Determination of the 2026 Electricity Allocation Factor

Contents

1. Purpose

1.1. This paper sets out the results of the Electricity Authority Te Mana Hiko (Authority) determination of the Electricity Allocation Factor (EAF) for the 2026 calendar year, in accordance with section 161FA of the Climate Change Response Act 2002 (the Act).

1.2. The EAF is notified to the Minster of Climate Change and used as an input to calculate eligible industrial producers' annual allocation of New Zealand Units (NZUs).

2. Background

2.1. The New Zealand government allocates NZUs to some businesses, in recognition that the costs associated with the New Zealand ETS might affect their competitiveness, and cause 'carbon leakage'. This allocation is targeted at activities (production processes) that are both emission-intensive and trade-exposed. A significant proportion of the NZUs allocated annually by the government is determined by the EAF.

2.2. The EAF is an estimate of the effect of the ETS on wholesale electricity prices in New Zealand. It represents the increase in electricity prices caused by the requirement to place a price on carbon emitted during the production of electricity. The EAF is therefore important to businesses that purchase large quantities of electricity.

2.3. Section 161FA of the Act requires the Authority to notify the Minister of Climate Change of the EAF for a calendar year by 31 July each year. This requirement came into effect on 1 January 2024, and this year is the third time that the Authority has calculated the EAF.[1]

2.4. Section 161FA of the Act prescribes the formula the Authority must use when determining the EAF, as well as imposing some technical requirements. The Authority's methodology is consistent with this legislative framework. This paper:

(a) documents the method used to determine the EAF, consistent with 2025,

(b) describes the data inputs, including some minor changes to update emissions factors, and

(c) presents the results.

3. Findings

3.1. The Authority has determined that the EAF for the **2026 calendar year** is **0.424 tCO_2e/MWh.**[2] This is a decline of almost 18% from the previous 2025 calendar year value of 0.516 tCO_2e/MWh.

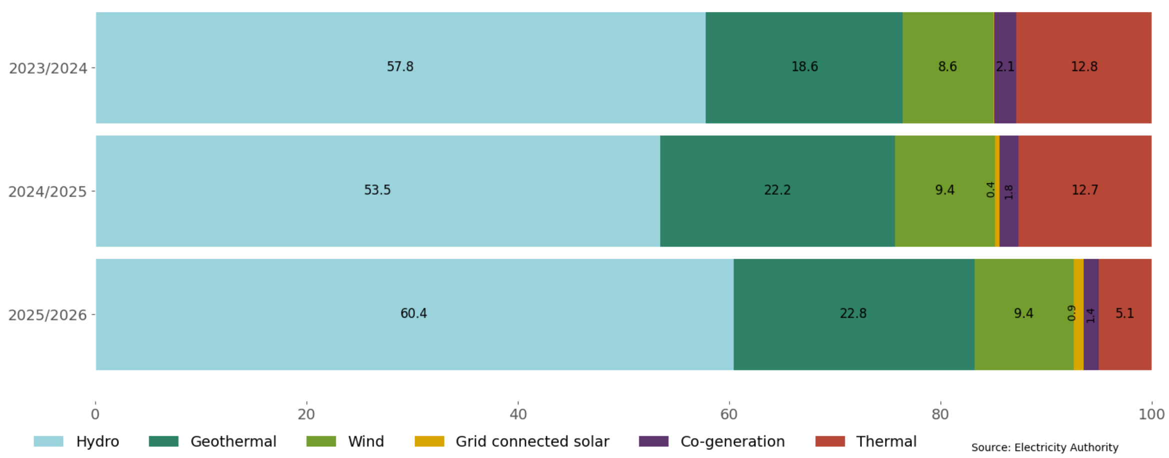
3.2. The EAF value for a calendar year is calculated as the average of the EAF for the three previous financial years. The drop in the 2026 calendar year EAF value is due to a low 2025/26 financial year EAF value — 0.261 tCO_2e/MWh — which was largely driven by low wholesale prices, strong hydro inflows, record levels of wind and solar generation and a large reduction in gas and coal fired generation (down 67.4% and 65.6% between the March 2025

[1] Before 2024, the EAF value didn't change over time.

[2] The impact of the ETS on the price of electricity is expressed as a ratio: tonnes of CO2 equivalent per megawatt-hour of electrical energy (tCO2e/MWh).

and 2026 quarters, respectively).[3] **Figure 1** also highlights a significant shift in the generation mix during the 2025/26 financial year, with thermal generation decreasing from 12.7% to 5.1% and hydro generation increasing from 53.5% to 60.4%. This stands in contrast to high prices seen in winter 2024 that were caused by low hydro storage, reduced wind output, and a shortage of natural gas. Low hydro inflows also contributed to elevated prices in the first quarter of 2025. Ultimately, these events resulted in a slightly higher EAF value for the 2024/25 financial year.

Figure 1: Electricity generation by generation type, as a percentage of total load. July 2023 to June 2026



3.3. Overall, wholesale electricity prices during the 2025/26 financial year were frequently well below the carbon-exclusive short-run marginal costs incurred by generators. Because, according to our methodology, we consider emission costs to influence offer behaviour only when the offer price exceeds the carbon-exclusive short-run marginal costs of generation, this means that these offers do not influence the EAF.

4. Methodology to estimate the EAF

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

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

4.2. The load-weighted average price (LWAP) of electricity is applied for the financial year. The electricity LWAP with carbon cost is calculated by weighting the observed wholesale electricity market prices (base case) with the reconciled purchase volumes used to financially settle the wholesale market. The NZU price is taken to be the annual average carbon price, calculated using daily carbon prices obtained from emsTradepoint.[4]

4.3. Estimating the electricity LWAP without carbon cost (ie, without the impact of the ETS) requires using a market model to run a counterfactual scenario to determine a new set of

[3] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-publications-and-technical-papers/new-zealand-energy-quarterly/march-2026-summary

[4] A spot market platform in New Zealand that facilitates trading of carbon units (NZUs) and natural gas [www.emstradepoint.co.nz].

electricity prices. The counterfactual scenario requires adjusting the energy offer prices, an input into the model, downwards to remove any carbon cost component of the offer price.

4.4. The EAF for a **calendar year** is based on the following formula as set out in section 161FA(2) of the Act:

$$\mathrm{EAF_{cy}} = \frac{(\mathrm{EAF_{fy1}} + \mathrm{EAF_{fy2}} + \mathrm{EAF_{fy3}})}{3}$$

where:

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

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}.

4.5. In other words: the EAF value for the current calendar year is the average of the EAF for the three preceding financial years.

Market model

4.6. The Act requires the Authority to use a market model to determine the impact of the ETS on electricity prices.[5] We have used the Authority's vSPD[6] (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.

4.7. 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.[7]

Modelling assumptions

4.8. According to the Climate Change (Eligible Industrial Activities) Regulations 2010,[8] 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"

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

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

[7] 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).

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

(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."

4.9. To calculate ETS-exclusive electricity prices, the vSPD model is used to rerun the pricing and dispatch algorithm using the counterfactual, or adjusted, offer prices that exclude carbon costs.

4.10. 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 are assumed to be influenced by the ETS. Hydro generation is explicitly considered in this analysis because hydro generators typically determine their offer prices based on the opportunity cost of stored water, which in turn is strongly influenced by thermal offers.

Offer prices for geothermal, co-generation, wind and solar generation are not adjusted in our counterfactual scenario

Geothermal generation

4.11. Geothermal generation contributes approximately 25% 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 base load only and offer energy at a fixed, must-run price of $0.01/MWh.

4.12. Data from 1 July 2025 to 30 June 2026 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 $5,000/MWh. This suggests these plants are not intending to generate electricity at all. Consequently, geothermal offer prices remain unadjusted for in this analysis.

Co-generation

4.13. There are several co-generation plants that offer energy into the electricity market. Examination of the data for the 2025/26 financial year reveals that co-generation plants offer energy at must-run prices of $0.01/MWh. As a result, co-generation's offer prices are not adjusted in the counterfactual.

Wind and solar generation

4.14. The contribution of wind and solar generation in the New Zealand electricity market is steadily increasing. While wind and solar farms can offer energy using up to five price tranches, they are typically 'price takers', meaning they offer at very low prices and take the prevailing market clearing price as determined by the marginal generator.

4.15. Therefore, for the purposes of this analysis, we assume that these renewable generators continue to operate at full capacity in real time, and that their offer prices are unaffected by the pricing behaviour of emission-producing plants.

How we adjust offer prices for thermal, hydro and BESS in our counterfactual scenario

4.16. In the counterfactual scenario, we adjust the offer prices of thermal, hydro generation and BESS. For thermal generation, offer prices are adjusted down based on the prevailing 30-day average carbon cost. The offer price of hydro generation is adjusted down using the capacity-weighted average carbon cost of thermal plant.

Thermal generation offers

4.17. For thermal generation, we adjust offer prices only when the base case, or actual, price exceeds the ETS-exclusive short-run marginal cost (SRMC). This is because we consider that offer prices below SRMC mean that factors other than the recovery of carbon costs are influencing the decision to generate.

4.18. The offer price adjustment process is:

a) if the offer price is at or above the ETS-inclusive SRMC, we reduce it by the carbon cost

b) if the offer price falls between the ETS-exclusive and ETS-inclusive SRMC, we adjust it down to the ETS-exclusive SRMC

c) if the offer price falls below the ETS-exclusive SRMC, we leave it as is.

4.19. The ETS-exclusive SRMC 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.

Hydro generation offers

4.20. Calculating adjusted hydro generation prices is more complex as hydro generation offers typically reflect the opportunity cost of the hydro resource rather than SRMC. As offer prices of thermal generation are lower in the counterfactual scenario, this lowers the opportunity cost of hydro and so hydro offer prices should also be adjusted down.

4.21. We adjust hydro generation offer prices to echo this change in opportunity costs, using a similar approach to that taken above to thermal generation offers.

4.22. Recounting the assumptions described in paragraph 4.18 we apply, in the case of hydro:

a) the smallest thermal ETS-exclusive SRMC as the ‘ETS-exclusive SRMC’.[9]

b) the thermal capacity-weighted average carbon cost as the ‘carbon cost’.

c) the sum of the smallest thermal ETS-exclusive SRMC and the thermal capacity-weighted average carbon cost as the ‘ETS-inclusive SRMC’.

4.23. The adjustment of hydro generation offer prices is as follows:

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

where:

average carbon cost is calculated as follows:

[9] This is usually the ETS-exclusive SRMC of Huntly unit 5 and TCC.

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

4.24. The methodology employed to adjust the hydro offer may underestimate the 'ETS-exclusive SRMC' and overestimate the carbon cost attributed to hydro generation. As a result, this method could overstate the EAF. However, it avoids complex modelling of the offer behaviour of hydro generators, and errs on the side of favouring the interests of affected parties.

BESS offers

4.25. Battery energy storage systems (BESS) have also participated in the energy market. However, if the BESS units consistently offer their energy at a price of $0.01/MWh, for these systems, we do not adjust energy offers.

4.26. For higher BESS offers, we adjust prices based on the idea that, for BESS units that submit both energy offers and demand bids, the bid prices are always lower than the offer prices. The energy offer price will be adjusted using the same method applied to hydro generation. Having calculated the maximum reduction in the offer price, we use that value to adjust the corresponding demand bid (if a demand bid exists for that trading period). We must also ensure that the adjusted demand bid price remains non-negative.

Overall calculation

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

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

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

where:

$\text{Price}_{\text{t.gxp}}$ is the price at grid exit point *gxp* for trading period *t*

$\text{Demand}_{\text{t.gxp}}$ is the demand at grid exit point *gxp* for trading period *t.*

4.28. The Authority has used emsTradepoint data for the EAF calculation. emsTradepoint data is highly correlated with other sources for carbon prices, such as Jarden CommTrade and a GitHub repository where NZU data from Carbon News and My Native Forest are compiled. More information on alternative sources of carbon price data is set out in the Authority's 2024 EAF Report.[10]

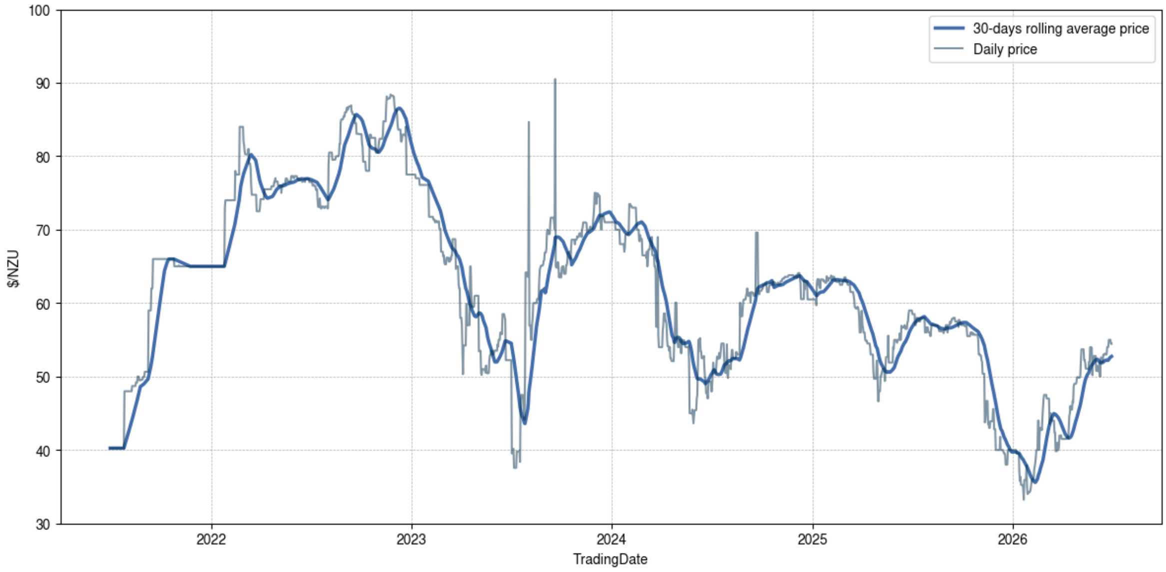
4.29. Since trading on emsTradePoint occurs only on business days, there are no volume-weighted average prices available for weekends or public holidays. In such cases, we assume that the most recent daily volume-weighted average price remains valid until a new price becomes available.

4.30. 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.

[10] https://www.ea.govt.nz/documents/5348/Determination_of_the_2024_Electricity_Allocation_Factor.pdf

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

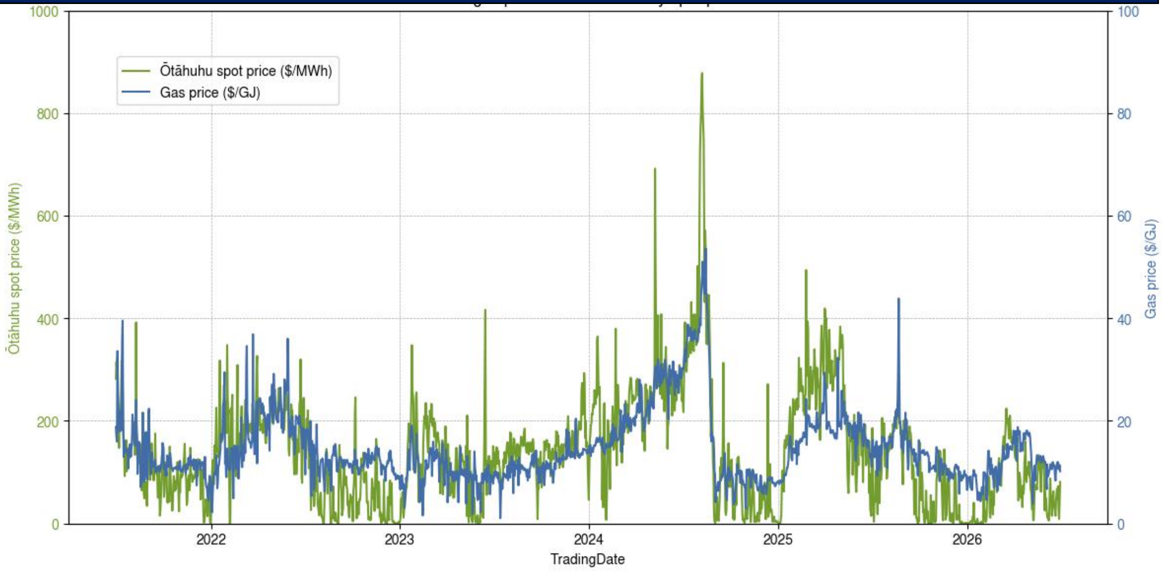
4.31. The Authority collects daily gas price indices from emsTradepoint. As with the carbon prices collected from emsTradepoint, these gas price indices represent the daily volume-weighted average price of gas traded on a secondary market. Gas prices include the cost of CO_2 and because we are already 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.

4.32. In the New Zealand wholesale electricity market, gas-fired electricity generation sets the spot price 70% to 90% of the time. Given that gas spot price data closely tracks wholesale electricity spot prices (**Figure 3**) it is likely to contain relevant information for modelling what electricity prices would have been in a counterfactual scenario (particularly over periods when gas-fired generation is price-setting). In theory, the reason for this observed relationship is that gas price data from emsTradepoint (more so than contracted prices) reflects the opportunity cost of gas at the time of generation.[11] That is, when pricing their generation offers, thermal generators are likely influenced by the real time value of gas that is traded on a secondary market, rather than the price they actually paid (which is often much lower).

4.33. Unlike contracted prices, secondary market prices are also transparent, dynamic, and consistent across generators, supporting more accurate modelling and efficient market signals.

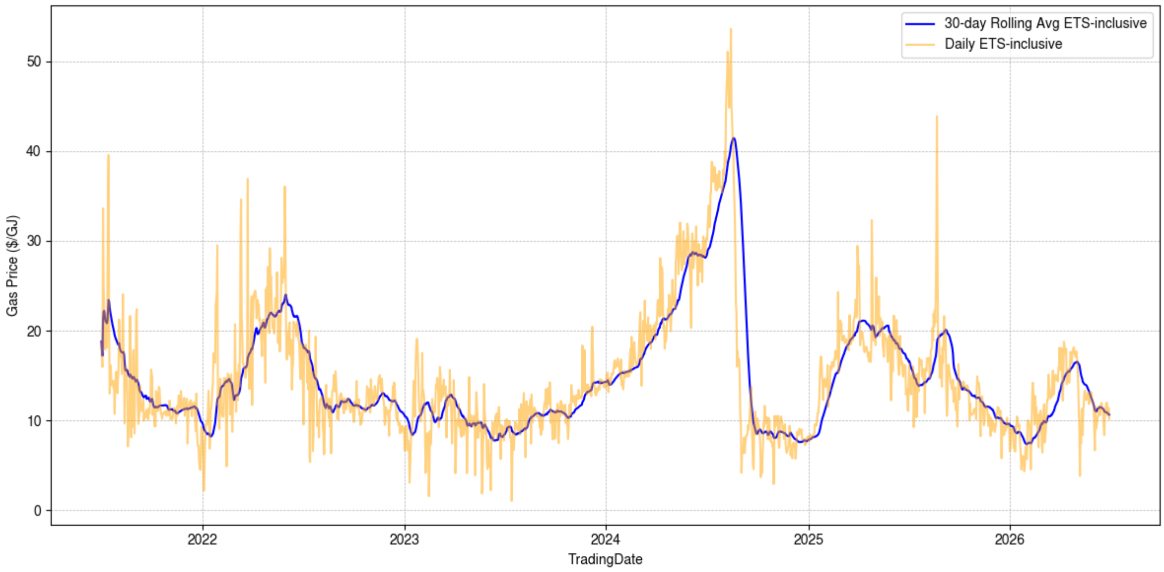
[11] https://www.ea.govt.nz/news/general-news/authority-publishes-data-source-assessment-for-determining-the-eaf/

Figure 3: Daily gas prices vs daily average electricity price



4.34. 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 calculated and used to estimate the SRMC for thermal generation. **Figure 4** displays the daily ETS-inclusive gas prices, and 30-day rolling average ETS-inclusive gas prices.

Figure 4: Daily gas prices and 30-day rolling average gas prices



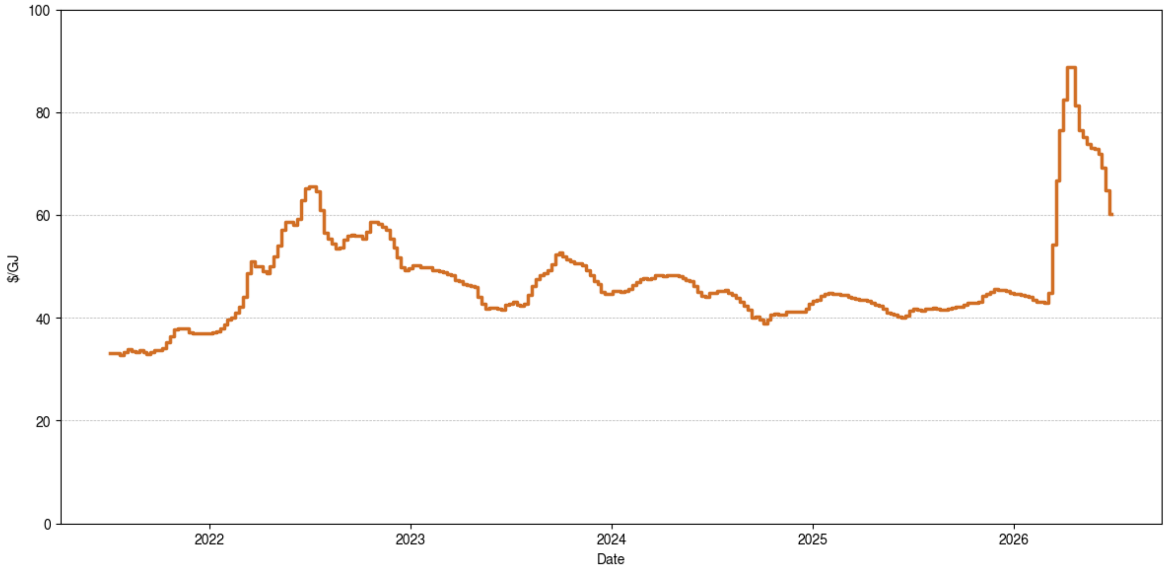
Diesel price

4.35. 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.[12]

[12] Weekly Oil Price Monitoring Data Dictionary (mbie.govt.nz) - [Diesel_price_excl_taxes_NZc.p.l].

4.36. We incorporate a diesel delivery cost of ten cents per litre and an energy content factor of 37 megajoules (MJ) per litre[13] to convert the diesel price from New Zealand cents per litre to New Zealand dollars per gigajoule ($/GJ). **Figure 5** illustrates the weekly diesel price in NZD per GJ for period from 1 July 2021 to 30 June 2026. Diesel prices increased significantly in 2026.

Figure 5: MBIE weekly diesel price excluding taxes, levies, and the ETS



Coal price

4.37. 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.

4.38. We used the monthly reference coal price reported by Enerlytica,[14] which is based on the FOB Melawan (Indonesia) price, and includes shipping, wharfage, and road transport costs. Where coal price data for a particular month was unavailable, the previous month's coal price was used as a proxy.

4.39. Enerlytica has advised that the benchmark coal prices may not be consistently achievable by Genesis, given Genesis's relatively low-volume and intermittent procurement requirements. This is consistent with publicly reported Genesis weighted average coal burn costs, which have recently exceeded the Enerlytica benchmark by around $2–3/GJ. Accordingly, the coal prices used in this analysis may understate the effective fuel costs faced by Genesis. To the extent that this occurs, our modelling may overstate the competitiveness and utilisation of coal-fired generation and therefore tend to increase the estimated value of the EAF.

4.40. We nevertheless consider the Enerlytica series to be the most suitable coal price data source for EAF modelling purposes, as it provides a consistent measure of delivered coal market prices at monthly frequency. By comparison, Genesis's reported coal burn costs are available

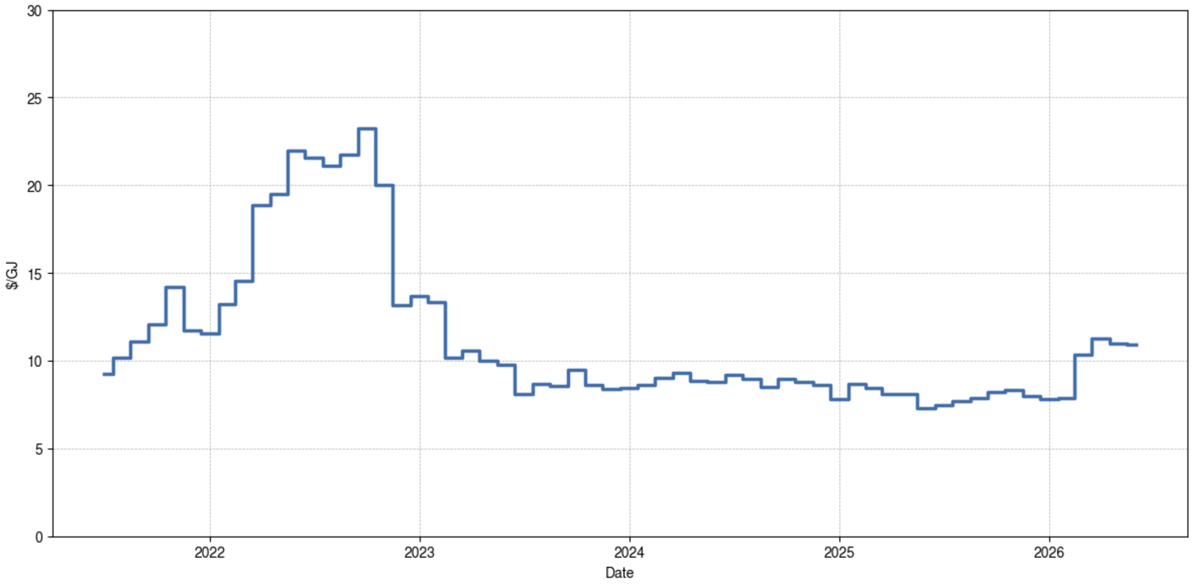
[13] 2020 Thermal Generation Stack Update Report, section 3.1.13.4.
[14] https://www.enerlytica.co.nz/.

only quarterly and are therefore less suitable for modelling trading-period SRMCs and generation decisions.

4.41. 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 6** displays the daily coal prices from 1 July 2024 to 30 June 2026.

4.42. Enerlytica coal price data is not usually publicly available. Enerlytica has agreed that the Authority may publish its coal price data in its GitHub repository alongside this determination, to meet the requirement for data inputs to be publicly available.

Figure 6: Monthly coal prices



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

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

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

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

4.44. 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.

4.45. **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[15]	VOM $/MWh[16]	Emission Factor[17] tCO_2e/GJ
Huntly 1-4	Coal	Rankine	10,900	9.6	0.092606
Huntly 5	Gas	CCGT	7,400	5.2	0.054179
Huntly 6	Gas	OCGT	10,525	9.7	0.054179
Junction Road[18]	Gas	OCGT	10,525	9.7	0.054179
McKee[19]	Gas	OCGT	10,525	9.7	0.054179
Stratford Peakers	Gas	OCGT	8,907	9.4	0.054179
Taranaki Combined Cycle	Gas	OCGT	7,400	5.2	0.054179
Whirinaki	Diesel	OCGT	10,906	11.6	0.069331

4.46. Consistent with last year's methodology, CH_4 (methane) and N_2O (nitrous oxide) have been included, whereas these gases were excluded from the 2024 determination. A CO_2 emission factor represents the amount of carbon dioxide (in tonnes) released when one gigajoule (GJ) of fuel is combusted. Although the inclusion of methane and nitrous oxide has a negligible impact on the overall CO_2-equivalent emissions factor, these gases are part of the ETS and should therefore continue to be included.

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[15] Heat rates are sourced from the MBIE 2020 Thermal Generation Stack Update Report.
[16] VOMs are sources from the MBIE 2020 Thermal Generation Stack Update Report.
[17] Emission factors are derived from New Zealand's Greenhouse Gas Inventory 1990–2024, Volume 2, Annexes.
[18] The values for this unit are assumed to be the same as Huntly 6.
[19] The values for this unit are assumed to be the same as Huntly 6.

4.47. Emissions factors for CH_4 and N_2O are converted to CO_2-equivalent (CO_2e) values in this report. Conversions to CO_2e values use global warming potential (GWP) values provided by the Intergovernmental Panel on Climate Change's Fifth Assessment Report (AR5). To convert emissions factors to CO_2e, we use the following formulae:

$$\text{Carbon dioxide equivalent emissions factor } (\frac{\text{tCH}_4\text{e}}{\text{GJ}})$$
$$= \text{ Methane emissions factor } (\frac{\text{tCH}_4}{\text{GJ}}) \times \text{Global warming potential}$$

$$\text{Carbon dioxide equivalent emissions factor } \left(\frac{\text{tCH}_4\text{e}}{\text{GJ}}\right)$$
$$= \text{ Nitrous oxide emissions factor } (\frac{\text{tCH}_4}{\text{GJ}}) \times \text{Global warming potential}$$

4.48.

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

4.49. The GWP for CH_4 is 28 and the GWP for N_2O is 265.[20] In other words, the global warming potential for CH_4 is 28 times higher than CO_2 and for N_2O is 265 times higher. However, the level of emissions from these gases in electricity generation is many orders of magnitude lower than CO_2.

4.50. **Table 2** presents the emissions factors for each fuel type for CO_2, CH_4 and N_2O for the most recently available data (Greenhouse Gas Inventory 1990-2024). The table also compares the difference between total CO_2-equivalent emission factor and CO_2 emission factor. This reflects that CH_4 and N_2O are significantly lower contributors to electricity generation emissions.

Table 2: Emissions factors used in 2026 determination (tCO_2e/GJ)

Fuel	tCO_2/GJ	tCH_4/GJ	tN_2O/GJ	Total (tCO_2e/GJ)	Difference
Coal	**0.09220**	0.95e-6	1.43e-6	**0.09261**	0.00041
Diesel	**0.06910**	2.85e-6	0.57e-6	**0.06933**	-0.00023
Gas	**0.05413**	0.90e-6	0.09e-6	**0.05418**	0.00005

5. Results[21]

5.1. The Authority previously determined that the EAF values for the 2023/24 and 2024/25 financial years were 0.587 tCO_2e/MWh and 0.425 tCO_2e/MWh respectively. The latest EAF value for the 2025/26 financial year is **0.261** tCO_2e/MWh.

5.2. Using the formula previously described in section 4, the EAF for the 2026 calendar year is calculated as follows:

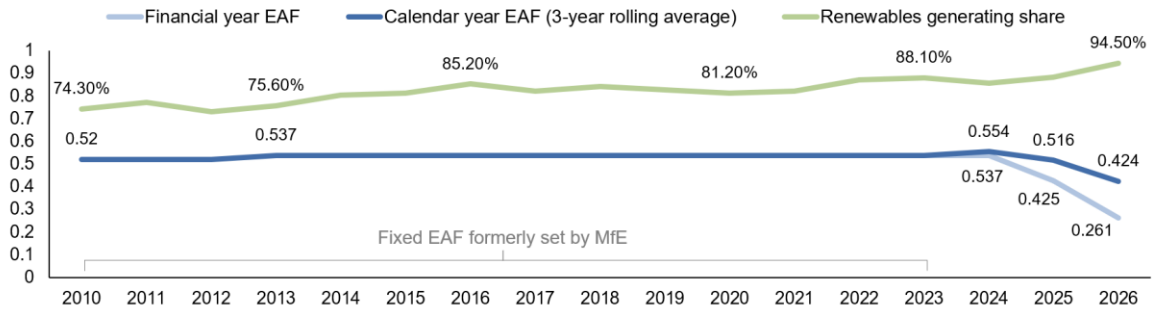
[20] https://www.stats.govt.nz/methods/updates-to-2024-greenhouse-gas-emissions-industry-and-household-statistics/.

[21] All input data files, simulation outputs and modelling codes are published in a 2026 EAF repository on the Authority's GitHub site at https://github.com/ElectricityAuthority.

$$\mathrm{EAF}_{2026} = \frac{(0.261 + 0.425 + 0.587)}{3} = 0.424$$

5.3. Accordingly, the Authority has determined that the EAF for the calendar year 2026 is **0.424 tCO2e/MWh**. Figure 7 illustrates the increase in renewable generation shares alongside the published EAF values.

Figure 7: Published EAF Values and Renewable Generating Share, 2013 to 2026[22]



5.4. **Table 3** displays the inputs that are used to calculate the 2025/26 financial year EAF. The inputs are:

- the LWAP with carbon cost, the **base case** (the actual price outcomes for electricity for the 2025/26 financial year)
- the LWAP without carbon cost, the **counterfactual scenario** (the expected price of electricity for 2025/26 that we determined without the impact of the ETS)

These inputs are used to calculate the 2025/26 financial EAF according to the formula previously set out in section 4:

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

Table 3: Electricity Allocation Factor for the 2025/26 financial year

	Base case (electricity LWAP with carbon cost)	**Counterfactual scenario (electricity LWAP without carbon cost)**
LWAP	\$82.60/MWh	\$69.90/MWh
NZU price	\$48.64/tCO_2e	
EAF-2025/26	0.261 tCO_2e/MWh	

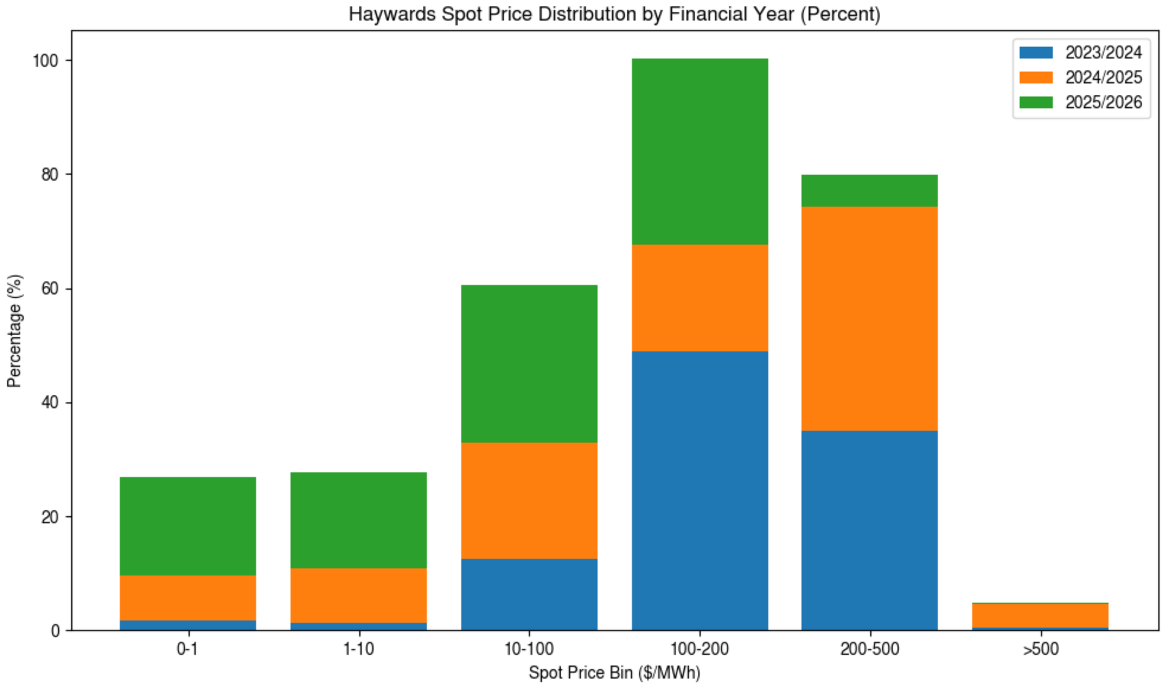
5.5. It is important to note that when electricity prices are high, the marginal offer prices of thermal generators are more likely to exceed the ETS-exclusive SRMC, and possibly even the ETS-inclusive SRMC (i.e., the floor price, below which thermal offers are not adjusted). This

[22] Renewable share figures in 2026 are for January 31 to March 31 only.

amplifies the influence of the ETS on market outcomes. In contrast, when electricity prices are consistently low (as observed in 2025/26) the removal of carbon costs has a much smaller impact.

5.6. **Figure 8** presents a bar chart comparing the distribution of daily prices at Haywards across three financial years: 2023/24, 2024/25, and 2025/26. It shows that the number of trading periods with very high prices (above $200) was lowest in 2025/26. This prevalence of lower price periods contributed to the reduced EAF calculated for that year.

Figure 8: Distribution of electricity spot price at Haywards for FY 2023/24, FY 2024/25, and FY 2025/26



5.7. When final prices fall below $10/MWh, they are well under the lowest ETS-exclusive SRMC of thermal generators. Under our methodology, offer prices at or below the ETS-exclusive SRMC are not adjusted. As a result, emissions costs have no impact on spot prices in the counterfactual scenario during these very low-price periods.

5.8. For prices below $100/MWh, marginal prices are still likely to be below the ETS-exclusive SRMC. In these cases, the emissions cost may have only a partial effect on adjusted offer prices, meaning its influence on spot prices in the counterfactual scenario is limited.

5.9. When prices exceed $100/MWh, marginal prices are more likely to be above the ETS-exclusive SRMC. This increases the likelihood that emissions costs are fully reflected in adjusted offer prices and therefore have a greater impact on spot prices in the counterfactual scenario.

5.10. **Figure 9** highlights a marked increase in the number of trading periods with low wholesale electricity prices during the 2025/26 financial year compared to 2023/24 and 2024/25. These prolonged period of low wholesale electricity prices has resulted in a notable decline in the EAF for 2025/26 financial year.

Figure 9: Electricity spot price at Haywards for FY 2023/24, FY 2024/25, and FY 2025/26