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energy modelling

Electricity Allocation Factor Estimates for 2016/17

Report

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About us

Scientia Consulting provides specialist advice, modelling and analytical expertise to the energy sector.

This knowledge is based on extensive practical experience spanning operational and regulatory environments of the electricity industry in New Zealand and overseas.

Scientia's key areas of specialisation include electricity market design and analysis, generation expansion planning, transmission planning, transmission pricing and load forecasting.

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Summary

The current electricity allocation factor (EAF) is a significant component of the assistance provided to eligible firms from the emissions trading scheme (ETS). The EAF is an estimate of the cost impact of the ETS that flows through to the electricity market. The EAF was agreed to in 2010 and then revisited in 2011 and 2012. The EAF was intended to be enduring until certain key variables changed, one of them being major plant changes. This has been the case with the retirement of over 1000MW of thermal generation in the upper North Island by January 2016.

MFE has engaged Scientia Consulting to analyse actual electricity market prices to get an initial assessment of the potential impact the ETS may have had on these prices and consequently the EAF following the thermal generation retirement. To do this, we simulated actual and counterfactual electricity market spot prices using the vSPD market model over the two-year period, 01 January 2016 to 31 December 2017 with modelled ETS cost impacts on generator offers. Given the uncertainty in how the removal of ETS costs may affect generator market offers[1], we considered three scenarios to evaluate a range of potential impacts.

The first scenario considers the impact if the removal of ETS costs reduced thermal generator market offers only. Under this scenario we assume all other generators market offers remain unchanged. The second scenario considers the potential impact if in addition to thermal generators, hydro generators with controllable storage also reduced their offers into the spot market to reflect a reduction in the value of water due to lower thermal costs. Finally, a third scenario is studied, which in addition to the scenario 1 and 2 assumptions, models a reduction in quantity of low-priced thermal generation offered into the market based on observed historical behaviour.

The calculated EAF for each of these scenarios over the two-year period are as follows:

- Scenario 1: 0.1
- Scenario 2: 0.48
- Scenario 3: 0.42

The range in the calculated EAF reflects its sensitivity to assumptions of the ETS impact on generator market offers. We consider Scenario 1 would provide a lower range estimate as it assumes that only thermal generators reduce their market offers with the removal of ETS obligations. Thus the EAF reflects the average impact of the ETS when thermal generation is setting the spot market price. Scenario 2 on the other hand models hydro generators with controllable storage also reducing their offer prices to always reflect the impact on marginal thermal generation. This is optimistic in terms of price effect (i.e. larger price effect) as the impact on the value of water due to the ETS obligations could reduce to below than that assumed as an example,

[1] These are offers to sell energy into the wholesale spot electricity market.

when storage levels are high and there is risk of spill. Given this, we consider this scenario would provide an upper range on the EAF over the modelled period. The reduction of the EAF in Scenario 3 relative to Scenario 2 reflects the impact of the assumption that thermal generators respond to lower spot prices and reduce their amount of lower-priced generation. The net effect of this is an increase in spot prices relative to Scenario 2 with a corresponding reduction in the calculated EAF.

The calculated EAF in this analysis is lower than the long-term EAF value of 0.537[2] tCO_2/MWh. In regards to this, we note that:

- The assessment of the long-term EAF value spans an extended horizon[3] covering periods of reduced and increased thermal generation as generation build evolves over time. Hence a direct comparison of these two EAF values would not be correct. We do however understand that in the previous EAF assessment used to inform the above long-term value there were years during the assessment period where the calculated EAF value reduced to below the values calculated in this report[4].
- Our calculation is based on a short-run assessment of two years (2016-2017). The addition of base load geothermal and wind generation together with expansion of the transmission system (thus removing transmission bottlenecks) in recent years has reduced the requirement for thermal generation. The EAF will tend to reduce when thermal generation is less likely to be marginal.
- Lastly, while we have considered several scenarios for the potential impact on generator offer costs in the counterfactual solve (with the removal of ETS obligations), we have not modelled any change in incentives on participants to increase or reduce spot prices. This may further impact spot price effects and the resulting EAF.

[2] See regulation 6(a) of the Climate Change (Eligible Industrial Activities) Regulations 2010.
[3] In fact the published long-term EAF assessment undertaken in 2008 covered a period 22 years with modelled generation build over the period. See SDDP Modelling of Carbon Dioxide Emissions from Electricity Generation, 25th November 2008 by Tom Halliburton.
[4] In particular the previous longer-term analysis reported EAF values of 0 to 0.04 tCO2/MWh in some years.

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1. Introduction

Thermal generation as a proportion of total generation has been declining in recent years due to the:

- increase in build of low marginal cost renewable generation[5]
- expansion of the transmission grid, removing transmission bottlenecks between hydro, geothermal and wind resources in the South Island, central North Island and Lower North Island and the North Island load centres of Wellington and Auckland.

This resulted in the retirement of over 1000MW of thermal generation in the upper North Island reflecting the uneconomic situation of these generators under the current market environment[6].

The Ministry for the Environment (MFE) would like to do an initial high-level assessment of the current state of the EAF given these recent changes in the electricity market.

We have undertaken an assessment using actual wholesale electricity market spot prices to estimate the potential impact the ETS may have had given the recent changes to the electricity market.

This report details our approach, results and analysis of the EAF over the period 01 January 2016 to 31 December 2017.

2. Assessment approach

The EAF is calculated as the impact on electricity market prices due to the ETS. This is captured in the following calculation:

$$EAF = \frac{Electricity\ price\ with\ ETS\ obligation - Electricity\ price\ without\ ETS\ obligation}{Effective\ NZU\ price}$$

Where the electricity price in this assessment is calculated as the load-weighted average price paid by spot market purchasers and the effective NZU price is the scaled NZU spot price[7].

We used the vSPD[8] model to assess the potential impact on spot prices with and without ETS obligations over the period 01 January 2016 to 31 December 2017. The vSPD model is a replica of the market clearing engine used in the New Zealand wholesale electricity market used to dispatch generators and calculate half-hourly wholesale electricity spot prices.

In the wholesale electricity market three types of spot prices published. These are:

[5] These being wind and geothermal generators.
[6] This included 400MW at Otahuhu and 140MW at Southdown in late 2015 as well as the retirement of two 250MW Huntly rankine units by June 2015.
[7] Half the spot NZU spot price in 2016 and two-thirds the NZU spot price in 2017.
[8] The vSPD model is available from the Electricity Authority (www.emi.ea.govt.nz/Wholesale/Tools/vSPD)

- Forecast prices: Used to provide market participants an indication of spot prices up to 36 hours into the future.
- Real-time prices: Used to provide an indication of prices of the 5-minute period that had just ended.
- Final prices: Calculated after the trading day for the 48 half-hour trading periods of the trading day. These prices are used for settlement in the market.

The vSPD model inputs used in this analysis are based on data used to calculate final prices. These include offers submitted by generators for energy and reserves for each 30 minute trading interval, metered wind generation, metered demand, transmission network topology and constraints. Using the base market inputs we were able to calculate the half-hourly spot market prices which would include the impacts of ETS obligations.

To calculate counterfactual prices, the vSPD market model was run over the period 01 January 2016 to 31 December 2017 with different assumptions of impact on generator market offers. For this, we considered three scenarios.

In the first scenario, adjustments were made to thermal generator market offers to account for the potential impact of ETS obligations on marginal costs. These adjustments are discussed in Section 2.1 below. No other adjustments were made to market generators.

The second scenario considers, in addition to the first scenario assumptions, the potential impact on hydro generation offers. A reduction in thermal generator marginal costs with the removal of ETS obligations, can impact hydro generators decisions in controlling their storage as the opportunity cost of water would likely reduce (all else being equal). To account for this we assess a scenario where hydro generators with controllable storage[9] always adjust their offer prices to reflect this reduction in marginal thermal generation cost. This is discussed further below.

The above two scenario will result in a reduction in spot electricity prices. The final scenario considers, in addition to the first two scenarios, the potential impact of reduced spot electricity prices on thermal generator offers. Thermal generators reduce the amount of low-priced energy offers into the spot market when spot prices are lower, to avoid unnecessarily running plant with fixed costs and constraints when expected spot prices are too low. This is discussed further in the next section.

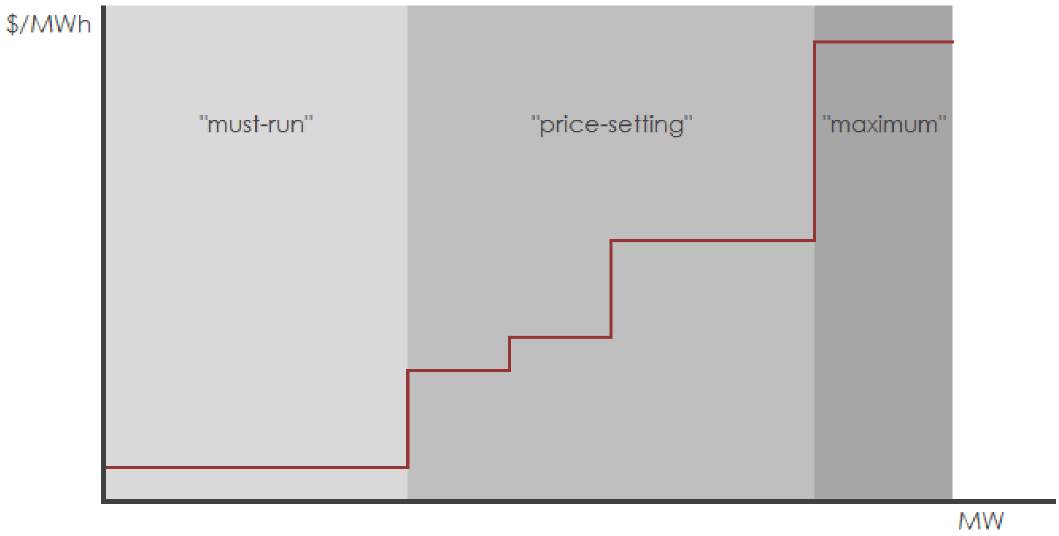
Apart from the above adjustments, no further changes were made to generator market offers to reflect any change in incentives to increase or reduce spot prices apart from what is already reflected in their existing offers to the market.

[9] These are Tekapo, Taupo, Pukaki, Hawea, Manapouri and Te Anau.

2.1. Adjusting thermal generator offers

In the New Zealand spot electricity market generators submit offers consisting of price-quantity pairs indicating their intention to sell electricity into the spot market. The generic form of these offers is shown in Figure 1 below.

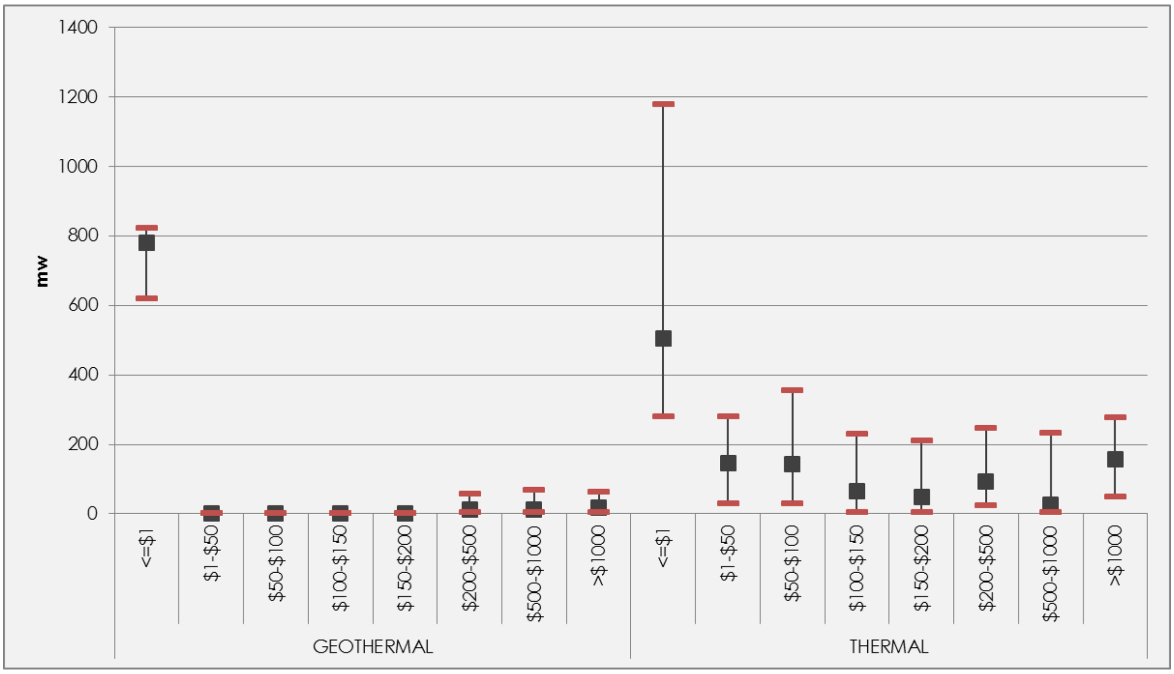
Figure 1: Typical generator energy offer in wholesale spot electricity market



The generator offer can typically be partitioned into three components. The initial component is what can be termed "must-run" which reflects the generators desire to dispatch its generation to at least a certain level and can be at prices below what is usually considered as marginal cost for the generator. This desire could be to meet physical constraints (such as minimum generation loading requirement) or due to contractual obligations being met by the generator. The next component generally represents the price setting component which is typically where the supply curve intersects the demand, thus setting the market price. A generator can also signal desired maximum generation level by offering a component of energy at a very high price that is unlikely to be dispatched in the market.

Figure 2 below shows a comparison of the median and range of MW offered in different price bands by geothermal and other thermal generators over the period 01 January 2016 to 31 December 2017. The range represents 95% of instances over this period with the median representing the 50th percentile value. Here we see that geothermal generators generally offer most of their capacity at very low prices (less than $1/MWh and typically at $0.01/MWh) signalling a desire to run all the generation at base load. This implies that geothermal generators will generally be price-takers as the spot price (price of the marginal generator) would typically be greater than the geothermal offer price. This also implies that absent any ETS obligation, we think it would be unlikely to see any change in the offering strategy of geothermal generation as they do not appear to be passing on the current ETS costs via their energy offers.

Figure 2: Statistics of geothermal and thermal generator market offers



Thermal generators also have a low-priced must-run component due to technical and financial reasons as outlined above. Similar to the geothermal energy offers, these low priced offers do not appear to include ETS cost effects and are also less likely to affect the spot price. For thermal generators, there is also significant generation offered above these low prices and these may include the incremental cost effects of meeting ETS obligations.

In our first scenario, we assume that these low-priced energy offers (<$1/MWh) from thermal generators would remain as currently offered as these offers do not appear to include the ETS cost effects. The higher-priced offers are adjusted to account for ETS cost effects as discussed in Section 2.5 below.

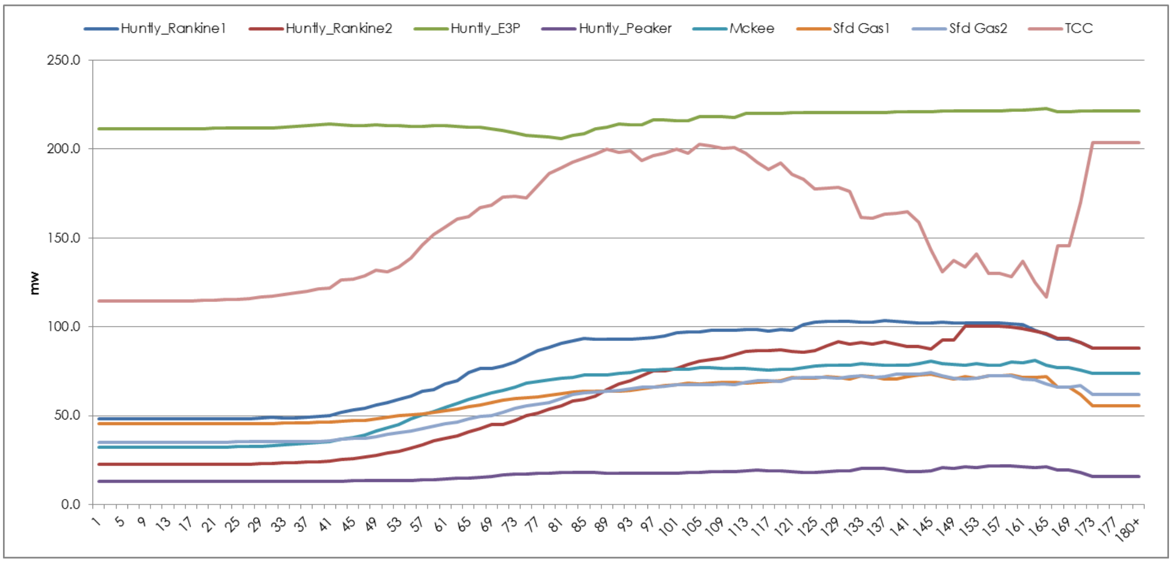
In Scenario 3, we consider a variation to this first scenario assumption where we assume thermal generators reduce the *quantity* of low-priced energy offers[10] when spot prices reduce. Figure 3 below illustrates the daily average low-priced energy offered by thermal generators at different spot market prices[11] over the period 01 January 2016 to 31 December 2017. With the exception of the two CCGTs (Huntly E3P and TCC), there is generally an increase in quantity of low-priced energy (<$1/MWh) offered by the thermal generators at higher spot prices[12]. This reflects the increased incentive to generate when spot prices are higher to cover both the fixed and variable costs. At the Huntly CCGT (Huntly E3P) the quantity of low-priced energy offers is quite insensitive to the spot price with similar quantities offered at low

[10] Less than $1/MWh.
[11] These are daily average spot prices.
[12] This does not include thermal co-generation such as the Glenbrook thermal generator. These generators tend to offer generation at low prices when they are offered into the market. Whirinaki predominantly offers all its generation above $1/MWh and so is excluded from this assessment.

and higher spot prices. At the Stratford CCGT (TCC), the reduction in quantity of low-priced energy offers at higher spot prices is due to plant outages during these periods. Across all generators there is an observed reduction in offers at the very high prices. We consider this not due to any planned output reduction but rather due to unexpected large price spikes during a day.

The modelled reduction in quantity offered by thermal generators is based on the observed reductions in quantity offered by the different generators over the last two years at different prices levels. So if a thermal generator historically reduced the quantity of its low-priced energy offers by 10% when the average daily spot price reduced from \$80-82/MWh to \$70-72/MWh, in Scenario 3, its low priced energy offers would be reduced by the same percentage (10%) during days where the modelled average spot prices from Scenario 2 reduces from actual spot prices in the same range (i.e. from \$80-82/MWh to \$70-72/MWh). The reduced quantity (i.e. 10%) was added to the thermal generator higher priced offers.

Figure 3: Low-priced thermal energy offers versus spot price



2.2. Adjusting hydro generator offers

Water stored by hydro generators is valued by its opportunity cost based on current hydro storage levels and uncertain future conditions such as inflows, demand and alternative generation availability. As an example, current hydro storage may be valuable if using it now results in greater likelihood of using higher cost generation (or load curtailment) in the future given the range of potential inflows and demand. Alternatively, the opportunity cost of stored water may be quite low if there is a high risk of spilling the water given the range of potential inflows and demand. Hydro generators would consider these factors in their market offers together with other market information such as forecast prices and contracts to signal their desire to generate at different price levels based on maximising the return on their assets.

In our second modelled scenario we consider as part of the counterfactual solve, the impact if hydro generators always adjusted the prices of their non "must-run" market offers (>$1/MWh) to reflect the average reduction in marginal costs of thermal generation[13] due to the removal of ETS obligations. We consider this assumption would tend to result in a greater reduction in spot prices than expected (i.e. increase the EAF) as the impact of reductions in marginal thermal generation costs on the value of water would tend to reduce as storage increases and there is a greater risk of spill.

This reduction is calculated as discussed in Section 2.5 below.

2.3. Generator emission intensity factors

Generator emission intensity factors provide an indication of equivalent CO_2 emissions for each unit of electricity produced by a generator. We calculated thermal and geothermal generator emission intensity factors based on the generator heat rate and fuel emission values provided in the Generation Expansion Model (GEM) input data files[14].

Where available, we also calculated and used emission intensity factors based on publically available reports of the large generator-retailers that operate thermal and geothermal stations. This included Genesis's E3P CCGT and Huntly rankine units[15] as well as Contact's geothermal generators.

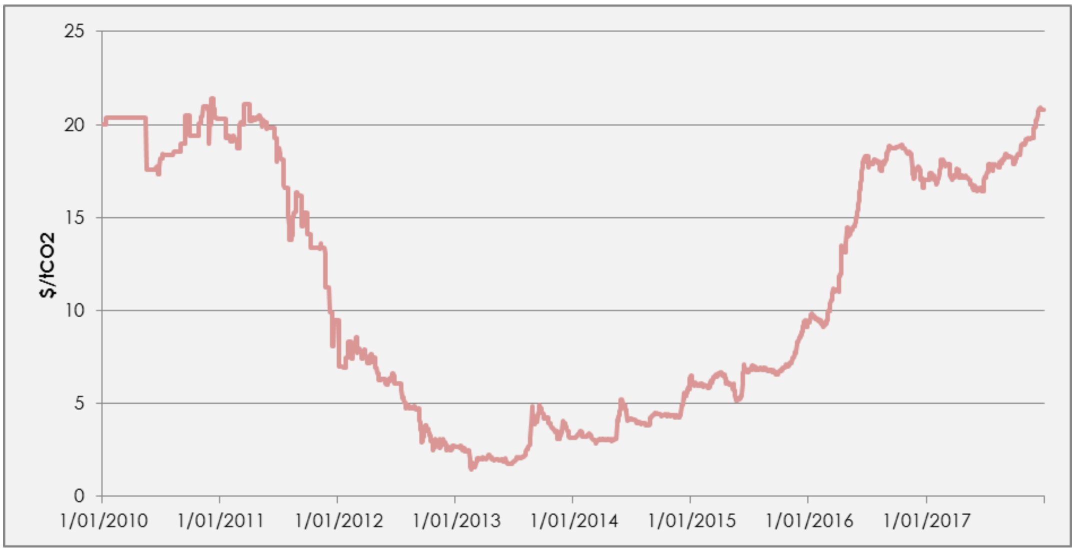
The list of the emission intensity factors used in this analysis and the data sources are provided in Appendix A.

2.4. Effective NZU spot price

The price of NZ units (daily NZU spot price) has been increasing in recent years following a drop in prices in mid-2013. Figure 4 below shows the daily NZU spot price over the period 01 January 2010 to 31 December 2017.

[13] These do not include thermal co-generation plant which are not expected to be marginal.
[14] See https://github.com/ElectricityAuthority/gem
[15] This captured the dual coal/gas fired operation of the Huntly rankine units.

Figure 4: Daily NZU spot price



The above NZU spot price provides an indication of the tradeable value of NZUs. We assume that the generator offer prices are adjusted to reflect the opportunity cost of NZUs held, in which case the above spot price provides an indication of this value.

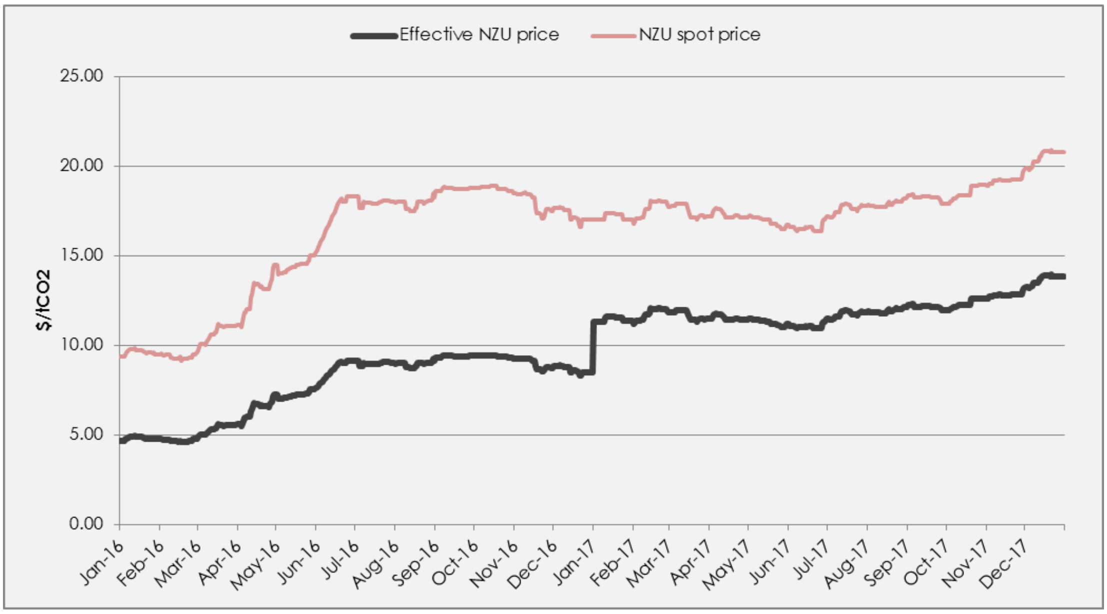
As part of this assessment we also consider the impact of the one-for-two policy that was in effect during 2016. This effectively halved the cost of emission obligations as it required the surrender of 1 NZU for 2 tonnes of CO_2 emissions. This was increased in 2017 where the surrender of 2 NZUs is required for 3 tonnes of CO_2 emissions. To cater for this, an *Effective NZU price* is calculated which is used in the analysis to adjust generator offer prices and calculate the EAF. The Effective NZU price is calculated as follows:

In 2016: $Effective\ NZU\ price = \frac{1}{2} \times NZU\ spot\ price$

In 2017: $Effective\ NZU\ price = \frac{2}{3} \times NZU\ spot\ price$

Figure 5 below illustrates the daily NZU spot price and effective NZU price for 2016 and 2017. The sharp increase at the start of 2017 in the effective NZU price is due to the increase in the number of units required to be surrendered as discussed above.

Figure 5: Comparison of effective NZU price and NZU spot price



2.5. Counterfactual offer price

To assess the counterfactual scenarios with no ETS obligations, we calculated an adjusted generator offer price for thermal generators based on the above discussed factors with the calculation as shown below:

$$\begin{aligned} Adjusted\ offer\ price \\ &= Original\ offer\ price \\ &- (Effective\ NZU\ \ price \times Emission\ intensity\ factor) \end{aligned}$$

Where:

Adjusted offer price is the $/MWh counterfactual price assumed for thermal generators in the alternate scenarios assuming no ETS cost

Original offer price is the actual $/MWh offer price submitted by the thermal generator into the spot electricity market

Effective NZU price is the effective price assumed to be passed through into thermal generator offers ($/tonnes of CO_2) as discussed above

Emission intensity factor is the amount of CO_2 emissions for each unit of electricity produced (tonnes of CO_2/MWh)

As an example, assuming an effective NZU price of $10/t$CO_2$ results in a price adjustment of $4/MWh for the Huntly CCGT unit.

In the second modelled scenario, hydro generator offers (>$1/MWh)are also adjusted under the counterfactual scenario with no ETS obligation, as discussed above.

$$
\begin{aligned}
&\mathit{Adjusted\ stored\ hydro\ offer\ price} \\
&\qquad = \mathit{Original\ offer\ price} \\
&\qquad - (\mathit{Effective\ NZU\ \ price} \times \mathit{Average\ emission\ intensity\ factor})
\end{aligned}
$$

Where:

Adjusted stored hydro offer price is the $/MWh counterfactual offer price assumed for hydro generators with controllable storage assuming no ETS cost in the second modelled alternate scenario

Original offer price is the actual $/MWh offer price submitted by the hydro generator into the spot electricity market

Effective NZU price is the effective price assumed to be passed through into thermal generator offers ($/tonnes of CO_2) as discussed above

Average emission intensity factor is the average amount of CO_2 emissions for each unit of electricity produced (tonnes of CO_2/MWh) by thermal generators likely to be marginal[16]

3. Modelling results and discussion

We simulated the market prices over the period 01 January 2016 to 31 December 2017 for the base case (with ETS) and counterfactual scenarios without the ETS (with offer prices adjusted as shown above).

The resulting impact on the load-weighted average spot price and average EAF over the two years from 01 January 2016 to 31 December 2017 is shown in the table below.

Table 1: Calculated EAF for different modelled scenarios

Scenario	Average Effective NZU price ($/t$CO_2$)	Average spot electricity price with ETS ($/MWh)	Average spot electricity price without ETS ($/MWh)	EAF
Scenario 1	9.79	67.64	66.66	0.1
Scenario 2	9.79	67.64	62.97	0.48
Scenario 3	9.79	67.64	63.5	0.42

[16] These include Huntly E3P, Huntly rankine, Huntly OCGT, Mckee, TCC, Stratford, Whirinaki.

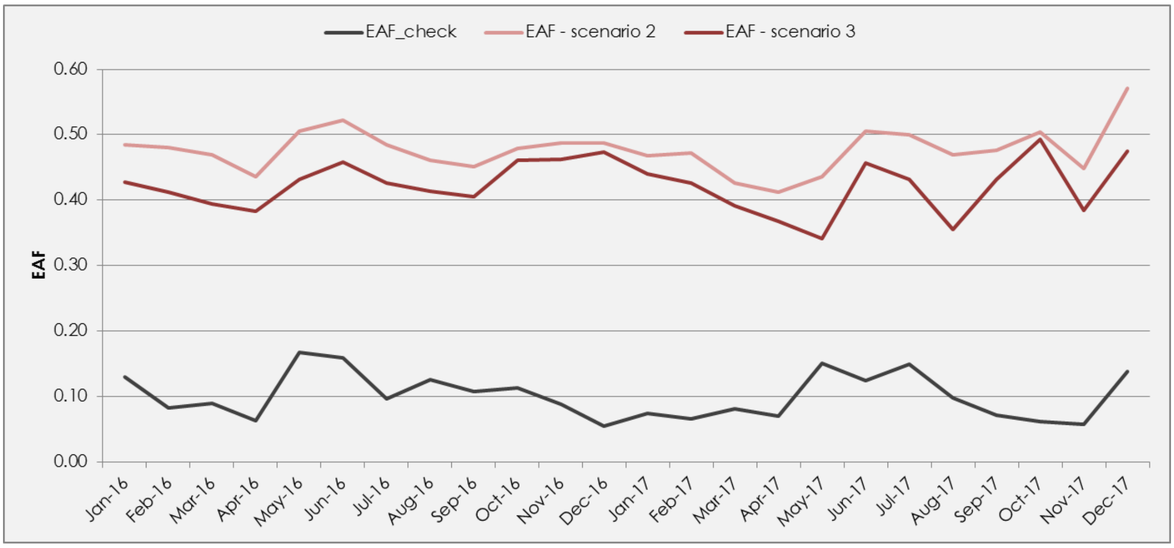
In Scenario 1, only thermal generation offers are modelled as reducing under the counterfactual assumption of no ETS obligations. No other changes are assumed to occur that would impact the market dispatch, hence resulting in a lower estimate of the EAF.

In Scenario 2, hydro generators are assumed to make corresponding adjustments to their offers to reflect the reduced cost of thermal generation reducing the marginal water value and hence their offers. Under this scenario there is a larger reduction in spot prices with a corresponding larger EAF of 0.48. As discussed above, we would consider the reduction in price in this scenario and the corresponding EAF an upper estimate as the hydro generator adjustment would not necessarily always reflect the marginal generation impact.

The removal of some lower priced thermal generation in Scenario 3, results in a slight increase in spot prices with a corresponding reduction in the EAF relative to scenario 2.

A comparison of monthly average EAF values over the period 01 January 2016 to 31 December 2017 is shown in Figure 6 below. Here we see monthly variability with the EAF increasing during May 17 to July 17 and Dec 17 when increased thermal generation was required to manage lower hydro storage levels. The impact of the ETS obligations is greatest during periods when thermal generators with greater emission intensities are used.

Figure 6: Comparison of monthly EAF values under different modelled scenarios



Appendix A

The table below indicates the emission intensity factors used for the different market offers.

Table 2: Table of modelled emission intensity factors

Market generator	Type	Emission intensity factor (tCO_2e/GWh)	Source
Huntly E3P	CCGT	400	1
Huntly rankine	Dual	845	1
Huntly OCGT	Gas	556	2
Hawera	Gas	491	2
Kawerau	Geothermal	100	2
Mckee	Gas	554	2
Ngatamariki	Geothermal	100	2
Nga Awa Purua	Geothermal	100	2
Ohaaki	Geothermal	459	3
Poihipi	Geothermal	38	3
TCC	CCGT	407	2
Stratford	Gas	560	2
Te Mihi	Geothermal	42	3
Te Rapa	Gas	560	2
Whirinaki	Diesel	803	2
Rotokawa	Geothermal	100	2
Te Huka	Geothermal	37	3
Wairakei	Geothermal	24	3

Notes on data sources:

1. Calculated from Genesis operational reporting
2. Calculated from GEM input data files
3. As reported in Contact 2017 Annual Report