He Pou a Rangi
Climate Change Commission

# Advice on NZ ETS unit limits and price control settings for 2023-2027

**Technical Annex 3: Electricity market modelling and retail price estimates**

**August 2022**

# Contents

# 1. Context

Section 30GC(6)(a) of the Act specifies that "the impact of emissions prices on households and the economy" must be considered when recommending NZ ETS price control settings.

As such, He Pou a Rangi Climate Change Commission has undertaken wholesale electricity market modelling to examine the impact of the NZ ETS on the electricity system. We have used the outputs of this modelling to estimate retail price impacts which have informed complementary analysis of household expenditure impacts. Electricity costs are an unavoidable expenditure for most New Zealanders and the focus of this analysis is largely on electricity price impacts. This analysis also includes an assessment of the potential impact of emissions pricing on generation earnings based on modelled spot market revenue.

The NZ ETS puts a price on emissions and this factors into the incentives to operate greenhouse gas emitting generation[1] and to develop renewables, and the resulting prices that emerge in the electricity spot market. As the costs of emissions is passed through to consumers, the NZ ETS can also influence electricity demand.

The wholesale electricity market in Aotearoa New Zealand is complex and so is the influence of the NZ ETS. The wholesale market is 'energy only' where generation offers are matched to demand in every 30-minute trading period and the market spot price is set by the offer of the marginal generator. Because Aotearoa New Zealand's electricity generation is highly renewable and predominately hydro generation, the market is highly dependent on the inflows into storage lakes. Fossil gas and coal 'thermal generation', which pay the cost of emissions, can be used to 'firm' intermittent renewables. However, the role of this generation in the electricity system is changing as the proportion of renewable generation increases.

Wholesale prices, which cover the cost of generating electricity, make up only a portion of a retail electricity bill. The total bill also includes the cost of transmission and distribution networks, retailer's non-energy costs, and GST. The contribution of the NZ ETS to wholesale and retail prices has been small historically. However, the price of an NZU has increased significantly in the last 2 years, and there is the potential for further increases. Complex modelling is presented here to quantify the impact of the NZ ETS on wholesale and retail electricity prices during a period when there is still considerable thermal generation operating in the system.

This is a continuation of modelling work undertaken for *Ināia Tonu Nei*. In *Ināia Tonu Nei* detailed wholesale electricity market modelling was used to complement the all-of-economy modelling that underpinned our advice on emissions budgets. Both the modelling for *Ināia Tonu Nei* and for this report tested electricity demand and generation scenarios under high resolution and simulated expected market prices. The electricity modelling for *Ināia Tonu Nei* incorporated emissions pricing assumptions. Although a number of key uncertainties were explored in the modelling for *Ināia Tonu Nei*, the impact of different NZ ETS price levels on wholesale price was not a key focus. This modelling explicitly explores the impact of various levels of emissions pricing.

Note that wholesale and retail electricity prices are dependent on many factors which have not been explored in this analysis. Because of this, care should be taken in any interpretation of absolute prices, or changes in absolute prices, shown in this report.

[1] Emissions pricing directly applies to 36% of generation, based on the proportion of thermal and geothermal generation reported in MBIE Electricity Statistics for 2021.

# 2. Methodology

The wholesale market modelling has been undertaken by Energy Link using their proprietary I-GEN and E-market models. We specified scenario inputs and worked with Energy Link consultants to refine results. We then analysed the model outputs to characterise emissions price sensitivity and used this to estimate retail price impacts.

The approach to modelling the wholesale electricity market and the build of new electricity generation is largely unchanged from that summarised by Energy Link for the Interim Climate Change Committee.[2] Any changes to this approach are described in this text where relevant.

We have modelled a range of electricity demand scenarios which are based on outputs from the Commission's ENZ model. The ENZ model has coarse spatial and temporal resolution. A process has been applied to apportion annual steps of demand across the full national grid and into representative demand profiles for use with the E-market model.

# 3. Scenarios

We have modelled seven scenarios which span a range of future electricity demand and emissions prices. These variables are changed independently, meaning that this work tests the impact of emissions pricing, isolated to the electricity system. The modelled scenarios extend to the year 2035.

The *Demonstration path scenarios* highlighted in green in ***Table 1*** systematically test a wide range of emissions prices with a single demand profile. The demand profile is the *Demonstration path (update)* which is defined in section 3.2 below. It is aligned with the legislated emissions budgets and this group of scenarios is used for most of the analysis set out in this annex.

***Table 1 The space of electricity demand and emissions price paths explored in this modelling. Modelled scenarios are marked by an 'X'.***

| | | | **Emissions price path** (Increasing emissions price →) | | | |
|---|---|---|---|---|---|---|
| | | | *Current ARP* | *Fixed price path* | *Current CCR trigger* | *Higher emissions price path* |
| **Demand profile** | (Increasing electricity demand ↓) | *Tiwai closes* | | | X | |
| | | *Current policy reference (update)* | X | X | | |

[2] (Energy Link, 2019)

| | | | | | |
|---|---|---|---|---|---|
| | *Demonstration path (update)* | X | X | X | X |

## 3.1. Emissions price paths

The modelled emissions price paths span a wide range of potential prices. These emissions price paths do not indicate predictions or projections of future market prices – the actual ETS price will be determined by the market. The modelled paths are shown in ***Figure 1*** below and the basis for their inclusion is:

- The *current auction reserve price (ARP)* and *current cost-containment-reserve (CCR) trigger* emissions price paths are based on the current NZ ETS price control settings. Together they act as safety valves to manage the risk of the NZU price at auction being out of line with what is considered necessary to meet emissions budgets. The price controls also serve to signal the bounds of expected and acceptable prices in the NZ ETS.
- The *fixed price path* at $70/t$CO_2$e is based on the NZU spot price at the beginning of 2022. Scenarios using this emissions price path are useful for establishing the relative impact of changes to emissions price.
- The *higher emissions price path* is $50/t$CO_2$e above the current CCR trigger and explores the impact of prices above current settings.

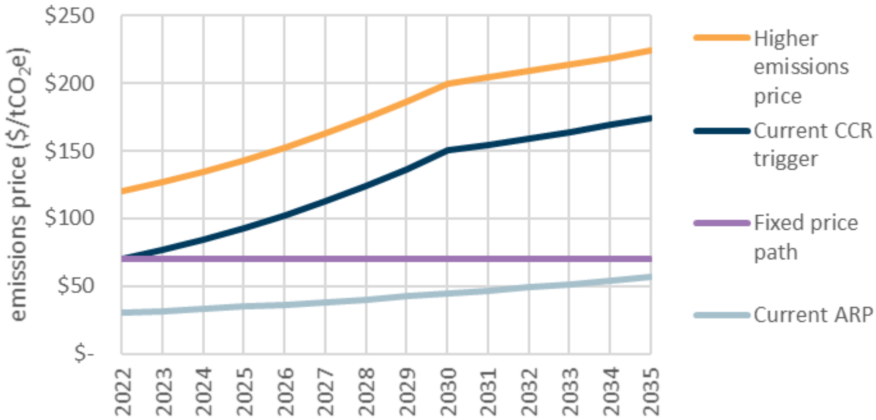


***Figure 1 Modelled emissions price paths (real 2022 prices)***

## 3.2. Electricity demand profiles

The modelled scenarios use three different electricity demand profiles which are based on outputs from the ENZ model. These profiles are from updates to the *Current policy reference* and *Demonstration path* scenarios modelled in *Ināia Tonu Nei*. They are shown in ***Figure 2*** and are described below in order of increasing demand:

- The *Tiwai closes* demand profile is the level of anticipated demand in a future where Aotearoa New Zealand takes action to reduce emissions and the Tiwai Point aluminium smelter ceases operations at the end of 2024.
- The *Current policy reference (update)* is projected demand growth in a future where additional policies are not applied to reduce emissions. It assumes the Tiwai Point aluminium smelter continues to operate beyond 2024 when its current main electricity supply contract terminates. The

*Current policy reference (update)* does not include the measures outlined in the Government's Emissions Reduction Plan. The demand growth is slower than the *Demonstration path (update)*.

- The *Demonstration path (update)* is anticipated demand growth in a future where Aotearoa New Zealand takes action to reduce emissions. It assumes that the Tiwai Point aluminium smelter continues to operate beyond 2024.

Note that electricity demand has been aligned with actuals for the period up to May 2022. This takes account of the conversion of the refinery at Marsden Point in April 2022, and the closure of Norske Skog's Tasman pulp mill in 2021.

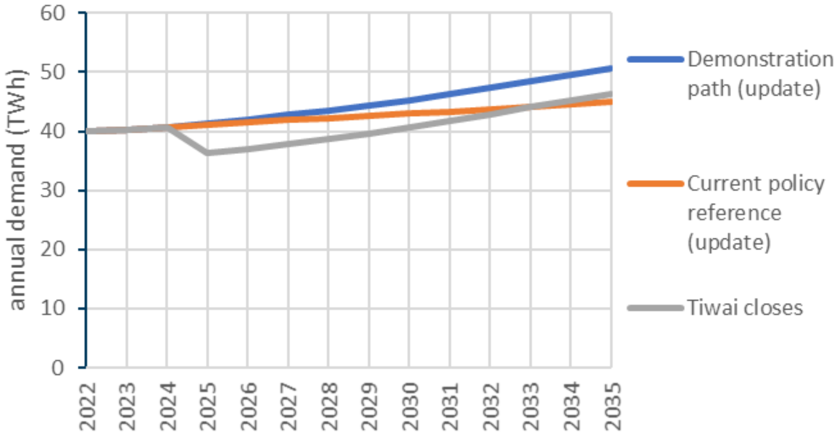


*Figure 2 Modelled grid connected annual demand*

## 3.3. Other model settings

Additional key settings and assumptions for the I-Gen and E-Market models are:

- Fuel prices are fixed across all scenarios and are summarised in the accompanying spreadsheet.
- We make assumptions about the operating mode and time of closure for large thermal generation plants. These assumptions are fixed between scenarios and are summarised below.

*Table 2 Thermal generation operating settings*

| Plant | Operating mode | | | Closure date |
|---|---|---|---|---|
| | *All year* | *Winter only* | *Dry year only* | |
| Taranaki combined cycle (TCC)[3] | | 2022-2023 | | October 2023 |
| Huntly unit 5 (e3p) | 2022-2027 | 2028-2031 | 2032-2035 | |
| Huntly Rankine unit 1[4] | | 2022-2024 | 2025-2026 | October 2026 |
| Huntly Rankine unit 2[4] | | 2022-2026 | | October 2026 |

[3] Since the completion of this modelling Contact Energy have extended the operational life of the TCC plant by 750 hours. This means it could operate during the winter of 2024.
[4] Only 2 Rankine units are made available in the model. Huntly Rankine unit 4 could operate in place of 1 or 2 as it is common to rotate units around maintenance schedules.

Note that Genesis Energy have recently announced that that they are trialing solid biomass as a fuel for the Rankine units and that with this fuel their lifetime could be extended beyond 2040.[5] We have not included this possibility in our scenario modelling.

- Other than the HVDC link, capacity constraints do not apply to the transmission network. It is assumed that grid capacity is expanded as required to meet the modelled demand.
- Reserve generation and the reserve market are not modelled.
- Cogeneration plant continues to operate at current levels.[6]
- The model is operated in 3-hour time steps.
- System operation is simulated for a 91-year record of hydrological inflows and a 40-year dynamic estimate of wind and solar resource.
- The modelled 'generation stack' of potential wind, solar, geothermal and gas generation projects is based on the 2020 generation stack updates commissioned by MBIE in 2020.[7] Existing generators' operational information have also been based on these reports. Some project costs or capacity factors have been updated based on other available information. This modelled generation stack is largely consistent with that used in *Ināia Tonu Nei*, but an adjustment has been made to inflate project costs to 2022 dollars.
- Market participance is in accordance with the current electricity 'Code'.
- All reported costs and prices are in real 2022 dollars.

# 4. Results

## 4.1. Generation build

For every scenario a 'build' of new generation is established which balances growth in demand and changes in operation of existing generation using a simulation of how market participants decide to build new generation, with future price expectation and earnings as key decision variables. The build sequence is generally from lower cost project to higher cost project, although location on the grid and the generation output profile of different types of renewable generation also play a part. The timing of project development is iteratively refined to ensure that new generation meets its earnings targets. If projects are developed too early then the market price becomes supressed and the projects can fail to cover their costs.

The earnings criteria and iteration process recognises the uncertainty inherent in making decisions around when to build what can be large new 'lumps' of supply. For every project it is ensured that new generation meets its annual earning target in the first 3 full years of operation. Some projects are more profitable than others due to their unique project costs, generation profile, and location premium.

There are a number of renewable generation projects which are currently under construction and it is assumed that these are completed on current timelines. These include the Tauhara geothermal power station, and the wind farms at Turitea, Kaiwaikawe and Harapaki.

[5] (Genesis Energy, 2022)

[6] Since the completion of this modelling Contact Energy have announced that Te Rapa cogeneration plant will close in 2023.

[7] (MBIE, 2020)

*Table 3 Summary of total new build by 2035 across each scenario*

| Scenario: Demand | Scenario: Emissions price | Measure | Wind | Solar | Geothermal | Gas | Total |
|---|---|---|---|---|---|---|---|
| Demonstration path (update) | Current ARP | Number of projects | 19 | 18 | 3 | 1 | 41 |
| | | Capacity (MW) | 1,772 | 2,210 | 354 | 200 | 4,536 |
| | | Annual generation (GWh) | 6,099 | 3,965 | 2,896 | 175 | 13,134 |
| | Fixed price path | Number of projects | 21 | 17 | 2 | 1 | 41 |
| | | Capacity (MW) | 2,139 | 2,160 | 242 | 200 | 4,741 |
| | | Annual generation (GWh) | 7,386 | 3,890 | 1,993 | 175 | 13,444 |
| | Current CCR trigger | Number of projects | 24 | 19 | 2 | 1 | 46 |
| | | Capacity (MW) | 2,311 | 2,410 | 242 | 200 | 5,163 |
| | | Annual generation (GWh) | 7,988 | 4,333 | 1,993 | 175 | 14,489 |
| | Higher emissions price path | Number of projects | 26 | 19 | 1 | 1 | 47 |
| | | Capacity (MW) | 2,608 | 2,410 | 162 | 200 | 5,380 |
| | | Annual generation (GWh) | 9,029 | 4,333 | 1,348 | 175 | 14,885 |
| Tiwai closes | Current CCR trigger | Number of projects | 13 | 17 | 2 | 0 | 32 |
| | | Capacity (MW) | 1,202 | 2,010 | 242 | - | 3,454 |
| | | Annual generation (GWh) | 4,101 | 3,597 | 1,993 | - | 9,691 |
| Current policy reference (update) | Current ARP | Number of projects | 8 | 12 | 2 | 0 | 22 |
| | | Capacity (MW) | 841 | 1,410 | 242 | - | 2,493 |
| | | Annual generation (GWh) | 2,838 | 2,545 | 1,993 | - | 7,377 |
| | Fixed price path | Number of projects | 11 | 12 | 2 | 0 | 25 |
| | | Capacity (MW) | 984 | 1,210 | 242 | - | 2,436 |
| | | Annual generation (GWh) | 3,338 | 2,160 | 1,993 | - | 7,491 |

*Annual generation is based on assumed project capacity factors.*

**Key scenario build observations:**

- Higher emissions prices drive additional renewables built. For the *Demonstration path scenarios*, the Current CCR trigger builds ~1 TWh (5 more projects) more than the Fixed price path scenario.

- In the scenario where the Tiwai Point aluminium smelter closes at the end of 2024, other than projects already committed, no renewable generation is completed for a 50-month period (~4 years). The cost of non-completed projects continues to fall during this time in-line with our assumed technology cost reductions. This means that when the build is resumed, the projects being constructed have lower LCOEs (levelised cost of energy) than scenarios where the smelter doesn't close and development happens earlier.
- Additional geothermal generation is not developed in the Higher emissions price path and build is reduced at the Current CCR trigger price path. This is because geothermal fields release fugitive emissions which are subject to emissions pricing. These emissions costs put geothermal fields at a disadvantage compared to wind and solar. However, we note uncertainty on the future emissions intensity of existing and potential geothermal stations. Fields undergo natural degassing. There is also the potential for process changes, such as the capture and reinjection of non-condensable gases, to reduce field emissions. In this modelling we have simplistically assumed constant emission intensities for geothermal fields.
- In the Higher emissions price path scenario a geothermal field fails to cover its costs. This is because the field has high emission intensity and geothermal generation is not able to pass on emission costs in offers. Despite the losses, operation of this generation continues in the model because of the potential for field emissions to be reduced through natural degassing and operational changes.

## 4.2. Wholesale electricity prices

This analysis largely considers the impact of emissions pricing on the time weighted average (TWA) annual wholesale electricity price. Modelled electricity prices vary considerably across simulated weather years, time of day, and spatially across the transmission grid. Although it is important to model this variation, focusing on averages allows us to isolate the impact of emission pricing from other variation.

Wholesale electricity prices are sensitive to many other factors which have not been examined in this modelling. Fossil fuel prices and availability, demand growth, and the timing of renewable build could have significant impact on wholesale market prices. Additionally, any Government intervention in market structure, or push towards 100% renewable electricity, could influence wholesale market prices.

### Demonstration path scenarios

Shown in ***Figure 3*** below is the variation in TWA price for a central Aotearoa New Zealand node for the *Demonstration path scenarios*.

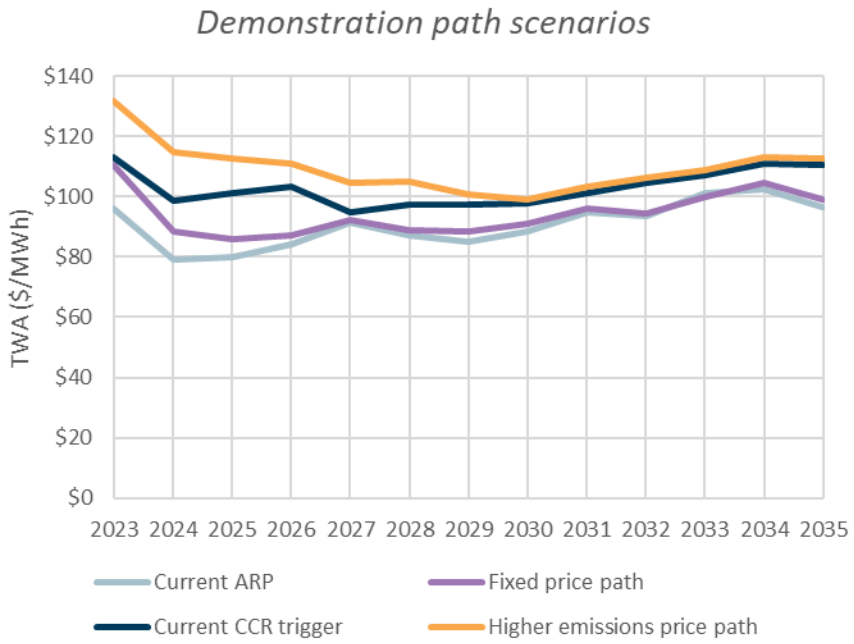


***Figure 3 Time weighted average (TWA) wholesale electricity prices for the Demonstration path scenarios. The prices are in real 2022 dollars for the Haywards grid exit point (GXP) and the average (mean) across all simulated weather years.***

This modelling shows that scenarios with higher emissions prices have higher wholesale electricity prices compared to scenarios with lower emissions prices. However, this effect decreases over time, as the proportion of renewable generation increases. All of the scenarios show an initial reduction in wholesale prices in absolute terms despite increases in emissions price.

The cost of emissions is included in the short run marginal cost (SRMC) of thermal generation. This sets the price at which this generation is offered into the market and influences how hydro generation is valued. These factors influence spot prices for any trading period, and the average price over the year. As thermal generation is displaced by renewables, this impact reduces considerably.

From the late 2020s the electricity system is highly renewable and emissions pricing has much less impact. Wholesale electricity prices begin to track the long run marginal cost (LRMC) of new entrant renewable generation. There is an upwards trend in wholesale price from that point (although prices generally remain below 2023 levels) which is due to the outcome of competing factors:

a) The cost of wind and solar generation are assumed to fall. This causes downwards pressure on the price.
b) However, as these technologies penetrate further into the market there are more periods when wind and solar generation are plentiful and the spot price falls to zero. Generators look for a higher average market price before building to ensure they achieve targeted returns.
c) The lowest cost projects in our assumed generation stack are developed first and generators move towards the next-best, more expensive, sites. This causes upwards pressure on the wholesale price.
d) The SRMC of thermal generation still has some impact. Gas offers increase with emissions pricing due to the direct cost of emissions and to cover plant fixed costs over a shorter operating period.

The upwards trend shown in ***Figure 3*** is the outcome of b, c and d outweighing a. This is driven by assumptions around the future cost of generation projects.

From around 2029 the *Demonstration path scenarios* follow two distinct tracks with the higher emissions price scenarios (Current CCR trigger price and Higher emissions price path) having wholesale prices around \$10/MWh (1c/kWh) above the lower emission price paths (Current ARP and Fixed price). This spread is largely because more renewable generation has been built in the higher emissions price scenarios and more of the low-cost renewable generation projects have been developed (factor c described above) – therefore the marginal project is more expensive to build.

Note that the *Demonstration path scenarios* all show a reduction in prices in absolute terms between 2023 to 2024 despite increases in emissions price. This is due to an assumed reduction in gas prices (excluding emissions cost) and the displacement of baseload gas generation with renewables. Baseload gas has high operating costs compared with committed geothermal and wind generation projects and so removing it from the system puts downward pressure on price. Other than the current ARP scenario, the TWA price for the *Demonstration path scenarios* in 2035 remains less than the 2023 modelled year.

These price trajectories are very similar to those presented in *Ināia Tonu Nei* although inflation has increased their magnitude. Inflation has been applied to new build capital cost, fuel prices and O&M (operation and maintenance) costs. Additionally, the emissions price trajectories modelled here are different - the emissions value price path used in *Ināia Tonu Nei* lies between the current ARP and current CCR trigger.

## Price sensitivity

The relationship between emissions pricing and TWA wholesale price is approximately linear but varies from year to year. The top plot of ***Figure 4*** shows the relationship across the *Demonstration path scenarios* for the 2023 model year. We have used linear regression to calculate the slope of the relationship for every model year – the evolution of this emissions price sensitivity is shown in bottom of ***Figure 4***.

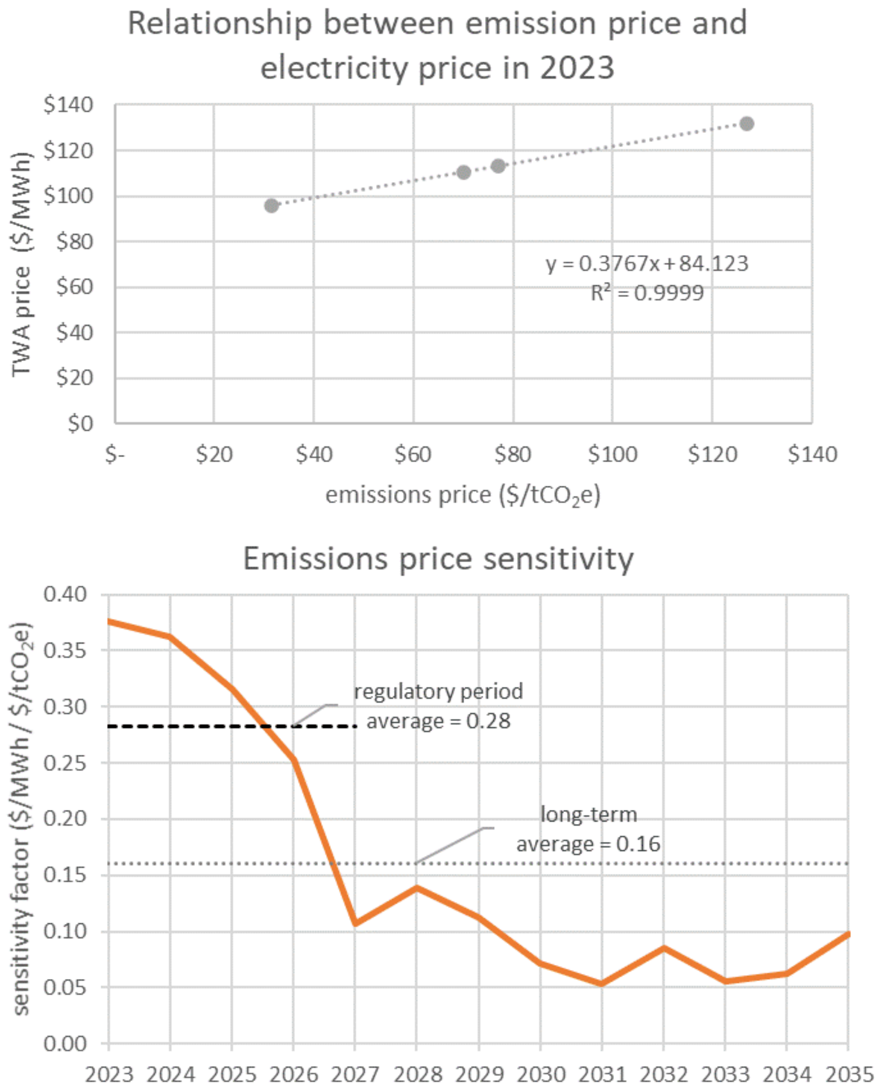


***Figure 4 Relationship between emissions price and TWA wholesale prices for the Demonstration path scenarios. The top plot shows the relationship for the 2023 model year, and the bottom plot shows the evolution of the price sensitivity factor.***

This emissions price sensitivity factor for wholesale electricity prices averages 0.28 $/MWh / $/tCO$_2$e across the regulatory period (2023 - 2027). This means that an increase in annual emissions price of $1/tCO$_2$e will flow through and increase TWA electricity prices by $0.28/MWh, when averaged across all weather years and considered in isolation from other year-to-year price changes. Averaged across the entire projection period out to 2035, the long-term average of this emission price sensitivity factor is 0.16 $/MWh / $/tCO$_2$e. These factors provide simple estimates of the impact of emission pricing in the short and long term. For example, if the NZU price remained flat at $100/tCO$_2$e out to 2035 it would be expected to contribute $28/MWh (or 2.8c/kWh) on average during the regulatory period of 2023-27, but only $16/MWh (or 1.6c/kWh) when averaged across the longer term out to 2035. These factors are used in subsequent analysis for estimating consumer price increases.

## Slower demand growth scenarios

Two scenarios were modelled with slower demand growth tracking the *Current policy reference (update).* The lower emissions price paths were used for these scenarios as these are more consistent with a future with slower demand growth.

***Figure 5*** shows the modelled wholesale prices for these low demand scenarios compared with those based on the *Demonstration path (update)*. Market prices are very similar for most of this decade for each emissions price path. However, the prices diverge from around 2030 onwards when the demand gap becomes more considerable (difference is ~2 TWh p.a in 2030, increasing to ~6 TWh p.a by 2035). The divergence in wholesale prices is because extra demand is met by more renewable development, which increases the costs of the marginal generation projects (this is factor c described for the *Demonstration path scenarios* in section 4.2 above).

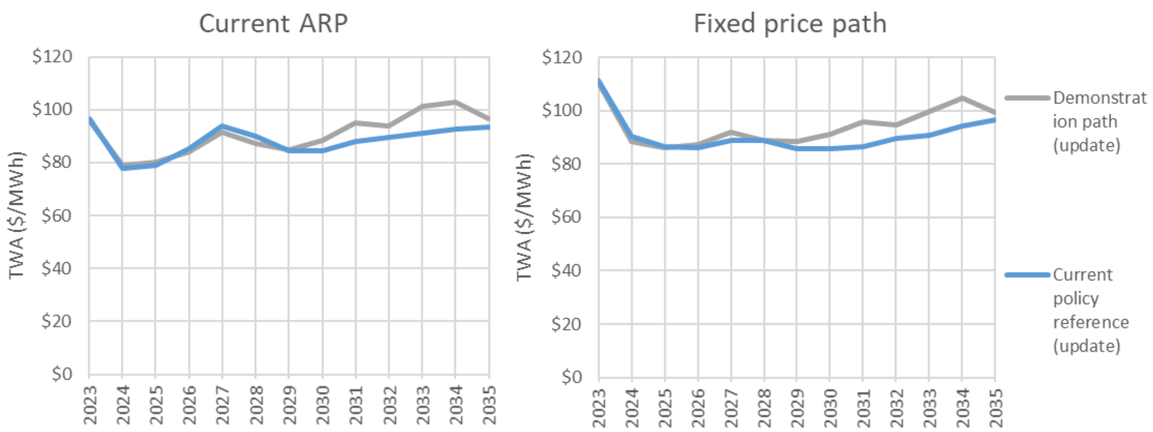


***Figure 5 The impact of demand growth on wholesale TWA prices for Current ARP and fixed emissions prices. TWA Prices are for the Haywards GXP and are the average across simulated weather years.***

This scenario comparison shows that up to around 2029 the rate of demand growth seems to have little influence on the impact of emissions pricing. We have not calculated sensitivity factors as was done for the *Demonstration path scenarios*, as we only compared two scenarios and this number is insufficient for an accurate calculation of sensitivity.

## Closure of the Tiwai Point aluminium smelter

We also modelled a scenario where the Tiwai Point aluminium smelter closes at the end of 2024 at the conclusion of their current main electricity supply contract. Wholesale electricity prices fall abruptly at the time of closing as is shown in ***Figure 6***. By 2029 the reduction in demand from the smelter has been offset by new demand growth and wholesale prices again track the LRMC of new entrant renewables.

The electricity system has a surplus of generation capacity once the smelter closes and this means that very little thermal generation operates. In the 2025 model year the system is 96% renewable,[8] compared with 91% in the counterfactual scenario (smelter remains). With this little fossil gas operating in the system the emissions price has little impact on the wholesale price. We haven't quantified a sensitivity factor as we only

[8] Including cogeneration

modelled the Tiwai exit scenario with a single emissions price path. However, as stated in the main advice report *the emissions price should have little influence on average market prices* as we anticipate that the price sensitivity factor will be small and similar to the other modelled scenarios at high renewable percentages.

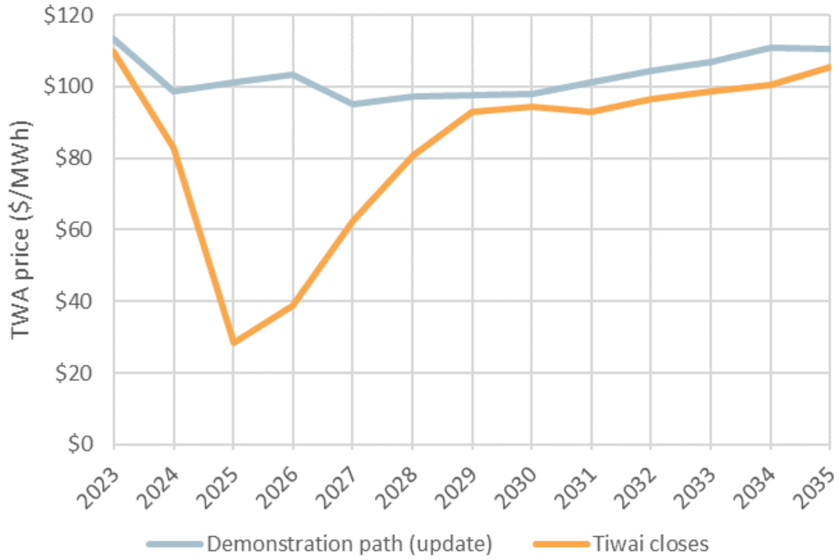


***Figure 6  TWA wholesale electricity prices for scenarios with and without the Tiwai Point aluminium smelter closing with Current CCR trigger emissions prices. The prices are in real 2022 dollars for the Haywards grid exit point (GXP) and the average (mean) across all simulated weather years.***

## 4.3. Retail prices

Most electricity consumers are isolated from the spot market by retail electricity contracts which are based on the expectation of future wholesale prices. Furthermore, the wholesale price, which covers the cost of electricity generation and is sensitive to emissions pricing, is only one component of the delivered retail price. Retail prices also includes line charges, the retailer's non-energy costs, and GST. Margins are also built into all components. The composition of an average retail bill is given in ***Table 4*** below.

***Table 4 Composition of an average electricity bill***[9]

| Component | Percentage of average electricity bill |
|---|---|
| Generation | 32% |
| Distribution | 27% |
| Transmission | 10.5% |
| Retail | 13% |
| GST | 13% |

[9] (Electricity Authority, n.d.)

| | |
|---|---|
| Other | 4.5% |

We assume wholesale price increases will ultimately be fully passed onto consumers, but the timescale for this is uncertain and may vary by customer segment. For example, it is unlikely that current residential retail prices fully reflect the impact of the emissions price in the wholesale market as NZU price growth has been sudden and residential contracts are based on longer term trends. We expect a lag between a step change in wholesale prices and the change in retail prices.

We have estimated the emissions component of retail electricity prices for residential, commercial, and industrial consumers. We have applied the methodology from the ICCC's electricity enquiry[10] where average wholesale prices are scaled by network losses ($L_s$), hedge premium ($H_s$), and a time of use factor ($R_s$). The assumptions for each consumer segment are summarised in ***Table 5*** below. Note that 15% for GST is applied in addition to this scaling for residential prices.

***Table 5 Assumptions for factors used to scale electricity prices by customer segment***

| Customer segment | $R_s$ | $H_s$ | $L_s$ | Total scaling factor |
|---|---|---|---|---|
| Residential | 1.03 | 1.10 | 1.03 | 1.17 |
| Commercial | 1.04 | 1.10 | 1.02 | 1.17 |
| Industrial | 1.00 | 1.10 | 1.00 | 1.10 |

Although the emissions price sensitivity varies in time, as is shown in ***Figure 4***, we have chosen to present a static quantification of the emissions component for retail prices with upper and lower bounds which is applicable during the regulatory period (2023-2027). This addresses uncertainty in the timescale over which wholesale price impacts will be passed onto consumers. A static quantification was also necessary for the Treasury's analysis of household expenditure impacts which this analysis informs.

***Table 6*** below presents potential high and low retail price components for the regulatory period. These estimates use the outcomes from the price sensitivity analysis of the *Demonstration path scenarios.* The high impact uses the sensitivity factor across the regulatory period (0.28), and the low impact uses the long-term average from 2023 to 2035 (0.16).

The analysis attempts to collapse the dynamic wholesale price variance seen in the *Demonstration path scenarios* into simple retail impacts which are independent of time. The estimates do not correspond to a single model year and are based on the average emission price sensitivity factor trends. However, that being said, this simplification is only appropriate for application in the near term. By 2027 the emissions price sensitivity factor falls below the low impact setting and this quantification would overstate potential price impacts.

[10] (Martin Jenkins, 2019)

*Table 6 Recent retail electricity prices and estimated high and low emissions price impacts. These estimates are based on analysis of the Demonstration path scenarios and reflect the emissions price sensitivity trend across multiple years. The impact estimates are applicable for the regulatory period of 2023-2027.*

| | | | Emissions component of price (c/kWh) | | | | |
|---|---|---|---|---|---|---|---|
| | | | *Emissions price ($/tCO₂e)* | | | | |
| | **Sector** | **2021 price (c/kWh)** | *50* | *100* | *150* | *200* | *250* |
| High impact | Residential | 30.6 | 1.9 | 3.8 | 5.7 | 7.6 | 9.5 |
| | Commercial | 18.5 | 1.7 | 3.3 | 5.0 | 6.6 | 8.3 |
| | Industrial | 17.1 | 1.6 | 3.1 | 4.7 | 6.2 | 7.8 |
| Low impact | Residential | 30.6 | 1.1 | 2.2 | 3.3 | 4.4 | 5.5 |
| | Commercial | 18.5 | 1.0 | 1.9 | 2.9 | 3.8 | 4.8 |
| | Industrial | 17.1 | 0.9 | 1.8 | 2.7 | 3.6 | 4.5 |

*2021 prices are based on MBIE reporting and represent fixed and variable components of a typical bill. All prices have been inflated to real 2022 dollars. Residential prices are inclusive of GST*

***Table 6*** includes actual retail prices for the 2021 calendar year for a sense of scale. These results should not be interpreted as implying specific absolute price increases. As discussed previously, wholesale electricity prices, which make up a component of retail electricity prices, are sensitive to many things which have not been examined in this analysis. The modelled scenarios also show a reduction of prices in absolute terms in the short term despite an increasing emissions price which could cause downwards pressure on retail prices – however these trends are not included in these table estimates.

Similarly, retail electricity prices also include a component to cover the cost of transmission and distribution networks. Regulation has recently been amended around transmission cost allocation,[11] and for residential consumers, the low-user fixed charge is being phased out.[12] Changes like these could have material impact on consumer prices, but they are beyond the scope of this analysis.

Additionally, because most of the network costs are fixed, there is an opportunity to reduce average consumer prices through higher use of the network at off-peak times. Electricity retailers offer off-peak rates based on this. Shifting or contributing new demand, such as EV charging, at off-peak times should reduce average prices.

For the Treasury's analysis of household expenditure impacts the high and low emissions component of price for residential consumers is added to 2019 actual prices to estimate relative price increases.

## 4.4. Generation earnings

The spot market modelling undertaken shows that increases in emissions prices are likely to increase wholesale electricity prices when considered in isolation from other year-to-year variation. This impact is most significant in the short-term while considerable thermal generation operates in the system.

Gas and coal generation includes the cost of their emissions in the price they offer into the spot market. Increases in emissions pricing would increase thermal generation offer prices. For periods when this

[11] (Electricity Authority, 2022)

[12] (Ministry for Business, Innovation and Employment, 2022)

generation is dispatched higher spot prices cover the additional cost of emissions. This also increases the value of hydro generation and the price at which it is offered to the market. For generation, which is not subject to emissions costs, higher market prices could translate to increased earnings.

We have analysed EBITDA (Earnings Before Interest, Taxes, Depreciation, and Amortization) at a generation plant, project, or hydro-scheme level for the *Demonstration path scenarios,* based on outputs from the E-Market model. EBITDA is spot market revenue less fuel and emission costs, fixed and variable O&M (operation and maintenance) costs. This is not a firm level analysis which considers portfolios of generation and does not include the hedge market which acts to reduce price volatility for both generators and electricity purchasers. Nor does it include the service of loans and write-down of asset valuation.

***Figure 7*** shows the difference in total EBITDA between these modelled scenarios for the period of 2023-2027. EBITDA is aggregated across all existing renewable generation, existing thermal generation, and new renewable generation which is built.[13] The EBITDA totals are relative to the scenario where emissions prices are fixed at \$70/t$CO_2$e. The average emissions price of the scenario is also shown in the plot.


***Figure 7 Difference in aggregated EBIDTA between scenarios by generation type. Values are totals across regulatory period (2023-2027) and the average across simulated weather years.***

The aggregated EBITDA differences are the average across all simulated weather years. There is considerable variation in EBITDA outcomes across discrete modelled generation and across simulated weather years.

For the modelled scenarios there is a relationship between aggregated EBIDTA and emissions pricing on average. Higher emission prices translate to increases in EBITDA, largely for existing renewable generation. In the scenario with emission prices tracking the current CCR trigger prices, existing renewable generation EBITDA is \$1.6bn more across the regulatory period than if prices held at \$70/ t$CO_2$e.

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[13] Cogeneration plants are excluded from this analysis because they make up only a small portion of total generation and because spot market revenue makes up only a component of their total revenue.

EBITDA variations are considerably less for existing thermal generation. This is largely because this generation has associated emissions costs and its operation costs drive the spot market price when it is operating. New renewable generation earnings vary a small amount across the scenarios and depend on how much additional generation is built and market prices.

There are complexities in the electricity market which affect whether these modelled earnings increases in the spot market will be realised by firms which generate electricity if emissions prices continue to rise. This will depend on their retail contracts, hedging position, generation portfolio, and the weather. For example, a generator's spot earnings may increase during a dry period, but be offset by hedge and retail contracts. A renewable generator that finds itself short on generation in a dry period, relative to its contracts, would suffer relative losses even with high prices.

In the longer term, the scenarios with higher emissions prices drive investment in new renewable generation at a higher rate relative to lower emissions prices. This investment is expected to be funded partly from debt and partly from the retained earnings of existing generators.

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