# Determination of the 2025 Electricity Allocation Factor

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# Contents

# 1. Purpose

1.1. This paper sets out the results of the Electricity Authority Te Mana Hiko (Authority) determination of the 2025 calendar year Electricity Allocation Factor (EAF) determined in accordance with section 161FA of the Climate Change Response Act 2002 (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.

2.2. Approximately one third of the roughly six million NZUs the government allocates per annum is determined by the EAF.

2.3. 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 have substantial electricity purchases.

2.4. Section 161FA of the 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 requirement came into effect on 1 January 2024 and this year is the second time that the Authority has calculated the EAF.[1]

2.5. 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, including some minor changes relative to last year to incorporate battery energy storage systems

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

(c) presents the results.

# 3. Findings

3.1. The impact of the ETS on the price of electricity is expressed as tonnes of $CO_2$ equivalent per megawatt-hour of electrical energy ($tCO_2e/MWh$). The Authority has determined that the EAF for the **2025 calendar year** is **0.516 $tCO_2e/MWh$**. This is a decline of almost 7% from the 2024 calendar year value of 0.554 $tCO_2e/MWh$.

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 2025 EAF is largely due to the low EAF value for the 2024/25 financial year of 0.425 $tCO_2e/MWh$, which was strongly influenced by low wholesale prices from September 2024 to January 2025, which in turn were due to warm temperatures, strong hydro inflows and record wind generation. This contrasts with the elevated prices

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

during winter 2024 due to low hydro storage, a reduction in wind generation and a shortage of natural gas.

3.3. Overall, wholesale electricity prices during the 2024/25 financial year were frequently well below the carbon-exclusive short-run marginal costs incurred by generators. This means that these offers do not influence the EAF factors. Note that we consider emission costs to influence offer behaviour only when the offer price exceeds the carbon-exclusive short-run marginal costs of generation.

# 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.[2]

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 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:

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

where:

**$\text{EAF}_{\text{cy}}$** is the allocation factor for the relevant calendar year

**$\text{EAF}_{\text{fy1}}$** is the ETS impact on the price of electricity in the financial year that ends on 30 June in the relevant calendar year

**$\text{EAF}_{\text{fy2}}$** is the ETS impact on the price of electricity in the financial year preceding the financial year described by $\text{EAF}_{\text{fy1}}$

**$\text{EAF}_{\text{fy3}}$** is the ETS impact on the price of electricity in the financial year preceding the financial year described by $\text{EAF}_{\text{fy2}}$.

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.

4.6. For the determination of the 2025 EAF, the Climate Change Response (Late Payment Penalties and Industrial Allocation) Amendment Act 2023 requires that variable $\text{EAF}_{\text{fy3}}$ is to be equal to 0.537 tCO2e/MWh.[3] Last year, the Authority determined the 2023/24 financial year EAF ($\text{EAF}_{\text{fy2}}$) was 0.587 $tCO_2e$/MWh.

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

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

## Market model

4.7. The Act requires the Authority to use a market model to determine the impact of the ETS on electricity prices.[4] We have used the Authority's vSPD[5] (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.

4.8. 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.[6]

## Adjusting offer prices by generation type

4.9. According to the Climate Change (Eligible Industrial Activities) Regulations 2010,[7] 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."

4.10. 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.

4.11. 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.

**Geothermal generation**

4.12. 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.

4.13. Data from 1 July 2024 to 30 June 2025 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

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

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

[6] 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).

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

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 this analysis.

**Co-generation**

4.14. There are several co-generation plants that offer energy into the electricity market. Examination of the data for the 2024/25 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 subject to adjustment.

**Wind and solar generation**

4.15. The contribution of wind and solar generation in the New Zealand electricity market is steadily increasing. While wind and solar farms are able to 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.

4.16. We have not observed any offers from wind or solar farms exceeding the must-run price of $0.01/MWh. 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 offers in our counterfactual scenario

4.17. In the counterfactual scenario, we adjust the offer prices of thermal and hydro generation. 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.

4.18. For thermal generation, we adjust offer prices only when the base case, or actual, price exceeds the ETS-exclusive 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.

4.19. 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-inclusive SRMC, we leave it as is.

4.20. 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.

4.21. Hydro generation offers are typically structured around the opportunity cost of the hydro resource rather than SRMC. When offer prices of thermal generation are adjusted down, hydro offer prices should also be adjusted down. To adjust hydro generation offers, we apply:

a) the smallest thermal ETS-exclusive SRMC as the ’ETS-exclusive SRMC’. [8]

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

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

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

4.22. 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 following:[9]

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

4.23. The methodology employed to adjust the hydro offer may result in an underestimation of the 'ETS-exclusive SRMC' and an overestimation of the carbon cost attributed to hydro generation. As a result, this could lead to an overstatement of the EAF. However, the adopted approach avoids the need to implement a complex modelling approach to estimating the offer behaviour of hydro generators. It errs on the side of favouring the interests of affected parties.

4.24. Battery energy storage systems (BESS) have begun participating in the energy market since the previous determination of the EAF. However, all but one of these BESS units consistently offers their energy at a price of $0.01/MWh. For these systems, we do not adjust energy offers.

4.25. The one exception is a BESS plant located at Rotohiko, which both injects energy into and withdraws energy from the market. For this particular BESS, we need to adjust both its energy offers and its demand bids.

4.26. We know 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.

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 reconciled 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:

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

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

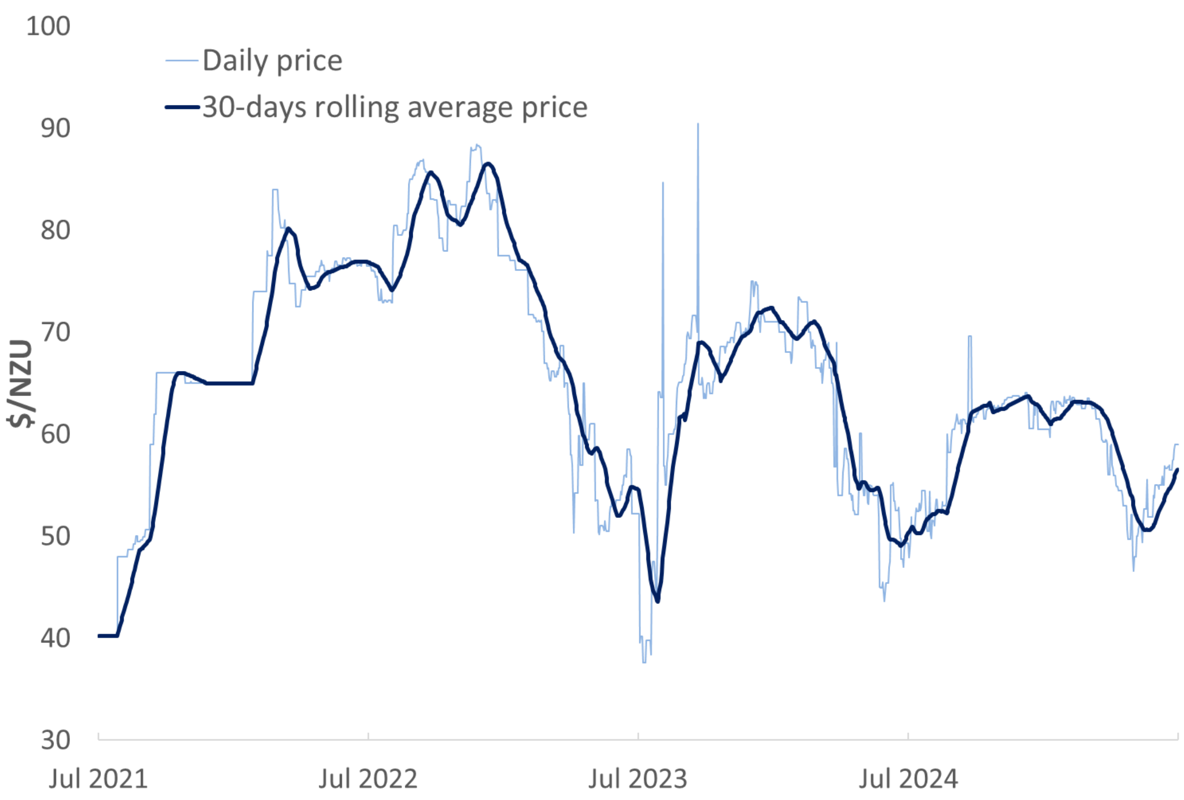
[9] This calculation is slightly different from the original approach from Electricity Allocation Factor Estimates for 2016/17 – Scientia Consulting.

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. **Figure 1** below illustrates the daily carbon price compared to the 30-day rolling average carbon price.

Figure 1: Daily NZU price v 30-day rolling average NZU price emsTradepoint



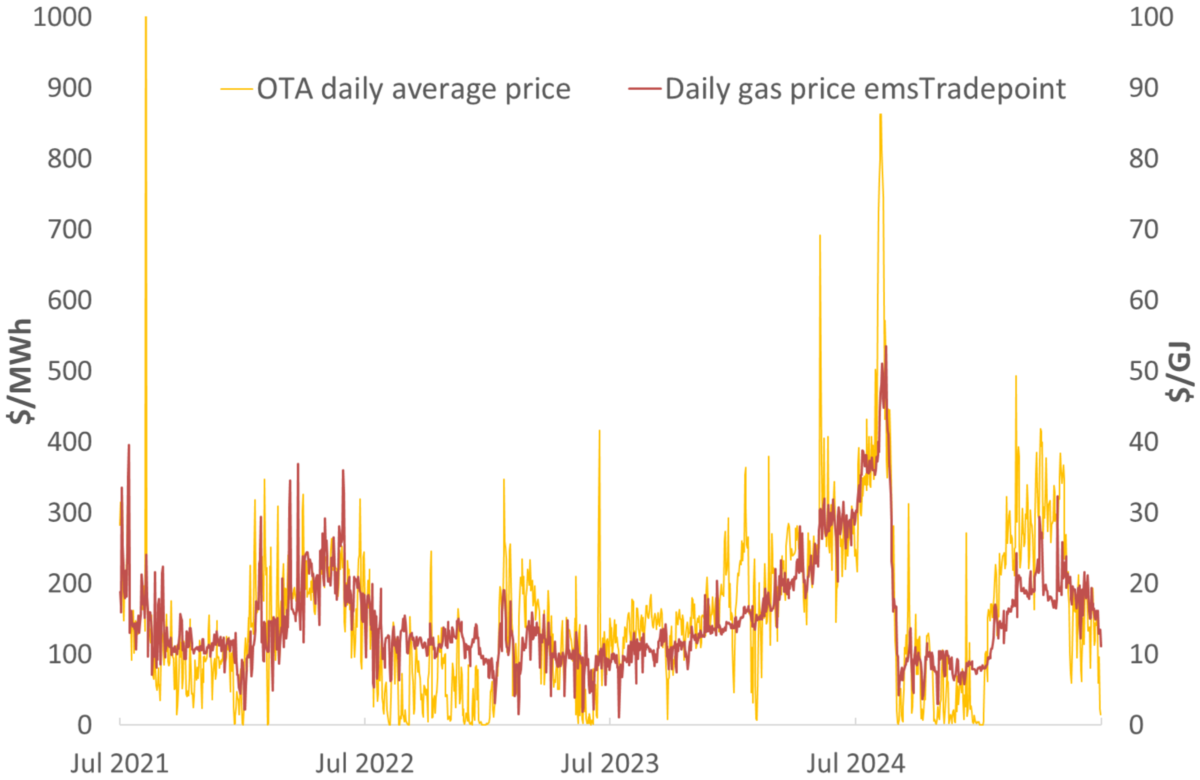

[10] https://www.ea.govt.nz/documents/5348/Determination_of_the_2024_Electricity_Allocation_Factor.pdf.

## 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.

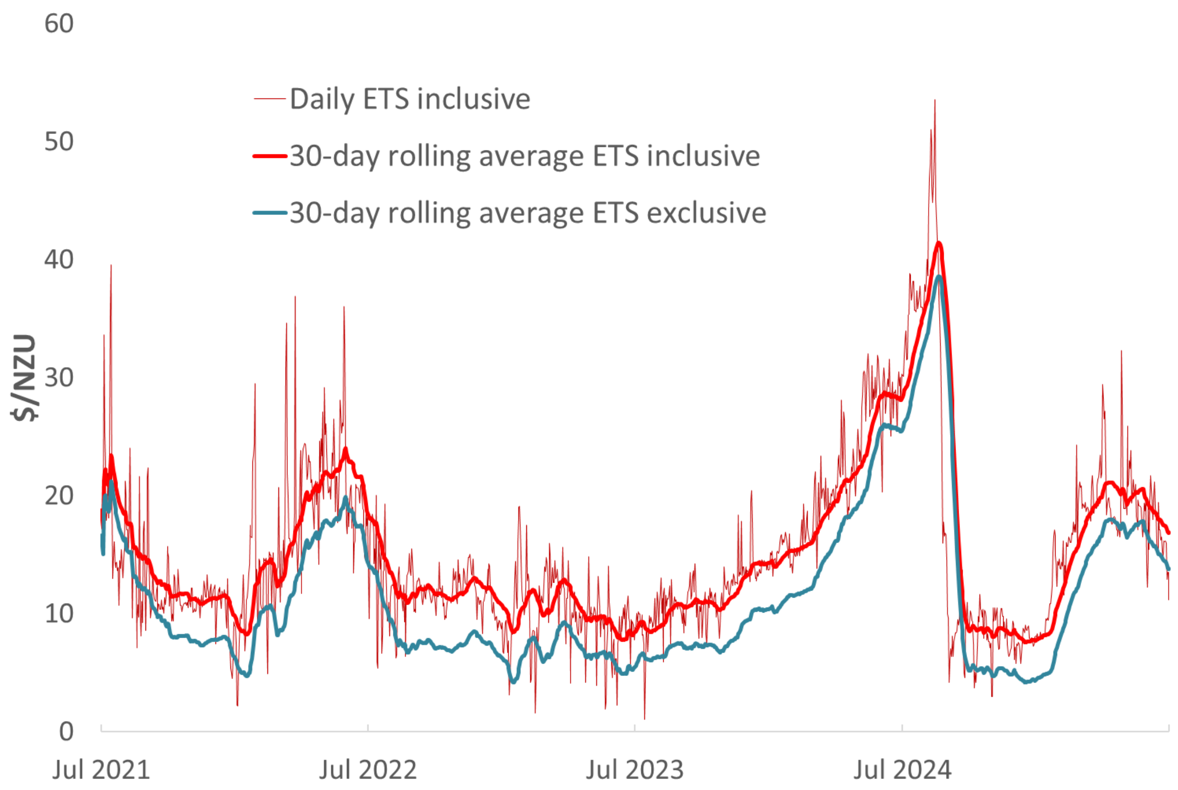
4.32. Using the gas price traded on a secondary market such as emsTradepoint to estimate the SRMC of generation is more appropriate than using actual contract prices because it reflects the true opportunity cost of gas at the time of generation. This market-based price aligns with observed electricity spot price behaviour, which shows a positive correlation with secondary gas prices (**Figure 2**), indicating that it better captures real-time cost dynamics. Unlike contracted prices, secondary market prices are transparent, dynamic, and consistent across generators, supporting more accurate modelling and efficient market signals.

Figure 2: Daily gas prices vs daily average electricity price




4.33. 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 3** displays the daily ETS-inclusive gas prices, 30-day rolling average ETS-inclusive gas prices and the 30-day rolling average ETS-exclusive gas prices.

Figure 3: Daily gas prices and 30-day rolling average gas prices



## Diesel price

4.34. 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.[11]

4.35. We incorporate a diesel delivery cost of ten cents per litre and an energy content factor of 37 megajoules (MJ) per litre[12] 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 2021 to 30 June 2025.

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


[11] Weekly Oil Price Monitoring Data Dictionary (mbie.govt.nz) - [Diesel_price_excl_taxes_NZc.p.l].
[12] 2020 Thermal Generation Stack Update Report, section 3.1.13.4.

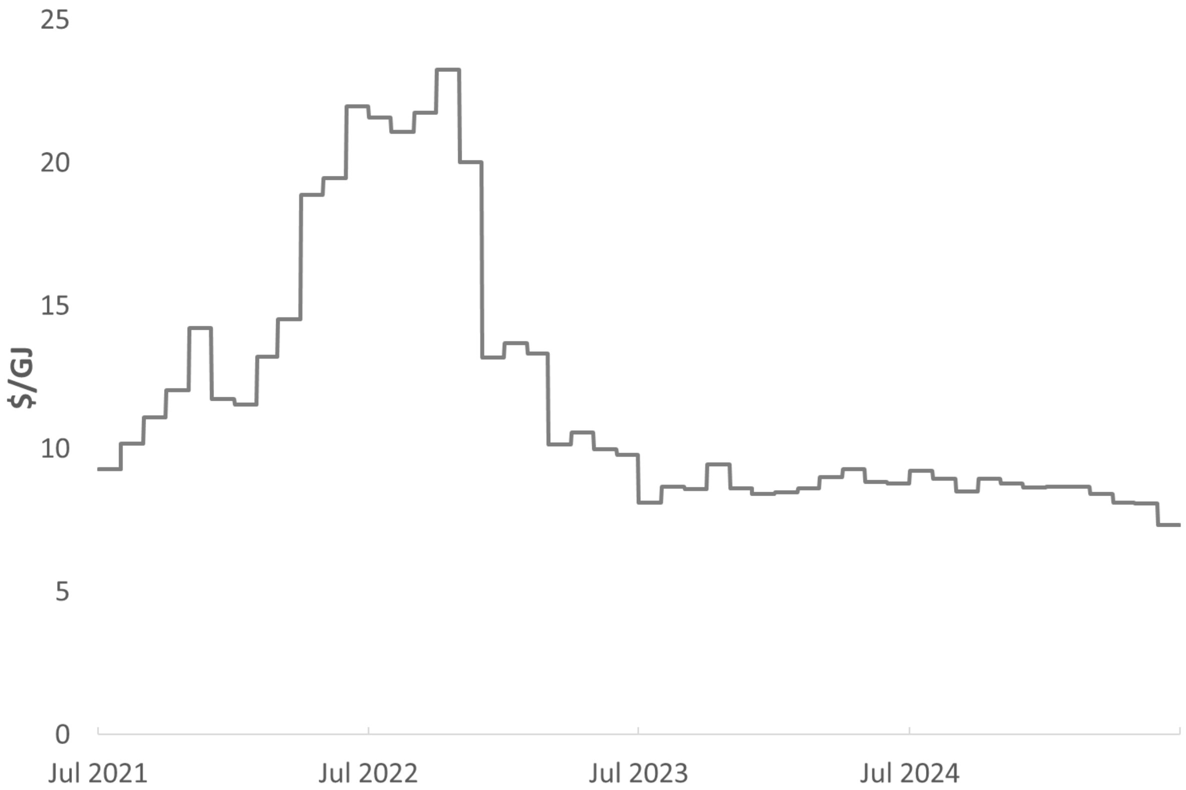
## Coal price

4.36. 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.

4.37. We use the monthly reference coal price reported by Enerlytica,[13] 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 2024 to 30 June 2025.

4.38. 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 5: Monthly coal prices




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

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

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

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

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

4.40. 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.

4.41. **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[14] | VOM $/MWh[15] | Emission Factor[16] $tCO_2e/GJ$ |
|---|---|---|---|---|---|
| Huntly 1-4 | Coal | Rankine | 10,900 | 9.6 | 0.092606 |
| Huntly 5 | Gas | CCGT | 7,400 | 5.2 | 0.054019 |
| Huntly 6 | Gas | OCGT | 10,525 | 9.7 | 0.054019 |
| Junction Road[17] | Gas | OCGT | 10,525 | 9.7 | 0.054019 |
| McKee[18] | Gas | OCGT | 10,525 | 9.7 | 0.054019 |
| Stratford Peakers | Gas | OCGT | 8,907 | 9.4 | 0.054019 |
| Taranaki Combined Cycle | Gas | OCGT | 7,400 | 5.2 | 0.054019 |
| Whirinaki | Diesel | OCGT | 10,906 | 11.6 | 0.069401 |

[14] Heat rates are sourced from the MBIE 2020 Thermal Generation Stack Update Report.
[15] VOMs are sources from the MBIE 2020 Thermal Generation Stack Update Report.
[16] Emission factors are derived from New Zealand's Greenhouse Gas Inventory 1990–2022, Volume 2, Annexes.
[17] Assumed to be the same as Huntly 6.
[18] Assumed to be the same as Huntly 6.

## Updating emissions factors

4.42. Two small changes have been made to emission factors relative to the factors used when determining the 2024 calendar year EAF:

a) $CO_2$ emissions factors applied to different fuel types have been updated to use 2022 data (whereas the 2024 determination used 2020 data). A $CO_2$ emission factor represents the amount of carbon dioxide (in tonnes) released when 1 gigajoule (GJ) of fuel is combusted.

b) CH4 (methane) and $N_2O$ (nitrous oxide) have been included, whereas these gases were excluded from the 2024 determination. Although the inclusion of methane and nitrous oxide has a negligible impact on the overall $CO_2$-equivalent emissions factor, they are part of the ETS so it is appropriate to include them.

4.43. 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:

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

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

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

4.44. The GWP for $CH_4$ is 28 and the GWP for $N_2O$ is 265.[19] 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 $CO_2$.

4.45. **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 1990-2022). The table also compares the 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 2025 determination) ($tCO_2e/GJ$)**

| Fuel | $tCO_2/GJ$ | $tCH_4/GJ$ | $tN_2O/GJ$ | Total ($tCO_2e/GJ$) | Difference from 2024 determination |
|---|---|---|---|---|---|
| Coal | **0.09220** | 0.95e-6 | 1.43e-6 | **0.09261** | 0.00041 |
| Diesel | **0.06917** | 2.85e-6 | 0.57e-6 | **0.06940** | 0.00023 |
| Gas | **0.05397** | 0.90e-6 | 0.09e-6 | **0.05402** | 0.00005 |

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

# 5. Results

5.1. Table 3 displays the inputs that are used to calculate the 2024/25 financial year EAF[20]. The inputs are:

- the LWAP with carbon cost, the **base case** (the actual price outcomes for electricity for the 2024/25 financial year)
- the LWAP without carbon cost, the **counterfactual scenario** (the expected price of electricity for 2024/25 that we determined without the impact of the ETS)
- the NZU price for 2024/25.

These inputs are used to calculate the 2024/25 financial EAF according to the formula previously set out in section 4:

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

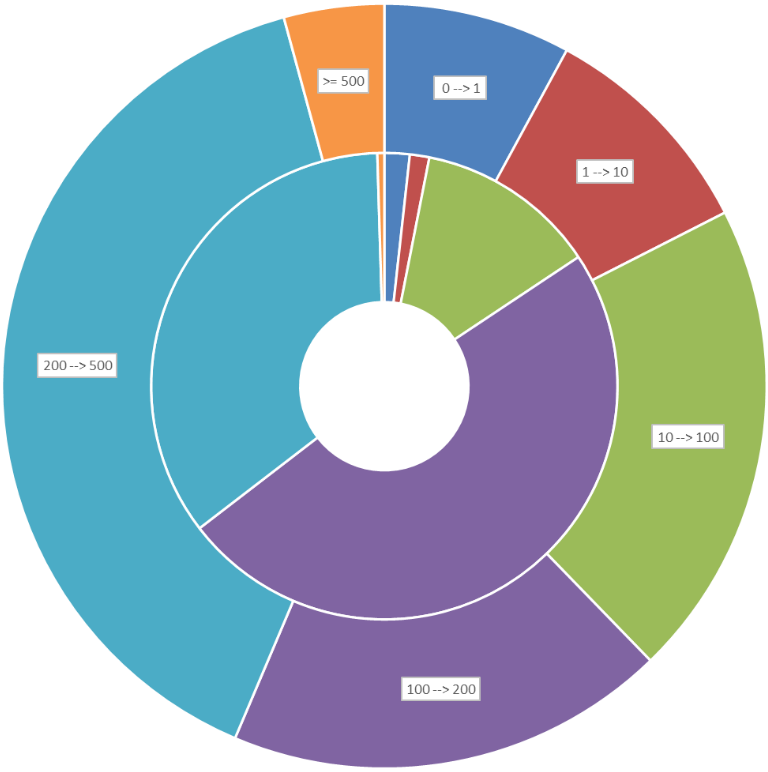
| Table 3: Electricity Allocation Factor for the 2024/25 financial year | | |
|---|---|---|
| | **Base case (electricity LWAP with carbon cost)** | **Counterfactual scenario (electricity LWAP without carbon cost)** |
| LWAP | \$208.13/MWh | \$183.20/MWh |
| NZU price | \$58.67/t$CO_2$e | |
| EAF | 0.425 t$CO_2$e/MWh | |

5.2. 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. This amplifies the influence of the ETS on market outcomes. In contrast, when electricity prices are consistently low—as observed at the end of 2024—the removal of carbon costs has a much smaller impact.

[20] 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.

5.3. Figure 6 presents a pie chart comparing the distribution of daily prices at Haywards across two financial years: 2023/24 (inner ring) and 2024/25 (outer ring). It highlights that the proportion of trading periods with low final prices—below $100/MWh and especially below $10/MWh—is noticeably higher in 2024/25 than in 2023/24. Though the number of trading periods with very high prices in 2024/25 was also higher than 2023/24, the low price periods outweigh the effect of the high price periods in the EAF calculation for this year.

Figure 6: Distribution of electricity spot price at Haywards for FY 2023/24 and FY 2024/25




**Note:**

- The outer ring represents the data for FY 2024/25
- The inner ring represents the data for FY 2023/24

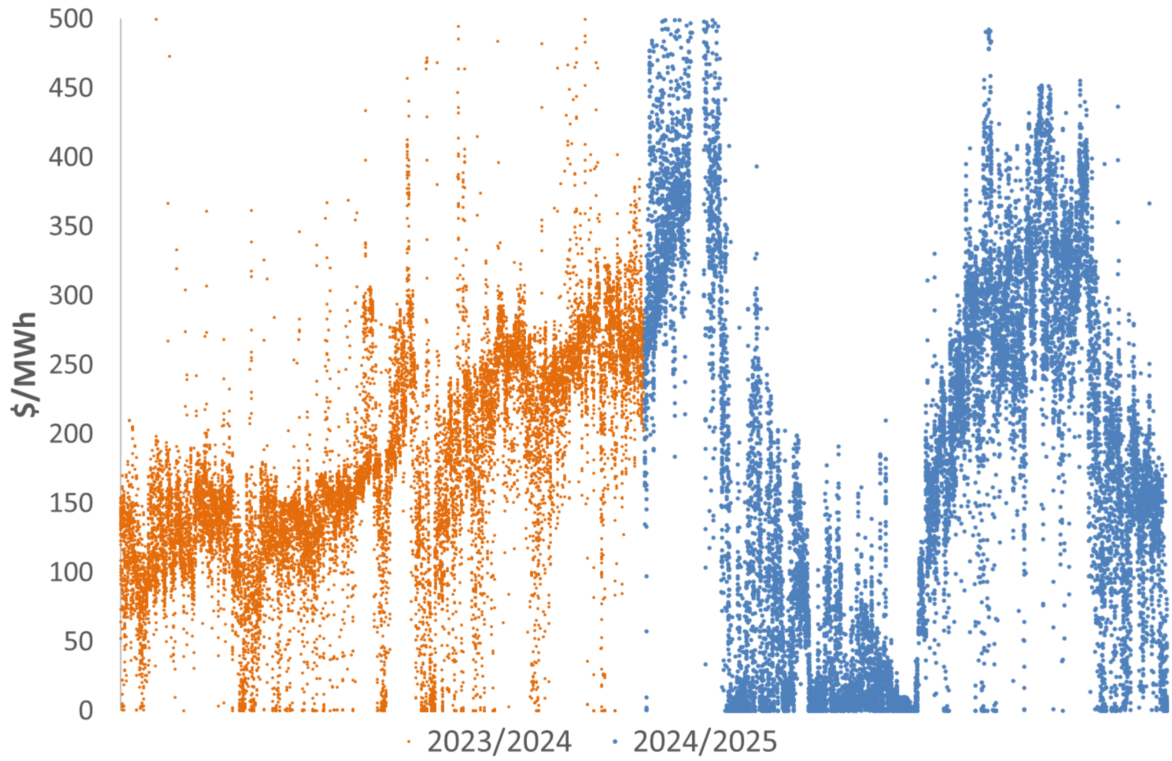
5.4. When final prices fall below $10/MWh, they are well under the lowest ETS-exclusive SRMC of thermal generators. Under our methodology, offer prices at or below the ETS-exclusive SRMC are not adjusted. As a result, emissions costs have no impact on spot prices in the counterfactual scenario during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

5.5. 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.

5.6. 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.

5.7. Figure 7 highlights a marked increase in the number of trading periods with low wholesale electricity prices during the 2024/25 financial year compared to 2023/24. These low-price periods are predominantly concentrated between late August 2024 and early January 2025. It is this prolonged period of low wholesale electricity prices that has resulted in a notable decline in the EAF for 2024/25 financial year.

Figure 7: Electricity spot price at Haywards for FY 2023/24 and FY 2024/25




5.8. Transitional provisions in the Act[21] set the EAF for the 2022/23 financial year to 0.537 $tCO_2e/MWh$. The EAF for the 2023/24 financial year was determined last year by the Authority to be 0.587 $tCO_2e/MWh$.

5.9. Using the formula previously described in section 3, the EAF for the 2025 calendar year is calculated as follows:

$$\mathrm{EAF}_{2025} = \frac{(0.425 + 0.587 + 0.537)}{3} = 0.516$$

5.10. Accordingly, the Authority has determined that the EAF for the calendar year 2025 is **0.516 tCO2e/MWh**.

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