Determination of the 2024 Electricity Allocation Factor

Contents

1. Purpose

1.1. The purpose of this paper is to determine impact of the emissions trading scheme (ETS) on the price of electricity for the 2023/24 financial year. This is used to determine the Electricity Allocation Factor (EAF) for calendar year 2024.

1.2. Section 161FA of the Climate Change Response Act 2002 (Act) requires the Electricity Authority Te Mana Hiko (Authority) to notify the Minister of Climate Change of the EAF for a calendar year by 31 July each year. This is a new requirement that came into effect on 1 January 2024; previously, industrial allocations used a set EAF value since 2012.

1.3. The EAF is an estimate of the effect of the New Zealand Emissions Trading Scheme (ETS) on wholesale electricity prices. It represents the uplift in electricity prices due to the requirement to place a price on the carbon emitted during the electricity production process and is therefore important to businesses for whom electricity purchases are substantial. Approximately one third of the roughly six million NZUs per annum the government spends on emissions units (New Zealand Units or NZUs) allocates for emissions-intensive, trade-exposed business is determined by the EAF.

1.4. Section 161FA of the Act prescribes the formula and market model the Authority must use when determining the EAF. The Authority's methodology works within this legislative framework. This report outlines the methodology used to calculate the EAF as prescribed in legislation, detailing two scenarios to estimate the impact of the ETS on electricity prices and identifying the preferred scenario. This paper:

(a) documents the method

(b) describes the data inputs

(c) presents the simulation results.

2. Findings

2.1. The Authority has determined that the ETS impact on the price of electricity for the 2023/24 financial year (also described in this paper as the EAF for a financial year) is 0.587tCO_2e/MWh (tonnes of CO_2 equivalent per megawatt-hour of electrical energy).

2.2. Using the formula to calculate the EAF as set out in legislation[1] this means the EAF for the calendar year 2024 is **0.554tCO_2e/MWh**. This is very slightly higher than the EAF for the previous two years, largely due to relatively dry weather conditions leading to higher thermal generation.

3. Methodology to estimate the EAF

3.1. The EAF applied for a calendar year is determined in accordance with the following formula as set out in section 161FA(2) of the Act:

$$\mathrm{EAF}_{\mathrm{cy}} = \frac{\left(\mathrm{EAF}_{\mathrm{fy1}} + \mathrm{EAF}_{\mathrm{fy2}} + \mathrm{EAF}_{\mathrm{fy3}}\right)}{3}$$

where:

$\mathbf{EAF_{cy}}$ is the allocation factor for the relevant calendar year

[1] Climate Change Response Act 2002 section 161FA(2).

EAF_{fy1} is the ETS impact on the price of electricity in the financial year that ends on 30 June in the relevant calendar year

EAF_{fy2} is the ETS impact on the price of electricity in the financial year preceding the financial year described by EAF_{fy1}

EAF_{fy3} is the ETS impact on the price of electricity in the financial year preceding the financial year described by EAF_{fy2}.

3.2. For the determination of the 2024 EAF, the Climate Change Response (Late Payment Penalties and Industrial Allocation) Amendment Act 2023 set out that variables EAF_{fy2} and EAF_{fy3} are to be equal to 0.537 tCO2e/MWh.[2] For the 2025 EAF, only variable EAF_{fy3} will be 0.537 tCO_2e/MWh.

3.3. The formula used to calculate the EAF for a financial year is:

$$\text{EAF} = \frac{\text{Electricity LWAP with carbon cost} - \text{Electricity LWAP without carbon cost}}{\text{NZU price}}$$

3.4. The load-weighted average price (LWAP) of electricity is applied for the financial year. The calculation of the electricity LWAP with carbon cost is based on the observed electricity market prices (base case) and reconciled demand volumes from the wholesale market. The NZU price is taken to be the annual average carbon price, calculated using daily carbon prices obtained from emsTradepoint.

3.5. Estimating the electricity LWAP without carbon cost, ie without the impact of the ETS, requires running a counterfactual scenario in the market model to determine a new set of electricity prices. The counterfactual experiment requires adjusting the energy offer prices, an input into the model, downwards to remove the carbon cost component of the offer price.

3.6. This report considers two counterfactual scenarios to estimate the ETS-exclusive electricity price. The first scenario is based on the Ministry for the Environment's approach to determining the EAF used in previous consultations, while the second includes Authority enhancements to incorporate generators' short-run marginal costs.

3.7. As set out in Part 5, the Authority decided to use the second scenario to determine the EAF.

Market model

3.8. The Act requires the Authority to employ a market model to determine the impact of the ETS on electricity prices.[3] We have used the Authority's vSPD[4] (vectorised Scheduling, Pricing, and Dispatch) model, as it is a mathematical replica of the system operator's SPD model, used to determine prices and dispatch schedules in the wholesale electricity market.

3.9. There are alternative market models available in New Zealand but only vSPD meets the requirements of the Act. Specifically, it ensures consistency with the market clearing algorithm outlined in the Electricity Industry Participation Code 2010. The vSPD model is also not a proprietary model so it meets the requirement that both the model and its input data can be made publicly available.[5]

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[2] Climate Change Response Act 2002, Schedule 1AA, section 42(2)(a).

[3] Climate Change Response Act 2002 section 161FA(3).

[4] https://www.emi.ea.govt.nz/Wholesale/Tools/vSPD.

[5] The requirements for the market model are set out in the Climate Change Response Act 2002 section 161FA(4). The requirement that the model and any input data necessary to operate the model must be publicly available is set out in the Climate Change Response Act 2002 section 161FA(5).

3.10. Before November 2022, final electricity prices were calculated ex-post by SPD. The ex-post schedule made use of the offer to supply prices that pertained in real time, the grid conditions at the start of the 30-minute trading period, and the actual metered demand for that trading period. Final prices were calculated the day after real time. Earlier EAF calculations have used the vSPD model employing ex-post final pricing.

3.11. Real-time pricing (RTP) took effect on 1 November 2022. Under RTP, electricity prices are calculated immediately at the end of each trading period and are based on a time-weighted average of the real-time dispatch prices calculated in real time, several times throughout a trading period. The EAF calculation for 2023/24 financial year is based on real-time pricing, which is a change from previous years but does not substantively impact the EAF.

Adjusting offer prices by generation type

3.12. According to the Climate Change (Eligible Industrial Activities) Regulation 2010,[6] the modelling assumptions for the market model used to determine allocation factors for electricity are:

(a) in the absence of the emissions trading scheme, thermal electricity generation would be offered at lower prices, as generators' marginal costs would be lower

(b) as a consequence of the modelling assumption in paragraph (a), hydro-electricity generators that have controllable water storage would offer electricity at lower prices, because lower overall prices reduce the opportunity cost of stored water.

3.13. To calculate the ETS-exclusive electricity prices, the vSPD model is used to repeat the pricing process using offer prices that exclude carbon costs. For each counterfactual scenario, the offer prices are adjusted differently to reflect this exclusion.

3.14. Diverse types of generation participate in the New Zealand market. Some generation, such as rooftop solar, does not get offered into the wholesale market and is therefore not considered in this analysis because it does not directly influence the wholesale price. Among those generation types that do participate, only thermal and hydro generation (along with one co-generation plant) are assumed to be influenced by the ETS. Hydro generation is considered because generators typically adjust their offer prices based on the opportunity cost of stored water—which is influenced by thermal offers.

3.15. Geothermal generation contributes approximately 18% of New Zealand's electricity supply. Geothermal plants provide a stable and continuous supply of electricity, functioning as base load power sources. Due to the complexity and expense involved in adjusting the generation output of geothermal plants, they typically operate as baseload only and offer energy at a fixed, must-run price of $0.01/MWh.

3.16. Historical data from 1 July 2023 to 30 June 2024 indicates geothermal plants rarely offer their energy above the must-run price of $0.01/MWh. On the few occasions they do, it is at a significantly higher price, such as $5000/MWh. This suggests they are not intending to generate electricity at all. Consequently, geothermal offer prices remain unadjusted for this analysis.

3.17. There are several cogeneration plants that offer energy into the electricity market. Examination of the historical data for the study period reveals that except for the Te Rapa

[6] Climate Change (Eligible Industrial Activities) Regulations 2010 section 6A(2) sets the assumptions for market model used to determine allocation factors for electricity.

cogeneration plant, all other cogeneration plant offer energy at must-run prices of \$0.01/MWh. As a result, only Te Rapa's offer prices are subject to adjustment.

3.18. The contribution of wind generation in the New Zealand electricity market is steadily increasing. Wind farms were traditionally treated as if they were price takers, meaning they were paid the prevailing spot price for what they supplied and did not offer their energy at specific prices in the electricity market.

3.19. Since September 2019, wind farms have been treated like any other type of generator offering into the market and have been able to offer energy using up to five price tranches. However, we have not observed offers from wind farms that exceed the must-run price of \$0.01/MWh and therefore assume for this analysis that wind farms continue to operate at their full potential capacity in real time and their offer prices are not impacted by the ETS.

Counterfactual scenarios

3.20. This report considers two counterfactual scenarios to estimate the ETS-exclusive electricity price. The first scenario is based on the Ministry for the Environment's approach to determining the EAF used in previous consultations, while the second includes Authority enhancements to incorporate generators' short-run marginal costs.

3.21. The first scenario adjusts the offer prices of both thermal and hydro generation. For thermal generation (including Te Rapa cogeneration), offer prices are adjusted downwards based on the prevailing daily carbon cost. The offer price of hydro generation is adjusted downwards using the thermal plant capacity-weighted average carbon cost.

$$\text{Adjusted offer price}_{\text{thermal}} = \text{Max}[\text{floor price, original offer price} - \text{carbon cost}]$$
$$\text{Adjusted offer price}_{\text{hydro}} = \text{Max}[\text{floor price, original offer price} - \text{average carbon cost}]$$

where:

floor price is a hypothetical must-run offer price of \$1.00/MWh[7]

original offer price is the offer price as observed in base case (\$/MWh)

carbon cost is the cost of CO_2 for every MW of electricity calculated as following:

$$\text{carbon cost} = 0.001 \times \text{heat rate}\left({}^{\text{GJ}}/_{\text{GWh}}\right) \times \text{emission factor}\left({}^{\text{tCO2}}/_{\text{GJ}}\right) \times \text{carbon price}\left({}^{\$}/_{\text{tCO2}}\right)$$

average carbon cost is calculated as following:[8]

$$\text{average carbon cost} = \frac{\sum_{\text{thermal generation(g)}} \text{carbon cost}_{\text{g}} \times \text{capacity}_{\text{g}}}{\sum_{\text{g}} \text{capacity}_{\text{g}}}$$

3.22. The second counterfactual scenario is similar to the first except different floor prices are used. In scenario two the floor price for each thermal generation offer is calculated using the relevant fuel cost (gas, coal or diesel) and the variable operating and maintenance (VOM) cost of each plant. This is the ETS-exclusive short-run marginal cost (SRMC).

$$\text{floor price} = 0.001 \times \text{fuel cost}(\$/\text{GJ}) \times \text{heat rate}(\text{GJ/GWh}) + \text{VOM}(\$/\text{MWh})$$

[7] Electricity Allocation Factor Estimates for 2016/17 – Scientia Consulting.

[8] This calculation is slightly different from the original approach from Electricity Allocation Factor Estimates for 2016/17 – Scientia Consulting.

3.23. Offer prices for hydro generation are typically structured around the opportunity cost of the hydro resource rather than the SRMC. We use the smallest floor price applied to thermal generation as the estimated floor price applied to all hydro generation.[9]

3.24. For each counterfactual scenario, the electricity LWAP is calculated using the half-hourly prices derived by using vSPD to repeat the market pricing calculation, and reconciled demand as follows:

$$\mathrm{LWAP} = \frac{\sum_{\mathrm{t,gxp}} \mathrm{Price}_{\mathrm{t,gxp}} \times \mathrm{Demand}_{\mathrm{t,gxp}}}{\sum_{\mathrm{t,gxp}} \mathrm{Demand}_{\mathrm{t,gxp}}}$$

$$\mathrm{t} \in \text{trading periods in a finacial year,}$$
$$\mathrm{gxp} \in \text{all grid exit points where there is demand (or grid offtake)}$$

where:

$\mathbf{Price_{t.gxp}}$ is the price at grid exit point *gxp* for trading period *t*

$\mathbf{Demand_{t.gxp}}$ is the demand at grid exit point *gxp* for trading period *t.*

4. Processing of input data

Carbon price (NZU price)

4.1. The Authority has used emsTradepoint data for the EAF calculation. To inform that decision, the Authority considered carbon prices from three different sources.

4.2. The first is a GitHub repository[10] that compiles NZU data sourced primarily from the website Carbon News,[11] and occasionally from emsTradepoint[12] and My Native Forest.[13] Although the Ministry for the Environment has used this data source in prior EAF reports, they have recently raised concerns about its reliability. Consequently, the Authority has not used this source in the current EAF determination.

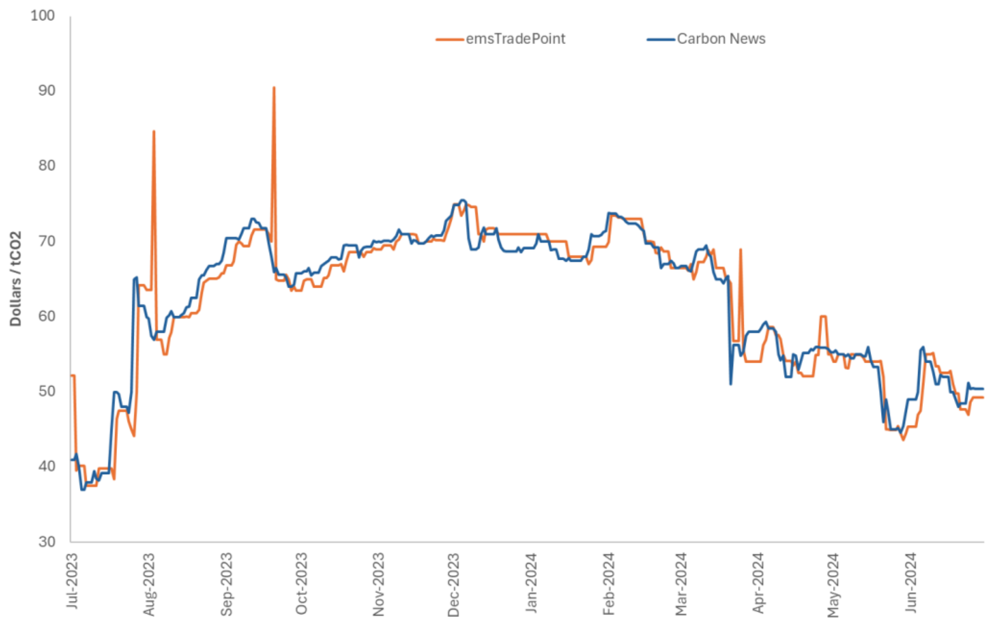
4.3. The second source of carbon prices is emsTradepoint. The Authority collects daily carbon indices from emsTradepoint, representing the daily volume-weighted average price of carbon (NZUs) traded on the secondary market, ie these are not the initial NZU auction prices.

4.4. The Ministry for the Environment has suggested using carbon prices compiled by Jarden CommTrade,[14] ie the Jarden closing price. This data is not readily available to the public or the Authority. However, the Ministry for the Environment has compared emsTradepoint and Jarden carbon prices and found a close correlation. As such, the Ministry for the Environment concurs with our decision to use emsTradepoint data.

4.5. The Authority has also conducted a comparative analysis of NZU spot prices sourced from the aforementioned GitHub repository and emsTradepoint. Our analysis revealed a strong correlation between these two datasets, as illustrated in Figure 1.

[9] This is usually the ETS-exclusive SRMC of Huntly unit 5 and TCC.
[10] https://github.com/theecanmole/nzu/blob/master/spotprices.csv.
[11] https://carbonnews.co.nz.
[12] https://www.emstradepoint.co.nz.
[13] https://www.mynativeforest.com/carbon-price-nz.
[14] https://www.commtrade.co.nz/.

Figure 1: Carbon price comparison – emsTradepoint v Carbon News NZU price



4.6. Given the Authority already has a process in place to regularly collect data from emsTradepoint and because of the strong correlation between emsTradepoint and Jarden data, we have used the emsTradepoint data for the EAF calculation.

4.7. To smooth out the fluctuations in the daily NZU carbon price, a 30-day rolling average has been calculated and used as the carbon cost for adjusting thermal generation offer prices. Figure 2 below illustrates the daily carbon price compared to the 30-day rolling average carbon price.

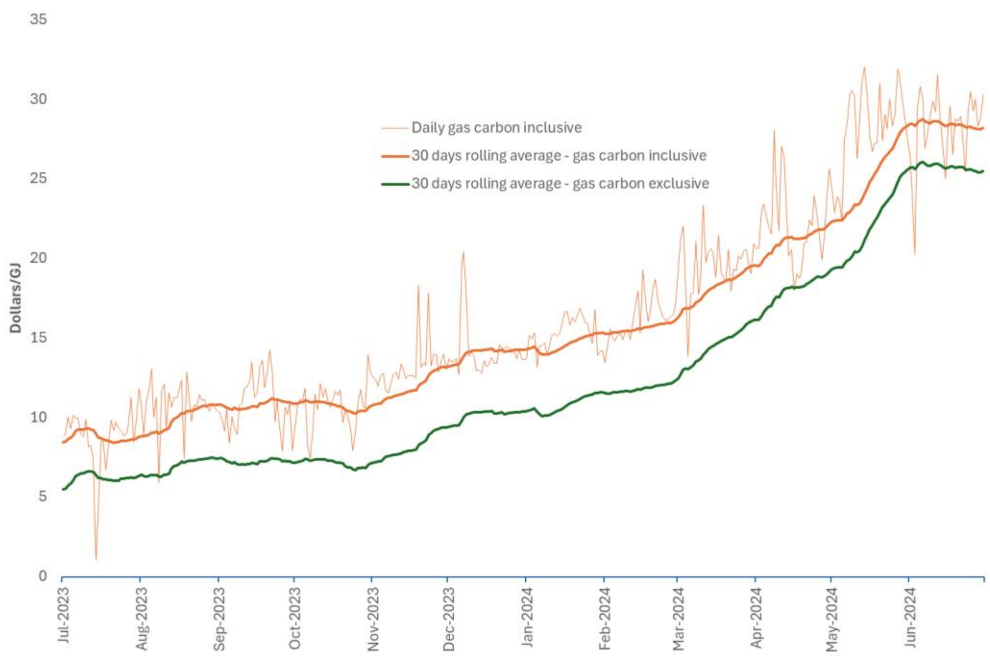
Figure 2: Daily NZU price v 30-day rolling average NZU price emsTradepoint

Gas price

4.8. The Authority collects daily gas price indices from emsTradepoint. As with the carbon prices collected from emsTradepoint, these gas price indices represent the daily volume-weighted average price of gas traded on a secondary market. Gas prices include the cost of CO_2 and because we are already adjusting offer prices to account for carbon costs, we need to subtract the CO_2 cost from the gas price indices to determine a gas-only price.

4.9. As with the daily carbon price indices, daily gas price indices also exhibit significant fluctuations. A 30-day rolling average gas price that smooths out the fluctuations is therefore similarly calculated and used to estimate the SRMC for thermal generation. Figure 3 displays the daily carbon-inclusive gas prices, 30-day rolling average carbon-inclusive gas prices and the 30-day rolling average carbon-exclusive gas prices.

Figure 1: Daily gas prices and 30-day rolling average gas prices

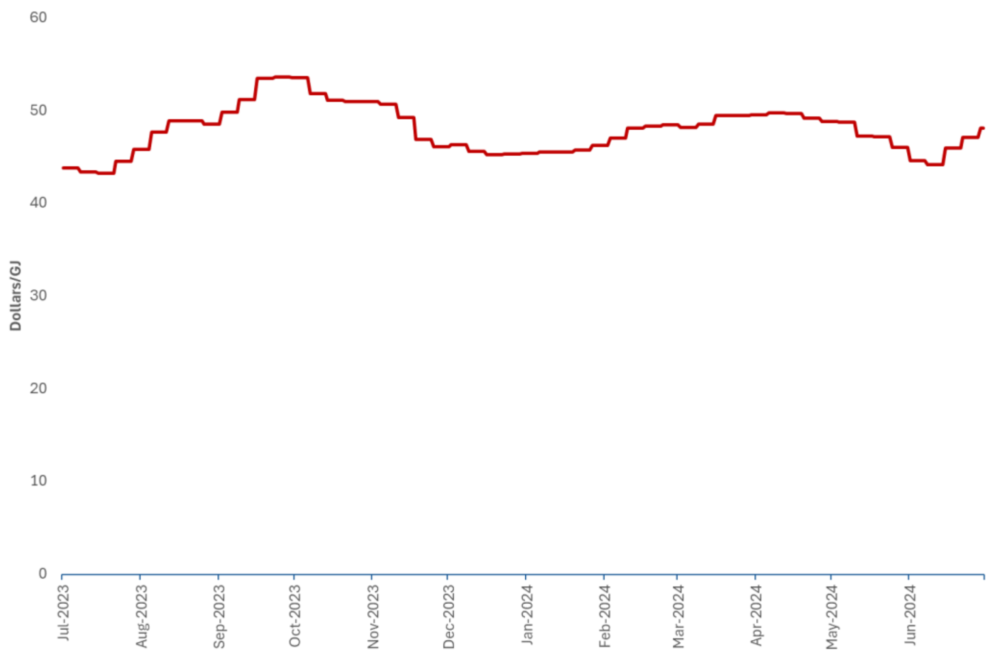


Diesel price

4.10. To estimate the SRMC of diesel generation, we use the diesel prices for the week ending each Friday published by the Ministry of Business, Innovation and Employment (MBIE). These prices reflect the discounted price paid by purchasers and have taxes, excise duty, levies, and the impact of the ETS excluded.[15]

4.11. We incorporate a diesel delivery cost of ten cents per litre and an energy content factor of 37 megajoules (MJ) per litre[16] to convert the diesel price from New Zealand cents per litre to New Zealand dollars per gigajoule ($/GJ). Figure 4 illustrates the weekly diesel price in NZD per GJ for period from 1 July 2023 to 30 June 2024.

Figure 4: MBIE weekly diesel price excluding taxes, levies, and the ETS



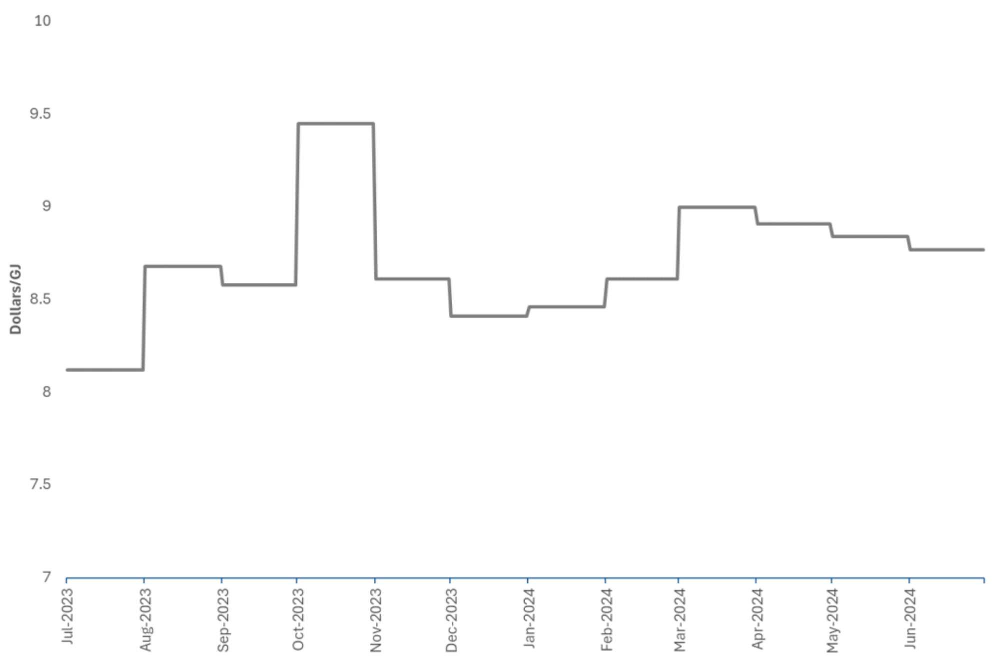
[15] Weekly Oil Price Monitoring Data Dictionary (mbie.govt.nz) - [Diesel_price_excl_taxes_NZc.p.l].
[16] 2020 Thermal Generation Stack Update Report, section 3.1.13.4

Coal price

4.12. The Huntly Rankine units can generate power using either gas or coal. The choice to use gas versus coal depends on many factors including electricity demand, gas purchase contracts, coal stockpile levels, and unit availability. The information required to determine the precise gas/coal split, and its incidence by trading period, is not available publicly so we make a simplifying assumption that the Huntly Rankine units use only coal for generation, and we therefore use the coal price to estimate ETS-exclusive SRMC for these units.

4.13. We use the monthly reference coal price reported by Enerlytica[17], which is based on the FOB Melawan (Indonesia) price, and includes shipping, wharfage, and road transport costs, ie it is an estimate of the price to have coal delivered to the Huntly power station. The analysis requires a coal price for every trading period so we assume daily coal prices are the same as the monthly Enerlytica coal price for each day of the corresponding month. Figure 5 displays the daily coal prices from 1 July 2023 to 30 June 2024.

Figure 5: Monthly coal prices



[17] https://www.enerlytica.co.nz/.

Carbon cost and the ETS-exclusive short-run marginal cost

4.14. To estimate the carbon marked-up cost and ETS-exclusive short-run marginal cost (SRMC), we use following formulae:

$$\text{Carbon cost} = 0.001 \times \text{heat rate}\left[{}^{\text{GJ}}/_{\text{GWh}}\right] \times \text{emission factor}\left[{}^{\text{tCO}_2}/_{\text{GJ}}\right] \times \text{carbon price}[{}^{\$}/_{\text{tCO}_2}]$$

$$\text{SRMC} = 0.001 \times \text{heat rate}\left[{}^{\text{GJ}}/_{\text{GWh}}\right] \times \text{fuel price}\left[{}^{\$}/_{\text{GJ}}\right] + \text{VOM}[{}^{\$}/_{\text{MWh}}]$$

4.15. The calculation of daily prices for carbon and fossil fuels (coal, gas and diesel) has been described in the previous section. Heat rates, emission factors, and variable operating and maintenance costs vary depending on fuel type and technology. As already noted, we assume the Huntly Rankine units (1-4) use coal for power generation.

Table 1: Thermal plant heat rates, variable O&M costs and emissions factors

4.16. Table 1 presents the heat rates, variable operating and maintenance costs, and emission factors for each thermal generation plant.

Table 1: Thermal plant heat rates, variable O&M costs and emissions factors

Plant Name	Fuel	Technology	Heat Rate GJ/GWh[18]	VOM $/MWh[19]	Emissions Factor[20] tCO_2/GJ
Huntly 1-4	Coal	Rankine	10,900	9.6	0.09218
Huntly 5	Gas	CCGT	7,400	5.2	0.05397
Huntly 6	Gas	OCGT	10,525	9.7	0.05397
Junction Road[21]	Gas	OCGT	10,525	9.7	0.05397
McKee[22]	Gas	OCGT	10,525	9.7	0.05397
Stratford Peaker 1	Gas	OCGT	8,907	9.4	0.05397
Stratford Peaker 2	Gas	OCGT	8,907	9.4	0.05397
Taranaki Combined Cycle	Gas	OCGT	7,400	5.2	0.05397
Te Rapa	Gas	Co-gen	11,700	4.9	0.05397
Whirinaki	Diesel	OCGT	10,906	11.6	0.06939

[18] Heat rates are sourced from the MBIE 2020 Thermal Generation Stack Update Report
[19] VOMs are sources from the MBIE 2020 Thermal Generation Stack Update Report
[20] Emission factors are derived from New Zealand's Greenhouse Gas Inventory 1990–2018, Volume 2, Annexes
[21] Assumed to be the same as Huntly 6
[22] Assumed to be the same as Huntly 6

5. Simulation results[23]

5.1. Table 2 displays the inputs that are used to calculate the EAF for 2023/24 under each of the scenarios we considered. The inputs are:

- the LWAP for the base case (the actual price outcomes for electricity for the 2023/24 financial year) along with each of the two counterfactual scenarios (the expected price of electricity for 2023/24 without the impact of the carbon cost) that we analysed of ETS-exclusive electricity prices.
- the NZU price for 2023/24

These inputs are used to calculate the 2023/24 EAF for each scenario according to the formula previously set out in section 3.3:

$$\text{EAF} = \frac{\text{Electricity LWAP with carbon cost} - \text{Electricity LWAP without carbon cost}}{\text{NZU price}}$$

5.2. As described above, we considered two counterfactual scenarios to estimate the ETS-exclusive electricity price, with the calculations for each set out in Part 3. The first scenario is based on the Ministry for the Environment's approach to determining the EAF used in previous consultations, while the second includes Authority enhancements to incorporate generators' short-run marginal costs (SRMC).

Table 2: Electricity Allocation Factor for financial year 2023/24

	Base case	**Scenario 1 (previous methodology)**	**Scenario 2 (Authority methodology including SRMC)**
LWAP	\$186.20/MWh	\$145.46/MWh	\$149.63/MWh
NZU price	\$62.26/tCO_2e		
EAF 2023/24		0.654tCO_2e/MWh	0.587tCO_2e/MWh

5.3. It is important to highlight that when electricity prices are high, as is the situation in the base case year, ie the actual outcomes in the 2023/24 financial year, offer prices are less likely to reach the floor price when adjusted downwards. This has the effect of amplifying the influence of the ETS.

5.4. After evaluating the assumptions underlying each scenario and assessing the simulation outcomes, the Authority has concluded the second counterfactual scenario, factoring in the SRMC when adjusting offer prices downwards, is the preferred approach for estimating electricity prices without the influence of carbon costs. The Ministry for the Environment concurs with this decision.

5.5. The following factors contributed to the decision to adopt the second scenario:

(a) In a competitive market, thermal generation units typically offer electricity at or below their SRMC for the energy they anticipate generating. This strategy ensures they are

[23] All input data files, simulation outputs and modelling codes are published in a 2024 EAF repository on the Authority's GitHub site at https://github.com/ElectricityAuthority.

dispatched when it is profitable to be dispatched and they are able to sell their generated power.

(b) In the New Zealand market, thermal generators often offer below their SRMC for the energy they need to produce to meet an array of obligations such as covering demand and fulfilling hedge contracts. Additionally, they sometimes offer as low as \$0.01/MWh for the minimum generation output required to keep their units operational and avoid the costly process of shutting down and restarting slow-start thermal units.

(c) A floor price of \$1.00/MWh is a contestably arbitrary figure. In the New Zealand market, a must-run offer price is typically set at \$0.01/MWh, and if they win the must-run auction (as set out in the Code), they can even offer at \$0.00/MWh. Offer prices between \$0.01/MWh and the SRMC are determined based on market conditions at the time and the risk preferences of individual traders.

(d) Traders set offer prices based on market expectations and business strategies, intending to generate power only when anticipated market prices justify production.

(e) Hydro generation strategies are influenced by thermal offer prices, price expectations, actual and expected future hydro storage levels, and opportunity costs. Adjustments in thermal offer prices, particularly when constrained by an SRMC floor, are expected to prompt corresponding adjustments in hydro generation offers.

5.6. Transitional provisions in the Act[24] set the EAF for both the 2021/22 and 2022/23 financial years to 0.537tCO_2e/MWh. Notably, the EAF for the 2022/23 financial year was not calculated anew but was carried over from the prior year.

5.7. Using the formula previously described in the ‘Methodology to estimate the EAF’ section, the EAF applied for 2024 calendar year is calculated as follows:

$$\mathrm{EAF}_{2024} = \frac{(0.587 + 0.537 + 0.537)}{3} = 0.554$$

5.8. Accordingly, the Authority has determined that the EAF for the calendar year 2024 is **0.554tCO2e/MWh**.

[24] Climate Change Response Act 2002, Schedule 1AA section 42(2)