then given the long lead times for building new generation, the market will tend to lag in building new plant to replace it and other modelling undertaken regularly by Energy Link strongly suggests that this will result in elevated spot prices that can continue for a few years, the result of a restriction in supply relative to demand. An elevation of forecast spot prices would produce an elevated EAF, relative to an EAF calculated with the retirement being signalled as definite, well in advance, or with no retirement.

Similarly, the Tiwai aluminium smelter could close with as little as 12 months of notice[10], an event which would precipitate a substantial drop in spot prices, particularly in the South Is, which could last for several years.

Obviously, the further out one attempts to forecast such events, the greater the uncertainty in the timing and impact, so as a result we recommended that the value of the EAF should be reviewed at least every five years and preferably every three years.

Furthermore, due to the magnitude of the events such as closure of a large thermal generator or closure of the Tiwai smelter, and the potential impact on the value of the EAF, we also recommended that such events not be considered in the EAF modelling. Instead, we recommended that such events should trigger a recalculation of the EAF.

We also recommended modelling a limited set of scenarios based on three values for annual demand growth (0.3%, 0.5% and 0.8% per annum) and three scenarios for the evolution of the carbon price (base case rising linearly to $50 per tonne by 2035, along with a low and a high scenario). Combining three demand scenarios with three carbon scenarios gives a total of nine market scenarios in total.

Demand growth of 0.5% per annum and the $50 carbon scenario together form what we refer to as the base case for the market scenario.

For each market scenario there is also potentially a unique counterfactual scenario, but with simplifying assumptions we can reduce this number down from nine to three: there is no carbon price in the counterfactuals, so the counterfactuals only change with a change in the demand assumptions.

The modelling proceeded as follows.

Step 1. **Historical Counterfactual Scenario 2009 to 2019**
This scenario is required to determine the starting plant mix for counterfactual scenarios[11].

Step 2. **Base Case Counterfactual and Market Scenarios**
Produce a base case counterfactual and market scenario with demand growth of 0.5% per annum for both scenarios and a carbon price rising linearly form today's value to $50 in 2035. By undertaking the base cases first, we uncover modelling issues that may need to be considered in other scenarios.

[10] This notice period is required under the smelter's hedge contract with Meridian Energy.
[11] Market scenarios start with the current plant mix.

Step 3. **Other Scenarios**
Produce the rest of the market and counterfactual scenarios.

Step 4. **EAF Calculations**
Using the appropriate scenario-counterfactual pairs, calculate the EAFs for each year modelled, and for the six-year period from 2020 to 2025. Assign a probability to each scenario and calculate the weighted average EAF for each year and for the six-year period.

Step 5. **Context Checking**
As recommended by the contact group in 2011, the calculated EAFs was checked against other reference datums described in section 4 of our earlier report (Energy Link Ltd, 2019).

Step 6. **Final EAF**
Calculate the final EAF as the weighted average over the annual EAFs calculated in Step 4 above.

In our earlier report we recommended using 'market modelling' which is an approach to modelling electricity markets which uses a model to forecast the plant that will be built in future, for any given set of scenario inputs: this is referred to as a 'build schedule' and it is based primarily on the assumption that a proposed plant will be built if it is forecast to provide a threshold return on investment over its lifetime.

The model we use for producing build schedules is an in-house simulation model called 'I-Gen', which undertakes a simplified simulation of the wholesale electricity market over the forecast period. The simulation takes account of complicating factors such as pricing variations across the electricity grid, and the 'market premium' that a new generator might expect, defined as $\frac{GWAP}{TWAP}$ where *GWAP* is the generation-weighted average price achieved by a generator and *TWAP* is the time-weighted average price at node where the generator connects to the grid.

For example, wind farms in New Zealand currently operate with a market premium of approximately -10%, because when windfarms generate they generate 'cheap' electricity but when they don't operate, because it is calm, then more expensive plant has to run, at higher prices, to make up for the lower wind farm output.

Geothermal plant tends to run baseload so its market premium is close to zero. Thermal peaking plant, on the other hand, is there to run when other supply is short and so it runs at a higher price[12] and achieves a positive market premium.

Once the build schedule is calculated for a scenario, then the new plant is added into the list of generators in our electricity market model called '*EMarket*'. *EMarket* is then run over the forecast period to produce forecast spot prices based on its highly detailed simulation of the operation of the spot market.

[12] The higher prices are typically the result of the need to recover short-run marginal costs such as fuel and carbon, along with fixed costs. Peaking plant doesn't run all the time, and perhaps as little as 30% of the time in the present day, so fixed costs have to be recovered over less output than is the case for baseload generators.

Spot prices are used as the basis for the calculation of how the prices paid by EITE's will vary in future because virtually all electricity that is bought and sold in New Zealand must be transacted through the spot market, thus the spot market tends to drive prices in the retail market in which electricity retailers (who may also be generators) sell electricity to consumers. The EAF calculation is limited to spot prices for energy and do not include line charges because line charges are not expected to vary significantly due to the existence, or otherwise, of the ETS or other explicit carbon charge.

In section 2.3 of our earlier report (Energy Link Ltd, 2019) we also recommended calculating regional EAFs because our system of spot pricing leads to the potential for EAFs to vary by location on the grid. This is a simple undertaking, once the scenarios are completed, because *EMarket* calculates spot prices at 221 nodes on the grid[13].

3.3 Alternative Methodologies

Application of equation (2) on page 6 requires a forecast of prices with a carbon cost and a forecast of prices in a counterfactual scenario without carbon costs. Forecasting the current market has uncertainty associated with it, but forecasting the counterfactual, which has to be established starting in 2009, has even more uncertainty associated with it. The uncertainty in the counterfactual forecast therefore increases over time whereas the uncertainty in the market forecast remains more-or-less constant, or at least changes at a lower rate than it does for the counterfactual.

We have therefore explored two different approaches to calculating the EAF:

1. comparing the actual market outcome for the last year to an alternative market outcome where the cost of carbon is removed;
2. comparing the actual market outcome for the last year to a "back-cast" of the counterfactual scenario.

Both of these alternatives require back-casts of the market, where a back-cast uses a market model to accurately simulate the market for the last year.

In the first alternative methodology, a back-cast of the actual market is compared to the same modelled market, except that the offers made by thermal generators[14] are reduced by the historical average cost of NZUs to give a 'no-carbon market back-cast'. Equation (2) can then be applied using the market back-cast, the no-carbon market back-cast and the average NZU price, to give another estimate of the EAF applying specifically to the year modelled.

In order to make the market back-cast, all inputs must be set up the same as in the actual market, including demand, hydro inflows, generator offers, the grid, and so on. This means that the EAF thus calculated is specific to that year, and that year only. This is in contrast to the EAF calculated using the current methodology which is entirely forward-

[13] Spot prices are published at about 250 nodes. The nodes that we do not model explicitly are those where there are multiple nodes at a substation, with very similar prices. For example, there may be nodes of 220 kV, 110 kV and 33 kV: we would model these as one node unless there is a possibility of a price separation between them, as can happen at Kawerau, for example.

[14] This includes only those offers that have a carbon component, so it does not include, for example, any offers priced at or near zero; such offers are typically intended to have a plant dispatched at its minimum output.

looking and therefore based on averaging the prices over all inflow sequences that might occur in future[15].

If this alternative methodology were to be adopted, then the EAF would vary year-by-year and possibly by quite large amounts, a point that was tested by running the methodology for the four years from 2016 to 2019 inclusive.

The second alternative methodology is similar to the above, except that the actual market prices are compared to prices from a back-cast of the base case counterfactual scenario developed for the current methodology.

4 Market Models

As mentioned in section 3.2, we used two Energy Link models to produce the counterfactual and the market scenarios: I-Gen and *EMarket*.

I-Gen is used to produce build schedules for each scenario, the lists of new plant that is built during the period 2020 to 2025, including the location, commissioning date, capacity and type of generation. It does this by simulating the process by which generators and would-be generators make decisions when to build new plant. The inputs to I-Gen include a list of potential projects based on those in the public domain, an estimate of the cost of building, owning and operating each of these projects over their respective economic lifetimes: this cost is known as the Levelised Cost of Electricity (LCOE) for each project.

LCOE is defined as the constant average annual electricity price attained by the plant over its lifetime that just achieves target return on investment after covering all cash costs. The LCOE of a project is calculated using discounted cash-flow analysis of all cash flows over the life of a project including revenue, construction costs, interest on debt, operating and maintenance costs, taxation, and where relevant carbon and fuel costs, taking into account inflation and an assumed figure for a generator's target post-tax nominal return on equity of 8%[16].

There is a lot of data available on the internet about LCOEs of various types of plant, but the methods by which these are calculated are not necessarily consistent, and they may also use input data which are neither correct nor relevant in New Zealand. For example, our exchange rate and our small size can lead to higher construction costs on some projects. Our approach is therefore to apply a consistent methodology which includes all local cash flow, and to calibrate to New Zealand conditions using publicly disclosed data for recent projects that were actually built in New Zealand.

I-Gen also models demand growth and any retirements of plant that is confirmed during the period of study.

In principle, a project is built when the approximate forecast price path produced in I-Gen, at the generator's proposed node, produces revenue that has an average price which consistently meets or exceeds the generator's LCOE, after taking account of the market premium and grid location. There some restrictions, for example only one new

[15] Which simply means running the model with all inflow years in the historical record.
[16] Assumed, for example, in work undertaken for the Interim Climate Change Committee.

project can be committed per month. Once a project is committed, then this is taken into account in the updated internal price forecast, including regional adjustments.

Once the build schedule is calculated, the new generation plant in the build schedule is added into the list of existing generators in the *EMarket* model, and *EMarket* is then run to simulate the spot market for the period of study.

The core elements of *EMarket* are listed below.

1. A grid consisting of 221 grid injection points (GIPs) and grid exit points (GXPs) and around 292 transmission lines: this provides enough detail to allow accurate calculation of power flows and losses on the grid including the high voltage DC (HVDC) link that connects the two main islands.
2. Detailed modelling of major hydro systems including large storage reservoirs, head ponds, individual generating stations, minimum flows and water values.
3. Detailed modelled of wind and solar farms including use of historical wind speed data for wind generators and reliable forecast solar data for any solar farms that are built during the period of study.
4. Detailed modelling of geothermal and thermal generation.
5. Full modelling of the competitive process of generators submitting offers into the spot market. Thermal offers are structured in a way that mimics what we observe in the actual spot market.
6. Full modelling of the dispatch process and the process of calculating the final spot price used for settlement.
7. An internal programming language that is used for a variety of purposes including modelling scheduled maintenance of large generating plant.

The outputs produced by *EMarket* include generation, power flows on the grid, storage in hydro lakes, demand response to high prices, and so on. Of interest in the context of the EAF are the spot prices that are produced.

5 Key Inputs to the Modelling

Our earlier report (Energy Link Ltd, 2019) recommended the values of, or approach to, variables to be used in the modelling[17], and these were included in the issues paper (Ministry for the Environment, 2019). The table below shows these recommendations in the second column.

A number of submissions were received concerning the parameters and the modelling, and in some cases we have altered the parameter values in response to these, as shown in the third column in the table. The submissions are discussed in section 5.1 below.

Table 5 – Values of Key Parameters

Parameter	Recommended Values	Values Used (if different to recommended)
Demand	0.3%, 0.5%, 0.8% p.a.	
Carbon price for final EAF results	Rising linearly to $50 by 2035, along with a low and a high scenario	• Base case rising linearly from $29 in 2020 to $50 by 2035 • Low scenario $29 in 2020 falling to $20 in 2025

[17] Refer to section 3 of (Energy Link Ltd, 2019).

Parameter	Recommended Values	Values Used (if different to recommended)
		• High scenario $35 in 2020 rising to $50 by 2025
Gas	Disclosed prices plus PPI where appropriate	
Coal	Indonesian coal price forecast for the type of coal burned at Huntly, plus domestic transport costs	
HVDC Charges	Phase out over the next few years	$5.50/MWh of injection onto the grid for South Is generators only
Solar	Value of behind-the-meter solar is the relevant forecast daytime spot price	
Wind farm offers	Newer windfarms $5/MWh through to the oldest windfarms at $20/MWh	
Genesis-Meridian swaption	Renewed in 2023	
Tiwai Pt smelter	Operates at its current normal operational load unless turned down during an extreme dry year	
Retirements	All plant remains in the market at current capacity	
Inflows	Market modelling include all historical inflows available back to around 1930	
River chains and lakes	Water values consistent with market	
Wind profiles	Moderate accuracy in terms of correlations between wind farms, high accuracy not required	Higher accuracy will be achieved by default
Solar profiles	Basic solar output profile for behind-the-meter solar	
Demand profiles	Detailed enough to capture peak, off-peak dynamics within each week of the year	
Time resolution	High resolution may be useful, e.g. particularly for finalising scenarios, but is not considered essential provided that the demand profile shape is captured at the required minimum level	
Demand response	Demand response would capture the likely response during an Official Conservation Campaign and also the possibility of Tiwai load being reduced when storage falls below trigger levels in the Meridian-Tiwai hedge agreement	
Outages	Known outages and expected planned outages of major plant to be modelled	
Transmission grid	If decided, sufficient detail is required in the grid model to allow the impact of marginal losses on the EAF to be assessed accurately	*EMarket* produces data at 221 grid nodes, so regional EAFs are provided for interest
Inflation	PPI 2% per annum	
Wind LCOEs	Calibrate to actual market data and deflate by 0.5% per annum in real terms	Deflate by 0.65% per annum in real terms
Solar LCOEs	Calibrate to actual market data and deflate by 4.5% per annum in real terms	

5.1 Submissions

This section works through the feedback provided by the 14 submitters and provides the rationale for either accepting or rejecting the submitters' suggestions, whether in part or in whole.

5.1.1 Transmission Charges

The Electricity Authority has proposed, for the third time, a new Transmission Pricing Methodology (TPM). Three submitters highlighted uncertainty around whether a new TPM will ever be adopted. Our recommendation was to assume that the proposed TPM is adopted and that the current High Voltage Direct Current inter-island link (HVDC link) charge applying to South Is generation would be phased out over the next few years. The HVDC charge is a marginal cost borne by South Is generation that is not borne by North Is generation, which potentially makes it more attractive to build new generation in the North Is, and hence the value of the assumed HVDC charge potentially changes build schedules used for forecasting new plant build.

Our recommendation was to start at the then-current value of $8.6/MWh and to phase this out over the next few years. For example, phasing out over five years would give an average value of $3.44/MWh over the modelling period, phasing out over six years would give an average of $4.3/MWh and so on.

In November the Commerce Commission released its decision on Transpower's maximum allowed revenue and the HVDC charge resulting from this is now only $5.35/MWh for the current year. Given that this is now closer to the average values above, and in the interests of simplicity, therefore, we have used a value of $5.50/MWh which allows for some inflation over the modelling period.

5.1.2 Modelling Period

Some submitters assumed the modelling would span the next 10 years, or even longer in one case, whereas our recommendation of reassessment every three to five years requires only a five-year modelling period (and we are actually using six years to provide the I-Gen model with one additional price data point). Using a shorter modelling period considerably reduces uncertainty in key inputs and makes the modelling exercise simpler than it would be with a longer period, in line with the 2011 contact group's recommendation that "simplicity and attention to the key variables of interest should be a focus"[18].

5.1.3 Carbon

One submitter noted that international projections of carbon prices provide an important point of reference. However, our ETS is not currently linked to other emissions trading schemes. At the end of 2019 the government released a consultation document[19] recommending a number of changes to the ETS settings for 2020 – 2025, ahead of the introduction of auctioning of NZUs which are scheduled to commence late this year:

- a price floor of $20 is introduced as a reserve price when auctions commence;
- a price ceiling of $50 is introduced for auctions via a "cost-containment reserve";

[18] Refer to section Modelling Methodology.
[19] Available at https://www.mfe.govt.nz/publications/climate-change/reforming-new-zealand-emissions-trading-scheme-proposed-settings

- the fixed price option (FPO) of $25 remains in place for 2019 emissions, which must be surrendered in May of this year, but then increases to $35 for 2020 emissions, prior to the first auction of NZUs.

The consultation document also states that the ETS will remain closed to international carbon units through to 2025, although this could be reviewed under “certain circumstances”.

The paper notes that the $50 ceiling “is designed to be set at an unexpectedly high NZU price outside of the predicted price path, and therefore only released in extreme circumstances” which is to say that the government does not expect the price of NZUs to reach $50 by 2025.

After the consultation document was released, the NZU price jumped from just under $25 up to around $29, although it has subsequently fallen back to $26.

Taken together, the above suggests that a scenario in which the price of NZUs rises linearly from $29 today through to $50 by 2035 is plausible as a base case through to 2025 by which time the carbon price reaches $36. The value of $29 assumes that the $35 FPO will be introduced for the 2020 emissions year, in which case the current FPO of $25 will no longer be relevant as a price ceiling and the price of NZUs will start to rise again.

As a low scenario, it is tempting to use $35, only $1 less than the base case, but the consultation document notes that this value is chosen because it is “set as an average between the proposed [auction] price floor and price ceiling” which provides “cost certainty … while the auctioning system is implemented but not yet fully operational”. As there is a large surplus of NZUs already held in reserve, the NZU price may not reach $35 or, if it does, then it may fall lower in 2021 when the $35 FPO is removed.

The objective of modelling three different carbon prices is to cover a range of what could reasonably be expected in future, and modelling a wider range of carbon prices also helps to illustrate the sensitivity of the EAF to the carbon price. This being the case, and given the settings shown in the consultation document, we have chosen the high scenario for the NZU price to be $35 in 2020 rising to $50 by 2025 and the low scenario to be $29 in 2025 falling to $20 by 2025.

5.1.4 Gas

One submitter suggested that gas prices will rise faster than Producer Price Index (PPI); another that where gas prices are not disclosed they should be inferred from the spot prices paid to gas-fired generators; and another that disclosed gas prices are lower than spot gas prices, and that the higher spot prices will eventually be reflected in the price of gas under contract to gas-fired generators.

There are three parties in the thermal sector – Contact, Genesis and Todd Energy[20]. Todd is also a major player in the gas market, but is privately owned and does not disclose gas prices. One way to estimate Todd’s gas prices would be work backward from the prices at which their 100 MW gas-fired generator at McKee is offered into the

[20] Owned by the Todd Group who also own electricity retailer Nova Energy.

market, however, McKee is offered in at a very low price when it runs. But if we assume that it is offered in when Todd expects it to recover costs, and subtract off an allowance for its carbon cost, then we observe that it tends to run at a price which suggests its gas price is $7.25/GJ.

We don't need to do this for Genesis Energy, however, because the company published the prices that it pays for Kupe gas[21] in a presentation in August 2018. The prices under contract include PPI adjustment and start at $7.50 - $8.50/GJ in 2019, rising to $8.5 - $9.5/GJ in 2025.

Genesis also published the quantities under contract with Kupe, and these do fall over time, so additional gas will be required: in a presentation in November of last year the company said it expected to pay between $7/GJ and $8/GJ for new gas in the first half of the current decade.

Contact Energy disclosed its average gas price of $6.1/GJ late in November 2018. The company subsequently last year indicated a price of $6.50/GJ as more likely looking ahead, and recently it has disclosed its forecast average gas prices for the next two financial years, and these are in the $7/GJ and $8/GJ range. However, the company must wait to find out how much gas OMV finds in the Maui field before the volumes it has contracted for 2021 and 2022 are confirmed. While there is a high probability that sufficient gas will be confirmed this year, this cannot be guaranteed, and a shortfall could yet lead to higher gas prices for Contact.

It is true that prices spiked up in the gas spot market last year[22], but these have since trended down and the monthly volume-weighted average currently sits around $8.60/GJ which includes the cost of carbon in each trade. The cost of carbon will not be the same in each gas trade, but if we assume the current value of $29 per tonne then this translates into $1.54/GJ, to give an average gas price of $7.01/GJ.

According to statistics published by MBIE the wholesale price of gas trended down after 2010, but rose again in 2018 and the annual average was $6.57/GJ.

Taken overall, gas prices do appear to be on the rise, but they also seem most likely to settle in a range between $7/GJ and $8/GJ. As a result, we have used gas prices in line with these current price indications.

5.1.5 Plant Retirements

A number of submitters raised the issue of the impact of plant retirement, as did we in our earlier report (Energy Link Ltd, 2019). Our recommendation was to ignore retirements in this EAF review, but to use the announcement of a significant retirement as a trigger to recalculate the EAF. However, we have included the possibility of the retirement of TCC as part of the sensitivity analysis in section 6.4.

5.1.6 Demand Growth

One submitter recommended explicitly accounting for electricity used for transport and process heat, but this appears to be on the assumption that the modelling runs well past

[21] Genesis has a 46% share in the Kupe field.
[22] www.emstradepoint.co.nz

2025. Using a shorter modelling period reduces uncertainty around demand growth, and this gives a range of 0.3% to 0.8% per annum which equates to a relatively wide range of 0.72 TWh to 0.192 TWh by 2025.

5.1.7 Demand Profiles and Time Resolution

The relatively short modelling period of six years means that any change in demand profiles due, for example, to solar uptake or the charging of EVs, will be relatively small. However, we undertook the initial modelling using a modelling resolution of D-N then, once the scenarios were settled, we then reran them[23] using a resolution of three hours (3h), which captures most of the impact prices of peak periods[24].

Sensitivity analysis and the alternative methodologies were undertaken using D-N resolution.

5.1.8 Water Values

One submitter interpreted our recommendation to use "water value consistent with the market" as a recommendation to use historic offers for hydro plant. However, the recommendation is to use water value algorithms which forecast how hydro generators' water values will be set in future under forecast conditions, a function performed in our *EMarket* model.

5.1.9 Inflows

One submitter noted that the National Policy Statement on Freshwater Management could result in changes to the water available for generation, and others wanted more recent inflows to be given priority over older inflows.

We do observe a long-term trend to a slightly drier summer-autumn in the southern lakes, and a slightly wetter winter, with no change in the annual average. But there is still huge volatility within this trend. Climate change could impact the total inflows, or change seasonal averages further, but the change will be small on average out to 2025, but we have included sensitivity analysis, described in section 6.4.3, where we only run with inflows from 2004.

5.1.10 Wind Profiles

One submitter stated that high accuracy in modelling wind profiles is required due to the likely increase in wind generation over the next decade and beyond. The modelling period, of course, is only half a decade, but in any case the data that we use is already at the higher end of the spectrum.

5.1.11 Demand Response

Our recommendation was intended to ensure that demand response is accounted for because it has a significant impact on prices during periods where the market is under stress. The demand response modelled is consistent with observed market behaviour

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[23] In some cases where the differences between scenarios was small, the scenarios were not rerun, but simply scaled based on comparing the results of day-night and three-hour scenarios that were directly comparable.

[24] 3h modelling is a trade-off between modelling accuracy and the time it takes to run the model and to process the results. This was tested, for example, in work undertaken by Energy Link for the Interim Climate Change Committee – refer to section 2.7 of the Accelerated Electricity Technical Annexe.

and can reduce demand by up to 15% in an extreme event on a sustained basis, a series of months with low inflows, for example.

We also model the possibility of one pot-line at the Tiwai smelter needing to be turned off, at the request of Meridian Energy, during a period of low and falling hydro storage.

5.1.12 Transmission Grid

One submitter noted that some scenarios, with the closure of Tiwai point as an example, could see constraints occur with sufficient frequency to affect average prices. Tiwai closure would trigger multiple constraints, but this is not modelled. We do enable some key constraints for all scenarios, so these do impact prices when they bind, and we can check other constraints to determine if they would have constrained if we had enabled them. Typically, however, constraints occur during outages of transmission or generation, and they will tend to impact equally on market and counterfactual scenarios.

5.1.13 Wind and Solar LCOEs

One submitter referred to wind LCOE figures published by the US National Renewable Energy Laboratory showing that "wind installation cost is likely to decrease by between 1% and 2%".

However, cross-border comparison of LCOEs is problematic because a range of parameters could be different to those prevailing in New Zealand, including costs of capital, construction costs, operating costs, annual energy output, taxation, emission reduction policies and so on.

LCOEs may be calculated differently by different analysts, academics and institutions, which makes it problematic to directly compare LCOEs.

As a result, we are careful to calculate the LCOEs that we use in our I-Gen model using a consistent methodology, and using data that is calibrated to the published costs of wind farms actually built, or about to be built, in New Zealand.

Based on data from windfarms built in New Zealand since 2009, along with the data available from recent announcements for Waipipi and Turitea windfarms, we have estimated the annual decline in construction costs in real terms to be 0.65% per annum. The sample only includes five windfarms, so the error in this estimate is relatively high, but nevertheless it is the only directly relevant domestic data that we have.

For solar power, we have sound residential data from the Electricity Authority, but there is only one data point for grid-scale solar[25], and this is yet to be built. Hence we cannot yet make any locally calibrated estimates of how fast the cost of grid-scale solar in New Zealand may be falling.

5.1.14 Cost of Capital

One submitter stated that the discount rate requires further consideration because it has an impact on LCOEs. Interest rates are at historically low levels and project developers are able to take advantage of this by increasing debt-to-equity ratios. These rates can be

[25] Refining NZ has announced that it will construct a 27 MW solar farm adjacent to the refinery at Marsden Point.

locked in for periods of up to five years, or perhaps longer if hedging can be arranged at a reasonable cost, but usually not for longer than 10 years[26]. So this leaves more than 50% of the lifetime of a typical project exposed to movements in interest rates.

Existing generators do not have an incentive to build more generation just because it is ‘cheap to build’, as this would tend to reduce prices and make it harder for existing generation to remain economic. On the other hand, new generators may build new generation if a combination of leveraging and lower interest rates brings down their cost of capital, and hence their LCOE, but only if they can obtain a suitably priced arrangement on a power purchase agreement (PPA) or some other suitable off-take arrangement.

Obtaining PPAs for new large, independent generation projects in New Zealand has proven to be a significant barrier in the past, but there are signs this is changing. For example, Genesis Energy recently signed a 20-year PPA with Tilt Renewables for the output of the new Waipipi windfarm, with prices relatively fixed for the first 10 years, then resetting to market-based prices for the next 10 years. The Major Electricity Users’ Group also has a project in play that aims to contract more new renewable generation, some of which could be provided by new-entrants.

If PPAs with new-entrants were to become more common, then this could reduce prices in both the counterfactual and the market scenarios, depending on whether existing generators postpone the construction of their projects, and whether existing plant were retired as a result. It is possible, for example, that new-entrants could displace incumbents in building new generation over the modelled period, but not to the extent that there is a net increase in the amount of plant added to the market.

From our point of view, the issue of cost of capital is “on watch” at present, but not yet at the point where firm conclusions can be drawn as to whether lower interest rates will actually lead to more plant being built than would otherwise be the case.

If low interest rates do spur a net increase in the rate at which new plant is built, then we might see one or two more medium or large projects built by the end of the modelling period. To test the impact of this on the EAF, we have included a sensitivity analysis in which the base case is modified by adding more new plant, and the results are described in section 6.4.2.

5.1.15 Reserves

One submitter recommended including reserves in the modelling because some capacity is not dispatched in the energy market so that it is available to cover an unexpected outage of generation or of the HVDC link.

EMarket can fully model reserves, but this slows the model down and requires additional assumptions to be made about the prices that reserve providers would offer in the reserves market. The approach that we typically use limits the transfers on the HVDC link, and reduces the offered capacity on the plant that can provide reserves, thus explicitly retaining capacity for reserves. This approach is explained in more detail in

[26] From discussions with project financiers.

our report to the Interim Climate Change Committee on the electricity market modelling undertaken in 2018 and 2019[27].

5.1.16 Market Dynamics

One submitter was concerned that dramatic changes in the generation mix and the interactions between the demand-side and supply-side of the market are likely to occur. While we agree with this concern in general terms, our own modelling suggests that this starts to become an issue when the market gets to the low to mid-ninety percent renewable generation. Given that renewables are currently up to 85% of the market, that the modelled period extends only to 2025, and that plant retirements and Tiwai closure are excluded from the forecasts, this is not an issue that needs to be considered.

5.2 Other Inputs and Assumptions

The following assumptions are made in the modelling:

1. The electricity market remains an energy-only market in which generators derive their revenue from the spot market along with payments on hedge contracts which are related to expected spot prices;
2. No extra mandatory costs directly affect spot prices;
3. All offers and resulting prices are expressed in nominal terms;
4. Forecast PPI of 2.0% p.a. is assumed where relevant;
5. Hydro generators will manage reservoirs to achieve dry year security matching that observed in the market;
6. Reservoir storage is started at actual levels from levels prevailing at the end of 2019, and for all other years starting storage is determined from the end of the previous year's modelling runs;
7. No consideration of any short-term generator strategy that may influence spot price outside of normal market conditions;
8. Dry year reserve generation initially offered as 155 MW at $411/MWh at Whirinaki;
9. Other small generators are offered to ensure dispatch to realistic schedules;
10. All generators offer below maximum capacity to reflect planned and unplanned outages, and the need to provide reserves;
11. The demand profile is based on the actual half hourly demand at each GXP in the year ending March 2018;
12. HVDC maximum flow is modelled as 1,000 MW (including 700 MW on Pole 3) northward and 700 MW southward;
13. All scenarios model demand Tiwai at full capacity (625 MW) except when a pot-line is turned off during a period of exceptionally low storage.

5.2.1 Existing Generating Stations

All generating stations that are connected to Transpower's grid have been modelled – we do not model generators which are embedded in local networks except where they have a history of injecting into the grid[28].

[27] See section 4.10.2 in our report for the ICCC available at https://www.iccc.mfe.govt.nz/assets/PDF_Library/83b8fe3407/FINAL-Energy-Link-ICCC-modelling.pdf

[28] Demand is generally modelled as GXP off-take, which is net of embedded generation.

Generation Types

- **Large Thermals -** Large generators which offer varying tranches of differing volume and price. A certain amount of generation is offered as baseload.
- **Mid-Merit Gas Thermals –** Medium sized generators which offer varying tranches of differing volume and price. No generation is offered as baseload.
- **Large Hydro's -** Four main hydro systems, Waitaki, Waikato, Clutha and Manapouri-Te Anau. Offers are made up of must-run volumes and discretionary volumes offered at optimised water values.
- **Small Hydro with Inflow Data -** Generic small hydro's modelled with actual inflow data since 1932. Offers are priced at $0.01/MWh but volumes are based on optimum releases.
- **Profiled Small Hydro -** One tranche offered at $0.01/MWh with quantities varying by time zone[29] and month based on historical average since January 1998.
- **Semi-Profiled Hydro –** One tranche offered at $0.01/MWh with quantities varying by time zone and month but are also linked to inflow year. In a low inflow year the hydro will generate less, while it will generate more in a high inflow year.
- **Profiled Cogeneration -** One tranche offered at $0.01/MWh with quantities varying by time zone and month based on historical average since January 1998.
- **Profiled Geothermal -** One tranche offered at $0.01/MWh with quantities varying by time zone and month based on historical average since January 1998.
- **Wind Farm -** One tranche offered at $0.01/MWh with quantities varied to reflect wind generation. The generation is determined using profiles calculated from real wind data.
- **Non-supply -** Non-supply generators are not actual generators. They are used in our modelling as indicators of supply shortages and one station is modelled in each of the islands.

6 Results

This section briefly describes the plant mix in the counterfactual, the plant mixes in the three demand scenarios, and then goes on to present the results of the counterfactual and market simulations.

There were 12 scenarios modelled: three counterfactual scenarios, one each for the three demand assumptions, and three market scenarios for each counterfactual, each with a different set of carbon cost assumptions. The scenarios used for the final results are summarised in Table 6 and other key variables are shown in Table 5.

Table 6 – Scenario Summary for Final Results

Counterfactual Scenario – No Carbon Cost	Market Scenario
Base Case Demand growth 0.5% p.a.	**Base Case: Medium carbon** • Demand growth 0.5% p.a.

[29] Time zones modelled: Week Day, Week Night, Other Day, and Other Night.

Counterfactual Scenario – No Carbon Cost	Market Scenario
Starting plant mix is based on the counterfactual 2009-19	• Carbon price rising from $29 in 2020 to $50 by 2035
	Low Carbon • Demand growth 0.5% p.a. • Carbon price falling from $29 in 2020 to $20 in 2025
	High Carbon • Demand growth 0.5% p.a. • Carbon price rising from $35 in 2020 to $50 by 2025
Low Demand Demand growth 0.3% p.a. Starting plant mix is based on the counterfactual 2009-19	**Medium carbon** • Demand growth 0.3% p.a. • Carbon price rising from $29 in 2020 to $50 by 2035
	Low Carbon • Demand growth 0.3% p.a. • Carbon price falling from $29 in 2020 to $20 in 2025
	High Carbon • Demand growth 0.3% p.a. • Carbon price rising from $35 in 2020 to $50 by 2025
High Demand Demand growth 0.8% p.a. Starting plant mix is based on the counterfactual 2009-19	**Medium carbon** • Demand growth 0.8% p.a. • Carbon price rising from $29 in 2020 to $50 by 2035
	Low Carbon • Demand growth 0.8% p.a. • Carbon price falling from $29 in 2020 to $20 in 2025
	High Carbon • Demand growth 0.8% p.a. • Carbon price rising from $35 in 2020 to $50 by 2025

To increase the speed at which the modelling could be completed, the scenarios were initially modelled using D-N resolution, and at a later stage the final results were recalculated using the outputs from modelling with 3h resolution.

Any additional modelling required for sensitivity analysis and for the additional methodologies described in section 3.3 were all run in D-N mode.

6.1 Counterfactual Plant Mix

The table below shows the plant mix assumed for the counterfactual scenario in 2019, based on the alternative evolution of the electricity spot market from 2009 to 2019. Of particular note is that neither Southdown nor Otahuhu B are decommissioned, which actually occurred at the end of 2015. Some renewable plant is built, but seven renewable generators were not built, and neither was the McKee gas-fired peaking generator.

We have assumed that thermal plant that pays its cash costs will remain in the market because the risk of being priced out of the market, due to carbon, is substantially less than it is in the market scenarios.

Table 7 – Counterfactual Plant Changes by End of 2019

	Plant	Type	Commission	Capacity
	Tauhara_Stage1	Geothermal	1/12/09	25
	Nga_Awa_Purua	Geothermal	1/06/10	132
	Stratford_Peaker	Thermal	1/02/11	200
	Turitea_Stage_1	Wind	1/01/19	119
	Pouto_Stage1	Wind	1/11/19	100
	Mt_Munro	Wind	1/12/19	60
Decommissioned				
	Huntly Unit 3	Thermal	1/04/12	250
	Huntly Unit 4	Thermal	1/04/14	250
Not Decommisioned				
	Otahuhu B	Thermal	30/09/15	390
	Southdown	Thermal	1/12/15	165
Not Built				
	Kawerau_Onepu	Geothermal		25
	Mahinerangi Wind Farm	Wind		36
	McKee_Peaker	Thermal		100
	Mill Creek	Wind		60
	Te Ahi O Maui	Geothermal		24
	Te Mihi	Geothermal		165
	Te Uku	Wind		64
	Ngatamariki	Geothermal		82

6.2 Market Plant Mixes

The following tables show the build schedules in the market and counterfactual scenarios for the medium, high and low demand scenarios.

Table 8 – Medium Demand Counterfactual Build Schedule

Plant	*Type*	*Commission Date*	*Installed MW*
Turitea_Stage_2	Wind	1/02/20	103
Wainui_Hills_Wind_Farm	Wind	1/07/20	30
Pouto_Stage2	Wind	1/12/20	100
Kaimai_Wind_Farm	Wind	1/01/21	100
Pouto_Stage3	Wind	1/04/22	100
Mt_Cass_Wind_Farm	Wind	1/08/23	93
Hurunui_Wind	Wind	1/04/25	71.3
Waipipi	Wind	1/05/25	133
Puketoi_Stage_1	Wind	1/10/25	60

Table 9 – Medium Demand Market Scenario Build Schedule

Plant	Type	Commission Date	Installed MW
Turitea_Stage_1	Wind	1/10/20	119
Waipipi	Wind	1/02/21	133
Ngawha_Expansion2	Geothermal	1/02/21	25
RefiningNZ_Solar	Solar	1/02/21	26
Turitea_Stage_2	Wind	1/02/22	103
Kaimai_Wind_Farm	Wind	1/10/23	100
Tauhara_Stage_2	Geothermal	1/10/24	80
Wainui_Hills_Wind_Farm	Wind	1/04/25	30
Awhitu_Wind_Farm	Wind	1/08/25	18

Table 10 – High Demand Counterfactual Build Schedule

Plant	Type	Commission Date	Installed MW
Turitea_Stage_2	Wind	1/02/20	103
Wainui_Hills_Wind_Farm	Wind	1/07/20	30
Pouto_Stage2	Wind	1/12/20	100
Kaimai_Wind_Farm	Wind	1/01/21	100
Pouto_Stage3	Wind	1/01/22	100
Mt_Cass_Wind_Farm	Wind	1/06/22	93
Puketoi_Stage_1	Wind	1/02/24	60
Waipipi	Wind	1/05/24	133
Hurunui_Wind	Wind	1/07/24	71.3
Mill_Creek	Wind	1/12/24	60
Te_Uku	Wind	1/04/25	64.4
Puketoi_Stage_2	Wind	1/09/25	130

Table 11 – High Demand Market Scenario Build Schedule

Plant	Type	Commission Date	Installed MW
Turitea_Stage_1	Wind	1/10/20	119
Waipipi	Wind	1/02/21	133
Ngawha_Expansion2	Geothermal	1/02/21	25
RefiningNZ_Solar	Solar	1/02/21	26
Turitea_Stage_2	Wind	1/02/22	103
Tauhara_Stage_2	Geothermal	1/05/23	80
Kaimai_Wind_Farm	Wind	1/10/23	100
Tauhara_Stage_2a	Geothermal	1/02/25	80
Wainui_Hills_Wind_Farm	Wind	1/04/25	30
Awhitu_Wind_Farm	Wind	1/06/25	18
Pouto_Stage1	Wind	1/12/25	100

Table 12 – Low Demand Counterfactual Build Schedule

Plant	*Type*	*Commission Date*	*Installed MW*
Turitea_Stage_2	Wind	1/02/20	103
Wainui_Hills_Wind_Farm	Wind	1/09/20	30
Pouto_Stage2	Wind	1/01/21	100
Kaimai_Wind_Farm	Wind	1/06/21	100
Pouto_Stage3	Wind	1/10/22	100
Mt_Cass_Wind_Farm	Wind	1/05/24	93

Table 13 – Low Demand Market Scenario Build Schedule

Plant	*Type*	*Commission Date*	*Installed MW*
Turitea_Stage_1	Wind	1/10/20	119
Waipipi	Wind	1/02/21	133
Ngawha_Expansion2	Geothermal	1/02/21	25
RefiningNZ_Solar	Solar	1/02/21	26
Turitea_Stage_2	Wind	1/02/22	103
Kaimai_Wind_Farm	Wind	1/10/23	100
Awhitu_Wind_Farm	Wind	1/08/25	18
Tauhara_Stage_2	Geothermal	1/09/25	80

6.3 Final Results with 3h Resolution

The relationship between demand and price in the spot market is non-linear, with spot prices during peak demand periods often rising well beyond the prevailing typical range of prices. The impact of these peak-period prices is significant in the real spot market, so to ensure the impact of peak-period pricing is taken into account in modelled prices, we ran the scenarios using 3h mode.

The annual average prices overall GXPs with medium carbon prices are shown in Figure 1 and average annual prices for all scenarios are shown in Table 14.

Figure 1 – Market and Counterfactual Scenarios with Medium Carbon Prices

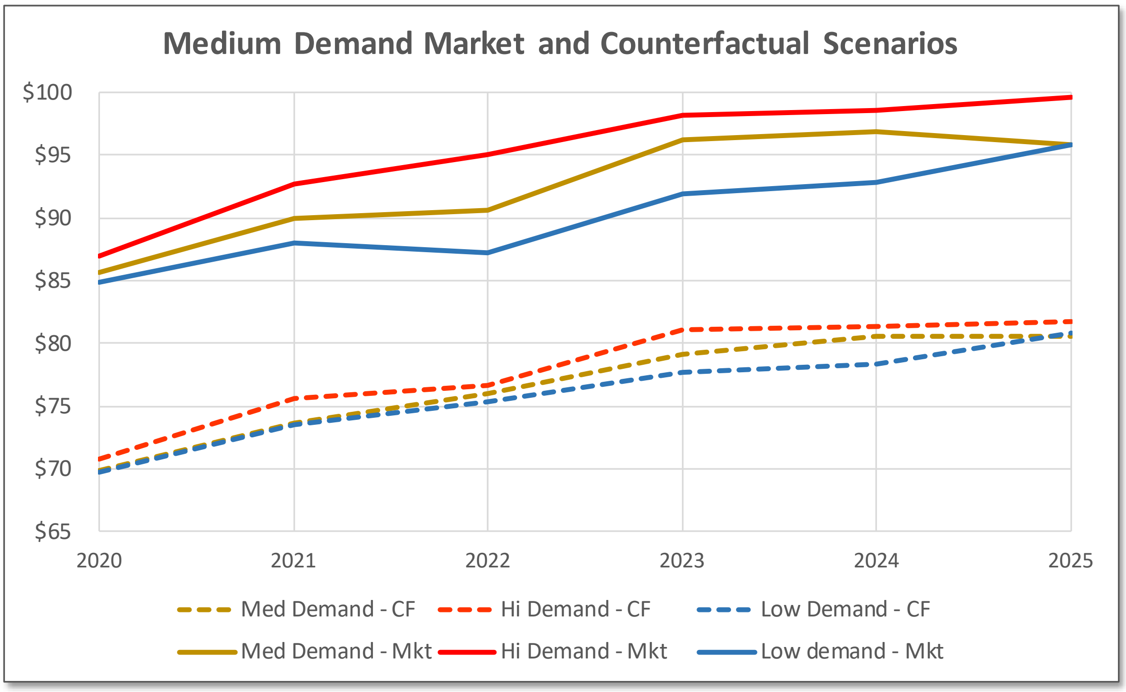


Table 14 – 3h Scenario Average Prices with Common Carbon Price

Year	Medium Demand				High Demand				Low Demand			
	Counterfactual	Market			Counterfactual	Market			Counterfactual	Market		
		Medium Carbon	High Carbon	Low Carbon		Medium Carbon	High Carbon	Low Carbon		Medium Carbon	High Carbon	Low Carbon
2020	$69.93	$85.68	$90.06	$85.52	$70.80	$87.01	$89.36	$86.80	$69.76	$84.88	$87.24	$84.77
2021	$73.72	$89.97	$93.23	$88.72	$75.58	$92.65	$96.10	$91.28	$73.48	$88.04	$91.36	$86.89
2022	$76.07	$90.59	$94.34	$87.89	$76.72	$95.02	$99.15	$92.41	$75.31	$87.26	$90.95	$84.85
2023	$79.21	$96.25	$100.88	$92.20	$81.08	$98.19	$102.95	$94.09	$77.66	$91.91	$96.38	$88.08
2024	$80.58	$96.95	$102.24	$91.75	$81.40	$98.58	$103.97	$93.40	$78.35	$92.80	$97.87	$87.71
2025	$80.55	$95.82	$101.34	$89.42	$81.76	$99.69	$105.40	$93.03	$80.88	$95.87	$101.34	$89.46

The six-year average EAFs calculated from the prices above, along with the relevant carbon prices, ae shown in Table 15: the spot prices and carbon prices used in these calculations are all averages over the six-year period[30].

In the EAF modelling undertaken in 2011 (Energy Modelling Consultants Ltd, 2011) the price averages were only taken across North Is grid nodes. In Table 15 we show the equivalent EAFs in bold in the first row of the data: these are the six-year average EAFs using North Is prices only.

Table 15 also shows EAFs calculated for other groupings of nodes, including across all GXPs, South Is only, and also for three nodes that are often used as key reference points on the grid: Otahuhu, Haywards (Hutt Valley) and Benmore in the centre of the South Is.

[30] If instead one were to average the annual EAFs, then the resulting average EAF would be very close to the values in the table.

Table 15 – 3h Six-year Average EAFs with Common Carbon Price

GXP Grouping	Scenario								
	Medium Demand			High Demand			Low Demand		
	Medium Carbon	High Carbon	Low Carbon	Medium Carbon	High Carbon	Low Carbon	Medium Carbon	High Carbon	Low Carbon
North Is GXPs	**0.478**	**0.469**	**0.488**	**0.513**	**0.499**	**0.531**	**0.432**	**0.432**	**0.433**
South Is GXPs	0.521	0.504	0.541	0.586	0.559	0.621	0.460	0.455	0.467
All GXPs	0.493	0.489	0.505	0.537	0.519	0.561	0.442	0.439	0.444
Otahuhu	0.539	0.520	0.561	0.572	0.549	0.601	0.492	0.482	0.506
Haywards	0.458	0.450	0.465	0.503	0.489	0.521	0.410	0.411	0.407
Benmore	0.492	0.476	0.510	0.552	0.527	0.585	0.435	0.430	0.441

As one might expect, the EAFs increase with demand: with medium carbon prices, for example, the high demand EAF (0.513) is 7.3% higher than the EAF with medium demand (0.478) and the low demand EAF (0.432) is 9.6% lower.

On a regional basis, the EAF is lower in the North Is and higher in the South Is, on average. However, in the North Is the EAF is higher in the upper North Is (Otahuhu) than in the lower North Is (Haywards): being in the centre of the grid means that the price swings in wet and dry years, which become more pronounced with more renewables in the market, are smaller at Haywards than at either end of the grid, leading to a lower impact on Haywards relative to the counterfactual.

The impact of different carbon prices at each level of demand is considerably smaller than the impact of the demand assumptions, but the EAFs calculated for higher carbon prices are lower than the EAFs calculated for the medium and low carbon scenarios at the same level of demand. The EAFs calculated for the low carbon scenarios, on the other hand, are the highest at the same level of demand, with only one exception. This pattern is counterintuitive, but is the result of a combination of two factors; demand response, in particular, but also the modelled cost of non-supply.

The modelling assumes a certain amount of demand response to high prices, which increases as spot prices rise, either during demand peaks or during dry periods. The impact of demand response is to reduce peak prices below what they would otherwise be, which in turn reduces average prices below what they would otherwise be without demand response. The scenarios with high carbon prices have the greatest demand response, and hence the greatest 'dampening' of the impact of the assumed carbon price. The opposite is true for the low carbon scenarios, where the dampening effect of demand response is least.

The second factor is that the price included in the model for rare periods of non-supply is the same in all scenarios, so the relative contribution of these periods to the average price for a scenario is greatest in the low carbon scenarios and least in the high carbon scenarios.

Running a range of scenarios for calculating EAFs recognises the fact that future prices cannot be predicted with certainty, and hence the final EAF for use in the Allocative Baselines[31] is a weighted average of the EAFs calculated for each scenario.

The weighted average EAFs are shown in Table 16 below for North Is GXPs, along with the weighted average EAFs that would be calculated for other groupings of GXPs. The table shows two weightings: one which assigns the same weighting to both the low and high demand scenarios, and one which assigns a lower probability to the higher demand scenarios. The latter weighting is included because it is considered that lower demand growth is more likely over the next six years as the uptake of EVs and electrification of industry is still in its early stages.

Table 16 – 3h Weighted Average EAFs with Common Carbon Price

	Probability-weighted EAF		Relative to Current EAF = 0.537	
GXP Grouping	Evenly Weighted	Med Demand 50%; Low 30%; High 20%	Evenly Weighted	Med Demand 50%; Low 30%; High 20%
North Is GXPs	**0.475**	**0.472**	**-11.5%**	**-12.1%**
South Is GXPs	0.524	0.517	-2.5%	-3.8%
All GXPs	0.492	0.488	-8.4%	-9.1%
Otahuhu	0.536	0.533	-0.2%	-0.8%
Haywards	0.457	0.453	-14.9%	-15.7%
Benmore	0.494	0.488	-8.0%	-9.2%

The evenly weighted EAF for North Is GXPs is 0.475 which is 11.5% lower than the current EAF, and for the uneven weighting it is 0.472 or 12.1% lower than the current EAF.

6.4 Sensitivity Analysis

The sensitivity of the EAF to changes in the numerator and denominator of equation (2) on page 6 is shown in detail in section 8, but in essence the analysis shows that the EAF calculated for a scenario is an order of magnitude more sensitive to the modelled prices in the market and counterfactual scenarios, than to the assumed carbon price. This is why, for example, Table 15 shows that the impact of various demand assumptions is much larger than the impact of the carbon price assumptions.

In this section, we explore how a range of variations to the scenario assumptions would impact on the EAF calculated in the base case with 0.5% per annum demand growth and carbon price rising linearly from $29 in 2020 to $50 by 2035.

These scenarios were all run at D-N resolution, but have been scaled to provide a good approximation to the results in 3h resolution[32].

The sensitivity results show the EAFs for North Is GXPs in bold, and other GXP groupings are shown for interest.

[31] Refer to equation (1) in section 3 on page 5.

[32] The scaling is based on the prices attained by modelling the base case in D-N mode and comparing it to the 3h base case.

6.4.1 Plant Retirement

To demonstrate the sensitivity of the EAF to the impact of plant retirements on price, we ran a scenario in which the TCC is retired at the end of 2021 in the market scenario, but not in the counterfactual[33], and results are compared in the table below.

Table 17 – Comparison of TCC In and Out of Market Beyond 2021

	Base Case	Base Case with TCC Retired end of 2021	Difference
North Is GXPs	**0.478**	**0.729**	52%
All GXPs	0.521	0.793	52%
South Is GXPs	0.493	0.747	52%
Otahuhu	0.539	0.782	45%
Haywards	0.458	0.725	58%
Benmore	0.492	0.748	52%

As noted in section 3.2, if plant retirement is not signalled well in advance, then there can be a period of a few years after retirement when there is a shortage of supply relative to the pre-retirement period. This shortage reduces the 'gap' between supply and demand, resulting in higher prices.

The table above shows that the average EAF for North Is GXPs for the six-year period increases by 52% if the retirement of TCC is not well signalled. This is a large increase which could skew the EAF toward the high side, if this scenario were included in a weighted average calculation of the EAF, even though it might not actually happen over the modelled period.

For this reason, we recommended in our earlier report (Energy Link Ltd, 2019) that retirements not be considered in the EAF modelling, but the announcement of a retirement should be a trigger for a recalculation of the EAF.

6.4.2 LCOE Depression

If the falling LCOE of new renewable plant led to a higher rate of build of new plant, then this would have an impact on the EAF. To test the impact, we assumed that 300 MW of additional windfarm capacity is commissioned from the start of 2023 in the base case counterfactual and market scenarios, but without any plant retirements, and the results are compared below.

[33] Retiring TCC is considerably more likely in the market scenario because the counterfactual retains existing thermal plant for longer.

Table 18 – Comparison With and Without Additional 300 MW Windfarm

	Base Case	Base Case with Additional 300 MW Windfarm	Difference
North Is GXPs	**0.478**	**0.379**	-21%
All GXPs	0.521	0.416	-20%
South Is GXPs	0.493	0.398	-19%
Otahuhu	0.539	0.431	-20%
Haywards	0.458	0.363	-21%
Benmore	0.492	0.398	-19%

The additional windfarm capacity, which generates on average about 40% of its rated capacity, drops the EAF for North Is GXPs by between 21%. This fall is due to the thermal generators running less on average, thus reducing the impact of thermal generation on the prices attained in the base case.

6.4.3 Inflows

We have observed a long-term trend in inflows in the southern hydro lakes of lower inflows, on average, in the late summer months, and higher inflows in winter, although there remains high volatility in the inflows in these periods from year-to-year[34]. So far, the historical data does not show a net increase or decrease in the average inflows over the year, but in future the total annual average inflows are more likely to increase in some catchments.

The following table compares the EAFs calculated using forecast prices with all inflows back to 1932[35] alongside EAFs calculated using inflows from 2004 to 2019.

Table 19 – Comparison of All and Recent Inflows

	Base Case	Base Case Inflows 2004 - 2019	Difference
North Is GXPs	**0.478**	**0.555**	16%
All GXPs	0.521	0.604	16%
South Is GXPs	0.493	0.569	16%
Otahuhu	0.539	0.621	15%
Haywards	0.458	0.532	16%
Benmore	0.492	0.570	16%

When only inflows from 2004 are considered, the EAF for North Is GXPs increases by 16%. This is perhaps counterintuitive as one might expect more rain in winter to provide greater supply when demand is highest, thus lowering prices. However, regardless of the general trend over the last 15 years, within that period there is also a high degree of volatility in inflows. Through the autumn-summer period in 2005/06, 2007/08 and 2011/12, for example, inflows were very low. While these periods

[34] See also https://www.meridianenergy.co.nz/assets/Sustainability/8d965d2519/Climate-change-Meridian-modelling-May-2019.pdf

[35] The inflow data actually extends back to April 1931, but not all of this data is used to model 88 inflow years from start of 1932 to the end of 2019.

contributed to the observed trend, they also caused hydro storage to be lower than expected before winter. Low storage going into winter increases the risk associated with low inflows over winter, which can still occur even if the overall trend is to slightly wetter winters.

The elevated risk, in turn, causes the opportunity cost of water in storage prior to winter to increase; hydro generators respond by raising the price at which hydro generation is offered into the market so that more thermal generation runs and water in storage is conserved. The impact of these dry periods since 2004, therefore, is to increase the average prices in the modelling relative to prices averaged over inflows back to 1932.

6.4.4 Individual Inflow Years

All EAFs shown in preceding sections are averaged over multiple inflow years to get a grand average value, and these averages represent the EAF that would, on average, be expected to occur in future years with those inflows.

The following table, however, shows EAFs calculated using base case data which is calculated for each year using only the modelled prices for that inflow year. We chose the six years from 2007 to 2012 because they have a wide range of inflows, with 2008 and 2012 being dry, 2009-11 being wet, and 2007 somewhere in the middle.

Table 20 – 3h EAFs for Individual Inflow Years 2007 - 2012

	Base Case with All Inflows	Base Case Individual Inflow Years	Difference
2007	0.478	0.641	34%
2008	0.478	1.344	181%
2009	0.478	0.224	-53%
2010	0.478	0.491	3%
2011	0.478	0.257	-46%
2012	0.478	0.943	97%
Average	0.478	0.650	36%

The modelling producing the data the table runs continuously from the start of the first year (2007) through to the end of the last of the six years (2012) in both the market base case and the counterfactual for medium demand. By using only the average prices for each inflow year from the market and counterfactual, we can calculate EAFs that apply to each year.

These single-inflow-year EAFs vary substantially from those calculated using the all-inflow average of 0.478. If it were possible to forecast future inflows accurately six years in advance, then individual EAFs could be calculated and applied for each of those years.

Of course, it is not possible to forecast inflows in advance, but the data in Table 20 strongly suggests that the alternative methodologies explored in section 6.5 will produce EAFs that vary widely, depending on the actual inflows in each year, combined with other factors such as the actual demand, actual retirements, actual builds, and so on.

6.5 Results for Alternative Methodologies

The two alternative approaches to calculating the EAF explored for this report would be updated on an annual basis, and they are:

1. comparing the actual market outcome for the last year to an alternative market outcome where the cost of carbon has been removed;
2. comparing the actual market outcome for the last year to a "back-cast" of the counterfactual scenario.

Both of the above require development of an accurate back-cast of the previous year, although in this instance we have gone back to 2016 to estimate how the EAF might vary from year-to-year. In principle, back-casting is a simpler undertaking than forecasting because 'everything is known'; the reality is not that simple.

While we do know what historical demand, generator offers, storage, and inflows were, there are many factors which impact on spot prices which are not in the public domain. A particularly difficult situation occurs when a generator's offer strategy is affected by a large contract of some sort, the details of which may not be in the public domain: contracts may alter the cost of generation in ways that may be hard to ascertain just by analysing market behaviour.

A back-cast and a forecast are also quite different in respect of what is and what is not known at the time they are produced. For example, when planning generation, hydro generators calculate water values based on expectations of the future. These expectations might turn out to be quite wrong, so in the real market a generator's behaviour may not match the water values a market model would calculate when back-casting using inputs that are based on what actually happened.

This problem can be summed up by stating that the back-cast is a simulation of the market with perfect foresight, whereas the market operates under conditions of uncertainty, and so the market outcomes may be significantly different to what 'ideally' should have happened.

Setting up a back-cast, therefore, is an iterative process in which the market is modelled many times over, progressively reducing the difference between the modelled prices and the market prices. For example, in our modelling of the years from 2016 to 2019, the 2017 year initially produced a large spike in spot prices during a period of record low inflows, which was not observed to the same degree in the real market.

As noted in section 3.1, it is difficult to detect the relationship between NZU prices and electricity spot prices in the real market. Rather than attempting to reverse-engineer the carbon component of generator offers, this problem is dealt with in this alternative methodology by assuming that all generators see the same carbon price, which is just the annual average NZU price for each historical year, adjusted by the subsidy factors that were in place in the ETS through to the end of 2018. This approach is also consistent with the choice of carbon price in previous calculations of the EAF and with the EAFs presented in section 6.3.

In the interest of short run times and rapid repeats of scenarios during the process of achieving a sufficiently accurate back-cast, all scenarios for the alternative methodologies were run in D-N mode. However, this does mean that the results for the alternative methodologies are not directly comparable to the final result of 0.478 for the base case.

6.5.1 Back-cast 2016 to 2019

The results of the back-cast of the spot market are shown in the following three figures for monthly average prices at key nodes Benmore, Haywards and Otahuhu. The average error[36] over the total 48 months is 2.8% for Benmore, 0.3% for Haywards and -1.0% for Otahuhu.

Figure 2 – Actual and back-cast Prices at Benmore

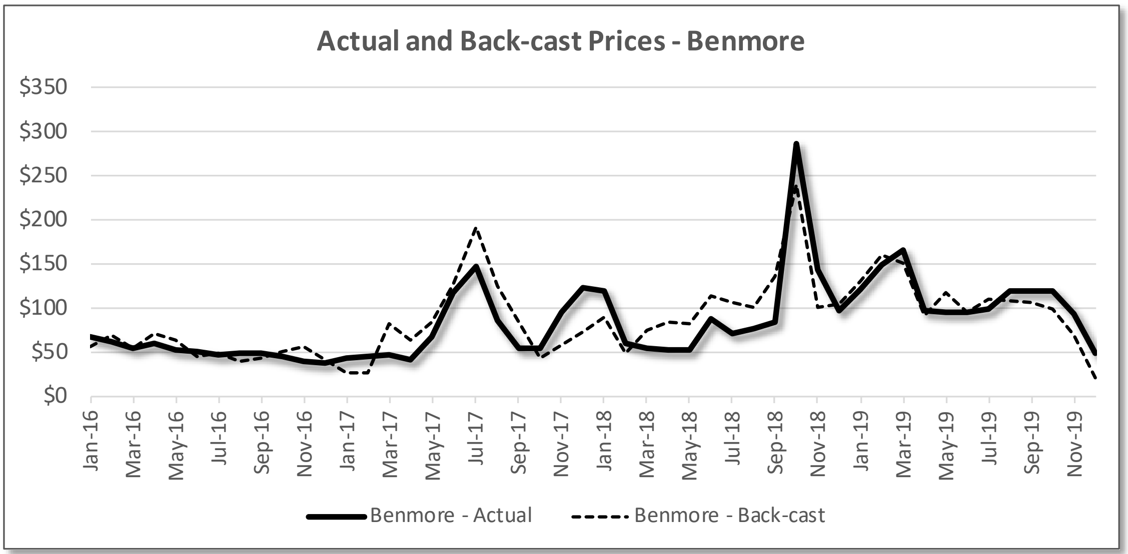
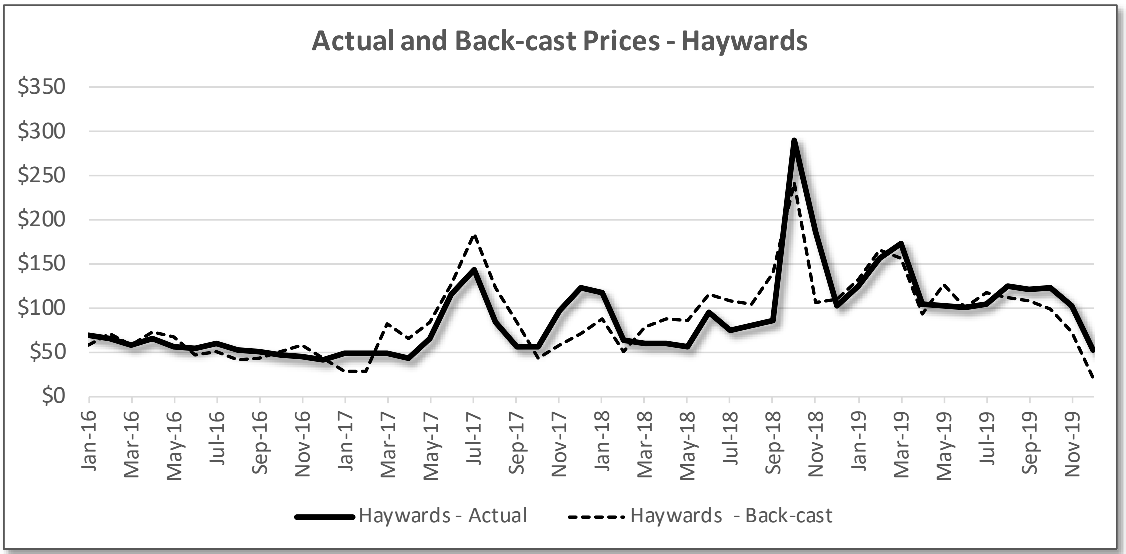
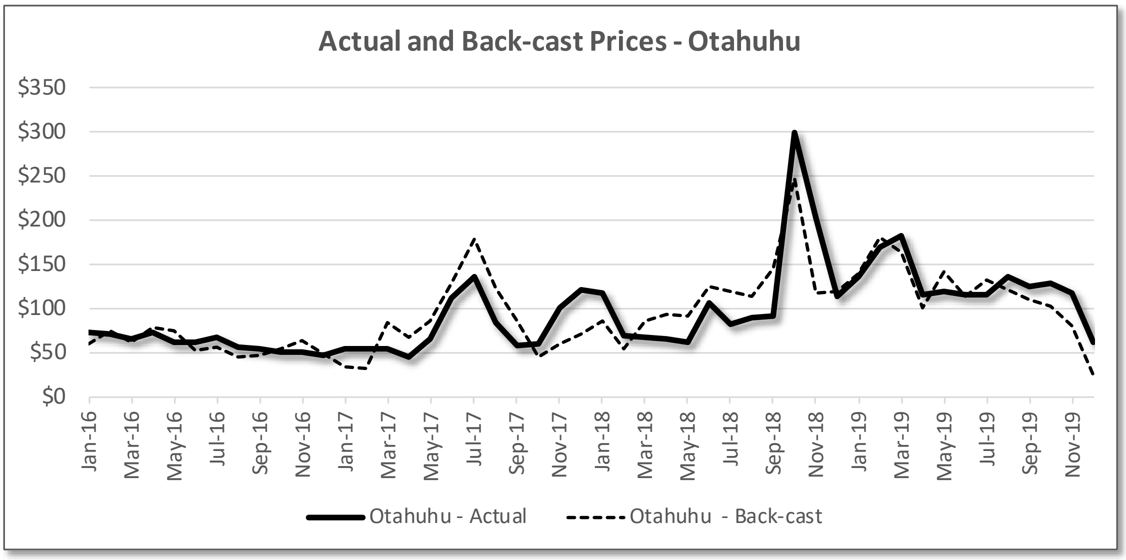


Figure 3 – Actual and back-cast Prices at Haywards



[36] The average price over the 48 months for the back-cast, relative to the actual market average price for the 48 months.

Figure 4 – Actual and back-cast Prices at Otahuhu



The fit of the back-cast month-by-month could certainly be improved further with more iterations and running in 3h mode, but after a point each iteration produces diminishing improvements in the accuracy of the calculation of the EAFs using this back-cast data. If an alternative methodology were to be used in annual backward-looking EAF calculations, then more time would need to be spent in producing the back-cast and in exploring its sensitivity to the assumptions made in the methodology.

6.5.2 EAF Using Back-cast With and Without Carbon Prices

The back-cast in *EMarket* matches the actual market outcomes with a small margin of error. To work out how the market might have turned out without a price on carbon, using this alternative methodology, the carbon components of all thermal offers are removed assuming that the carbon prices are the same for all generators and that they are equal to the average annual price of NZUs in each year.

The effect of the removal of carbon from thermal offers is to reduce the price at which thermal generation is offered into the market simulation, but water values for all major hydro systems also adjust to the new expectations of thermal offers. *EMarket* runs with the no-carbon offers, and the EAF calculated in the usual way, to give the following results.

For avoidance of doubt, the EAFs shown below are calculated using the price differences between the back-cast with and without carbon: the actual market prices are not used. If this alternative methodology were to be adopted, then actual prices could be used, but if the back-cast is sufficiently accurate, then it should not make a significant difference which set of carbon-inclusive prices are used to calculate the EAFs.

Table 21 – Annual EAFs Using Back-cast With and Without Carbon, All GXPs

Year	Back-cast Without Carbon	Back-cast With Carbon	EAF	Running Average EAF
2016	$53.2	$56.6	**0.427**	**0.427**
2017	$78.9	$82.8	**0.312**	**0.369**
2018	$104.5	$112.3	**0.410**	**0.383**
2019	$98.3	$111.8	**0.557**	**0.426**

Table 22 – Average EAFs Using Back-cast With and Without Carbon

GXP Grouping	EAF
North Is GXPs	**0.452**
All GXPs	0.449
South Is GXPs	0.443
Otahuhu	0.468
Haywards	0.435
Benmore	0.422

The average EAF over the four years using this alternative methodology is 0.449 for all GXPs and 0.452 for North Is GXPs, as shown above in Table 22. In the case of all GXPs, the four-year EAF[37] is 0.449 but the running average EAF[38] over the four years is 0.426 as shown above in Table 23.

As noted above, the values above are not directly comparable to the 3h base case EAF value of 0.478. Nevertheless, they do confirm that EAFs calculated annually using a back-cast approach will move around significantly. However, as noted above, the back-cast initially produced higher prices in 2017, a year of record low inflows in the South Is from February to May, than were actually set in the market. Instead of 2017 producing a higher than average EAF, therefore, it produced a lower than average EAF using the back-cast approach.

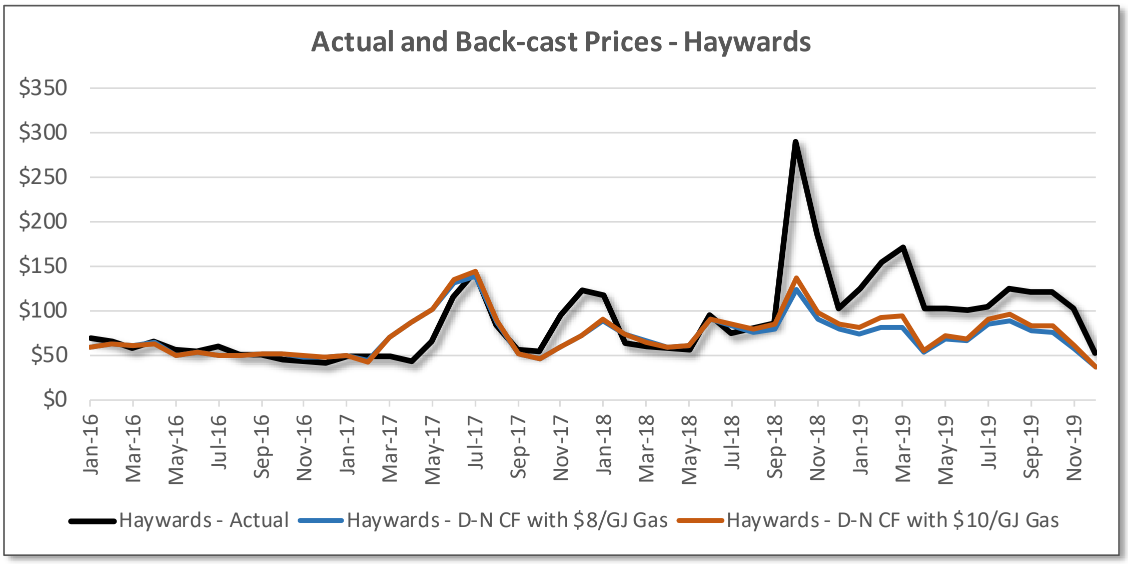
6.5.3 EAF Using Actual Market and Base Case Counterfactual

The following results are calculated using the actual market prices and the D-N base case counterfactual, but where the counterfactual is rerun using actual demand and offers reflecting the conditions that actually applied during the last four years. This is a more difficult task than simply removing the assumed carbon offers (as in section 6.5.2) because more thermal generators remain in the counterfactual market, which means that their respective fuel supply arrangements could have been quite different to those that actually occurred: fuel contracts could have been much longer, for example, given the extended lifetime of the thermal fleet.

For the 2019 year, a key factor affecting prices is the gas price used for thermal generators. There is ample evidence that there was a ‘squeeze’ on gas supply last year, with the increased price possibly approaching $10/GJ on average, up from around $6/GJ in 2018. Whether or not this squeeze would have occurred if the thermal fleet remained larger, as it is in the base case counterfactual, is a matter of conjecture. However, the chart below shows that the difference between $8/GJ and $10/GJ gas in 2019 is small, to the point of being insignificant.

[37] This is calculated using prices that are the average over all four years from 2016 to 2019.
[38] This is the average of the EAFs calculated using prices for one year at a time.

Figure 5 – Haywards Actual Prices versus D-N Counterfactual Prices



Also of note is that the counterfactual prices for 2017 and 2018 are slightly higher than the actual market prices, giving negative EAF, which occurs when the counterfactual price is higher than the market price.

Table 23 – Annual EAFs Using Actual Market and Base Case Counterfactual

Year	Back-cast Without Carbon	Back-cast With Carbon	EAF - $8/GJ Gas	EAF - $10/GJ Gas
2016	$55.9	$55.0	**-0.109**	**-0.005**
2017	$78.5	$77.2	**-0.107**	**-0.080**
2018	$82.5	$106.4	**1.262**	**1.183**
2019	$71.9	$117.7	**1.898**	**1.693**

Table 24 – Average EAFs Using Actual Market and Base Case Counterfactual

GXP Grouping	EAF - $8/GJ Gas	EAF - $10/GJ Gas
North Is GXPs	**1.100**	**1.059**
All GXPs	1.066	0.982
South Is GXPs	0.997	0.827
Otahuhu	1.337	1.178
Haywards	1.104	0.949
Benmore	0.960	0.798

The EAF values calculated using this alternative methodology vary more than EAFs calculated using any other method. The four-year average EAFs above are more than twice the values calculated using the current methodology. The last two years have presented unusually difficult trading conditions for thermal generators, given restrictions on fuel supplies, but the counterfactual simply has more thermal plant available, which it is assumed also means more fuel, significantly reducing the impact of the disruptions.

6.6 Context Checking

In our earlier report (Energy Link Ltd, 2019) we provided a range within which the EAF should fall, as a check that it is at least within reasonable bounds. Our recommendation was that the EAF should be greater than zero[39] and lower than the marginal emissions factor of the most emission-intensive thermal station, which is Huntly burning coal at 0.92. We also recommended that "additional context is attained by reference to the base case internal EAF and to market expectations of an EAF close to 0.53 tCO2/MWh".

The base case internal EAF is calculated by running a counterfactual for the base case which is just the base case with all carbon costs set to zero. Running this at D-N resolution allows an internal EAF to be calculated, which was done with a common carbon cost in the base case, giving internal EAF of 0.444 for North Is GXPs.

The range of EAFs shown in Table 15 is from a low of 0.407 to a high of 0.621 and when considering only the North Is EAFs the range is from 0.432 to 0.531: these are within the upper and lower bounds, and also comparable to both the base case internal EAFs shown above and to the 'market expectations' EAF of 0.53.

The same cannot be said however, for the second alternative methodology, which produced both negative EAFs and EAFs greater than one for individual years. However, the current methodology is based on averaging over all inflow scenarios in the historical record, and as the data in Table 20 shows, any methodology that is based on using individual years would need to have bounds that are wider than those that apply to EAF using averages over inflow years.

7 Conclusions

Table 16 shows final results using 3h modelling resolution and carbon prices that are the same for all generators, and a weighted average EAF of either 0.475 or 0.472 for North Is GXPs depending on the weighting given to the low, medium and high demand scenarios. Given the relatively short term of the modelling, during which the uptake of EVs and electrification of industry will see only incremental change, partially offset by the addition of solar power behind the meter, we recommend choosing the value of 0.472 tCO_2/MWh which is a reduction of 12.1% on the current value of the EAF.

This value is consistent with the current methodology, including the choice of North Is prices for use in the calculation of the EAF, and it assumes that lower demand growth is a little more likely than higher demand growth.

Part of the reason for the 12.1% lower EAF is the non-inclusion of any scenarios which include retirement of large thermal plant. The EAF values in Table 17 show that including TCC's retirement would increase the weighted average EAF, with the increase depending on the probability given to retirement. The signals from Contact Energy suggest that retirement is relatively likely in 2021 or 2022, but between now and then there are a range of events that could cause retirement to be postponed. For example, recent announcements from Genesis Energy[40] suggest that one or more units Huntly might be retired in 2023, in which case TCC could conceivably remain in the market for longer.

[39] Negative values for the EAF are possible, and were produced by some scenarios in previous EAF modelling exercises, and using one of the two alternative methodologies investigated for this report.
[40] Concerning a 300 MW solar farm in the North Waikato that Genesis is looking to contract with.

In our earlier report we recommended that retirement not be considered, but that a major event such as thermal retirement or closure of the Tiwai aluminium smelter should trigger a recalculation of the EAF. Given how different the TCC retirement sensitivity EAFs are to the recommended value of 0.472, this reinforces our recommendation.

The values in Table 16 also show that it would be possible to publish and use EAFs that vary by region, for example upper and lower North Is, and South Is. In this case Table 16 suggests that the North Is would have the lower EAF, and the South Is would have the higher EAF.

If there is a region in which most EITEs are located, Auckland for example, then an EAF could be calculated for that region, which would cater to the majority of EITEs.

The results of section 6.4.3 and 6.5 suggest that if EAFs were to be calculated on an annual basis looking backward, then they would vary substantially from year to year, with higher values expected in dry years (high prices and more thermal generation) and lower values in wet years (low prices and less thermal generation).

Using annually-updated backward-looking EAFs arguably would provide a more efficient outcome overall. For example, a succession of dry years similar to those in the 2000s would provide a succession of higher EAFs, which would correlate better with prices in the spot market.

However, from the point of view of EITEs, those that are exposed to spot prices would see the higher correlation, but those who are under contract on a fixed-price variable volume basis would see a series of EAFs that might correlate poorly with their respective contract prices.

Calculating annually-updated backward-looking EAFs with a counterfactual based on no carbon charge, as described in section 6.5.3, would require almost as much effort as calculating EAFs using the current methodology. It would require a counterfactual scenario with no ETS, which over time becomes increasingly uncertain as each year passes.

Calculating annually-updated backward-looking EAFs, as described in section 6.5.2, would require less effort than the current methodology, because only one year at time has to be back-casted, but it would have to be updated at least annually instead of every few years. It would also produce EAFs which vary substantially from year to year.

8 Appendix - EAF Equation

The electricity purchase costs shown in equation (2) on page 6 are the sum over a year of the product of the energy component of the delivered electricity price[41] and the quantity consumed. On the assumption that the consumption profile is flat, in which case the same quantity is consumed in each and every hour of the year, then (2) becomes

$$EAF_0 = \frac{S_{ms} - S_{cf}}{C} \qquad (3)$$

[41] Where the lines component of the electricity price is assumed to be the same for both market and counterfactual scenarios.

where S_{ms} is the average spot price in the market scenario, S_{cf} is the average price in the counterfactual scenario, and C is the weighted-average carbon price in the market scenario, for the period being considered.

Suppose that an assumption changes in the market scenario, and that the average price is recalculated as $S_{ms} + \Delta S_{ms}$ where ΔS_{ms} is the change in the average price, then (3) becomes

$$EAF_1 = \frac{S_{ms}+\Delta S_{ms}-S_{cf}}{C} = \frac{S_{ms}-S_{cf}}{C} + \frac{\Delta S_{ms}}{C} = EAF_0 + \Delta EAF$$

where we define $\Delta EAF = \frac{\Delta S_{ms}}{C}$

If we now take the ratio of the change in the EAF to the original EAF we get

$$\frac{\Delta EAF}{EAF_0} = \frac{\Delta S_{ms}}{S_{ms}-S_{cf}} \tag{4}$$

which is to say that the relative change in the EAF when one of the average prices in the denominator changes, is given by the right-hand side of (4).

Suppose that C = \$20 per tonne, S_{ms} = \$80 and S_{cf} = \$70 then EAF = \$10/\$20 = 0.5. If we change our assumptions, even by a small amount, it is not unusual for a modelled scenario to change its average price by \$1 or more. A change of \$1 would produce a relative change in the EAF of \$1/\$10 = 0.1 or 10%, and the calculated EAF would be 0.55. In other words, a 1.25% change in S_{ms} produces a 10% change in the EAF.

On the other hand, if the carbon price C were to change by 1.25% while the scenario prices remained constant, then the calculated EAF would be \$10/\$19.75 = 0.5063 which would be a change of only 1.26%.

What the above illustrates is that the calculated EAF is an order of magnitude more sensitive to the scenario prices in the numerator than to the carbon price in the denominator of (2) and (4), which explains why the modelled scenarios in the previous EAF assessment (Energy Modelling Consultants Ltd, 2011) produced such a wide range of EAF values.

It is also largely for this reason that in our earlier report (Energy Link Ltd, 2019) we recommended modelling a more limited set of scenarios, with a narrower range of assumptions. If the assumptions become invalid at some later date, then the EAF can always be reassessed at that point in time.

A range of sensitivity runs were completed as part of the modelling and the results of these are shown in section 6.4 and in section 6.5, the latter covering two alternative methodologies.

9 References

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