Government Leadership

Regional Energy Transition Accelerator (RETA)

Taranaki – Phase One Report

October 2024

TE TARI TIAKI PŪNGAO
ENERGY EFFICIENCY & CONSERVATION AUTHORITY

He kupu takamua

E tutuki ai te whāomoomo ā-pūngao me te whakawhiti kora kaitā, me whai pārongo whai mana i te taha o te mahi ngātahi pakari ā-rohe. Kua hoahoatia te Taranaki Regional Energy Transition Accelerator (RETA) ki te poipoi i te māramatanga whānui ki ngā tūāoma e waiwai ana ki te whakaheke i te tukuwaro i te rohe mā tētahi hātepe mātau, ruruku pai.

Kei te iho o tēnei hōtaka ko te tohu i ngā arawātea me ngā taupā e motuhake ana ki a Taranaki i a mātou e whakaahua ana i ngā mahere rori whakawhiti pūngao ā-rohe. Ko Taranaki te rohe kotahi i Aotearoa e hua ake nei te haurehu (waiwaro rānei), ka mutu, he wāhi hirahira tōna i te tauritetanga ā-pūngao o Aotearoa. Ko te pae tawhiti, ka tutuki ngā herenga pōkākā o te wā i te rohe i te kapuni kora anake.

E motuhake ana ki a Aotearoa, ko ngā wāhi e rua i Taranaki e whakamahi ana hoki i te kapuni hei matū taketake. Ahakoa e āta aro ana tēnei pūrongo ki te whakamahinga o te pūngao hei hātepe pōkākā, e mōhio ana mātou ka whīwhiwhi ake te hātepe whakatau mō ngā rōpū whakahaere e whakamahi ana hoki i te kapuni i roto i ā rātou hātepe whakaputa.

E whakamahi ana tā mātou tātaritanga mō te rohe o Taranaki i a 2022 hei paepito mō te popono pūngao. Nō taua wā, kua whakaawe ngā kōpiritanga tuku haurehu i ngā utu kapuni, me te aha, kua panoni i ngā tauira whakapeto – e tino pērā ana i ngā taupuni e whakamahi ana i te kapuni hei matū taketake.

E whakaatu ana tēnei pūrongo i ngā ara whakaheke waro pōkākā huhua, e whakatauira ana i tā ngā whakatau tōpū a ngā kaiwhakamahi huhua ārahi i ngā rautaki mahi tahi ki ngā wero tūāhanga nō te tirohanga tukunga. Ka whakaatu i ngā angamahi whakatau hei whakaaro ake pea mā ngā rōpū whakahaere hātepe pōkākā i a rātou ka kōwhiri i ngā kora, i muramura mai ai ngā hua huhua ka taea.

E whakatauira ana hoki te pūrongo ka huri pea ngā whakatau i raro i ngā horopaki ā-utu maha. Mā te tirohanga ā-rohe e taea ai tētahi arotakenga whānui o ēnei tūāhuatanga, e mātau ake ai ngā whakatau a ngā kiritaki hātepe pōkākā, tuku kora anō hoki.

E tohu ana tēnei pūrongo i te tihi o te tūāoma whakamahere o te hōtaka, e tuku ana i ngā matapae me ngā mahere o te popono pūngao wera o te rohe, i te taha o ngā aromatawai tuku ngao whakahou.

E whanake ana te hōtaka RETA i ngā whāomoomo ā-pūngao, whakawhiti kora anō hoki kua whakaterea kētia i te rohe. He huhua ngā pakihi i te Tairāwhiti kua whai kē i tētahi ara puhanga-iti, ā, kua whakamaheretia ki EECA.

I hua ake ngā mōhiotanga i runga i te āta mahi tahi ki a Trust Tairāwhiti – the Regional Economic Development agency, local EDB Firstlight Networks, Transpower, ngā kamupene ngahere o te rohe, ngā pūtukatuka rākau, ngā kaiwaihanga hiko me ngā kaihoko, otirā ngā kaiwhakamahi pūngao ahumahi waenga, ki te nui. E mihi nui ana ki ngā rōpū whakahaere nei i tā rātou whai wāhi mai, ā, i tō rātou hiamo anō hoki. E hiamo ana mātou ki te tautoko tonu i te rohe i a tātou ka mahi tahi ki te tūhura i tōna pitomata.

1 Foreword

Achieving energy efficiency and fuel switching at scale requires valuable information alongside strong regional collaboration. The Taranaki Regional Energy Transition Accelerator (RETA) has been designed to foster a comprehensive understanding of the steps necessary for lowering emissions in the region through a well-informed and coordinated approach.

Central to this programme is identifying unique, Taranaki-specific opportunities and barriers when crafting regional energy transition roadmaps. Taranaki is New Zealand's sole gas producing region and plays an important role in the supply of New Zealand's energy balance. The downstream opportunity is that current process heat requirements in the region are met almost exclusively by natural fossil gas.

Uniquely in New Zealand, two sites in Taranaki also use natural gas as a feedstock. While this report focuses specifically on energy use for process heat, we acknowledge that the decision-making process becomes more complex for organisations that also use natural gas in their production processes.

Our analysis for the Taranaki region uses 2022 as the baseline for energy demand. Since then, constraints in gas supply have influenced natural gas prices and, consequently, altered consumption patterns—particularly in facilities using natural gas as a feedstock.

This report illustrates various process heat decarbonisation pathways, demonstrating how the collective decisions of multiple users can lead to shared approaches to infrastructure challenges from a supply perspective. It presents diverse decision-making frameworks that process heat organisations might consider when choosing alternative fuels, highlighting the potential range of outcomes.

The report also demonstrates how decisions may change under various different pricing scenarios. A regional view enables a comprehensive evaluation of these factors, allowing process heat consumers and fuel suppliers to make more informed decisions.

This report marks the culmination of the programme's planning phase, offering forecasts and maps of regional stationary heat energy demand, alongside renewable energy supply assessments.

The RETA programme builds on energy efficiency and fuel switching work already happening in the region. Several businesses in Taranaki already have a low-emissions pathway mapped out with EECA.

Surfacing the insights has involved working closely with Venture Taranaki – the Regional Economic Development agency, local EDB Powerco, Transpower, regional forestry companies, wood processors, electricity generators and retailers, and medium to large industrial energy users. A big thank you to these organisations for their input and enthusiasm. We look forward to continuing to support the region as we work together to unlock its potential.

Dr Marcos Pelenur
Chief Executive, EECA

2 Acknowledgements

This RETA project has involved a significant amount of time, resource and input from a variety of organisations. We are especially grateful for the contribution from the following organisations:

- Process heat users throughout the Taranaki region
- Venture Taranaki
- Local Electricity Distribution Business Powerco
- National grid owner and operator Transpower
- Regional forestry companies
- Regional wood processors
- Electricity generators and retailers

This RETA report is the distillation of individual workstreams delivered by:

- **Worley** – process heat demand-side assessment
- **Forme** – biomass availability analysis
- **Ergo Consultants** – electricity network analysis
- **EnergyLink** – electricity price forecast
- **Sapere Research Group** – report collation, publication, and modelling assistance

> *The downstream opportunity is that current process heat requirements in the region are met almost exclusively by natural fossil gas.*
>
> **Dr Marcos Pelenur, Chief Executive, EECA**

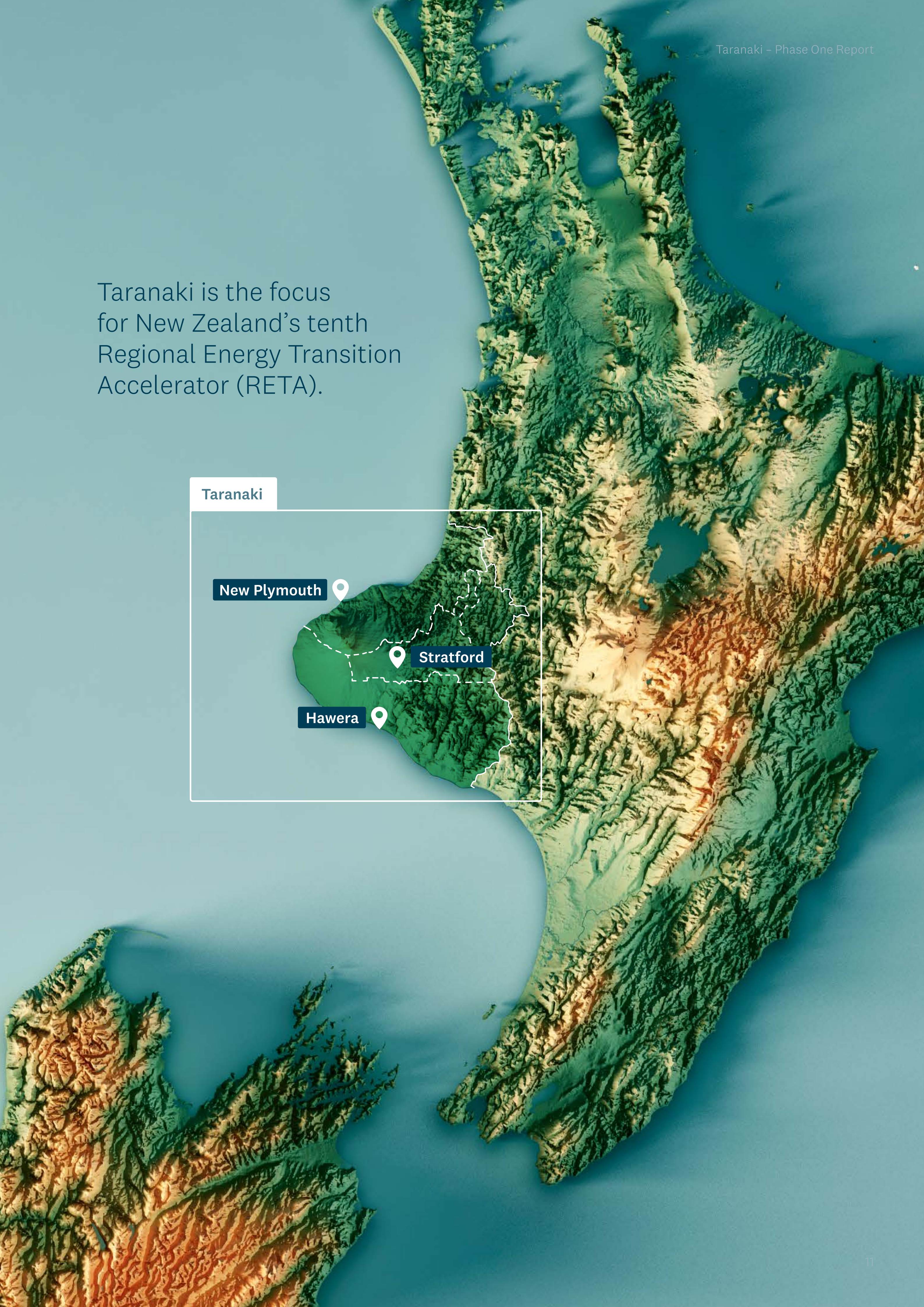
Mountain to Sea coastline New Plymouth. Photo credit: Venture Taranaki

3 Table of contents

Table of contents

Table of contents

Taranaki is the focus for New Zealand's tenth Regional Energy Transition Accelerator (RETA).

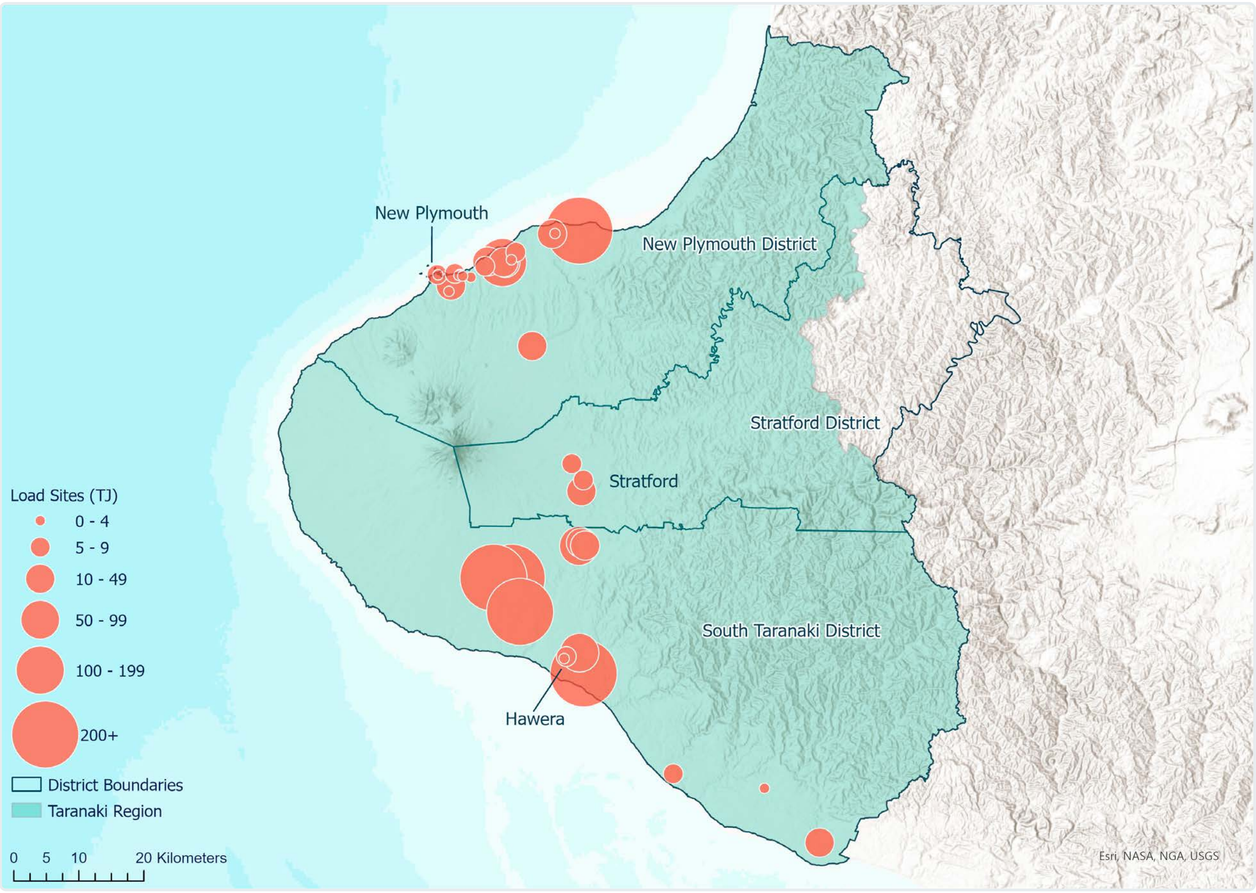


4 Executive summary

This report summarises the results of the planning phase of the Taranaki Regional Energy Transition Accelerator.

The report has looked at 36 sites that are using fossil fuel process heat within the region, shown in Figure 1.

Figure 1 – Map of area covered by the Taranaki RETA (red dots are process heat demand sites)



The 36 RETA sites cover the dairy, industrial and commercial[1] sectors. These sites either have fossil fuelled process heat equipment larger than 500kW or are sites for which EECA (Energy Efficiency and Conservation Authority) has detailed information about their decarbonisation pathway.[2]

1 The commercial sector includes schools, hospitals, and accommodation facilities.

2 For example, process heat equipment details have been captured in an Energy Transition Accelerator opportunities assessment report.

Our analysis of energy requirements in Taranaki uses year 2022 as baseline. We note that since then, constraints in gas supply have affected prices for natural gas, and as a result have altered natural gas consumption patterns, particularly for sites using natural gas as feedstock.[3] Our analysis focuses on the use of fossil fuels for process heat energy only, and we recognise the decisions are more complicated for organisations that also use natural gas as feedstock.

In 2022, together, these sites collectively consumed 23,950 TJ of process heat energy, primarily in the form of natural gas, producing 1,287kt pa of carbon dioxide equivalent (CO_2e) emissions from the fossil fuels used for process heat.

Unique to this region, two of these sites use natural gas as a feedstock as well as for process heat. The RETA assessment focuses on reducing process heat emissions, but for these organisations, the implications of gas supply and cost are wider than solely in terms of fuel switch for process heat. Assumptions made in this analysis are therefore key and noted in section 7.4, where we also undertake sensitivities around natural gas prices.

Table 1 – Summary of Taranaki RETA sites process heat demand and emissions (2022)

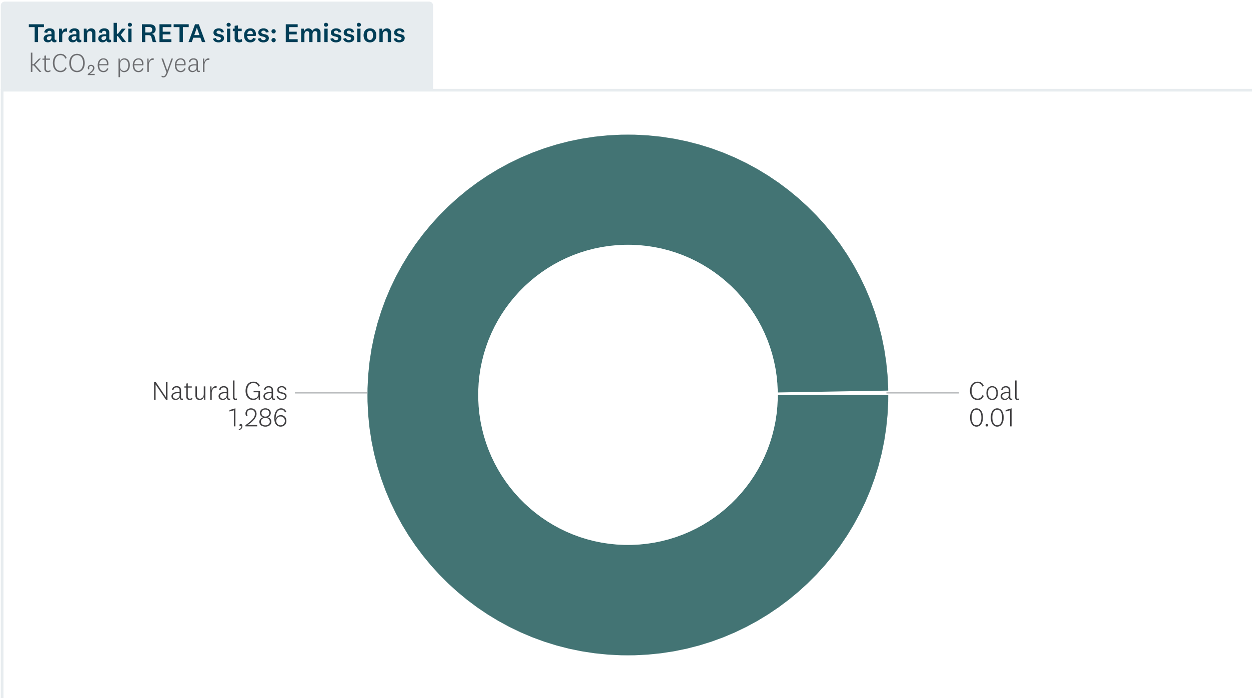
Sector	Sites	Thermal capacity (MW)	Thermal fuel consumption (GWh/yr)	Process heat demand (TJ/yr)	Process heat annual emissions ($ktCO_2e/yr$)
Industrial	24	1,273	6,636	23,880	1,283
Commercial	12	13	20	70	4
Total	**36**	**1,286**	**6,656**	**23,950**	**1,287**


Photo credit: Powerco

[3] MBIE notes that gas production forecast is expected to fall below demand https://www.mbie.govt.nz/about/news/gas-production-forecast-to-fall-below-demand.

Most Taranaki RETA emissions come from piped natural gas (Figure 2).

Figure 2 – 2022 annual emissions by process heat fuel in Taranaki RETA. Source: EECA

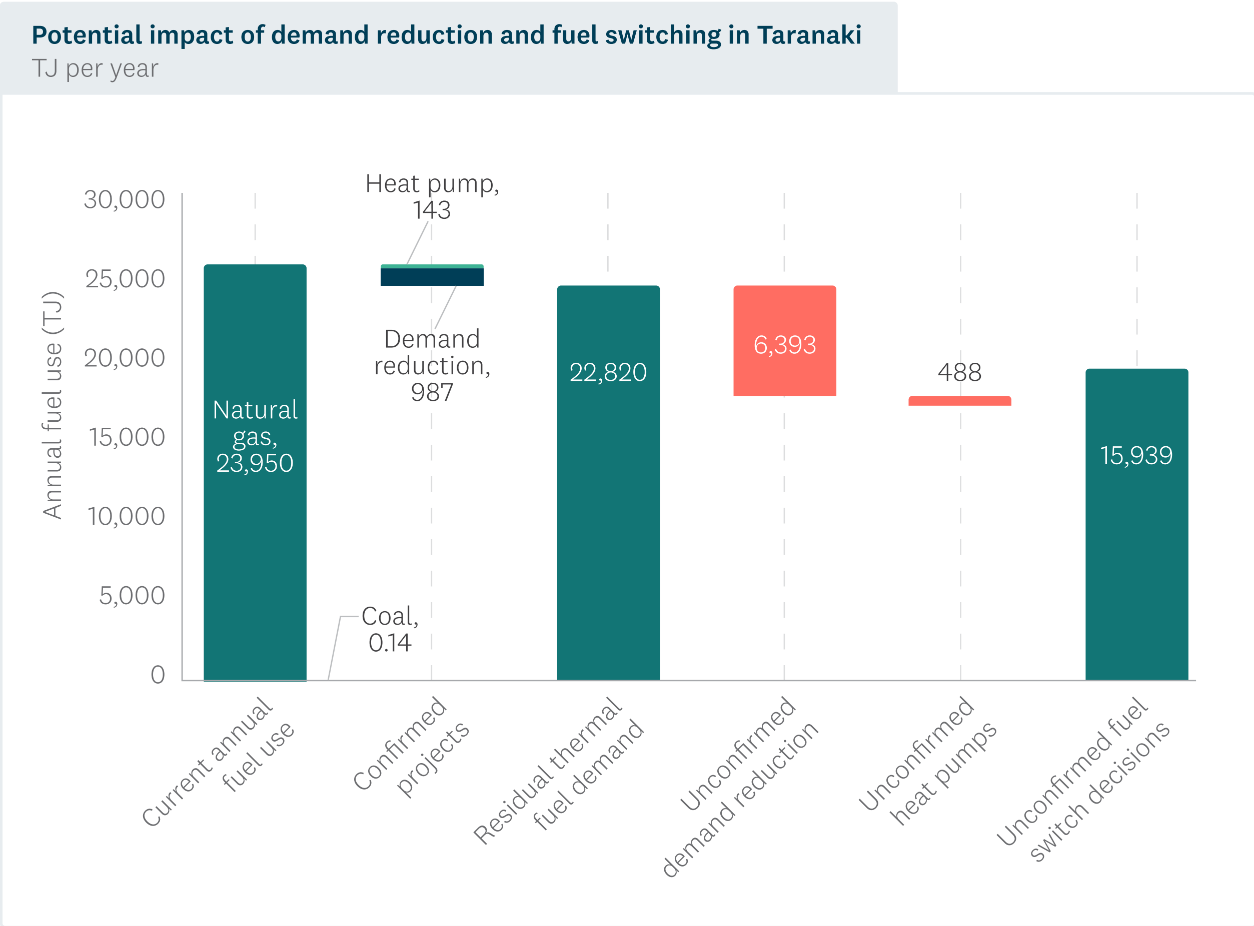


The objective of the Taranaki RETA is to demonstrate pathways which eliminate as much of these process heat emissions as possible. It does this by supporting organisations in their consideration of:

- Demand reduction (for example reducing heat demand through process optimisation)
- Heat pumps (for heat requirements <100°C, which may be integrated with heat recovery)
- Switching away from fossil-based fuels to a low-emissions source such as biomass and electricity.

Figure 3 illustrates the potential impact on Taranaki's regional fossil fuel demand of demand reduction and fuel switching decisions for those investments that are already confirmed and those where decisions are yet to be made.

Figure 3 – Potential impact of fuel switching on Taranaki fossil fuel usage, 2022—2050. Source: EECA



'Heat pumps' in this chart refers to heat recovery through the use of heat pumps. 'Electric fuel switch' includes electrification through high-temperature heat pumps for <100° requirements (see Appendix A for more details).

This report looks at the impact of 92 emissions reduction projects across the 36 sites – covering demand reduction, heat pump efficiency, and fuel switching. It also investigates the regional availability of biomass and electricity to replace natural gas and coal. Combining these two analyses – demand-side and supply-side – we can provide the indicative economics of each of the 92 process heat decarbonisation decisions.

There are a range of decision criteria that individual organisations may use to determine the timing of their decarbonisation investments. Decisions are impacted by available finance, product market considerations, strategic alignment, and other factors. It is challenging to incorporate many of these into a single analysis of the 'economics of a decision.

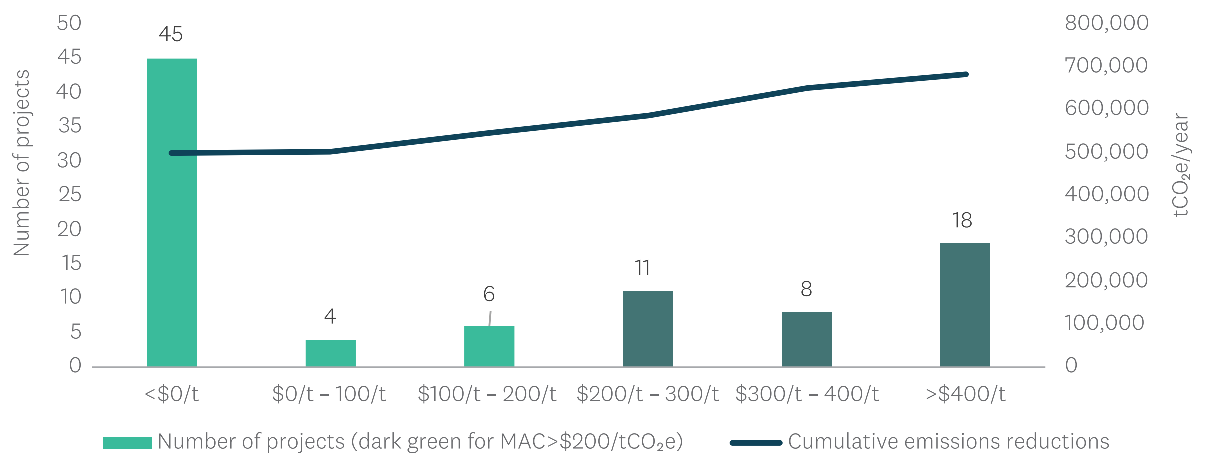
Rather than attempt to include all these factors, we use a global standard 'marginal abatement cost', or 'MAC', to quantify the cost to the organisation of decarbonising their process heat. This is expressed in dollars per tonne of CO_2e reduced by the investment.

4.1 Even without a carbon price, 39% of emissions reductions from RETA projects are economic[4]

Figure 4 summarises the MACs associated with each decision, and the emissions reduced by these projects, based on the cost estimates outlined in this report.

Figure 4 – Number of projects by range of MAC value. Source: EECA

All Taranaki region projects by MAC value ($tCO₂e)
Number of projects and cumulative emissions reduction (assumes 2022 baseline production year)



Out of 1,287kt of process heat emissions from Taranaki RETA sites, 500kt (39%) have marginal abatement costs (MACs) less than zero, while a total of 578kt (45%) have marginal abatement costs less than $200/$tCO_2e$.

Using a commercial MAC decision-making criterion, combined with expected future carbon prices (MAC Optimal), it would be commercially favourable to execute these projects over the next ten years.

[4] By ‘economic’, we mean that at a 6% discount rate these projects would reduce total costs for the firms involved over a 20-year period (i.e. the Net Present Value of the change in costs would be greater than zero) using the cost estimates developed in this report, including at the assumed trajectory of carbon prices. Forty-four RETA projects (constituting 39% of RETA Taranaki’s process heat emissions) have a Marginal Abatement Cost less than zero.

4.2 Indicative Taranaki pathways

4.2.1 Comparing emissions reductions across four pathways

Four indicative decarbonisation pathways are considered:

- In a Biomass Centric pathway, all unconfirmed site fuel switching decisions proceed with biomass where possible in 2049.[5]
- In an Electricity Centric pathway, all unconfirmed fuel switching decisions proceed with electricity where possible in 2049 at the latest.
- In a BAU Combined pathway, all unconfirmed fuel switching decisions (i.e. biomass or electricity) are determined by the lowest Marginal Abatement Cost (MAC) value for each project in 2049.[6]
- In a MAC Optimal pathway, each site switches to a heat pump or switches its boiler to the fuel (i.e. biomass or electricity) with the lowest MAC value for that site. Each project is timed to be commissioned in the first year when its optimal MAC value first drops below a ten-year rolling average of Treasury's central estimate of carbon shadow prices. If the MAC does not drop below the ten-year rolling average of future carbon prices, then the project is assumed to start in 2049.

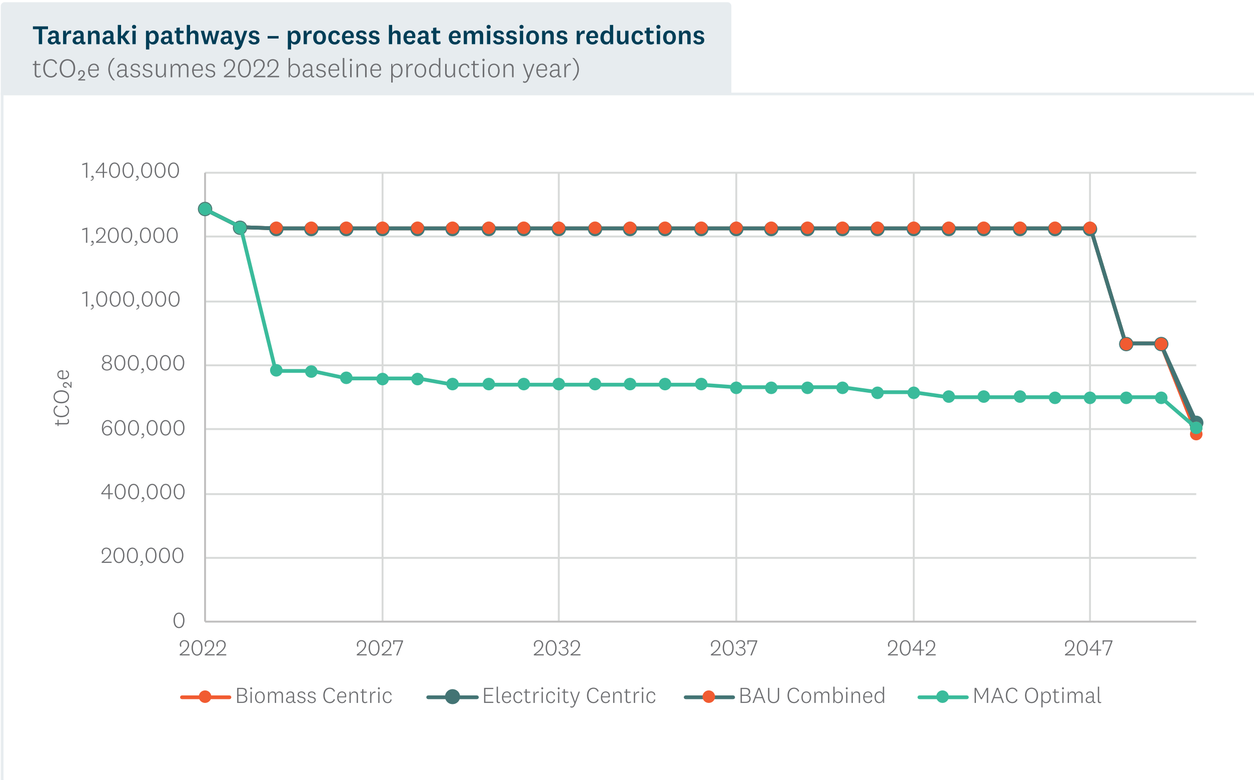

Photo credit: Venture Taranaki

[5] Except in the MAC Optimal pathway, it is assumed that all unconfirmed projects occur in 2049 in line with New Zealand's target of net zero greenhouse gas emissions by 2050 in the Climate Change Response (Zero Carbon) Amendment Act.

[6] The method for calculating MACs is explained in Appendix B.

Compared to a 'BAU' pathway, executing these projects using a commercial MAC decision-making criteria ('MAC Optimal') would accelerate decarbonisation, and reduce the cumulative release of long-lived emissions by 292kt over the period of the RETA analysis to 2050 (Figure 5).

Figure 5 – Simulated emissions using Electricity Centric, Biomass Centric, BAU Combined and MAC Optimal pathways. Source: EECA[7]



For the 42 unconfirmed fuel switching decisions, the MAC Optimal and BAU Combined pathways choose the fuel with the lowest MAC value. MAC values for each potential fuel – and the optimal fuel, and timing of investment – is driven by both the capital costs, and ongoing operational costs, of the investments. Biomass MAC values in the Taranaki region are (generally) more driven by total capital costs than operating costs.[8]

Generally, operating costs are higher for electrode boilers because electricity (per unit of delivered heat) tends to be more expensive than biomass when used in a boiler.[9] A focus for companies considering electrification should be to find ways to reduce the total retail and network charges paid for electricity. The ability to enable flexibility in consumption – even just the ability to shift their demand forward or back by a small number of hours – could have a material effect on the electricity price and therefore the overall economics of the project.

7 The pathway charts in this document typically commence in 2022, because that is the year against which emissions were baselined. The Taranaki RETA modelling was conducted in 2023 and show a number of confirmed fuel-switching projects, and thus emissions reductions, occurring in that year.

8 This statement is specific to Taranaki and not a general statement about the difference between electricity and biomass. See discussion in Section 7.1.2.

9 As opposed to using electricity through a heat pump, where the efficiency of the heat pump often more than offsets the higher cost of electricity relative to biomass.

4.2.2 Testing for sensitivities

We tested a range of sensitivities on this modelling - including different electricity, biomass, gas and carbon prices, and higher network upgrade costs for electrification. We found that:

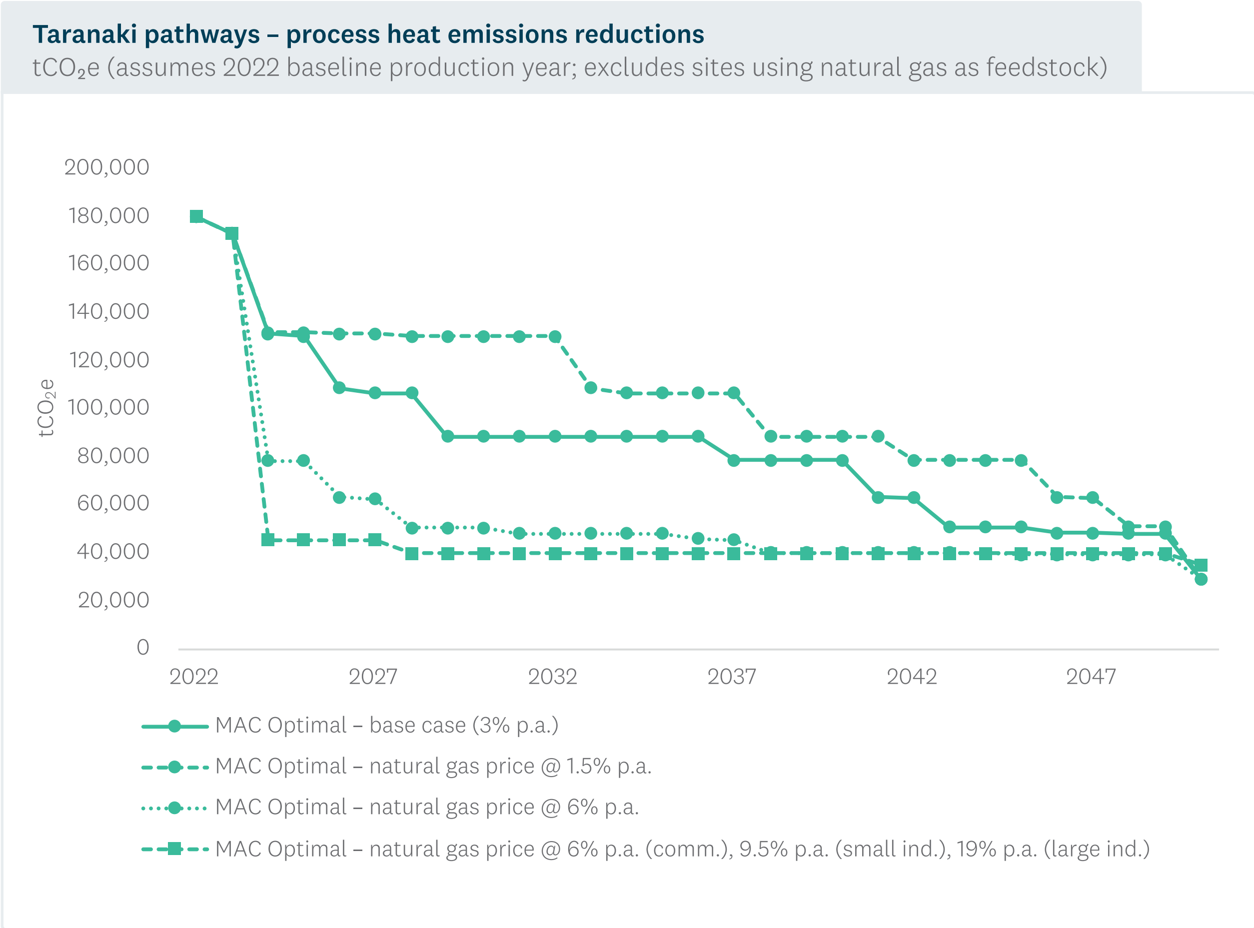
- **Electricity prices.** The 'low' electricity cost scenario changed the fuel choice for three projects, from biomass to electricity, whereas the 'high' price scenario triggered two changes in fuel choice. A 20% reduction in the combined (network and retail) electricity cost changed five fuel switch projects from biomass to electricity, and accelerated 14 electricity-related projects, delivering an additional 143ktCO_2e emissions reductions by 2050. A 50% reduction changed nine projects from biomass to electricity, and accelerated 23 projects, resulting in a cumulative additional emissions reduction of 929ktCO_2e by 2050.
- **Electricity network upgrade costs.** Neither a 50% increase nor decrease in network upgrade costs changed the optimal fuel switching decisions for the Taranaki sites.
- **Biomass prices.** A 20% reduction in the 'wholesale' biomass fibre price from $21.3/GJ[10] to $17.4/GJ changed two fuel switch projects from electricity to biomass, and accelerated eight projects, delivering an additional 1,112kt of CO_2e emissions reductions by 2050. A 50% reduction in the biomass price changed the fuel switch decision to biomass for two projects and accelerated nine projects with a cumulative additional emissions reduction of 1,416ktCO_2e by 2050.
- **Natural gas prices.** The sensitivity analysis excluded sites that also use natural gas as feedstock, to determine the sensitivity from an energy-only demand perspective. However, we recognise that changes in natural gas prices will affect the overall natural gas consumption patterns for sites that also use the fuel as feedstock. As shown in Figure 6, we found that halving the annual escalator for natural gas from 3% to 1.5% resulted in 533kt of additional emissions on a cumulative basis through to 2050. By contrast, doubling the escalator to 6% changed one fuel switch project from biomass to electric, and accelerated 23 projects, delivering an additional 834kt of CO_2e emissions reduction by 2050.[11] A significant increase in the natural gas price to $45/GJ by 2035 (excl. ETS) for all users changed five fuel switch projects from biomass to electricity and accelerated 24 projects with a cumulative additional reduction of 1,012ktCO_2e by 2050.[12]
- **Carbon prices.** The 'high' carbon price trajectory delivers 636kt more emissions reductions cumulatively through to 2050, compared to a 'central' case. By contrast, a 'low' carbon price trajectory delivers 634kt fewer emissions reductions.

[10] This includes an underlying cost of fibre of $18.3/GJ, plus a $3/GJ margin at the hub.

[11] See section 7.4.4 for detailed analysis on assumed natural gas prices.

[12] We reiterate that our analysis did not consider what these natural gas prices meant for the input costs for businesses that also use natural gas as a feedstock.

Figure 6 – Sensitivity of emissions reduction pathways to different gas price assumptions. Source: EECA

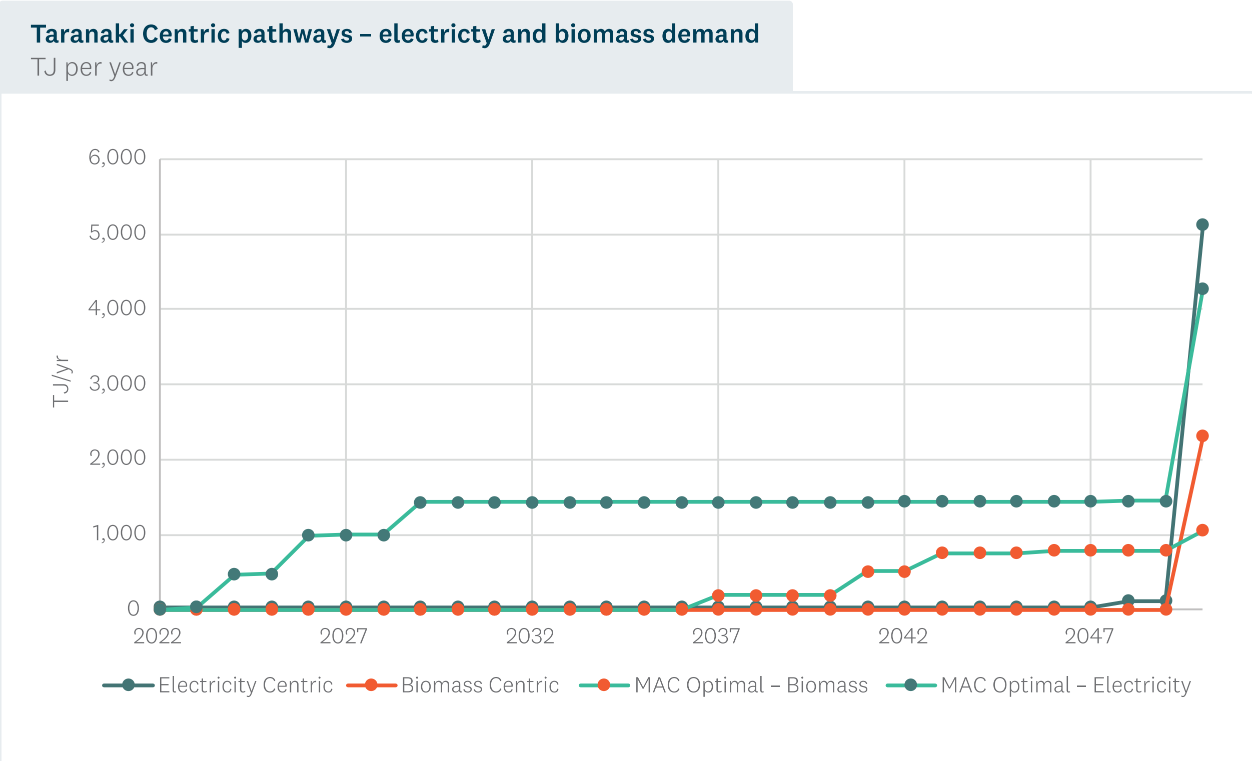


The sensitivity analysis reinforced that process heat users should refine their understanding of their requirements, supply, logistics, and costs for both electricity and biomass before committing either way. This includes early and regular engagement with supply organisations (biomass suppliers and electricity companies).

4.3 What emissions reductions mean for fuel switching

From a supply-side perspective, the MAC Optimal pathway results in 80% of the process heat energy being supplied by electricity, and 20% by biomass by 2050 (Figure 7).

Figure 7 – Electricity and biomass demand in MAC Optimal pathway



Electricity demand in the MAC Optimal pathway is dominated by the fuel switching decisions of three large industrial sites – two in 2024, and one in 2050 (that relates to a hydrogen conversion, where the hydrogen is assumed to be produced via electrolysis). The majority of the remaining, smaller, fuel switching decisions choose biomass as their fuel, as has been the case in other North Island regions.

Although the fuel switching decision is typically the most significant in terms of energy usage and emissions reduction, it is important to recognise the impact that demand reduction and heat pump efficiency projects have on the overall picture of the Taranaki region's process heat decarbonisation. Investment in demand reduction and heat pumps (for heat recovery) could meet 31% of today's Taranaki RETA sites energy demands from process heat, which in turn reduces the necessary fuel switching infrastructure required.[13] We estimate thermal capacity required from new biomass; electric boilers would be reduced by around 399MW if these projects were completed.[14] Further, we estimate that demand reduction and heat pumps would avoid investment of between $480M and $620M in electricity and biomass infrastructure.[15]

13 This is true for both energy consumption and the peak thermal demand required from biomass or electric boilers.

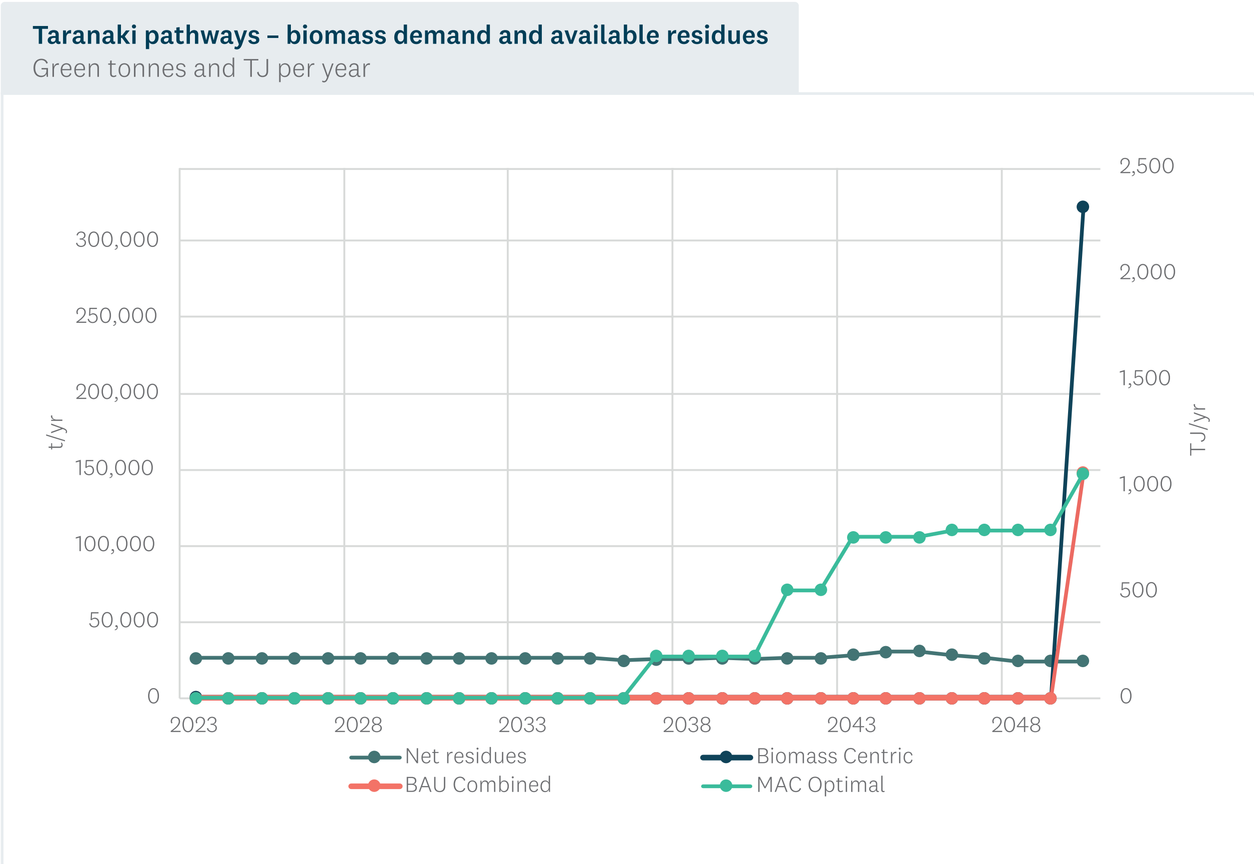
14 Across Taranaki RETA sites, there is 1,286MW of fossil fuel thermal capacity today.

15 On the assumption that 1MW of electrode boilers, and associated network connections, or 1MW of biomass boilers, cost on average $1.55M and $1.2M, respectively.

4.3.1 Biomass

Irrespective of the pathway, by 2050, demand from all biomass fuel switching projects significantly exceeds available surplus processing residues and a pragmatic estimate of harvesting residues (Figure 8).[16] Meeting this significant demand would mean tapping into the higher-valued logs from the Taranaki region (export K/A), and/or exploring opportunities for importing residues from other regions.

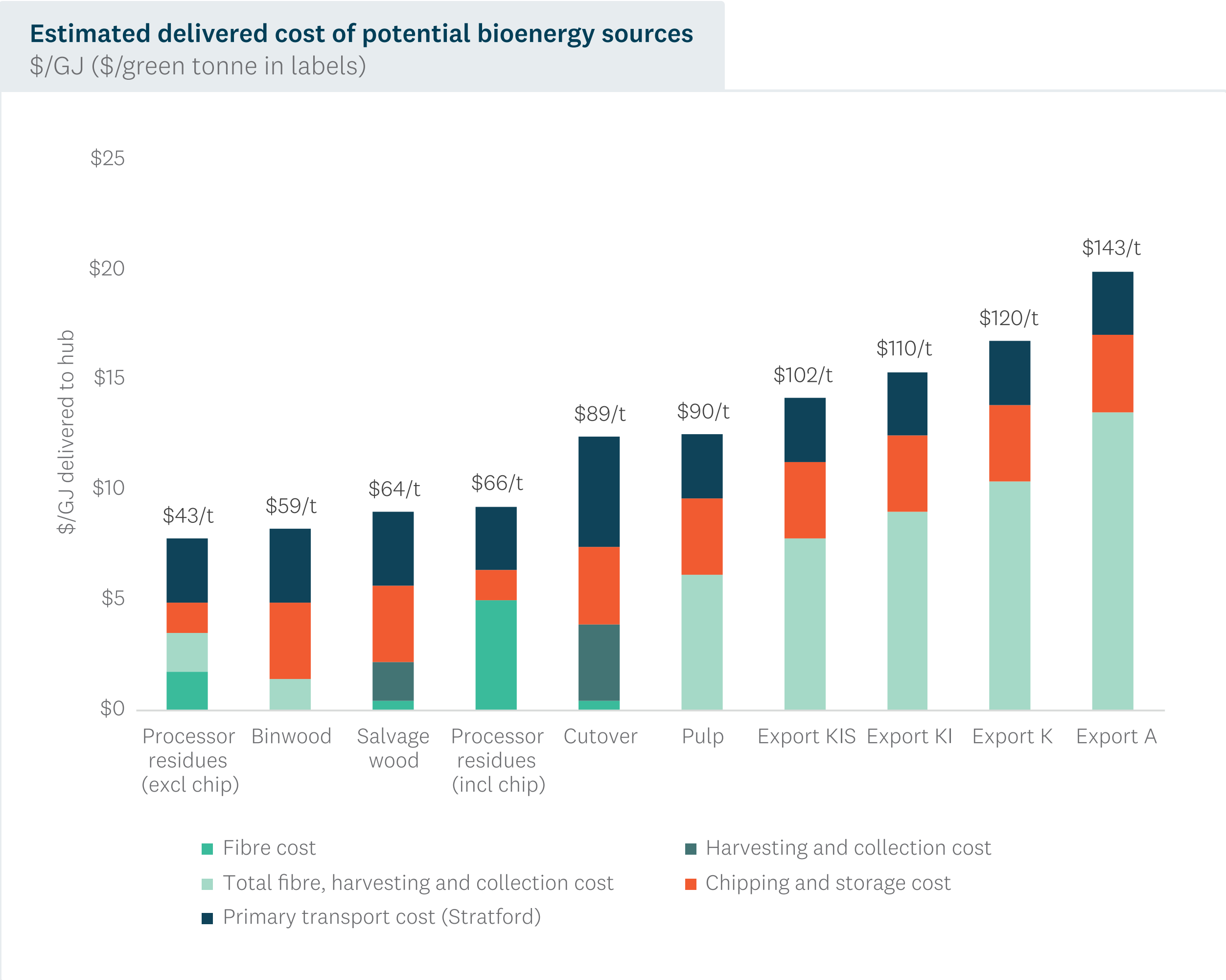
Figure 8 – Growth in biomass demand under MAC Optimal, BAU Combined and Biomass Centric pathways. Source: EECA



[16] Actual recovery of forest residues can be complicated by difficult terrain. As such, theoretical potential in the Wood Availability Forecasts is scaled back to show realistic recovery based on interviews with foresters and expert opinion.

Figure 9 shows costs of collection and delivered per volume of green tonnes and GJ. Given that the significant increase in biomass demand by 2050 would mean tapping into the higher-grade logs, we assume that the long-term biomass price (delivered at hub) in the Taranaki region is set by the average of the K-log and A-grade logs, i.e. $18.3/GJ ($131/GMT).[17]

Figure 9 – Estimated delivered cost of potential bioenergy sources. Source: Forme (2024)



[17] This includes secondary transport cost from the hub to the user of $1.67/GJ over a 35km distance, and processing costs at the end user's site.

4.3.2 Electricity

Generation investment is expected to keep pace with the increase in national demand growth that arises from decarbonisation. This is likely to lead to modest increases in electricity prices for process heat consumers over the next 15 years. Forecasts obtained by EECA from EnergyLink predicts the wholesale and retail component of electricity charges increasing from around 10c/kWh in 2026 to 11c/kWh in 2040 (in real terms). These figures are annual averages. Typically, commercial and industrial retail prices vary across the year (reflecting the underlying supply and demand for electricity). As a result, some sectors, such as dairy, will effectively pay a lower price than this, as their demand is weighted towards periods of the year that have lower retail prices.

We also note that some retailers may offer lower prices for large process heat users who convert from fossil fuels to electricity. These prices are lower than the forecast numbers above.

In addition, the annual charges applied to major customers by electricity distribution businesses (EDBs) for the use of the current distribution and transmission network can make up a significant component of the bill particularly where the annual electricity consumption is low relative to peak demand and/or connection size.

The Taranaki region is home to one EDB, Powerco, which maintains the myriad assets that connect consumers to Transpower's national grid, and also works with Transpower to ensure that the national transmission grid is sufficient to cope with increased demand.

The precise way in which Powerco calculates distribution charges (and passes through transmission charges) has been applied to each site individually. We also estimate the network upgrades required to accommodate those process heat users who are contemplating electricity as a fuel switching option.

For most sites considering electrification, the 'as designed' electrical system can likely connect the site with minor distribution level changes (as defined in section 9.3.4) and without the need for substantial infrastructure upgrades. Most of these upgrades would have connection costs under $1M (and many under $300,000) and experience connection lead times of less than 12 months.

More substantial upgrades to the distribution network are required for two of the sites, with higher costs (between $3M and $20M per stage, dependent on the level of security) and longer lead times (12-48 months).

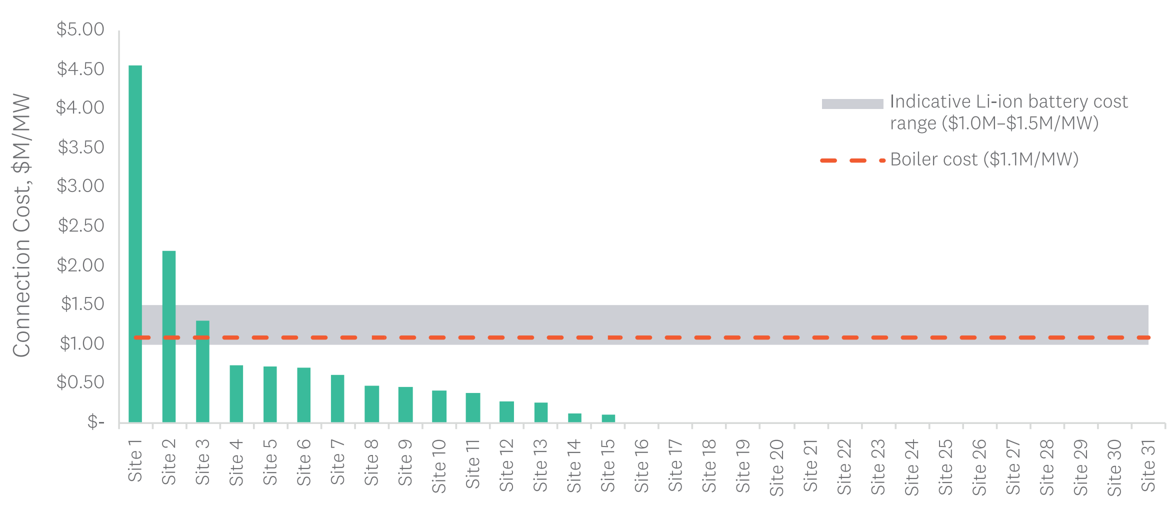
Two sites may require major distribution and transmission upgrades, depending on level of network security required. The cost of these upgrades may reach $16M for one site and up to $82M for the other (which includes a number of stages) and may take up to 48 months per stage to execute.

These costs are summarised (in $/MW) in Figure 10. We note these costs represent the estimated total construction costs of the expected upgrades, and do not take account of the portion of upgrade costs that may be funded by the EDB, rather than the process heat user. We recommend process heat users engage with their EDB to discuss options for connection, more refined cost estimates, and the degree to which process heat users need to make capital contributions to these upgrades.

Figure 10 also compares the connection costs with the cost (per MW) of a battery. We provide this comparison because the ability to shift demand forward or back in time (using batteries, hot water, ice slurry etc) could reduce the capacity required from new network investment. It could also reduce a site's network charges, where these are based on some measure of peak demand. However, we note that storage devices are not a perfect substitute for network capacity, as their ability to reduce demand is usually limited to a small number of hours at any point in time.

Figure 10 – Normalised cost of network connection vs boiler cost. Source: Ergo, EECA

Normalised cost of network connection vs boiler cost
$/MW; boiler capacity, in MW, shown in labels



Based on the various electricity cost parameters, including a 50% contribution to the cost of network upgrades, 80% of the energy required under the MAC Optimal pathway is supplied by electricity. Our sensitivity analysis suggests this outcome is relatively robust under different electricity price scenarios.

The critical aspect of electricity demand growth that concerns network owners is not the growth in electricity consumption resulting from new electric boilers and heat pumps, but rather the impact on the network's peak demand that arises from electrification of boilers.

Figure 11 – Potential increase in Taranaki peak electricity demand under MAC Optimal and Electricity Centric pathway. Source: EECA

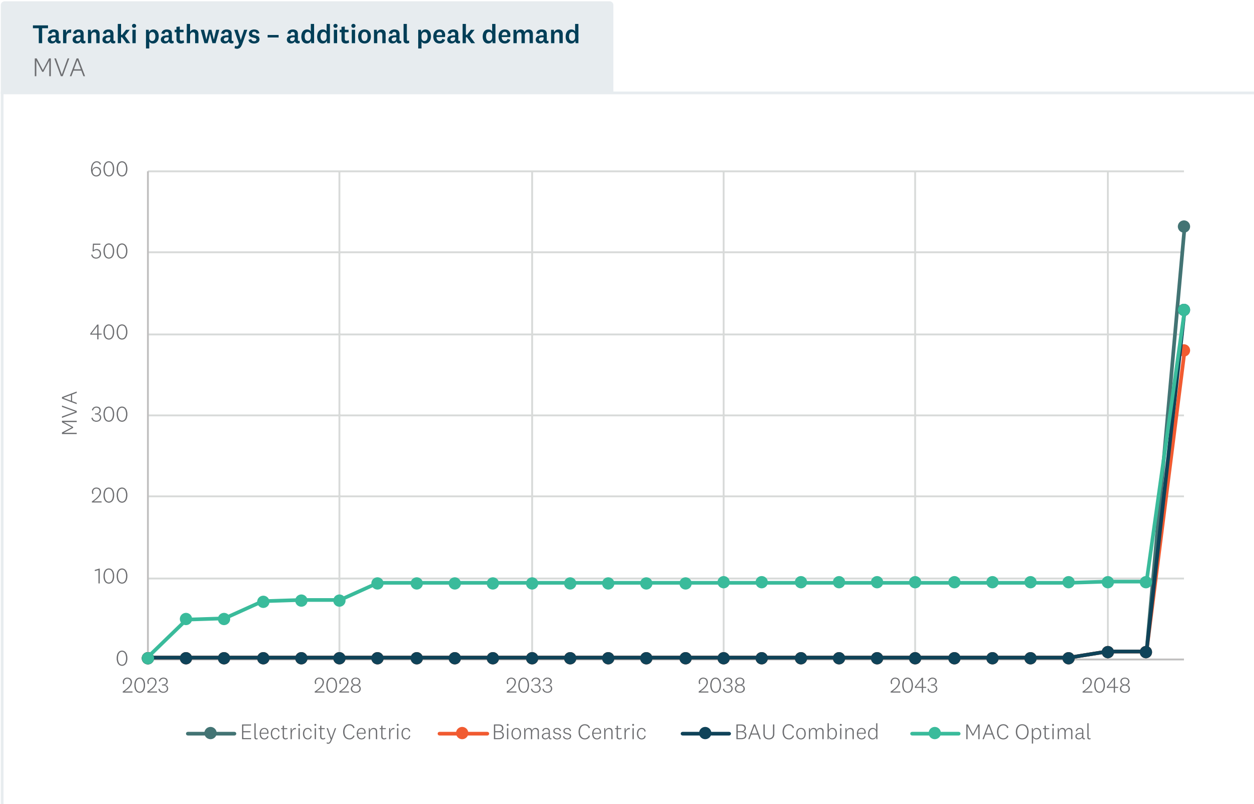


Figure 11 shows that should all unconfirmed process heat users in Taranaki convert to electricity (the 'Electricity Centric' pathway), the increase in demands could be significant by 2050 – a potential increase in peak demand of 532MVA, or 127% compared to today.[18] Table 2 breaks down the costs to Powerco. Due to the significant cost associated with the connection of potential hydrogen electrolysers, we have reported hydrogen and non-hydrogen-related costs separately.

Table 2 – New connections (MW) and customer-driven connection costs under Electricity Centric and MAC Optimal pathways

EDB	Electricity Centric Pathway		MAC Optimal Pathway	
	Connection Capacity (MW)	Connection Cost ($M)	Connection Capacity (MW)	Connection Cost ($M)
Hydrogen projects (in 2050)	302	$273	302	$273
Other electrification projects[19]	230	$161	127	$50
Powerco total	532	$434	429	$323

18 This chart shows the cumulative increase in peak demand assuming all electricity projects peak at the same time. The main report discusses a more realistic view which considers the natural diversity between process heat users in terms of when each is likely to peak. This results in a slightly lower peak demand requirement from the networks.

19 This includes both confirmed and unconfirmed projects.

As outlined above, the costs presented in Table 2 are the total construction costs associated with any network upgrade costs, and may not necessarily reflect the connection costs paid by process heat users, as costs may be shared between the EDB and the new process heat user. These costs also exclude the ongoing network charges paid by each process heat user that electrifies their process heat.

The extent to which this increase in peak demand triggers investment in Powerco's network depends on several factors, such as existing spare capacity and security of supply requirements.

The costs faced by process heat users to connect their electric boilers to the network, and the wider network upgrades that Transpower and Powerco are contemplating, could both be reduced by harnessing the potential for process heat users to be flexible about when they use their boilers. We highlighted previously that demand reduction and heat pumps could reduce the need for thermal capacity by around 399MW.

Similarly, if process heat users could shift some or all their electricity consumption away from critical peak times on the network (usually winter mornings and evenings), or maintain an alternative supply of fuel, a greater degree of cost savings could be experienced.

For process heat users that have some flexibility, we estimate that they could reduce their electricity procurement costs by around $56,000 per year, for each MW of demand that is used flexibly. In addition, at the planning stage, they could reduce costs associated with the size of their connection to the electricity network – the investment required in the physical connection, and also any network charges from Powerco that relate to the size of the connection.

Photo credit: Powerco

4.4 Recommendations and opportunities

Our analysis has highlighted a range of opportunities and recommendations which would improve the overall process heat decarbonisation 'system'. These recommendations are summarised here.

Recommendations to improve the use of biomass for process heat decarbonisation:

- Although information is improving since the start of the RETA programme (nationally), there may still be opportunities to refine the understanding of residue costs, volumes, energy content (given the potential susceptibility of these residues to high moisture levels) and alternative methods of recovering harvesting residues.
- Work should be undertaken with forest owners to understand the logistics, space and equipment required for harvesting residues.
- The development of an 'energy- grade', or E-grade would greatly assist in the development of bioenergy markets. Further, clarity regarding the grade and value of biomass should help the development of an 'integrated model' of cost recovery achieving the best outcomes in terms of recovery cost and volumes.
- Undertake analysis to determine the impact of recovering harvesting residues on soil quality, carbon sequestration, the risk of forest fires and what actions may be required to offset this.
- Investigate and establish mechanisms to help suppliers and consumers within and outside the region to see biomass prices and volumes being traded and have confidence in being able to transact at those prices for the volumes they require. These mechanisms could include standardised contracts which allow longer-term prices to be discovered, and risks to be managed more effectively. The analysis for Taranaki showed that the cost of biomass can significantly affect investment decisions; given the significant potential demand for biomass relative to available residues in the region (processing and harvest), process heat users would benefit from a mechanism that could help identify opportunities for inter-regional trade of biomass resources.
- National guidance or standards should be developed, based on international experience tailored to the New Zealand context regarding the sustainability of different bioenergy sources, accounting for international supply chain effects, biodiversity, carbon sequestration and the risk of forest fires.
- Undertake research into the likely competing demands for wood fibre from other emerging markets, such as biofuels and wood-derived chemicals.

Recommendations to improve the use of electricity for process heat decarbonisation:

- Powerco to proactively engage on process heat initiatives to understand intentions and help process heat users obtain a greater understanding of required network upgrades, cost, security levels, possibilities for acceleration, use of system charges and network loss factors. Powerco should ensure Transpower, and other stakeholders (as necessary) are aware of information relevant to their planning at an early stage.

- Process heat users to proactively engage with Powerco, keeping them informed of their decarbonisation plans and providing them with the best information available on the nature of their electricity demand over time (baseload and varying components); the flexibility in their heat requirements, which may allow them to shift/reduce demand, potentially at short notice in response to system or market conditions; the level of security they need as part of their manufacturing process, including their tolerance for interruption; and any spare capacity the process heat user has onsite. While the costs associated with network connection used in this report have been estimated based on the best publicly available information available to us, when process heat users provide the information above, it will allow EDBs to provide more tailored options and cost estimates.

- Powerco to develop and publish clear processes for how they will handle connection requests in a timely fashion, opportunities for electrified process heat users to contract for lower security, and how costs will be calculated and charged, especially where upgrades may be accommodating multiple new parties (who may be connecting at different times).

- To support this early engagement, Powerco to explore, in consultation with process heat users and EECA, the development of a ‘connection feasibility information template’ as an early step in the connection process. This template would include a section for process heat users to provide key information to Powerco, and a network section where Powerco provide high-level options for the connection of the process heat user’s new demand. Information provided by Powerco would include the potential implications of each option for construction lead times, capital contributions, network tariffs and the use of the customer’s flexibility.

- Retailers, flexibility aggregators, Powerco and the Electricity Authority should assist by sharing information that helps process heat consumers model the benefits of providing flexibility.

- The electricity sector and process heat users should collaborate to explore and demonstrate flexibility. This is consistent with steps in the FlexForum’s Flexibility Plan.

- Powerco and retailers should ensure that the tariffs they offer process heat users are incentivising the right behaviour.

- EECA expand future iterations of regional analyses to include transport as a decarbonising decision that will compete for electrical network capacity and biomass.

Recommendations to assist process heat users with their decarbonisation decisions:

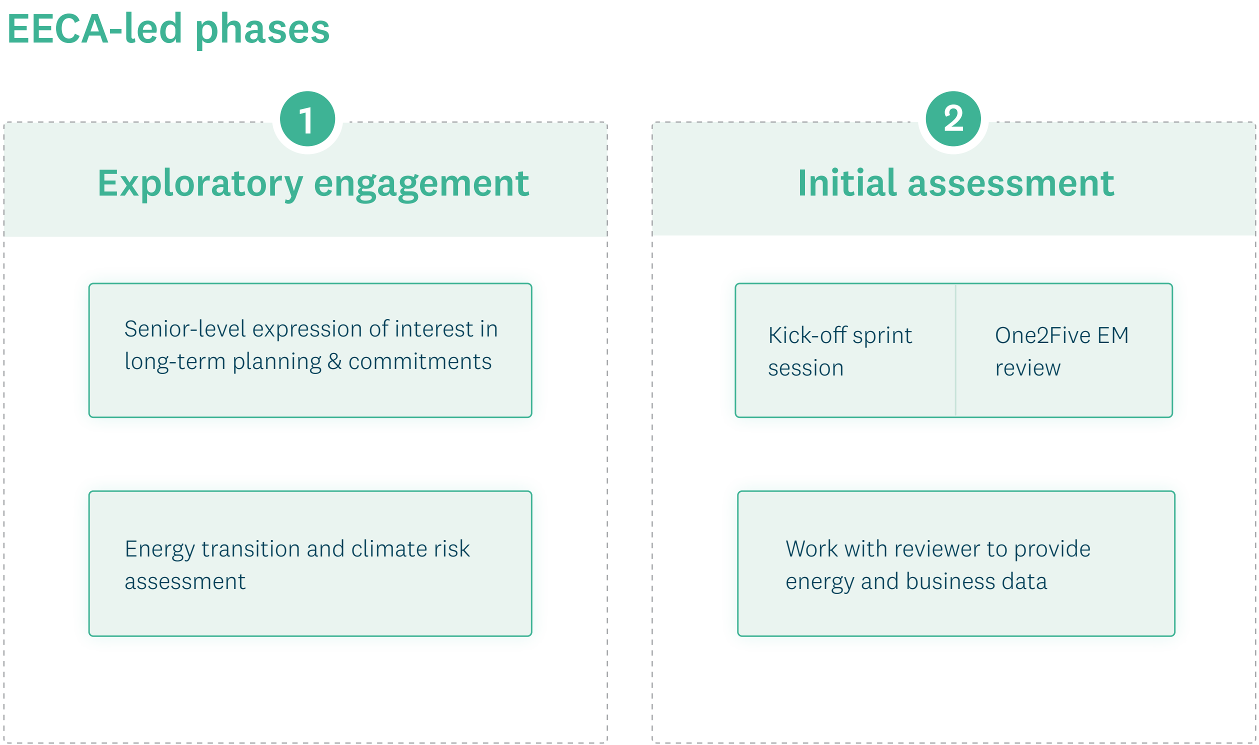
- EECA to work with the Treasury and Ministries (such as Ministry for the Environment) to create an easily accessible, centralised portal that publishes up-to-date carbon price assumptions and scenarios that are used to guide policy and regulatory decisions, e.g. Treasury’s shadow carbon prices used for cost-benefit analysis, Treasury’s ETS price assumptions for fiscal forecasting etc.

5 Introduction

5.1. The Energy Transition Accelerator programme

EECA has run the ‘Energy Transition Accelerator’ (ETA) programme since 2019. The programme aims to support New Zealand’s largest businesses to make technically and economically viable process heat decarbonisation decisions and investments which support their energy transition pathway to a low-carbon future. EECA assists organisations in committing to a longer-term transition, based on the opportunities and risks on the economic and technological horizons. The ETA programme is designed to help businesses prepare for the future, by capitalising on the process heat energy and carbon saving opportunities that are in the pipeline now, and beyond 2030. An overview of the ETA programme is shown in Figure 12 below, while the key components of a process heat decarbonisation analysis for an individual organisation are described in Appendix A.

Figure 12 – Overview of the Energy Transition Accelerator programme. Source: EECA



All existing EECA business tools remain available as appropriate (e.g. One2Five, business cases, feasibility studies, technology demonstrations).

Customer-led phases

3 Detailed analysis and pathway setting

- GHG accounting
- Extensive energy audit
- Feasibility studies
- Pinch analyses
- Energy management system enhancement
- ETA steering group established internally

4 Planning, implementation and review

- Develop and implement energy transition pathway plan
- Track/review/improve
- **Celebrate success**

The philosophy underpinning the ETA programme aligns with EECA's strategic principles:

- Focus on impact (target largest emitters).
- Understand the organisation (direct engagement and long-term support).
- Define the problem (root cause analysis).
- Join the dots (work with and connect people and organisation).
- Display leadership (pro-active action, fact-based approach).

The number of companies that EECA assists in ETAs provides the ability to use some of the individual information collected to develop an analysis of regional process heat decarbonisation pathways. This analysis informs coordination and information challenges faced by individual organisations when dealing with process heat problems that were collective in nature, such as the need for common infrastructure or new markets.

The RETA programme was therefore designed to combine information and learning from the ETAs to provide a regional perspective.

5.2 Taranaki Regional Energy Transition Accelerator

There are two stages of a RETA project – planning and implementation. This report is the culmination of the RETA planning stage in the Taranaki region.

The first planning phase aims to:

- Provide coordinated information specific to the region so that process heat users can make more informed decisions on fuel choice and timing.
- Improve fuel supplier confidence to invest in supply side infrastructure; and
- Surface issues, opportunities, and recommendations.

The implementation stage aims, through collaboration with regional stakeholders, to:

- Identify and address the regional barriers or opportunities in process heat decarbonisation which could benefit from government support; and
- Identify and commit to opportunities to fast-track process heat decarbonisation projects.

EECA acknowledges that the RETA focus does not consider in any detail the interaction with transport, which is also drawing on electricity (electric vehicles and hydrogen) and bioenergy (biofuels) to decarbonise. A proper whole-of-system approach would span all forms of energy demand and consider the interconnections, but this was not possible in the time available for this project. This report acknowledges obvious links to other sectors where applicable.

Further, this RETA report is based on what is known at the time of writing. We acknowledge that the nature of energy supply and demand is changing faster than at any time in history, both domestically and globally. Future iterations of RETA analyses could consider current and likely future demands from other sectors, future changes in the energy system, including new technologies, markets, and sources of energy.

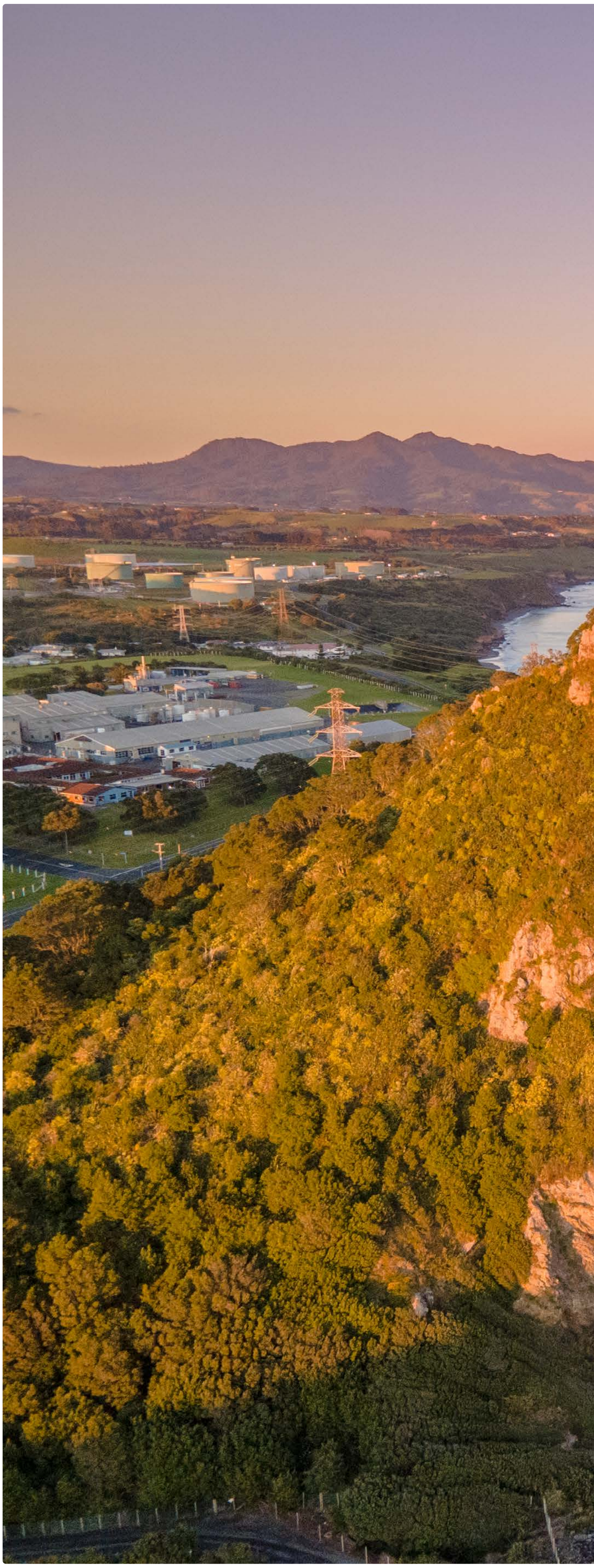


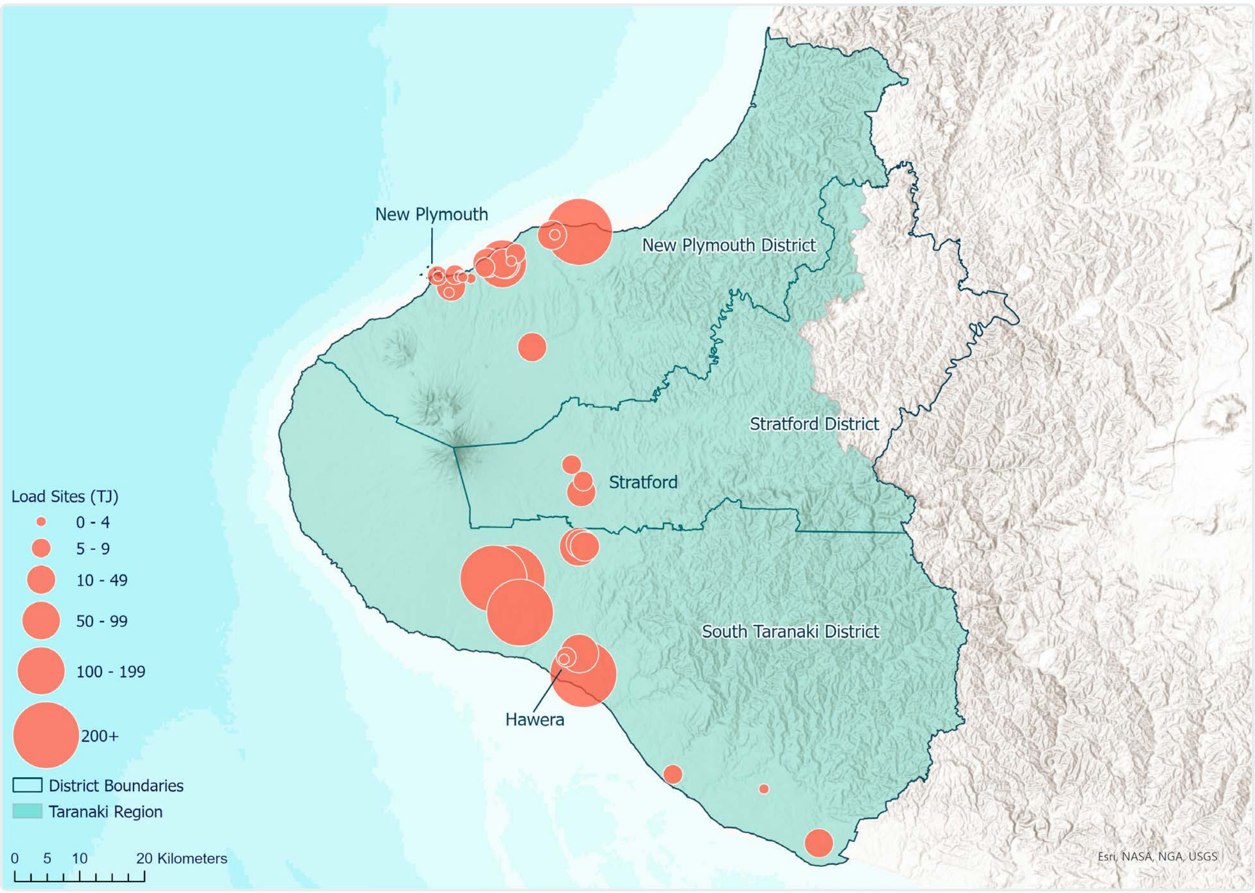
Photo credit: Venture Taranaki

6 Taranaki process heat – the opportunity

6.1 The Taranaki region

Figure 13 illustrates the region considered in this report, with the process heat sites that are considered in this report identified and sized according to their annual energy requirements.

Figure 13 – The Taranaki RETA Region



6.2 Taranaki regional emissions today

StatsNZ's regional greenhouse gas inventory presents emissions for the whole Taranaki region. Figure 14 shows that the energy sector has the highest emissions in the region (expressed in carbon dioxide equivalent, or 'CO_2e'), followed by agriculture. Emissions from the energy sector include both from transport energy and stationary energy,[20] together making up 2,809kt (55%) of emissions out of the region's total emissions of 5,129kt (Figure 14). Agriculture is the second largest emitting sector, with 2,134kt (42%).

Figure 14 – Emissions inventory for the Taranaki region. Source: Stats NZ[21]

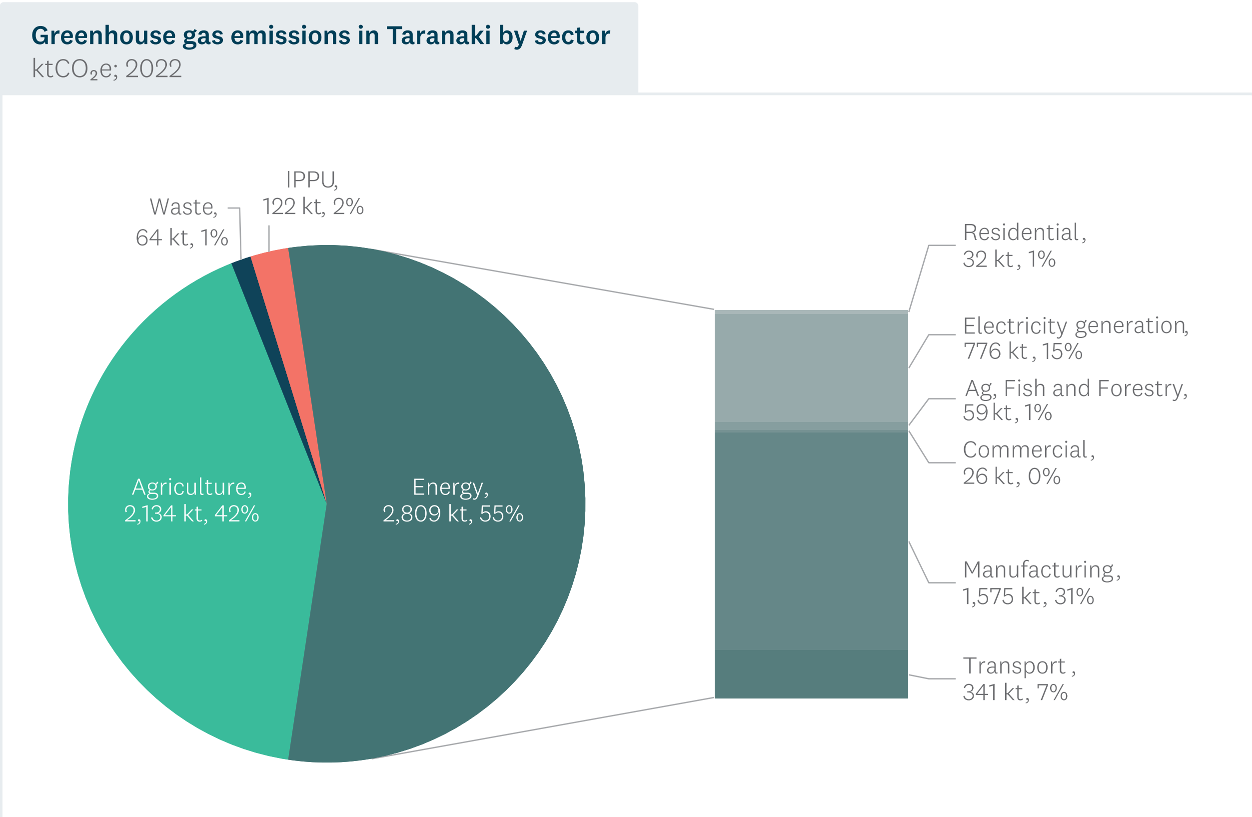


Figure 14 breaks energy emissions down into sector sources. Electricity generation, transport, agriculture, and residential emissions are outside the focus of this RETA study. We expect that most agriculture emissions relate to off-road vehicle use or diesel generators. We conclude that the majority of the remaining 1,601kt of commercial and manufacturing emissions would be 'process heat' (including space heating).

[20] 'Stationary energy' includes agriculture, fishing, and forestry; commercial; residential and manufacturing.

[21] In this chart, 'IPPU' is Industrial Process and Product Use.

6.2.1 Emissions coverage of Taranaki region RETA

Our analysis of energy requirements in Taranaki uses year 2022 as baseline. We note that since then, constraints in gas supply have affected prices for natural gas, and as a result have altered natural gas consumption patterns, particularly for sites using natural gas as feedstock.[22] Our analysis focuses on the energy use for process heat only, and we recognise the decisions are more complicated for organisations that also use natural gas as feedstock.

The Taranaki RETA covers a total of 36 process heat sites spanning dairy and meat, industrial (including construction, and wastewater treatment) and commercial (predominantly facility heating). To target the greatest level of emissions reduction opportunities, the sites selected represent all fossil fuelled process heat equipment above 500kW and any other sites (e.g. schools) where EECA had information from various programmes (e.g. EECA's Regional Heat Demand Database (RHDD)and ETA) up to 2024. [23] These sites are summarised in Table 3. Most of the emissions arise from the industrial sector.

Table 3 – Summary of fuel consumption and emissions from process heat sites included in Taranaki RETA. Source: EECA

Sector	Sites	Thermal capacity (MW)	Thermal fuel consumption (GWh/yr)	Process heat demand (TJ/yr)	Process heat annual emissions ($ktCO_2e/yr$)
Industrial	24	1,273	6,636	23,880	1,283
Commercial	12	13	20	70	4
Total	**36**	**1,286**	**6,656**	**23,950**	**1,287**

Overall, the Taranaki region RETA sites in aggregate account for 1,287kt of process heat greenhouse gas emissions, around 80% of the 1,601kt of commercial and manufacturing energy emissions shown in Figure 14 using StatsNZ's figure.

While this is a lower proportion of total commercial and manufacturing energy emissions than most other RETA regions, we note that StatsNZ regional emissions estimates are based on national assumptions around the average emissions intensity (per dollar of GDP) of different subsectors of the economy. Although these intensities are accurate at the national level, the emissions intensity of any individual economic activity in a particular region can deviate markedly from national averages. Hence StatsNZ's figure may not be an accurate representation of stationary energy emissions in the region.

22 MBIE notes that gas production forecast is expected to fall below demand https://www.mbie.govt.nz/about/news/gas-production-forecast-to-fall-below-demand.

23 See https://www.eeca.govt.nz/insights/eeca-insights/regional-heat-demand-database

We now consider the source of RETA emissions by fuel. As shown in Figure 15, current process heat requirements are almost exclusively met by 23,950TJ of natural gas, with only 0.14TJ from coal and therefore almost all Taranaki RETA emissions come from natural gas (99.97%), shown in Figure 16.[24]

Figure 15 – 2022 Annual process heat fuel consumption in Taranaki RETA. Source: EECA

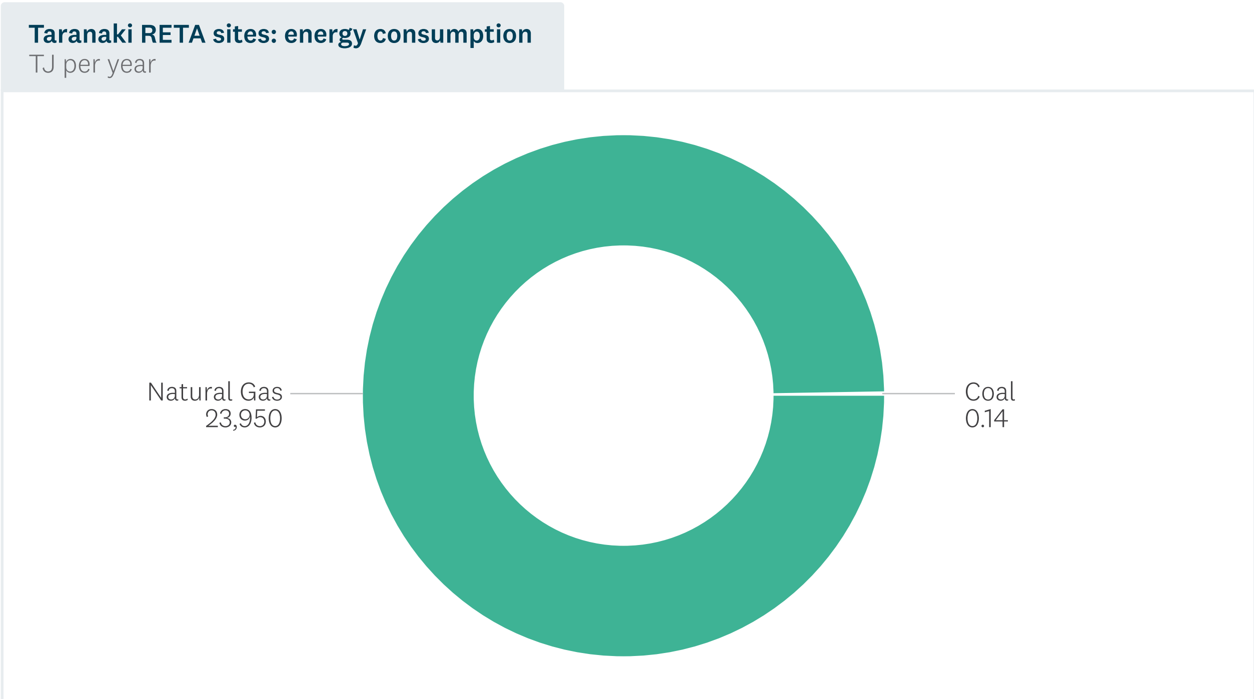
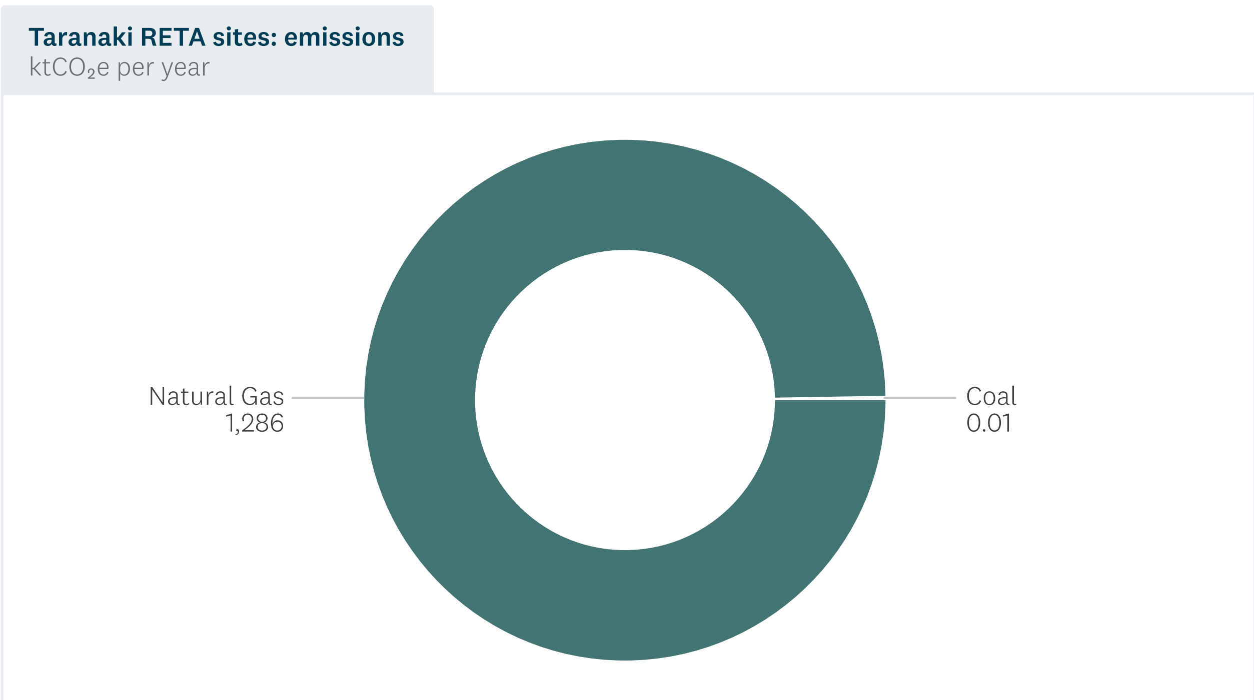


Figure 16 – 2022 Annual emissions by process heat fuel in Taranaki RETA. Source: EECA



[24] Emissions factors used are as follows (t CO_2e per t of fuel): natural gas – 2.68; coal – 2

6.3 Characteristics of RETA sites covered in this study

As outlined above, there are 36 sites considered in this study. Across these sites, 92 individual projects have been identified across the three categories discussed in Appendix A – demand reduction, the use of heat pumps for efficiency,[25] and fuel switching.[26] Table 5 shows the different stages of the RETA process heat projects. As shown, only two demand reduction projects, one heat pump efficiency and three fuel switching (heat pumps) projects have been confirmed. The majority of the possible projects identified are unconfirmed – i.e. yet to commit to the final investment – and most of these are possible fuel switching projects.

Table 4 – Number of projects in the Taranaki region RETA by category. Source: Worley, EECA.

Status	Demand reduction	Heat pump efficiency	Fuel switching	Total
Confirmed	2	1	3	6
Unconfirmed	33	11	42	86
Total	**35**	**12**	**45**	**92**

6.4 Implications for local energy resources

All RETA decarbonisation pathways (presented in Section 7) assume that the 36 Taranaki RETA sites, representing 23,950TJ pa of fossil fuelled energy consumption for process heat in 2022, will have executed demand reduction projects and switched to low emissions fuel before 2050.[27] The rate at which the unconfirmed fuel choices are made are the subject of the rest of this report. Whichever way this occurs, the outcome has potentially significant implications for the use of various fuels and resources in the region.

As outlined, demand reduction and heat pumps (for heat recovery and efficiency) are key parts of the RETA process and, in most cases enable (and help optimise) the fuel switching decision. This RETA report has a greater level of focus on the fuel switching decision, due to the higher capital and fuel intensity of this decision. However, in assessing the required boiler capacity for each unconfirmed fuel switching project, this report assumes that every site has invested in a demand reduction project. Where applicable, it will also assume a heat pump will be installed for any <100°C heat needs, as this would achieve significant efficiencies.[28] These investments will replace current fossil fuel usage and reduce the amount of low-emissions fuel required for any remaining fuel switching decision.

25 As outlined in Appendix A, some sites have a range of heat needs (in terms of temperatures). Where part of a site's heat needs is <100°C, heat pumps can be used to supply that demand, at very high efficiencies. Sometimes these heat pumps can be integrated with heat recovery from e.g. refrigeration processes. If these opportunities only relate to part of the site's heat demands, we define them as 'Heat pump efficiency', as this should be undertaken prior to considering a fuel switch decision. Where the site only demands <100°C heat, the use of a heat pump is categorised as a fuel switch.

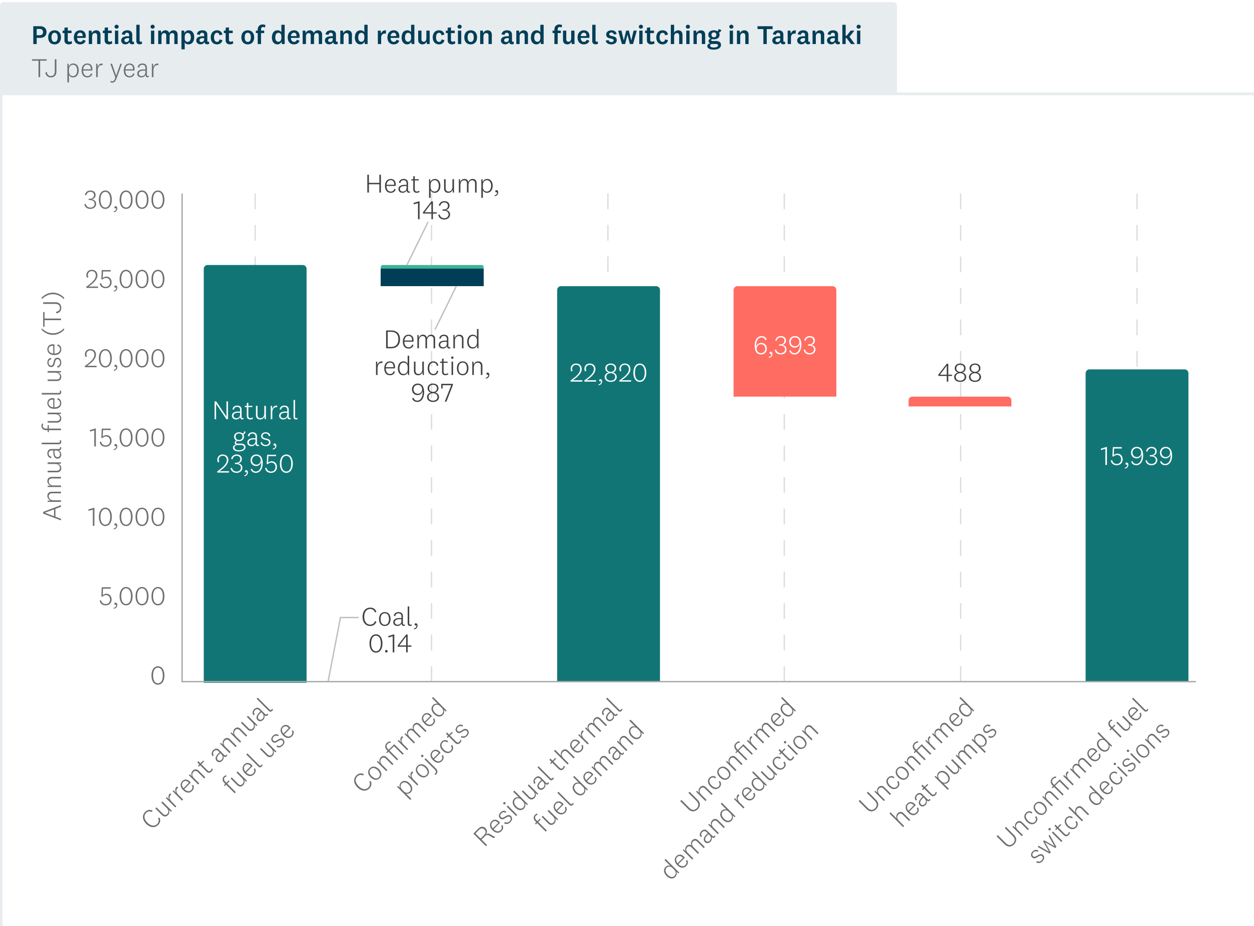
26 For Taranaki, as well as biomass and electrode boilers, fuel switching options include direct heating, induction furnace and hydrogen.

27 Including any use of heat pumps to achieve increased efficiency.

28 That is, where there is a low temperature heat requirement. It will not assume a heat pump for sites that have confirmed a switch to biomass for low-temperature heat needs.

These components are presented in Figure 17, to provide a picture of how fossil fuel use may change over the period of the RETA study.

Figure 17 – Potential impact of fuel switching on Taranaki region fossil fuel usage, 2022-2050. Source: EECA



As 16,000TJ of fuel switching decisions are unconfirmed, the magnitude of change in biomass and electricity demand cannot be known with any precision. However, we can say:

- If all unconfirmed fuel switching decisions choose electricity, this could result in an increase in instantaneous electricity demand of 232MW[29] across the region's electricity network by 2050, if all sites reached their maximum outputs at the same time.[30] This instantaneous demand would increase the maximum demand in the region by 127%.[31] If the proposed hydrogen electrolyser project also went ahead, this would add 300MW to this increase in peak demand. Combined, these electrification decisions would also increase the region's annual consumption of electricity by 1,500GWh, approximately 140% of today's gross electricity consumption in Taranaki.[32]
- If all unconfirmed boiler fuel switching decisions choose biomass, this could result in an increase of 322kt (2,310 TJ) per annum by 2050 (see Section 8.7). Assuming sufficient resources were available, this is an increase in biomass demand by a factor of 14.6, given our estimate of 24kt of biomass currently being used for heat within the Taranaki region.

[29] This excludes hydrogen projects.

[30] It is unlikely that all sites reach their peak demands at the same time. See Section 9.4 for an analysis.

[31] Transpower reports that the 2022 regional peak demand was 234MW.

[32] Taranaki regional electricity consumption is around 1,048GWh per year (source: emi.ea.govt.nz)

These two scenarios of low emissions fuel use paint the 'end points' of a spectrum of mixes of biomass and electricity fuel switching decisions. The reality is that each process heat user will make fuel switching decisions based on their own requirements and drivers.

The degree to which the resulting fuel demand – in a range of scenarios – can be met through local resources (electrical or biomass-related) is considered in Section 7.

In Table 5 we show the expected remaining fuel demands from each site in the Taranaki RETA, after any demand reduction projects and/or heat pump projects are accounted for. We present biomass demands both in TJs and wet tonnes (55% moisture content, also known as green tonnes) and report the peak demand from electrification projects, should they electrify. The fuel choice that has the lowest MAC value (see Section 7.1) is highlighted in green. Confirmed projects are shaded in blue.

Table 5 – Summary of Taranaki region RETA sites with potential fuel switching requirements

Site name	Industry	Project status	Bioenergy required TJ ('000t)/yr	Electricity peak demand (MW)
Ministry of Health Hāwera Hospital	**Commercial**	**Confirmed**	**--**	**0.08**
South Taranaki District Council Hāwera Aquatic Centre	**Commercial**	**Confirmed**	**--**	**0.07**
Ministry of Education Waverley Primary School	**Commercial**	**Confirmed**	**--**	**0.09**
Methanex Motunui	Industrial	Unconfirmed	n/a	**40**
Ballance Agri-Nutrients Ltd Kapuni	Industrial	Unconfirmed	n/a	**317.28**
Fonterra Limited Whareroa[33]	Dairy	Unconfirmed	**1,533.50 (213.52)**	**87.29**
Fonterra Limited Kapuni	Dairy	Unconfirmed	**453.2 (63.10)**	**45.63**
Taranaki By-Products Hawera	Meat (with rendering)	Unconfirmed	**149.69 (20.84)**	12.47
Mckechnie Aluminium Solutions Limited Bell Block	Industrial	Unconfirmed	n/a	**4.67**
ANZCO Foods Eltham	Meat processing	Unconfirmed	34.01 (4.73)	**0.4**
Silver Fern Farms Limited Hawera	Meat processing	Unconfirmed	n/a	**1.47**

33 At this site, two projects have biomass as optimal fuel and another two have electricity, hence both options are shaded.

Site name	Industry	Project status	Bioenergy required TJ ('000t)/yr	Electricity peak demand (MW)
Ministry of Health Taranaki Base Hospital	Commercial	Unconfirmed	n/a	**0.56**
Fonterra Limited Eltham Collingwood St	Dairy	Unconfirmed	**9.60 (1.34)**	1.44
New Plymouth District Council Wastewater treatment plant	Industrial	Unconfirmed	**18.91 (2.63)**	3.49
Fonterra Brands Limited Eltham Bridge St	Dairy	Unconfirmed	29.07 (4.05)	**5.79**
ANZCO Foods Waitara	Meat processing	Unconfirmed	12.15 (1.69)	**0.71**
Silver Fern Farms Limited Waitotara	Meat processing	Unconfirmed	n/a	**0.54**
Taranaki Abbattoir Stratford	Meat (with rendering)	Unconfirmed	**5.84 (0.81)**	0.83
Little Knoll Greenhouses Ltd Patea	Horticulture	Unconfirmed	n/a	**0.28**
La Nuova Inglewood	Commercial	Unconfirmed	**9.98 (1.39)**	0.73
Downer New Zealand Limited New Plymouth Bitumen	Industrial	Unconfirmed	n/a	**1.71**
Ministry of Education Stratford High School	Commercial	Unconfirmed	n/a	**0.25**
Downer New Zealand Limited New Plymouth Asphalt	Industrial	Unconfirmed	**4.87 (0.68)**	n/a
New Plymouth District Council Todd Energy Aquatic Centre	Commercial	Unconfirmed	n/a	**0.24**
Tegel New Plymouth	Meat processing	Unconfirmed	**31.5 (4.39)**	2.84
New Plymouth District Council Puke Ariki	Commercial	Unconfirmed	n/a	**0.12**
State-integrated school Francis Douglas Memorial College	Commercial	Unconfirmed	n/a	**0.09**
New Plymouth District Council Len Lye Centre	Commercial	Unconfirmed	n/a	**0.06**
New Plymouth District Council Waitara Pool	Commercial	Unconfirmed	n/a	**0.06**

Site name	Industry	Project status	Bioenergy required TJ ('000t)/yr	Electricity peak demand (MW)
New Plymouth District Council Civic Centre	Commercial	Unconfirmed	n/a	**0.10**
Van Dyck New Plymouth	Industrial	Unconfirmed	n/a	**0.12**
Western Institute of Technology in Taranaki (WITT) Taranaki	Commercial	Unconfirmed	n/a	**0.36**
Tegel Bell Block Feedmill	Meat processing	Unconfirmed	**17.97 (2.50)**	0.64
Taranaki Galvanizers Stratford	Industrial	n/a	n/a	**0.16**
Poppas Peppers 2009 Limited New Plymouth	Horticulture	n/a	n/a	**0.12**
Technix Bitumen Technologies Limited Port Taranaki	Industrial	n/a	n/a	**0.78**


Photo credit: Methanex

7 Taranaki's decarbonisation pathways

As outlined above, a primary driver for the RETA approach is to identify where the collective decisions of process heat users, and potential providers of low-emissions process heat fuel (biomass or electricity), give rise to 'system' challenges and opportunities. These challenges and opportunities may not be apparent to individual RETA organisations, as they only become apparent when the collective impacts of many RETA project decisions are considered. If these challenges and opportunities can be anticipated, along with the types of conditions under which they might occur, they can be addressed in advance, improving process heat users' ability to make informed decarbonisation decisions.

The modelling presented below uses the detailed information from Sections 8, 9 and 10 to develop different scenarios of the pace and magnitude of low emissions fuel uptake across the whole Taranaki region. We refer to each of these scenarios as 'pathways'.

7.1 Simulating process heat users' decarbonisation decisions

To explore different decarbonisation pathways for Taranaki, we must develop a simple, repeatable methodology to simulate the decisions of process heat users – specifically, which low-emissions fuel (electricity or biomass) will they choose to replace their existing fossil fuel, and when would they make that investment.

Two simplistic pathways have been adopted (described in Section 7.2), which assume that all (unconfirmed) process heat users choose either biomass or electricity. These pathways are somewhat unrealistic in most regions but serve a useful purpose of 'bookending' the possible total future demand for each type of fuel.

To increase our understanding of more realistic scenarios, we also explore pathways which simulate a world where process heat users choose their investment using a more commercial decision-making process.

There are a range of factors organisations face when deciding when to invest in decarbonisation, and which fuel to choose. These factors will invariably include the financial cost of the decision, but also may include confidence in future fuel supply, competitor behaviour, funding and financing, asset age or consumer expectations. As these factors are difficult to model quantitatively, the methodology used here focuses on the financial components of the investment decision that can be modelled with available data. These are primarily the factors relating to efficiencies and costs listed above, as well as known information about the current annual consumption of heat at each of the RETA sites.

Our simulated 'MAC optimal' pathway presumes that the decision regarding which fuel to switch to, and when, is purely about the change in capital and operating expenditure arising from the project. The various sources of our estimates used in our modelling are outlined in Appendix B, and some are developed in more detail in Sections 8, 9 and 10. Using discounted cashflows analysis, at an appropriate discount rate, we can determine the 'net present value' (NPV) of the combination of up-front capital costs and changes in ongoing operational costs (including the cost reduction from not consuming fossil fuels), tailored to each type of technology (heat pump or boiler) and fuel (electricity or biomass). We then assume that the process heat user would choose the option with the best (highest) NPV.

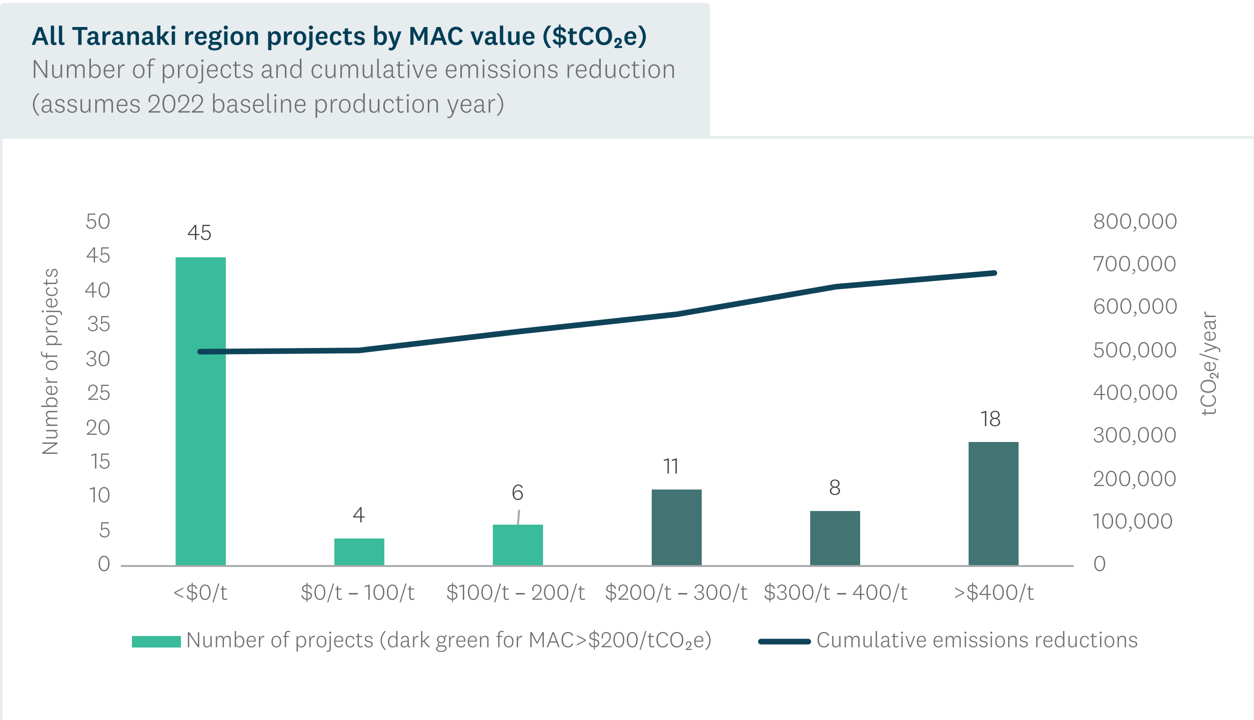
We represent the NPVs for different fuels as 'marginal abatement costs' (MAC). Our methodology for calculating MACs is outlined in more detail in Appendix B, but essentially, they represent the net cost[34] to the RETA organisation of reducing emissions – for a particular demand reduction, heat pump or fuel switching project – and expresses this cost per tonne of emissions reduced by the project. As a result, we can compare decarbonisation projects across RETA sites, and for different low emissions fuels.

All our economic calculations and assumptions are in real 2022 dollars.

7.1.1 Resulting MAC values for RETA projects

The range of marginal abatement costs for Taranaki RETA projects are illustrated in Figure 18 below. Individual MACs have been calculated for each site's demand reduction and heat pump projects, as well as the optimal choice of fuel for boilers. These charts include all 92 confirmed and unconfirmed projects.

Figure 18 – Number of projects, and cumulative emissions reductions, by range of MAC value. Source: EECA

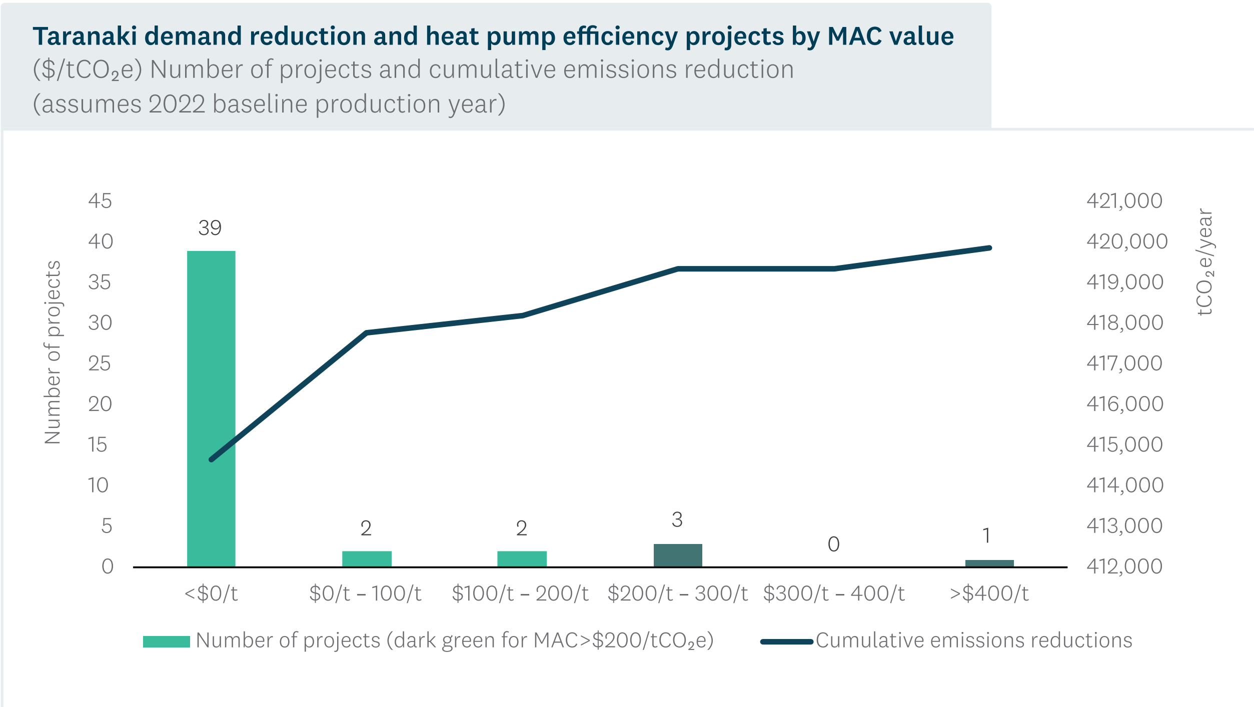


[34] In some situations, this can be a net benefit if the reduction in fossil fuel procurement costs exceeds the costs of the decarbonisation project. In these situations, the MAC value will be less than $0/t CO_2e.

Figure 19 shows that 43 of these 55 low-MAC projects are demand reduction and heat recovery projects, delivering 418kt of emissions reductions. This reflects the fact that demand reduction and heat pump projects have low capital and operating costs, relative to the reduction in fossil fuels (and emissions) they achieve.

Figure 18 shows that 55 (out of a total of 92) Taranaki projects have MAC values less than $200/tCO$_2$e, and 45 of these projects are economic without any carbon price. These projects would be economic if executed between now and 2033, which is when carbon prices are expected to reach $200/tCO$_2$e, if they rise in line with the Treasury's shadow carbon prices.[35, 36] Together, these 55 projects would deliver a 42% (547ktCO$_2$e) reduction in the total RETA site process heat-related emissions.

Figure 19 – RETA Demand Reduction and HP Projects by MAC value. Source: EECA



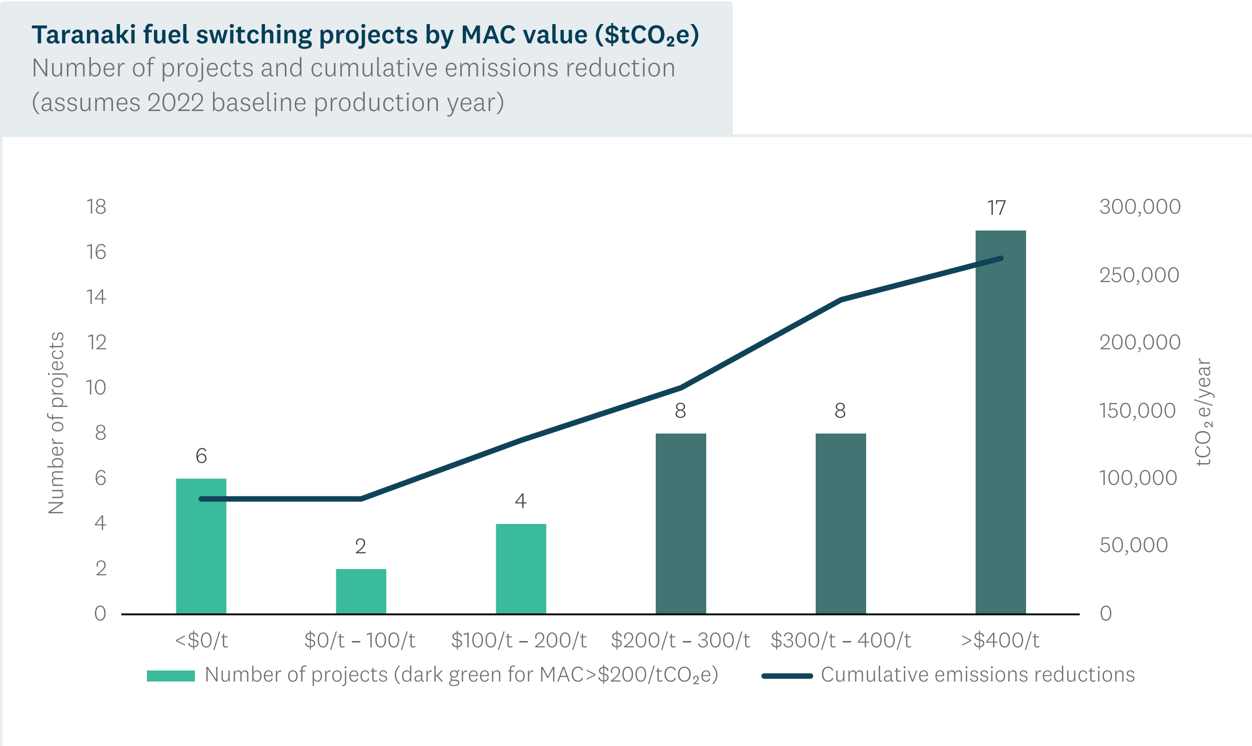
Most of the fuel switching projects in the Taranaki region have MAC costs greater than $200/tCO$_2$e (Figure 20), reflecting electricity pricing and the various combinations of site-specific factors, such as the lumpy nature of potential electricity upgrade costs where relevant (calculated in Section 9); the operating profile over the year; and the overall utilisation of the boiler capacity.

35 These 'shadow prices' are consistent with the marginal abatement cost needed in the economy to deliver the next ton of CO$_2$e emissions reduction, given New Zealand's emissions reduction targets. However, shadow prices are not the same as a forecast of the actual prices that might be observed in the New Zealand Emissions Trading Scheme (NZ ETS).

36 We note that although most of these projects were assessed over a period of 20 years, for projects that also used piped gas as a feedstock, a shorter period of five years was used instead to align with how these businesses operate. Five of these shorter-period projects are for demand reduction and have MAC values < $200/tCO$_2$e. Another four have MAC values greater than $200/tCO$_2$e and include electrification and demand reduction.

Twelve fuel switching projects are economic if executed prior to 2033, delivering 128kt of emissions reductions – 10% of the total RETA process heat emissions. Seven involve use of heat pumps, and five involve electrification (through boilers, direct heating or reformer pre-heating).

Figure 20 – RETA Fuel Switching Projects by MAC Value. Source: EECA



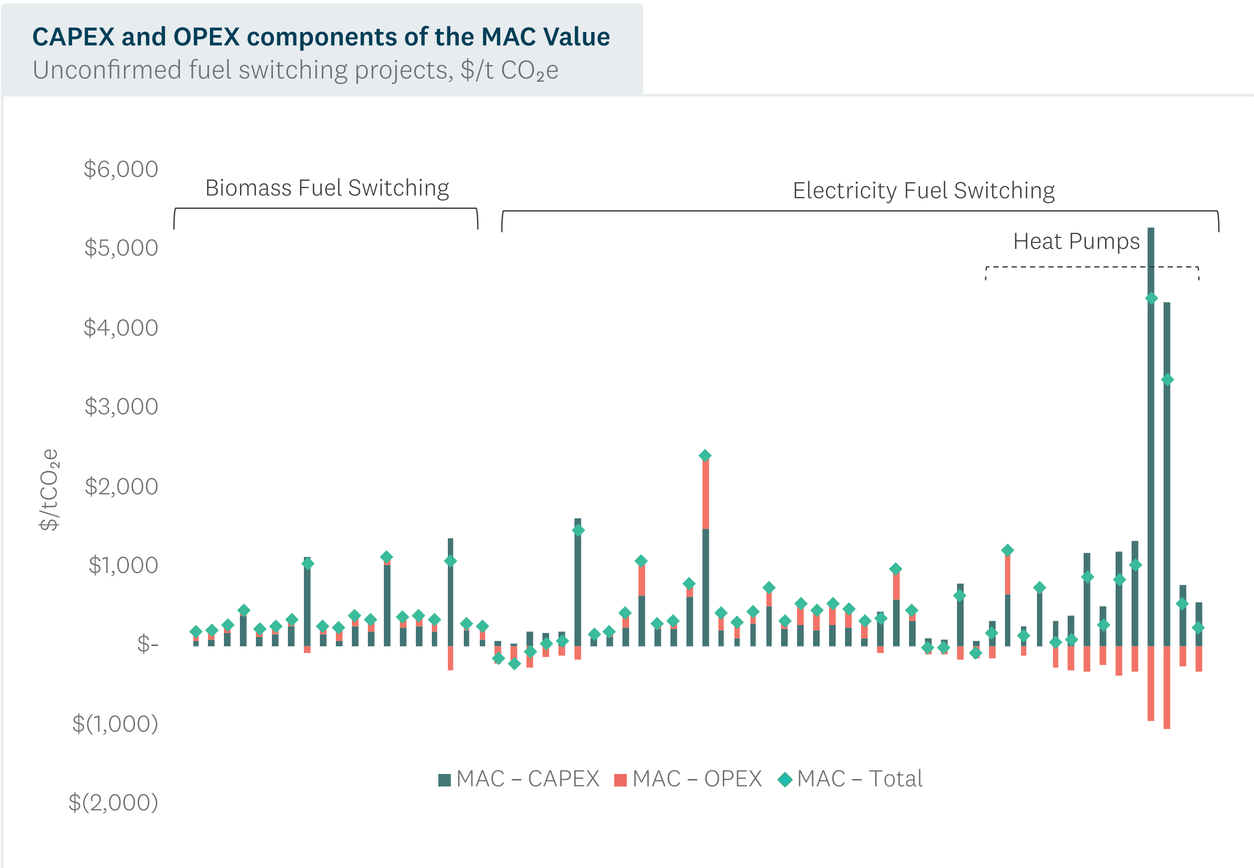
7.1.2 What drives Taranaki's MAC values?

Particularly for projects that have higher MAC values, there could be a range of ways cost reductions could be achieved to make the projects more viable over the term of the RETA. For example, securing access to lower cost biomass resources, or enabling plant flexibility to reduce the cost of electricity connections and/or electricity consumption.

Given that all unconfirmed fuel switching projects are concerned with switching from piped natural gas to either electricity or biomass, the assumed cost of these fuels is an important factor to the project economics. These fuel assumptions are discussed in section 7.4.

To better understand what components of a project's overall costs is driving the MAC values for Taranaki RETA sites, Figure 21 illustrates the MAC values for the unconfirmed fuel switching options, across the biomass and electricity options.[37] The MAC value is separated between the project's up-front capital costs (CAPEX) and operating costs or benefits (OPEX).

Figure 21 – CAPEX and OPEX MAC values for unconfirmed fuel switching projects. Source: EECA



[37] The chart excludes the two hydrogen projects.

The difference in MAC values for biomass, electrode boiler and heat pump projects is due to a number of factors that affect OPEX and CAPEX:

- the capital costs for biomass and electricity (heat pumps, electrode boilers, direct heating) are reasonably similar but electricity-related projects may incur connection costs;
- retail electricity costs (including network charges) are higher (per unit of energy) than biomass; but
- both heat pumps (if they can be used) and electrode boilers are more efficient than biomass boilers, so require less energy to achieve the same reduction in fossil fuel consumption than biomass boilers.

Note that the operating component of the MAC value is the combined effect of the reduction in fossil fuel cost, and the cost of procuring the biomass or electricity. As shown in Figure 21, there are some situations where the combined OPEX effect can be negative, because the low emissions fuel is overall cheaper than the fossil fuel, even without accounting for the impact of carbon emissions.

Further, the capital component of the MAC value is influenced by the utilisation of the heat plant. This is especially evidenced by the very high MAC – CAPEX values for two heat pump projects in Figure 21. Ordinarily, due to their very high efficiency, heat pumps are very capital efficient. However, the two projects with high MAC – CAPEX values represent situations where the heat pump would be used very infrequently. As a result, the capital cost of a heat pump needs to be recovered across a small quantity of emissions reductions.

The overall relativity of electricity and biomass MAC values, shown in Figure 21, is very context dependent – especially on whether a heat pump can be used, or if an electrode boiler is required for a switch to electricity. We also reinforce that the relativity of biomass and electricity MAC values in the Taranaki region is based on the regionally specific assumptions this report has used, and which are described throughout this report. It is not a general commentary on the relative economics of biomass versus electricity.

As will be reinforced in both Section 8 and Section 9, process heat users could achieve a lower level of costs than what we have used in our MAC value calculations – for example, by using flexibility to reduce the impacts on electricity networks (and therefore network charges) or accepting a lower level of security of supply.

Photo credit: Taranaki Pine

7.2 Indicative Taranaki pathways

Indicative pathways for decarbonisation have been prepared on the following basis: All other unconfirmed projects are assumed to occur in 2049 in line with New Zealand's target of net zero greenhouse gas emissions by 2050 in the Climate Change Response (Zero Carbon) Amendment Act. This means that any projects that are still not 'economic' using our MAC criteria by 2049, are assumed to be executed in 2049.

The pathways used in this analysis are as follows:

Pathway name	Description
Biomass Centric	All unconfirmed site fuel switching decisions proceed with biomass, where possible, in 2049 (in line with New Zealand's target of net zero greenhouse gas emissions by 2050 in the Climate Change Response (Zero Carbon) Amendment Act.
Electricity Centric	All unconfirmed fuel switching decisions proceed with electricity, where possible, in 2049 (in line with New Zealand's target of net zero greenhouse gas emissions by 2050 in the Climate Change Response (Zero Carbon) Amendment Act.
BAU Combined[38]	All unconfirmed fuel switching decisions (i.e. biomass or electricity) are determined by the lowest MAC value for each project, with the timing as for the fuel-centric pathways above.
MAC Optimal	Each site switches to a heat pump or switches its boiler to the fuel with the lowest MAC value for that site. Each project is timed to be commissioned in the first year when its optimal MAC value first drops below a ten-year rolling average of the future NZ Treasury's shadow carbon prices. If the MAC does not drop below the ten-year rolling average before 2049, then the timing based on the fuel-centric pathway is used.

The MAC Optimal pathway is dependent on the underlying view of carbon prices. We do not have perfect foresight over these prices, and for our MAC calculations we have used two sources of information:

- For the first four years in the RETA period, we have used ETS price assumptions as per Treasury's ETS fiscal forecasting.[39]
- For the longer term, we have used shadow carbon price projections used by central agencies to inform policy decisions, and which are published by the Treasury.[40]

The assumptions above have 'low' and 'high' ranges, which we test for sensitivity in section 7.4.3. We encourage process heat decision-makers makers to explore a range of carbon price scenarios.

We also note that currently the prices above are not available in a format that is easily accessible for process heat users, and we recommend EECA to work with agencies to improve this.

38 'BAU' in this case for Taranaki means that all unconfirmed fuel switching projects take place in 2049. Some projects are likely to go ahead earlier in line with the National Direction for GHGs from Industrial Process Heat, which requires emissions plans submitted with resource consents to include an assessment of any 'technically feasible and financially viable lower-emissions alternatives.' https://environment.govt.nz/assets/publications/climate-change/National-Direction-for-Greenhouse-Gas-Emissions-from-Industrial-Process-Heat-Industry-Factsheet.pdf

39 https://www.treasury.govt.nz/sites/default/files/2023-08/cefa23-technical-appendix-1.pdf

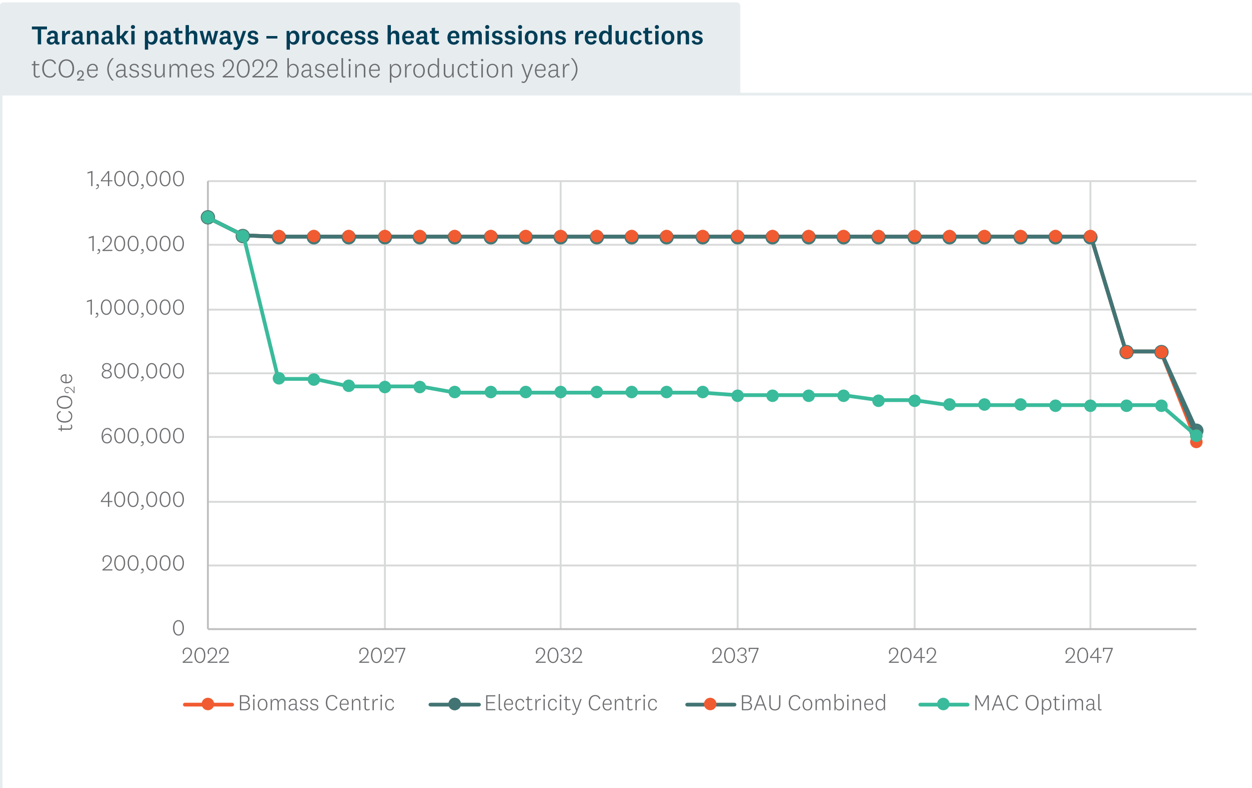
40 See Table 1 in https://www.treasury.govt.nz/sites/default/files/2023-12/cbax-tool-climate-environmental-impacts.pdf

7.2.1 Pathway results

Figure 22 shows the MAC Optimal pathway delivers the largest annual emissions reductions early in the RETA period – by 2024, 504kt of annual emissions are eliminated (31% of Taranaki region's process heat emissions). By 2050, all pathways eliminate between 42% and 44% of the Taranaki region's 1,601kt of annual process heat emissions (as reported in Section 6.2) (Figure 22).

The cumulative difference between the MAC Optimal and the fuel-centric pathways is around 12Mt CO_2e – exclusively long-lived greenhouse gases – across the period 2024 – 2050.

Figure 22 – Taranaki emissions reduction trajectories for different simulated pathways. Source: EECA[41]



[41] We note that emissions reduction shown for year 2023 are for confirmed projects only. The earliest implementation year for 'MAC Optimal' projects is 2024 in the modelling.

7.3 Pathway implications for fuel usage

We can now compare the trajectory of demand for biomass and electricity arising from the various Taranaki pathways. Below we compare the growth in demand in the following pathways:

- Biomass Centric
- Electricity Centric
- MAC Optimal (which includes a mix of biomass and electricity projects).

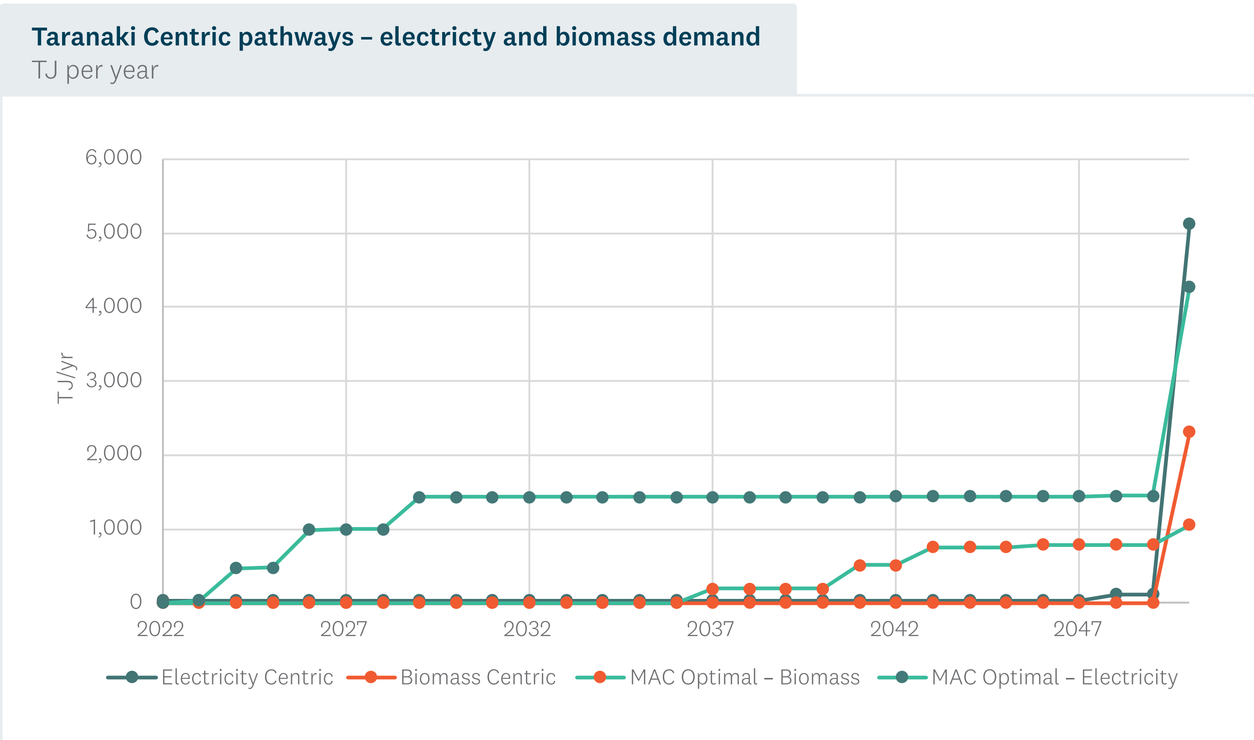
As shown in Figure 23, the increase in demand for electricity and biomass takes places earlier in the RETA period in the MAC Optimal pathway compared to the Centric pathways. However, in 2050 the Centric pathways deliver a higher demand for biomass or electricity in absolute terms.

More specifically:

- In the MAC Optimal pathway, electricity demand gradually increases from 34TJ/yr in 2023 to 1,440TJ/yr in 2029 and then to 4,280TJ/yr by 2050. In the Electricity Centric pathway, demand for electricity increases at the end of the RETA period, from 35TJ/yr in 2047 to 120TJ/yr in 2048 and to 5,130TJ/yr in 2050.
- Biomass demand in the MAC Optimal pathway gradually increases from zero to 197TJ /yr in 2037, 758TJ in 2043 and 1,090TJ/yr in 2050. In the Biomass Centric pathway, biomass demand increases from zero in 2049 to 2,310TJ/yr in 2050.

Overall, compared to the Centric pathways, the pathways that use MACs to determine fuel switching decisions result in a different set of fuel decisions in 2050, with around 20% of the energy needs supplied by biomass (with a consumption of 1,090TJ/yr of delivered energy), and 80% of energy needs supplied by electricity (with 4,280TJ/yr of delivered energy).

Figure 23 – Simulated demand for biomass and electricity under various RETA pathways. Source: EECA



The dominance of electricity demand in the MAC Optimal pathway is due to the switch to electric boilers at three large industrial sites, although most of the increase in electricity demand in 2050 is for a potential hydrogen process heat project.

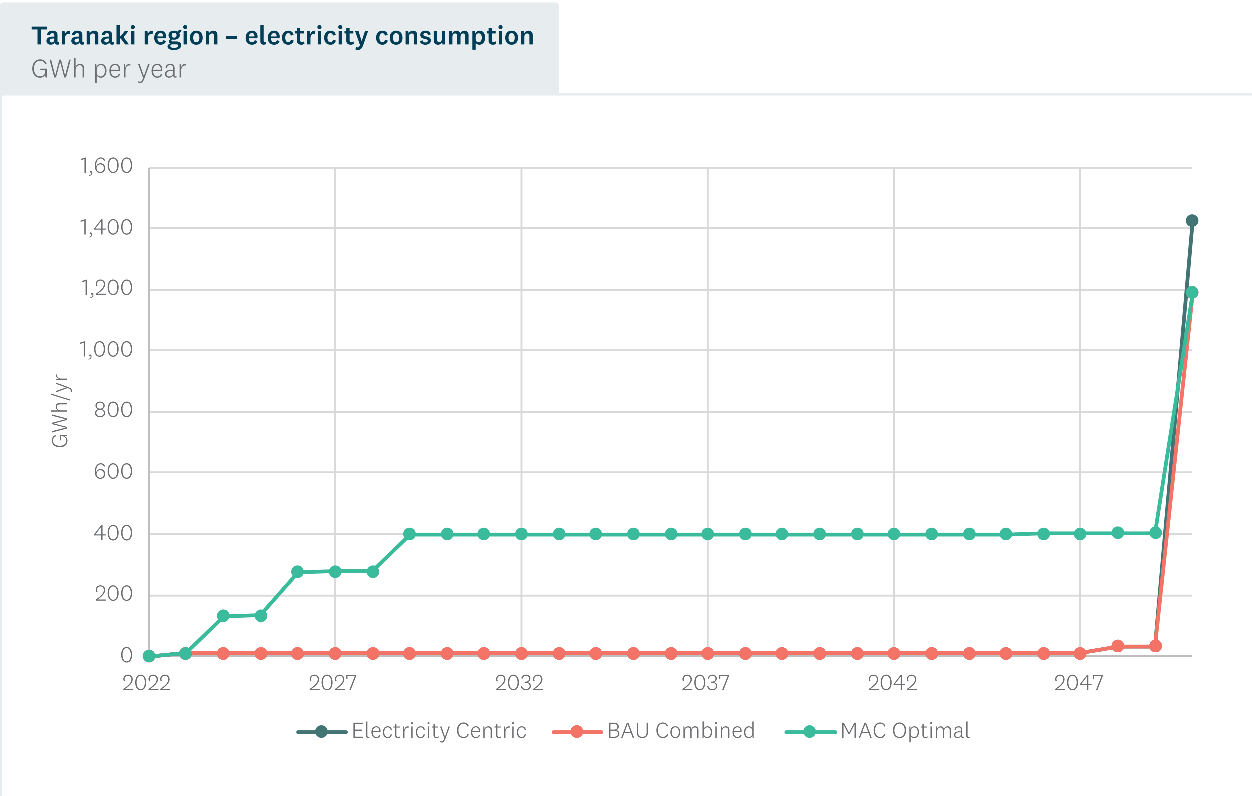
This result, reflecting the structure of the industrial sector in the Taranaki region, differs from other RETA regions in the North Island, where demand in the MAC Optimal pathways is typically dominated by biomass. In those cases, the dominance of biomass reflects its lower overall cost as a fuel for large industrial and dairy projects, which require high temperature boilers for their process heat.[42]

We now consider the implications for each fuel in more detail.

7.3.1 Implications for electricity demand

Figure 24 shows the growth in electricity consumption in each of the pathways.

Figure 24 – Growth in electricity consumption from fuel switching pathways. Source: EECA

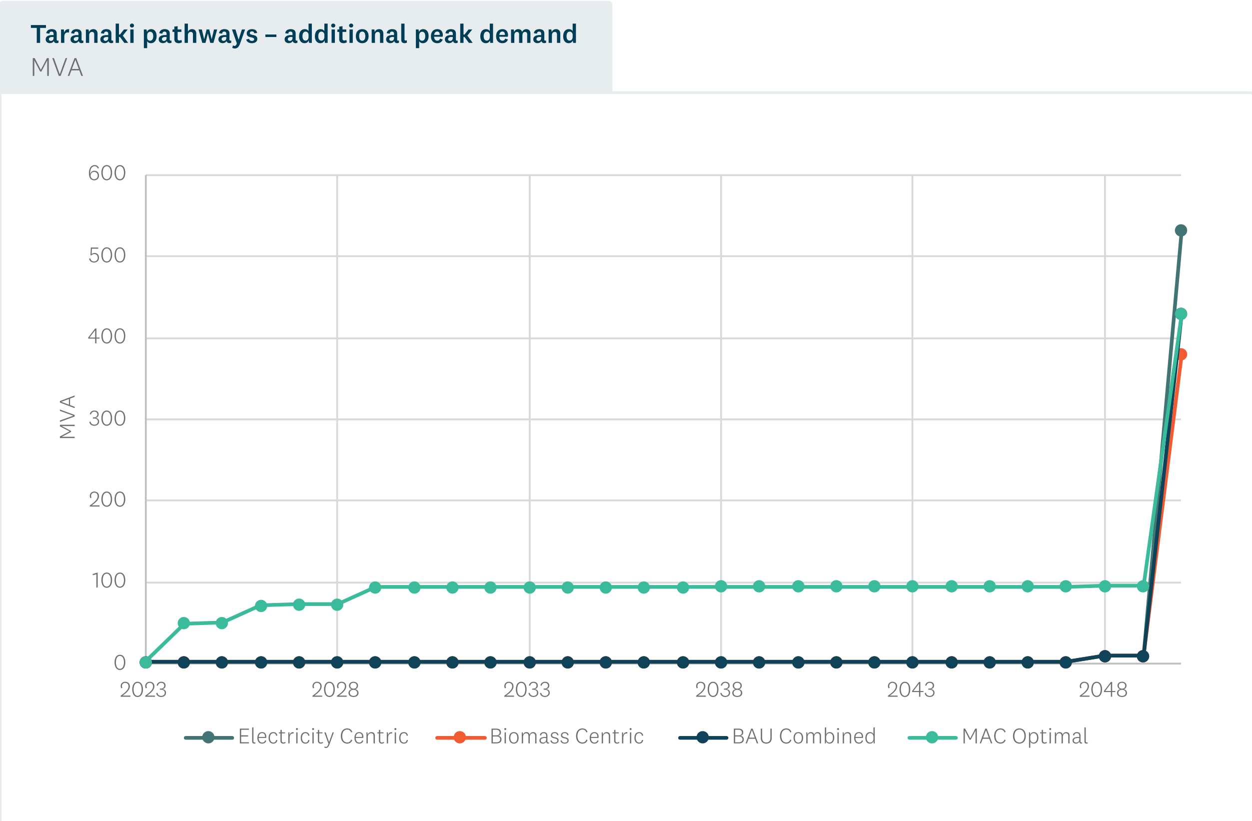


[42] That is, they can't fuel switch using high efficiency heat pumps alone.

Figure 24 shows that the use of MACs to simulate decision making significantly accelerates 400GWh of electricity consumption growth, by bringing forward the investment in electrification fuel switch projects from 2049 to between 2024 and 2028.

A more critical aspect of the process-heat driven growth – and timing of growth – in electricity demand is the impact it has on network planning. Networks will be more interested in the impact on potential peak demand than energy consumption *per se*. Figure 25 illustrates the potential increase in peak demand, for each pathway. This is determined by adding together the maximum demand from each boiler and heat pump, without taking account of demand diversity. The impact of demand diversity is considered in Section 9.4.

Figure 25 – Potential peak electricity demand growth under different pathways



By 2029, process heat electrification could add up to 94MVA to peak electricity demand, depending on the pathway, representing an increase of up to 40% in the local EDB's (Powerco) peak. In 2050, the Electricity Centric pathway increases further and significantly (noting that an increase of 532MVA in one year is largely attributable to one potential project of 300MVA), with a resulting demand that would represent a 127% increase compared to current peak demand in the region. **This increase is an artefact of our pathway assumptions (that all projects, not already executed commercially by 2049, will be executed in 2049), rather than an assessment of what a plausible increase in a single year could be.**

However, even in the near term, Powerco will likely find annual increases implied in the MAC Optimal pathway challenging, requiring a significant degree of planning to have any investment timed in advance of the increase in demand.

We reinforce that these contributions to peak network demand are upper bounds (in each pathway), as they assume that all fuel switching projects reach their maximum consumption at the same time of day and time of year (i.e. coincident peak demand). This is a conservative assessment, as there is likely to be a diversity amongst peak demands as outlined in Section 9.4; as well as commercial incentives to shift this peak demand away from the time that the wider network peaks. The impact of flexibility and diversity on capacity upgrades depends on a range of factors that need to be considered more fully. Appendix C discusses the opportunities and benefits from enabling flexibility in more detail.

7.3.1.1 EDB Analysis

Powerco is the single electricity distribution business in the Taranaki region. The impact of the modelled electricity peak demand on Powerco's network is shown in Table 6.

Table 6 – New connections (MW) and customer-driven connection costs under Electricity Centric and MAC Optimal pathways

EDB	Electricity Centric pathway		MAC Optimal pathway	
	Connection capacity (MW)	Connection cost ($M)	Connection capacity (MW)	Connection cost ($M)
Hydrogen projects (in 2050)	302	$273	302	$273
Other electrification projects	230	$161	127	$50
PowerCo total	532	$434	429	$323

Note that the connection costs presented in Table 6 are total construction costs and may not necessarily reflect the connection costs paid by RETA organisations, as they may be shared between the EDB and the new process heat user. The degree of sharing ('capital contributions') depends on the policies of individual EDBs, as discussed further in Appendix C. These costs also exclude the ongoing network charges paid by each process heat user that electrifies their process heat.

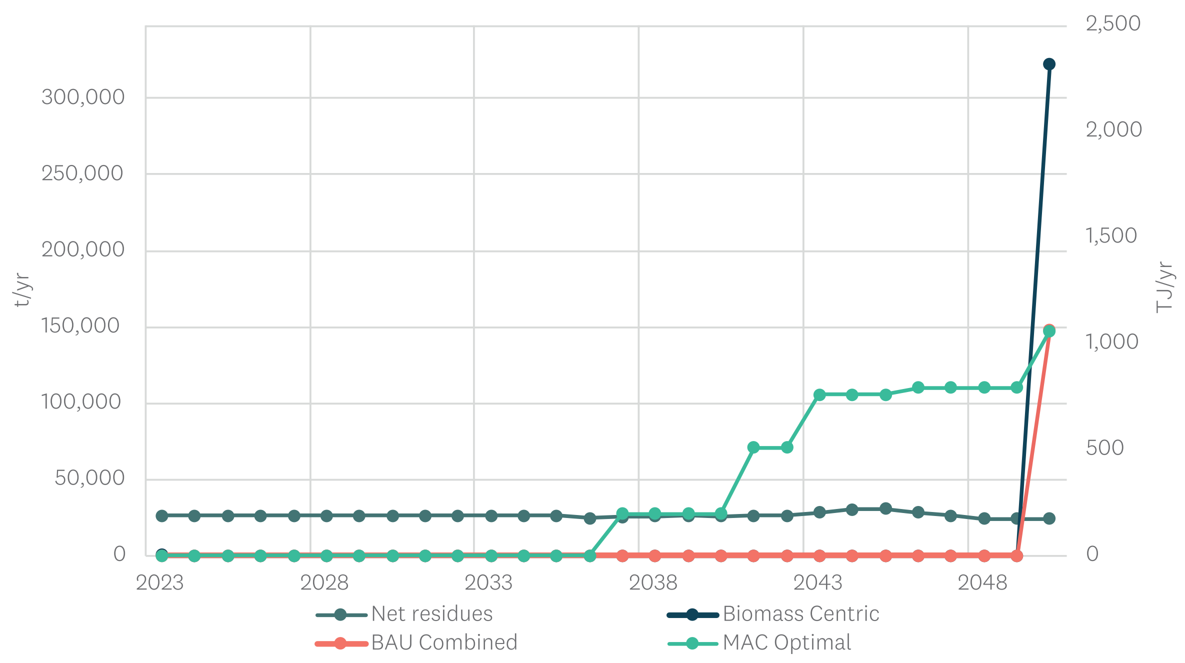
7.3.2 Implications for biomass demand

Figure 26 shows the growth in biomass demand (in both tonnes and TJ per year) arising from each of the pathways.

As discussed previously, biomass demand in the MAC Optimal gradually increases from 197 TJ/yr in 2037 to 510 TJ/yr in 2041, 758 TJ/yr in 2043 and to 1,090 TJ/yr in 2050. In the Biomass Centric pathway, the use of biomass grows to 2,310 TJ/yr by 2050.

Figure 26 – Growth in biomass demand from pathways. Source: EECA

Taranaki pathways – biomass demand and available residues
Green tonnes and TJ per year



The figure shows that in 2050, the estimated volumes of unutilised harvesting and processor residues (after existing bioenergy demands are removed) are not sufficient to meet the biomass demand in any pathway and are exhausted by 2037 in the MAC Optimal pathway.[43] As will be explained in Section 8, meeting demand beyond 2039 would mean tapping into the higher-valued logs from the Taranaki region (export K/A), and/or exploring opportunities for importing residues from other regions.

[43] See Section 8.6

7.4 Sensitivity analysis

EECA acknowledges that there are a range of factors which determine each organisation's final decision on fuel switching. The NPV of a project (at the expected carbon price) is only one factor, albeit an important one for owners and shareholders. However, capital constraints, competing priorities, risk appetite, uncertainty about future costs, asset age, supply chain constraints and labour market implications are examples of the myriad factors that must be considered when deciding when to switch away from fossil fuels, and which fuel to choose.

This report does not speculate on those factors. However, understanding how sensitive the fuel choice is to the commercial factors may go some way to providing confidence of the best decision, both in terms of fuel choice, and timing. This RETA report has outlined some of the uncertainties related to both up-front and ongoing fixed and variable costs, for example:

- The uncertainty in the underlying variable fuel costs (natural gas, electricity and biomass). Electricity has a combination of fixed (per-annum use-of-network charges) and variable costs.
- The uncertainty regarding the magnitude of up-front upgrade costs required to connect an individual site to the electricity network (including the degree to which flexibility in plant consumption could reduce these costs – see Appendix C).
- The uncertainty in the quantity of sustainable biomass that could be practically brought to market and made available as a source of bioenergy.

In terms of fuel switching, one way to consider how sensitive the fuel switching decision is to the variability in underlying costs is to look at how close the MAC values for the competing fuels are, where the project has more than one low-emissions fuel to choose from.

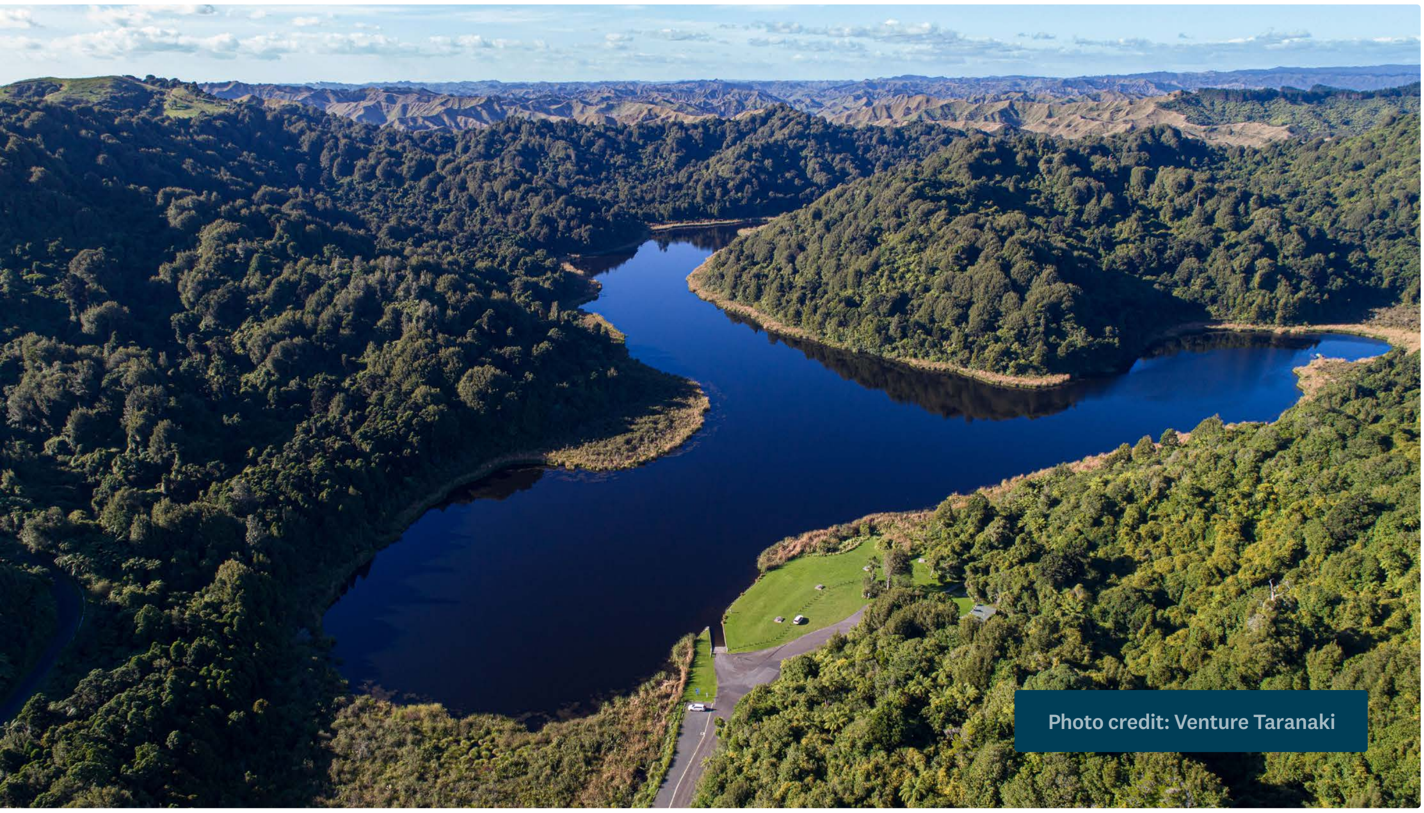
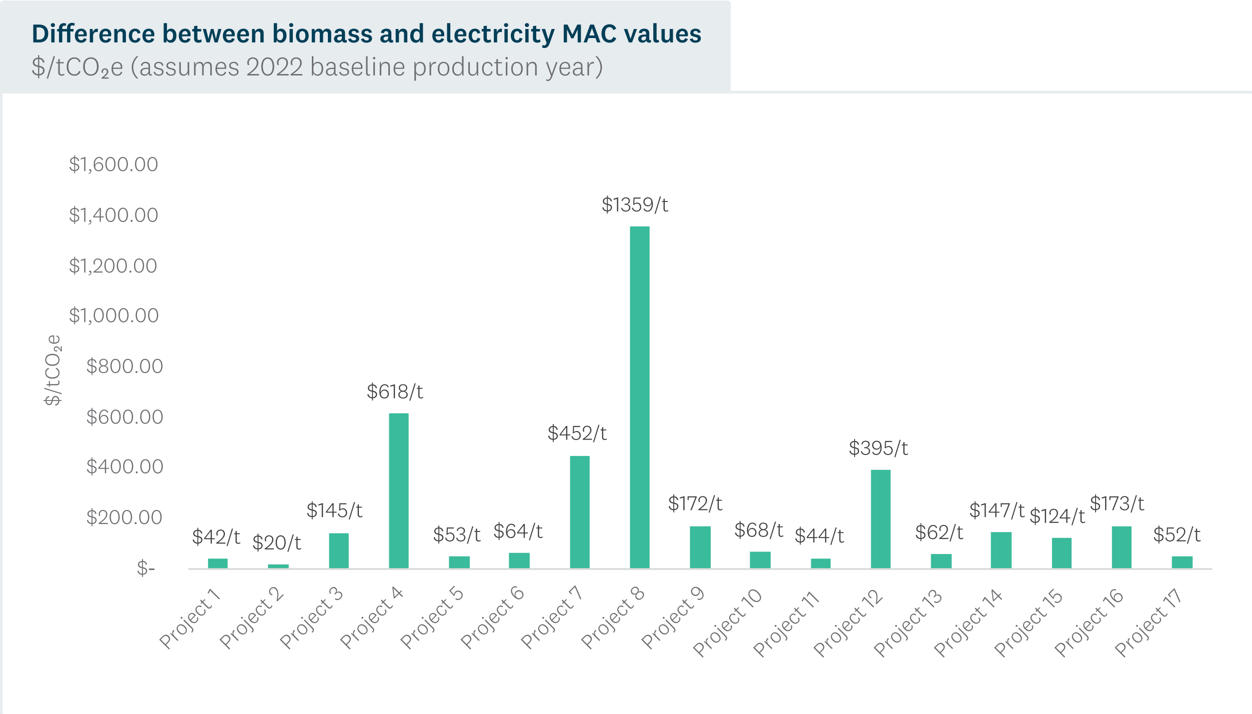


Photo credit: Venture Taranaki

Figure 27 – Difference between electricity MAC value and biomass MAC value; sites that are considering both options. Source: EECA[44]



Only 17 of the 42 unconfirmed fuel switch projects had a choice between biomass and electricity for their fuel switching decision.[45] Figure 27 shows that for the majority of these projects (13 in total) the difference in the MAC is under $200/tCO_2e.

It would take a considerable change in underlying costs to change the optimal fuel decisions for the remaining projects, but, for these thirteen projects, plausible deviations from EECA's input estimates used in this analysis could change the decision. To illustrate the sensitivity of these MAC values for the projects in Figure 27:

- A 20% change in up-front capital costs (including network upgrade costs) for either electricity or biomass can change the MAC value of fuel by around $48/tCO_2e on average, and up to $212/t for one project.
- A change in the incremental operating costs (including fuel procurement) of 20% could change the MAC value by $18/tCO_2e on average, and up to $39/tCO_2e for one project.[46]

Given this, plausible changes in these costs may change a small number of fuel switching decisions. However, even if the fuel switching decision didn't change, the change in MAC could accelerate or delay the timing of the fuel switch, in the MAC Optimal pathway.

44 Project 8 in the figure has a low utilisation, with capex being a major contributor to the MAC.

45 Most of these other 25 other projects were for sites with <100oC requirements that could be fully met by heat pumps. There were also a few other sites with no modelled biomass alternative, such as electric furnaces and the creation of green hydrogen for process heat via electrolysis.

46 This is not the same as saying that a 20% change in electricity price, or biomass price, will have this effect. As outlined above, the OPEX component of a MAC calculation is the difference between the cost of continuing to use fossil fuel, and the cost of switching to electricity or biomass. Here we are changing the magnitude of the difference, which would require a greater than 20% change in the cost of the fuels.

To test the impact of potential changes on the pathways, EECA undertook the following sensitivity analyses:

- Two sensitivities relating to the retail price of electricity, using Energylink's 'low' and 'high' retail price scenario, described more fully in Appendix C.
- A 50% increase or decrease in the capital cost of any network upgrades required to accommodate a fuel switch to electricity.
- Amending the decision criteria for the timing of a decarbonisation investment, depending on the carbon price assumptions used to compare with MAC estimates (as discussed in Section 7.1.2).
- An analysis which explores the changes required in fuel costs (electricity, biomass and natural gas) to significantly accelerate emissions reductions.

The following sections discuss these sensitivity analyses.

7.4.1 Lower and higher electricity prices

As discussed in Section 14.1.2.1, there are a range of factors that could lead to electricity prices that are materially different to the 'central' scenario used for the analysis in this chapter. Below we present a 'high' and 'low' price scenario. These reflect the following price paths:

- The low scenario assumes an average price of 8.7c/kWh in 2026, rising to 11.4c/kWh by 2048 (a 14% increase).[47]
- The high scenario assumes 10.2c/kWh in 2026, rising to 13.5c/kWh by 2048 (a 15% increase).
- The base (central) scenario assumes 9.7c/kWh in 2026, rising to 12.4c/kWh by 2048 (a 12% increase).[48]

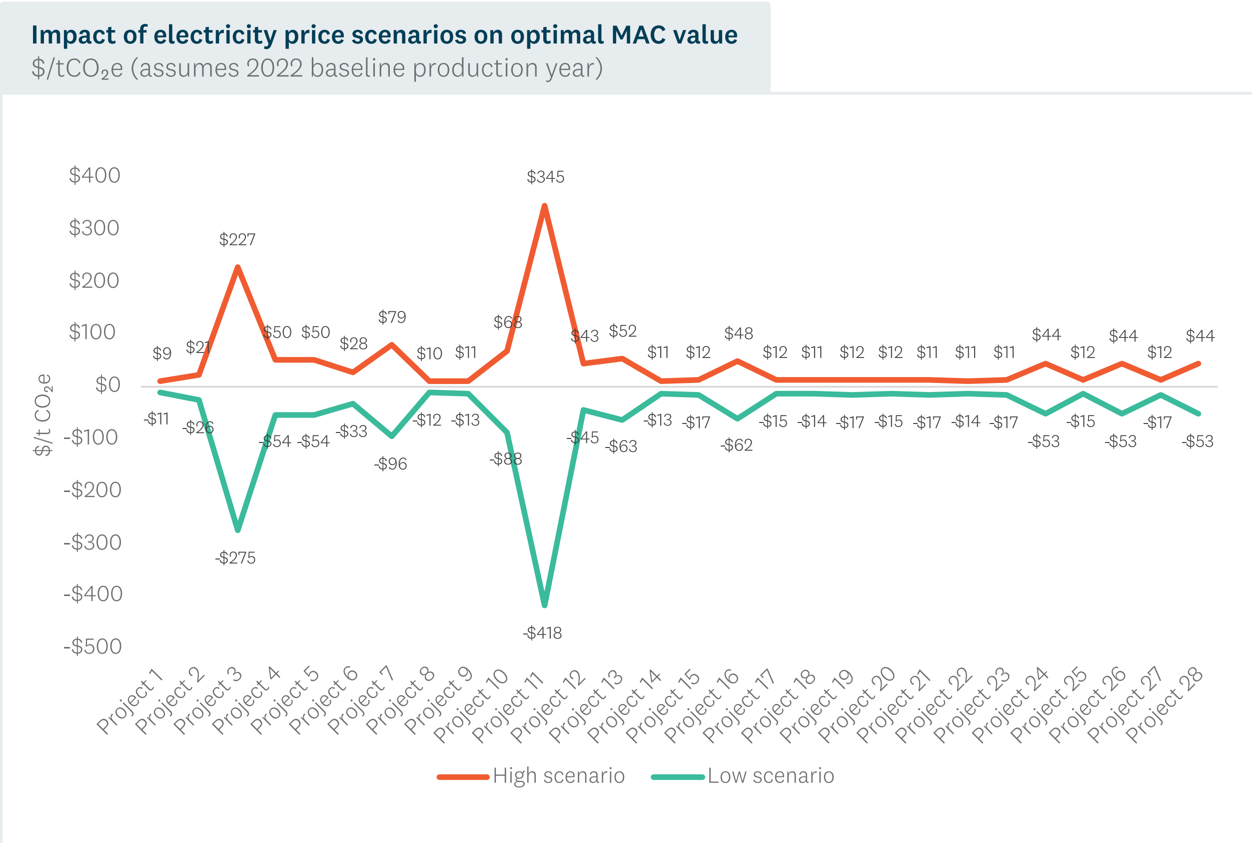
Using the 'high' scenario in the MAC calculations led to increases of \$7-16/tCO_2e for 14 projects, and just under \$52/tCO_2e for another 10 projects. Two projects saw increases of over \$200/tCO_2e.

Similar changes were observed for 18 projects in the 'low' scenario, as shown in Figure 28.

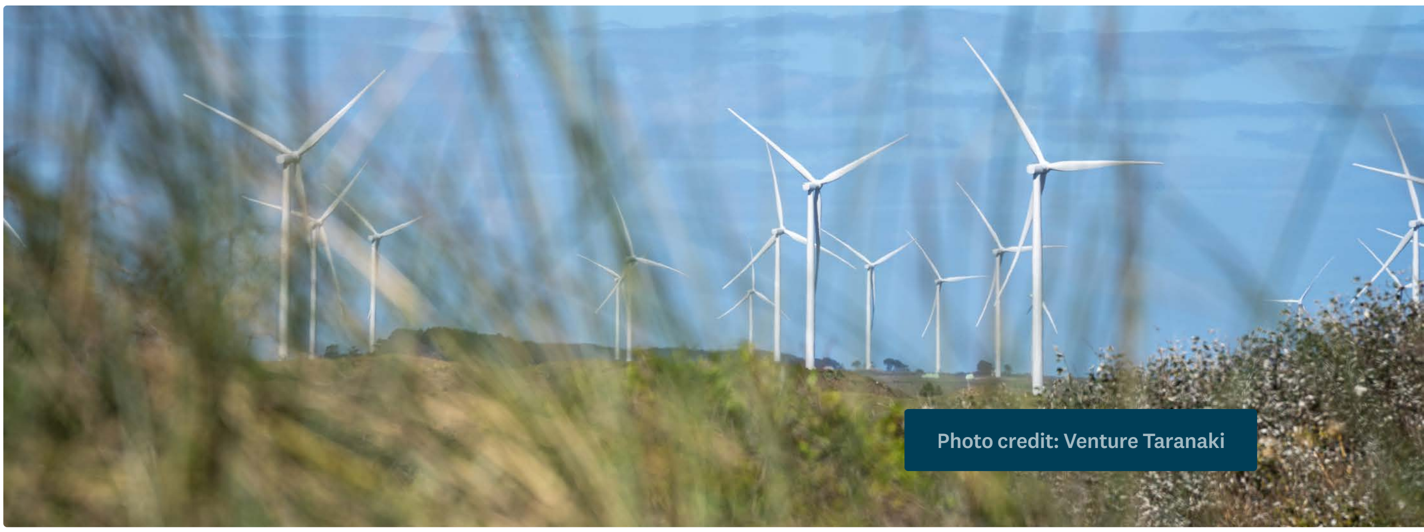
[47] These figures are annual averages: typically, commercial and industrial retail prices vary across the year (reflecting the underlying supply and demand for electricity). As a result, some sectors, such as dairy, will effectively pay a lower price than this, as their demand is weighted towards periods of the year that have lower retail prices.

[48] For years up to 2026, we use ASX electricity futures prices at the time of commencing the modelling

Figure 28 – Impact of EnergyLink's electricity price 'Low Scenario' and 'High Scenario' on MAC values for unconfirmed electricity fuel switch projects



The 'low' scenario reduced the gap between biomass and electricity for most unconfirmed projects, with the most significant variance observed for the two potential hydrogen projects where the reduction in MAC was over $200/tCO_2e$. The 'low' scenario led to three changes in fuel choice (in the MAC Optimal pathway), from biomass to electricity. The 'high' price scenario triggered two changes in fuel choice, from electricity to biomass (in the MAC Optimal pathway).



7.4.2 A 50% change in the cost of network upgrades to accommodate electrification

For the projects that required upgrades to the electricity network to allow them to switch to electricity (either an electrode boiler or a heat pump), we evaluated a 50% increase and decrease in the cost of these upgrades.

Neither a 50% increase nor decrease changed the optimal fuel switching decisions for these sites. Figure 29 shows the impact of a 50% increase in the cost of network upgrades on the MAC value (a 50% decrease would have an inverse effect of the same magnitude).

Figure 29 – Impact of a 50% increase in network upgrade costs required to accommodate fuel switch to electricity.

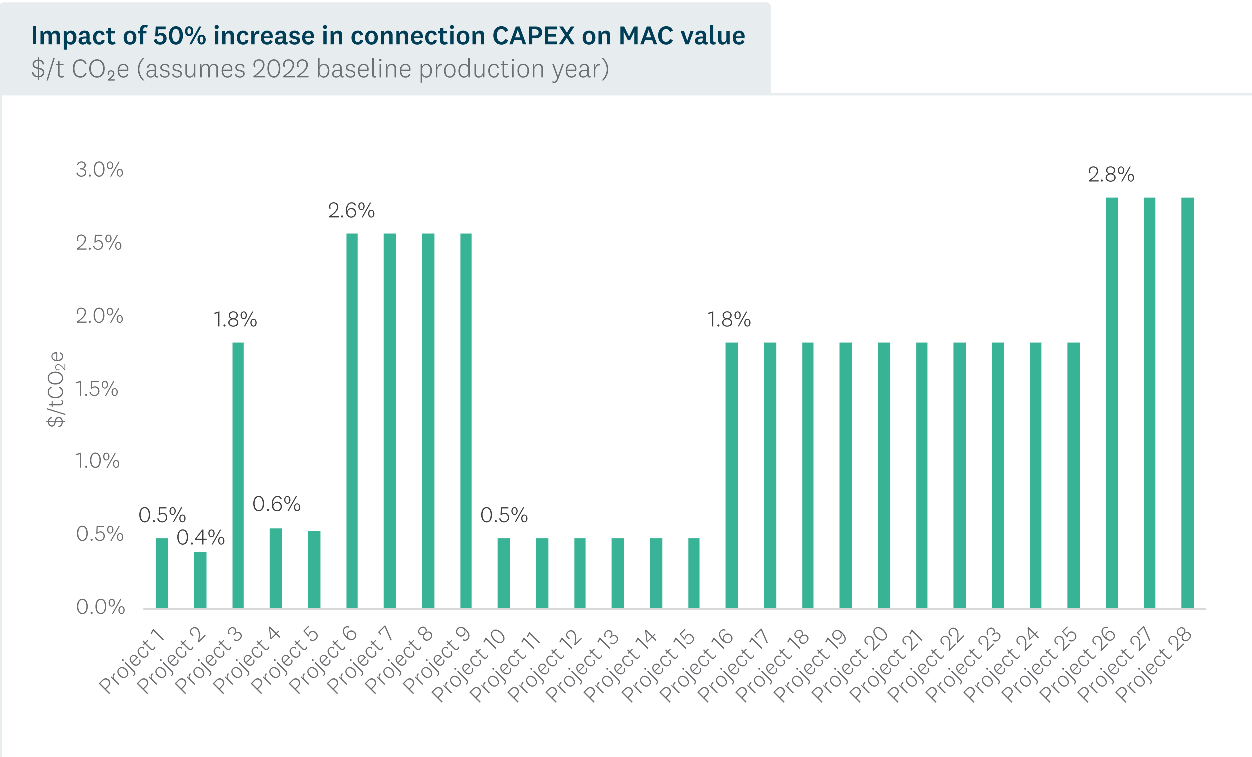


Figure 29 shows why the change in network connection cost doesn't alter decisions; although the absolute change in MAC value ranges between \$1 and \$65/tCO_2e across the projects, this is only, at most, 3% of the total MAC value.

7.4.3 Amending the decision criteria for investment timing

This sensitivity test compared the demand for biomass and electricity under four decision making criteria related to future carbon price assumptions. In the base case, the MAC Optimal pathway is based on the 10-year average future carbon price, assuming a 'central' scenario of future carbon prices as explained in Appendix B. We compare this with a 'low' and 'high' 10-year average future carbon price. We also compare this with simply waiting for the carbon price to exceed the MAC value of the project ('current year' carbon price).

Figure 30 – Comparing carbon prices for MAC-based decision-making criteria.

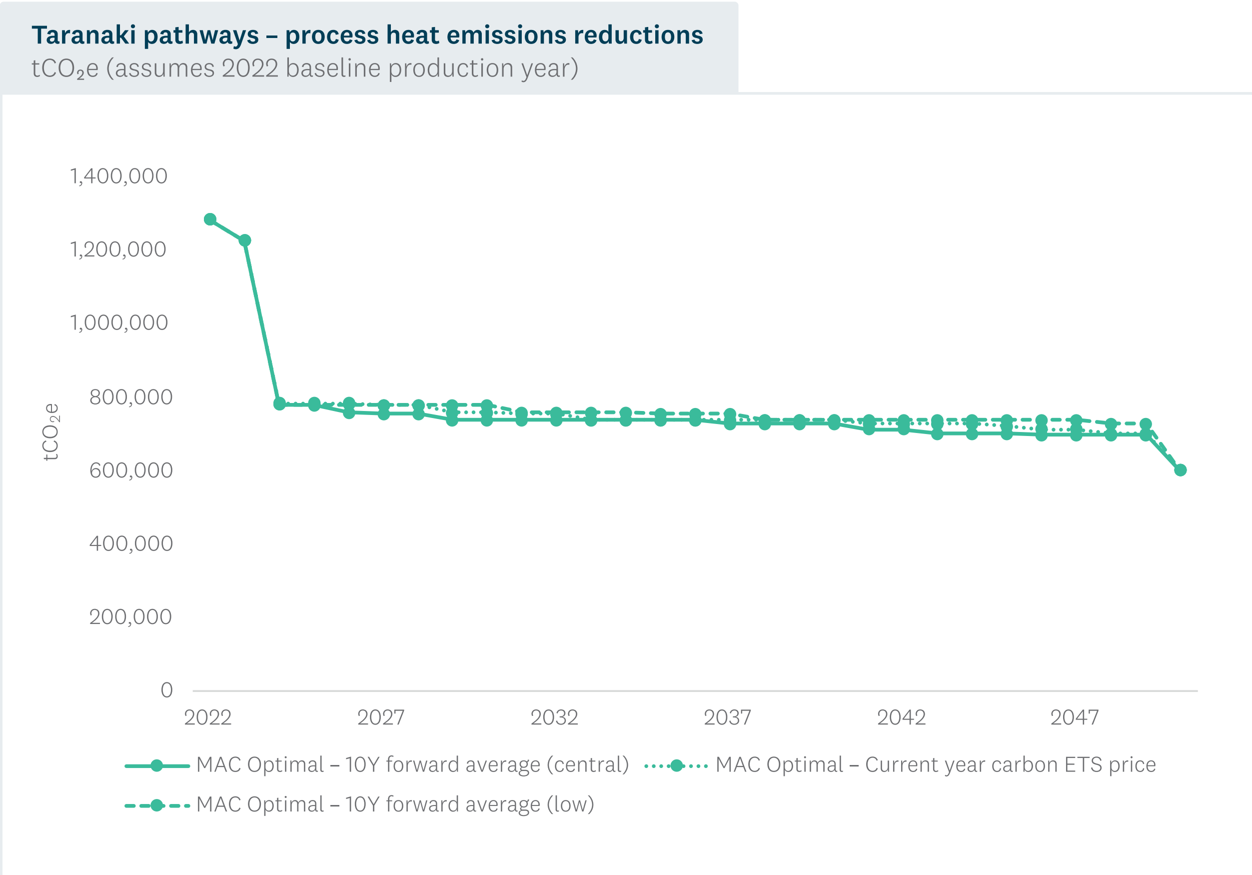


Figure 30 shows that using a 10Y forward average (*central*) rather than a *current* ETS price accelerates some emissions reductions. On a cumulative basis over the study period, the *current* price scenario delivers 339kt fewer CO_2e emissions reductions than the *central* 10Y forward average scenario. Similarly, we find that, compared a MAC Optimal pathway using central 10Y forward average carbon prices, one based on *low* 10Y forward average carbon prices delivers 634kt fewer emissions reductions by 2050 on a cumulative basis. By contrast, a MAC Optimal pathway using *high* 10Y forward average carbon prices delivers 636kt more emissions reductions by 2050, on a cumulative basis.

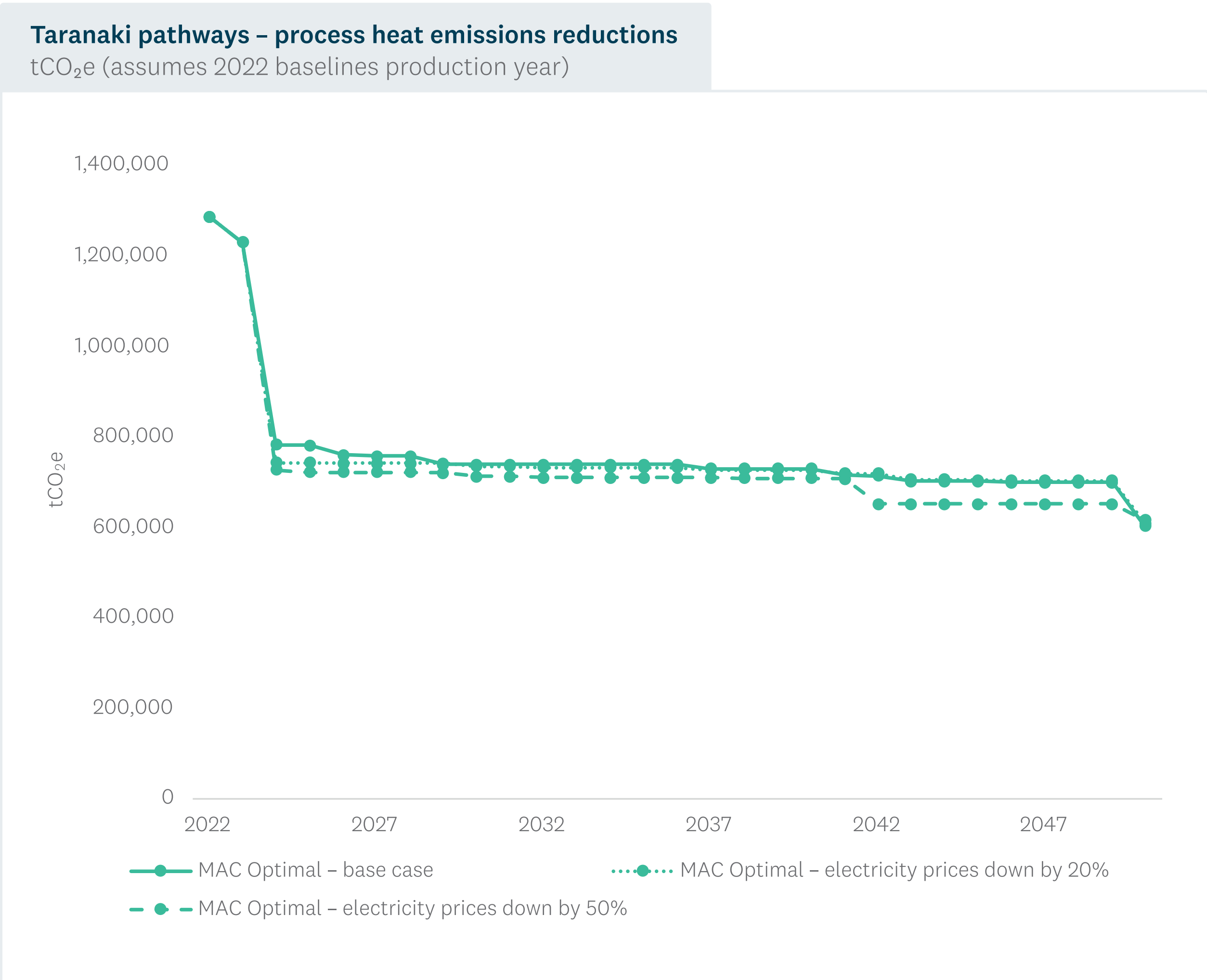
7.4.4 Changes in fuel costs to accelerate emissions reductions

For this sensitivity, we progressively reduced input costs to see at what point a significant acceleration of emissions reductions occurred.[49]

Electricity retail prices

As explained in Section 9, electricity prices are made up of a combination of retail electricity prices (covering generation and retail costs) and network charges. A 20% reduction in the combined (network and retail) cost changed five fuel switch projects from biomass to electric and accelerated 14 projects, delivering 143kt of additional CO_2e emissions reductions by 2050 on a cumulative basis. A 50% reduction changed nine projects and accelerated 23 projects, with a cumulative additional emissions reduction of 929ktCO_2e by 2050.

Figure 31 – Impact on emissions reductions of a 20% and a 50% reduction in electricity prices. Source: EECA



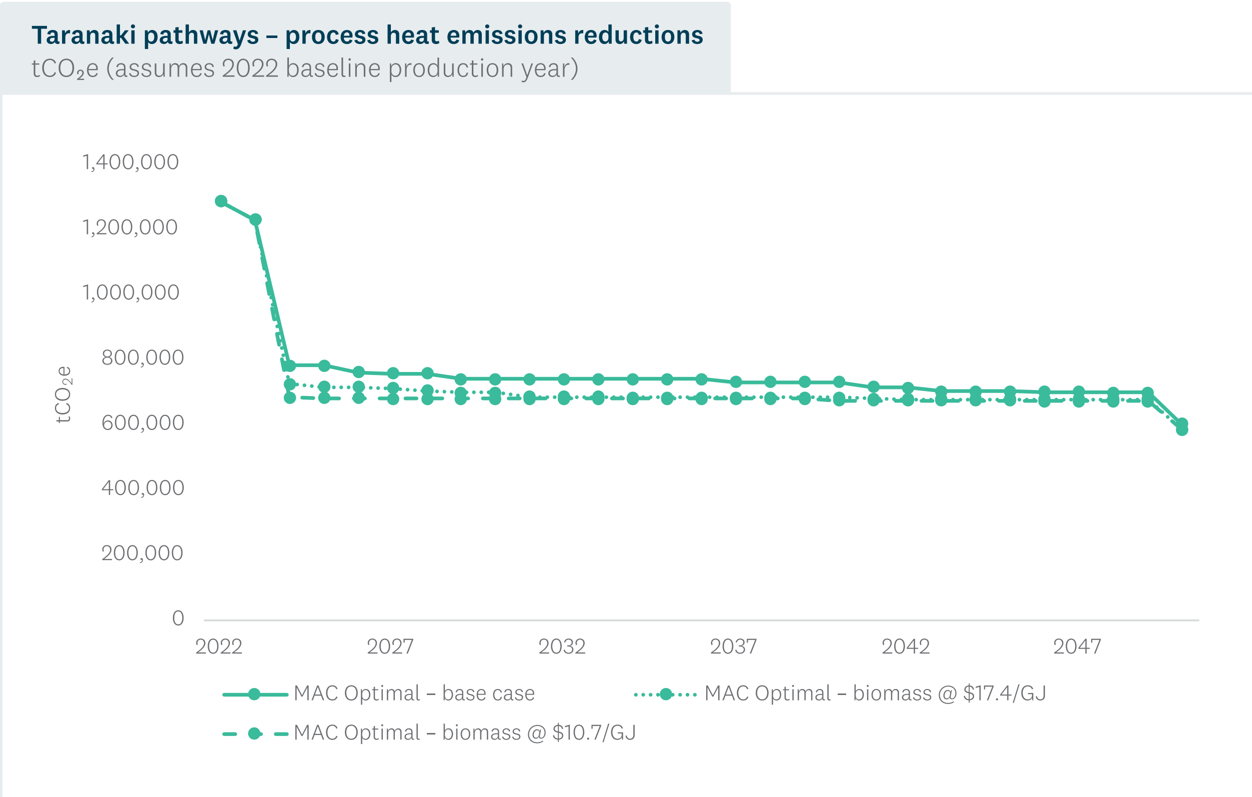
[49] For electricity prices, this is different than the 'high' and 'low' scenarios in section 7.4.1 because the question is framed in terms of what needs to happen to electricity prices in order for electrification projects to be significantly accelerated.

Biomass fibre cost

The base-case assumptions in our modelling assumed that biomass could be supplied for $21.3/GJ[50] ($153/green tonne from a 'hub' to businesses who would, in turn, transform this biomass into a final product (dried woodchip or pellets).[51] Hence this price is akin to a wholesale price for biomass.

A 20% reduction in the wholesale biomass fibre price to $17.4/GJ ($125/t) changed two fuel switch projects from electric to biomass, and accelerated eight projects, delivering an additional 1,112 kt of CO_2e emissions reductions by 2050 on cumulative basis. A significant 50% reduction also changed two projects, and accelerated nine projects, delivering an additional cumulative emissions reduction of 1,416ktCO_2e by 2050.

Figure 32 – Impact on emissions reductions of a 20% and a 50% % reduction in biomass fibre price. Source: EECA



For the Taranaki region, this analysis suggests that finding ways to lower the cost of biomass fibre would be a fruitful avenue for accelerating emissions reductions.

50 This includes an underlying cost of fibre of $18.3/GJ, plus a $3/GJ margin at the hub.

51 Total biomass delivered costs to the end users are assumed to be $25/GJ and $$27.8/GJ for woodchip and pellet respectively. These costs include secondary transport costs from the hub to the end user plus biomass processing costs.

Natural gas prices

In this section we test the sensitivity of emissions reductions to the price of natural gas used as energy. Sites that also use natural gas as feedstock are excluded from this analysis, due to the complexity of estimating what different natural gas prices would mean for their overall operation.

Box 1 – Assumptions on future natural gas prices

Although gas prices are quoted in $/GJ, the vast majority of the costs associated with exploring, producing and delivering natural gas to customers are in fact fixed. Future gas prices will reflect the degree to which additional investment will be required to continue to supply gas, or the need to develop any gas substitutes (biogas, hydrogen).

Today, production from existing fields is declining. Various analyses suggest that, without further successful drilling, existing fields would be largely depleted by the early 2030s. The high cost of drilling, and the uncertainty about its success, means that the prospect of further exploration is heavily driven by field owners' confidence that there will be a market for that gas, as they look for reliable gas consumption to underpin the significant investment costs of further exploration and extraction.

EY's Gas Supply and Demand scenarios explores four scenarios of gas supply and demand. Irrespective of which scenario occurs, EY's scenarios suggest the ability for today's industrial gas users to continue to secure gas supply beyond 2030 will require some combination of:

i) Exploration for, and extraction of, new resources (known as '2C' resources2).

ii) Development of a domestic biogas supply.

iii) Production of hydrogen; and/or

iv) Importing LNG

Almost any combination of these future supplies would have significant implications for the price of gas (or its substitutes), so it is difficult to forecast prices in this context. EECA has not analysed the potential price of gas in these different scenarios but expect that the cost of importing LNG is a 'worst case' scenario, as it is likely to be a cap on any domestic options. In an effort to understand the potential impact of a stressed gas transition, we explored a scenario where gas prices move from the base case assumptions in 2030 to the cost of imported LNG (~$45/GJ excl ETS) by 2035.

Notes:

(1) https://www.gasindustry.co.nz/assets/CoverDocument/Gas-Supply-and-Demand-Study-December-2023.pdf; https://www.ea.govt.nz/news/eye-on-electricity/natural-gas-and-the-electricity-sector-transition/

(2) These resources are referred to as 'contingent reserves,' per https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-publications-and-technical-papers/energy-in-new-zealand/energy-in-new-zealand-2023/natural-gas

For commercial users, the base natural gas prices assumed in the analysis is the MBIE estimate of the annual average of retail prices in 2023 for commercial users. This is $25.66/GJ or $0.09/kWh.

For industrial users, the MBIE estimate of the annual average of retail prices in 2023 is $10.39/GJ or $0.037/kWh. Within the industrial category, we expect there are two broad sets of customers – those who use also use gas as a feedstock, and those who don't. For our analysis, we have assumed that the natural gas price paid by industrial users that also use gas as feedstock for their product is 75% of MBIE's average price, or $7.79/GJ ($0.028/kWh). For the other industrial users, we have assumed the mid-point of MBIE's estimates for commercial and industrial users, or $18.02/GJ ($0.065/kWh).

We note that MBIE's estimate include an ETS component. Our annual price escalator (discussed below) is applied to the natural gas price excluding ETS.

Publicly available scenarios of future gas prices suggest real price escalators (annual growth rate) could be between 1.5%[52] and 6%[53] per annum. In our base case, a mid-point of 3% is assumed, with the other values being tested for sensitivity.[54]

We also test for sensitivity the case where the natural gas price for users (excluding sites that also use natural gas as feedstock) reaches $45/GJ ($0.16/kWh) by 2035, excluding ETS (see Box 1).[55] This implies the following annual escalators: 6% for commercial users, 9.5% for small industrial users, and 19% for large industrial users.

52 Based on energy modelling for the Climate Change Commission's advice on the fourth emissions budget.

53 This applies to retail gas prices as per EY's 2023 Gas Supply and Demand Study.

54 Note that MBIE's recent Electricity Demand and Generation Scenarios (EDGS) assume an annual increase in wholesale natural gas prices of between 2% and 4% (in real terms).

55 See Table 12 Enerlytica's 2023 report on LNG imports and options to increase indigenous gas market capacity and flexibility in New Zealand.

Figure 33 – Impact on emissions reductions from changing the natural gas price escalator. Source: EECA

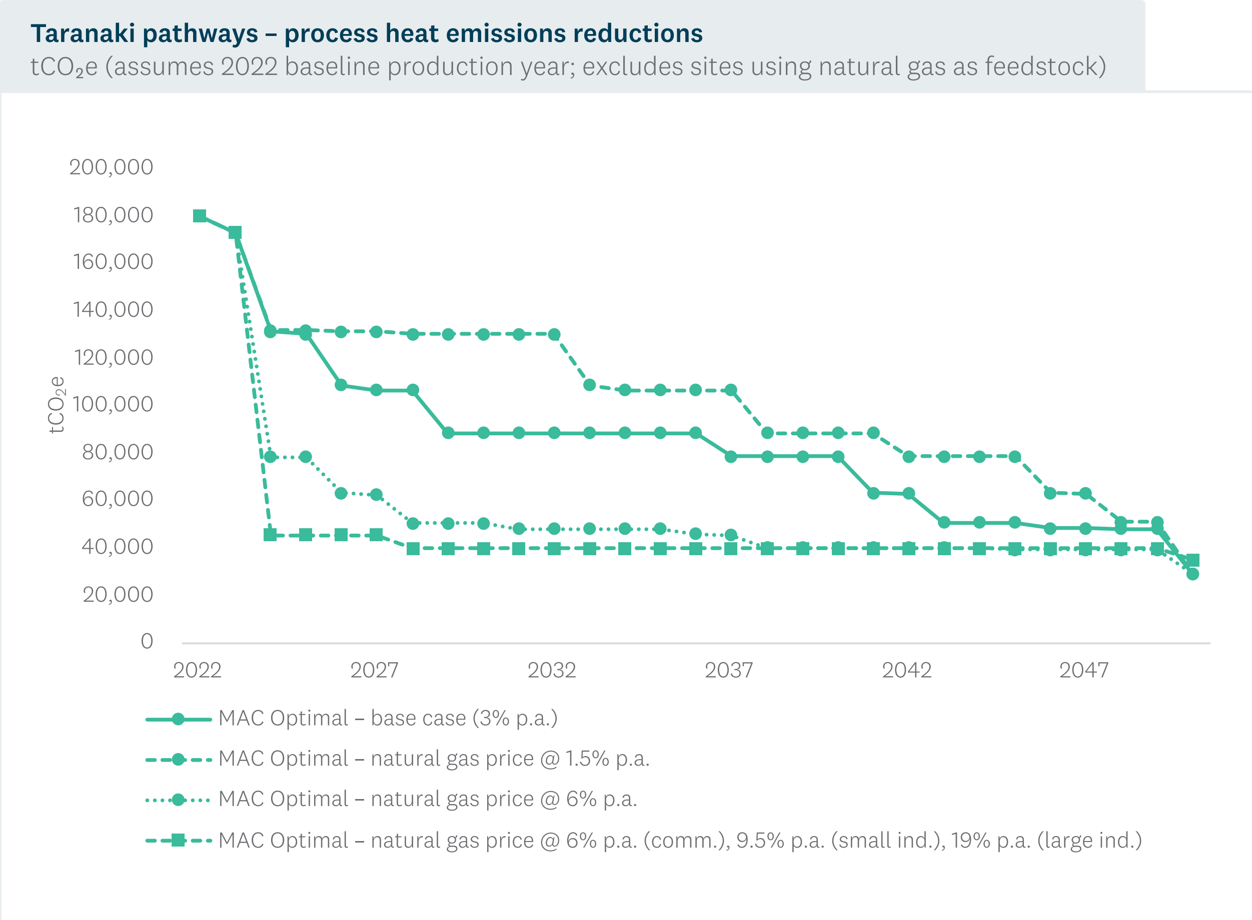


Figure 33 shows that:

- Halving the natural gas price escalator to 1.5% resulted in 533kt of additional emissions on a cumulative basis through to 2050.
- By contrast, doubling the escalator to 6% changed one fuel switch project from biomass to electric, and accelerated 23 projects with 834kt of additional CO_2e emissions reduction by 2050, on a cumulative basis.
- Finally, an increase in the wholesale natural gas price to $45/GJ by 2035 (excl. ETS) changed five fuel switch projects from biomass to electric, and accelerated 24 projects with 1,010kt of additional CO_2e emissions reductions by 2050, on a cumulative basis.

8 Bioenergy in the Taranaki region

8.1 Approach to bioenergy assessment

This section considers the availability and potential cost of wood resources in the Taranaki region as a potential source of bioenergy for process heat fuel switching.[56] Although there are other sources of biomass (e.g. landfills), the focus of this report is on major sources that could collectively provide the demand should all RETA sites elect to switch to biomass for process heat.[57]

Factors that need to be considered when determining the sustainability of biomass from forestry are outlined in this section. The approach is to:

- Consider the total availability of biomass from forestry in the region, including those sources that are not currently being recovered (for example, in-forest harvesting operations) to obtain a theoretical potential for locally sourced biomass for process heat. We adopt both a top-down and bottom-up (via interviews with forest owners) approach to this. The bottom-up analysis provides an assessment of existing usage of woody biomass for bioenergy, as well as of how the wood is expected to flow through the supply chain – via processors to domestic markets, or export markets.
- Expert judgement is applied to allow for a more realistic assessment of the volumes of harvesting residues that can be economically recovered.
- Highlight the existing domestic and international markets for the harvested wood, either for timber products or existing demand for bioenergy (e.g. firewood) that will likely constrain the ability to divert wood to bioenergy for process heat in the near-term.
- Consider what this analysis implies for the potential cost of delivering different types of biomass to process heat users.
- Overlay the 'MAC Optimal' and 'Biomass Centric' scenarios of process heat demand for biomass from RETA fuel switching decisions, to ascertain whether this demand could be met from near term available sources, noting that the supply of bioenergy will evolve through time.

The results give a plausible view of the medium-term availability of Taranaki biomass for process heat purposes, and the foreseeable economic implications of using these resources, based on what we know at the time of writing. This will help potential users make indicative commercial judgments about the attractiveness of biomass, in the quantities required, relative to other fuel switching alternatives.

56 The Taranaki region used for the biomass assessment includes the entirety of New Plymouth, South Taranaki, and Stratford Districts.

57 Other than those which have already confirmed, at the time of this report, they are choosing electrode boilers.

Only biomass sources within the Taranaki region are considered. More generally, neighbouring regions could also use biomass from the forests that are included in the Taranaki region RETA assessment, where transport costs and logistics make this practical. The potential for inter-regional trade in biomass will be considered when all North Island RETA reports are complete, and the entire island can be analysed.

We are aware that process heat is not the only future user of bioenergy competing with existing markets for wood. International demand for bioenergy may increase in the future, leading to countries trading in biomass. Further, demand for biomass can also increase from other sectors, e.g. engineered timber replacing steel in building construction. This requires further analysis, as EECA does not currently have reliable estimates for the likely local demand for biofuels.

8.2 The sustainability of biomass for bioenergy

The use of woody biomass for bioenergy requires careful consideration of emissions and sustainability – for example, depending on the source, the diversion of wood to bioenergy may change the timing of the release of emissions by a significant period (compared to the natural decomposition of biomass), while diversion of low-grade export wood to domestic bioenergy has an unknown global impact (via the supply chain). Suppliers and consumers of biomass for bioenergy will want to be confident they understand any wider implications of their choices.

No formal guidelines or standards exist in New Zealand at this point. There is, however, international guidance, such as:

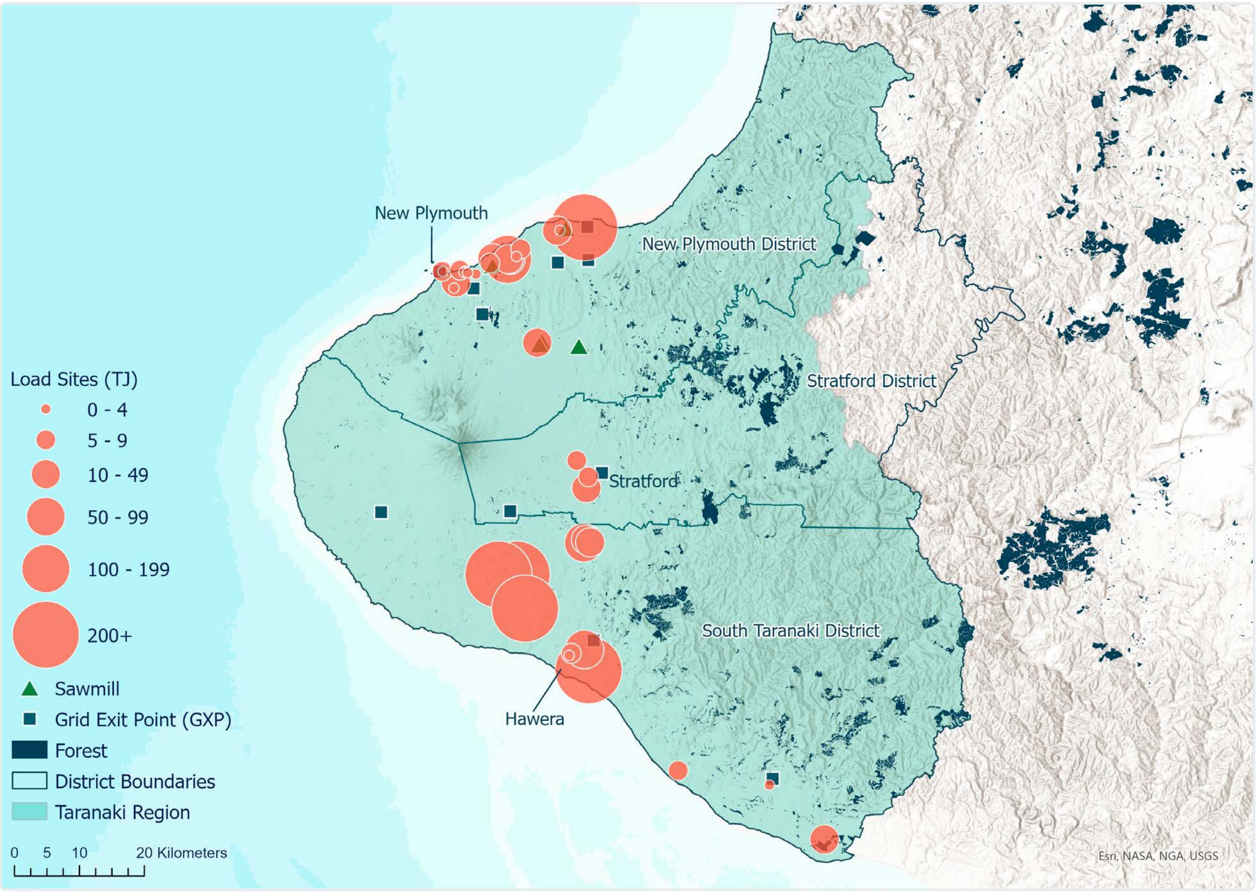
- The Roundtable for Sustainable Biomass, Biofuels, and Biomaterials (RSB), which states that no roundwood should be used for bioenergy.
- The International Sustainability and Carbon Certification scheme (ISCC) discusses deforestation.
- The European Union Renewable Energy Directive II (RED II), which aims to limit the risk that biofuels, bioliquids and biomass fuels trigger indirect land use change. Annex IX of RED II lists a range of potential bioenergy sources that are considered sustainable. This list includes harvesting residues.

These international guidelines need to be interpreted carefully in New Zealand, in the context of our wider policy and regulatory context that may already be preventing some of the outcomes that the RSB and ISCC are seeking to avoid.

EECA recommends guidance is developed for the New Zealand context, drawing on international standards and experience.

8.3 Taranaki regional wood industry overview

Figure 34 – Map of Taranaki process heat demand sites showing forest resources and wood processors.



The Taranaki region has approximately 23,700 ha of planted forests. These forests are dominated by Radiata Pine. Harvesting of minor species is unpredictable as many of these are grown as amenity species or for environmental protection reasons; consequently, minor species are excluded from the analysis.

8.3.1 Forest owners

Large corporate forest owners account for 35% of the planted forests (8,190 ha). These owners tend to have long-term forest management contracts and aim to harvest at sustained levels. Small owners account for the remainder 65% (15,500 ha), with only a few of them engaged in long-term contracts.

8.3.2 Wood processors

Log and timber processors in Taranaki process approximately 135kt of log in mixed grades and sizes every year,[58] mostly creating products for the domestic market, using logs purchased from the forest companies. These products include building and farming products. The main residues from wood processors are sawdust,[59] bark,[60] woodchip,[61] shavings,[62] dockings,[63] post peeling.[64]

Photo credit: Taranaki Pine

58 This figure is for year 2023.

59 Sawdust is the residues from sawing logs and is one of the more difficult products to sell. It can be mixed with other residues and sold as animal bedding. It could also be made into wood pellets but needs to be dried beforehand.

60 Bark is created when preparing the log for processing and the volumes are generally small as most of the bark is removed in-forest.

61 Woodchip is created onsite from all viable offcuts and is sold for landscaping, animal bedding or to MDF.

62 Shavings are created when dressing the timber, which creates a finished product smooth and clean. Shavings are usually created after the timber has been dried so it is light and dry and is good boiler fuel.

63 Cutoffs from docking the timber to specified lengths. It is used as firewood.

64 Post peeling are the residues created from round posts (fencing poles, lamp post). They are thin and long in shape, making them difficult to handle. Additional processing may be necessary to create a more uniform product for bioenergy.

8.4 Assessment of wood availability

This section considers:

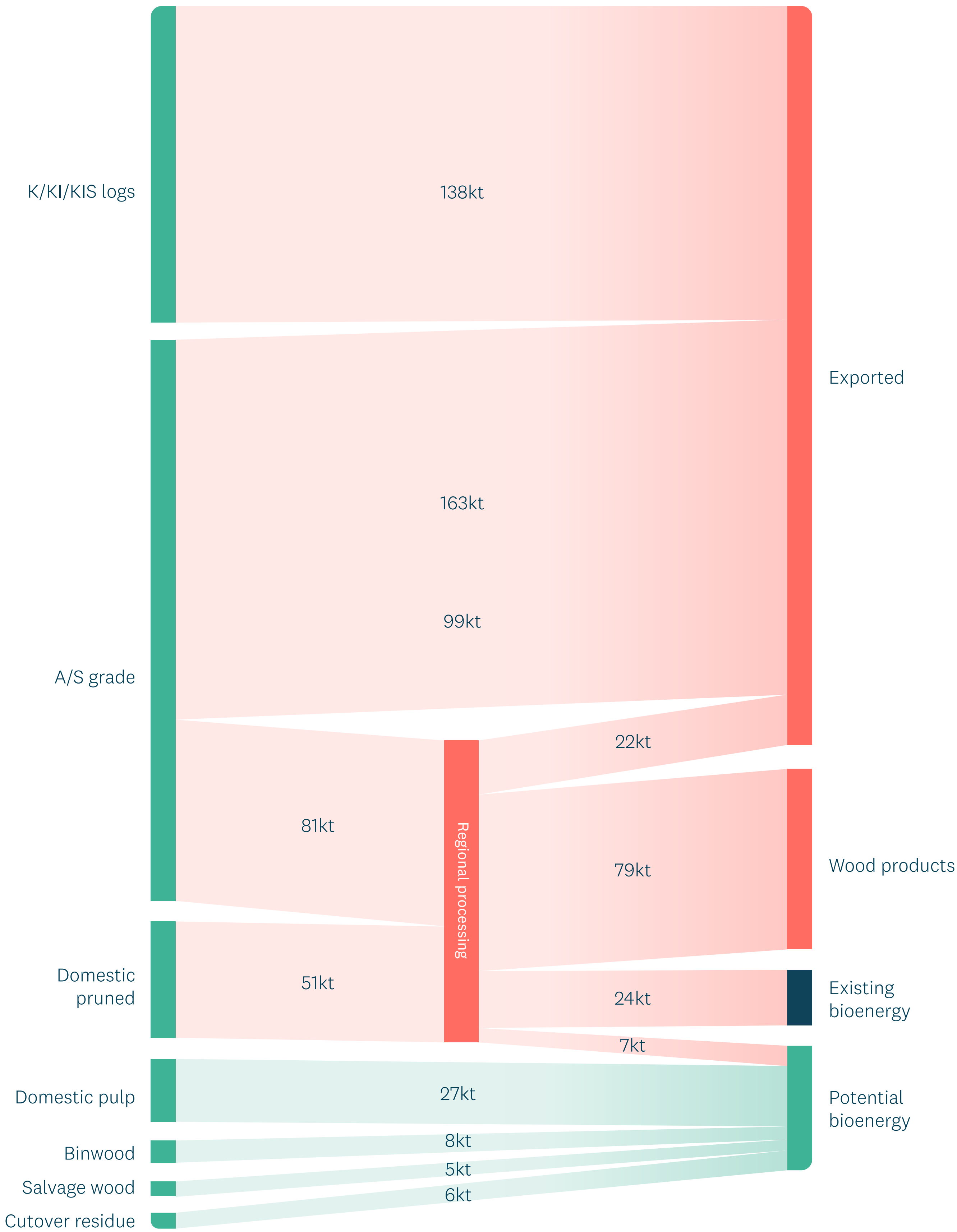
- The total wood, and the grades of wood, expected to be harvested in the region over the next 15 years.
- The existing markets for that wood, including the role of any processors in the region, and existing bioenergy uses.
- How much of that wood (including harvesting and processor residues) are currently unutilised.

The outcome of this section is summarised in Figure 35. Wood flows that could be utilised for new bioenergy demand from process heat are shown in green.

Note that the numbers in this figure are averages over the 15-year period from 2024 to 2038. We use this period to highlight the near-term availability. Later in this section, Figure 39 illustrates this changing availability in more detail, and over a longer period.

Photo credit: Taranaki Pine

Figure 35 – Wood flows in the Taranaki region, 2024-2038 average. Source: Forme



A top-down analysis suggests that an average of around **479 kt pa (3,440 TJ pa) of wood will be harvested in the Taranaki region over the next 15 years.**[65] A more comprehensive view of resource availability, that combines the top-down and bottom-up analyses reveals:

- On average, **19 kt pa (136 TJ pa) of harvest residues could be available for bioenergy**. Around 13 kt pa. (90 TJ pa) is currently being recovered (binwood and salvage wood), while the rest is not currently utilised (mainly cutover residues).
- Interviews with sawmills suggested that around **53 kt pa (382 TJ pa) of processing residues** are produced (mostly woodchip) of which 24 kt pa (170 TJ pa) is already used for bioenergy.[66] Most of the woodchip (22 kt pa or 158 TJ pa) is exported to a pulp mill in central North Island, while the remaining residues (7kt pa or 51 TJ pa) could be made available for new process heat users.[67]
- On average through to 2038, **83kt pa (599TJ pa) of domestic pulp/firewood and export KI/KIS logs is available**.

Overall, EECA estimates that, on average over the next 15 years, **approximately 53kt pa (382TJ pa) of woody biomass is currently unutilised and could be recovered for new boiler demands without disrupting low grade export markets or existing bioenergy consumers**. However, this average disguises the significant variance in the annual availability shown in the analysis below.

8.4.1 Forecast of wood availability

For this report, a recent mapping of the forests in the Taranaki catchment has been undertaken to assess distribution of crop types and ages. This has been complemented with log-grade data provided by forest owners. The wood availability forecast below is based on this more recent mapping of the catchment.

In Figure 36 total volumes are broken down into modelled log grades, which are an adjustment to the WAF log grade categories.[68]

Key log grades are:

- **Export grade** – This includes A, K, KI and KIS grades logs exported to Asia.
- **Domestic grade** – This includes Pruned, Unpruned, and Pulp log grades. These grades go to domestic markets including wood processors and firewood.
- **Harvesting residues** – A by-product of harvesting and a primary source for bioenergy and firewood. It is commonly referred to as 'billet' wood; here it is split into 'binwood' (biomass that is easily accessible and is collected by truck with a bin), 'salvage wood' (salvageable biomass collected using a log reach excavator) and 'cutover' (residues from stems and branches left in the forest and not as easy to access). Based on surveys of Taranaki forest owners, residue volumes have been estimated to 14.2% on average out of total available wood (including non-recoverable biomass). This 14.2% is broken down as follows: binwood – 1.5%, salvage wood – 0.9%, cutover – 11.9%. However, due to the difficulty of accessing cutover residues, only 10% of cutover residues has been determined to be economically recoverable. Note that Figure 35 shows the total volumes, whereas Figure 36 and subsequent analysis will only consider the economically recoverable volumes.

65 We use 15 years as a reasonable assessment of the near-term period that process heat users considering biomass would likely want to contract for, if they were making the decision in the next few years.

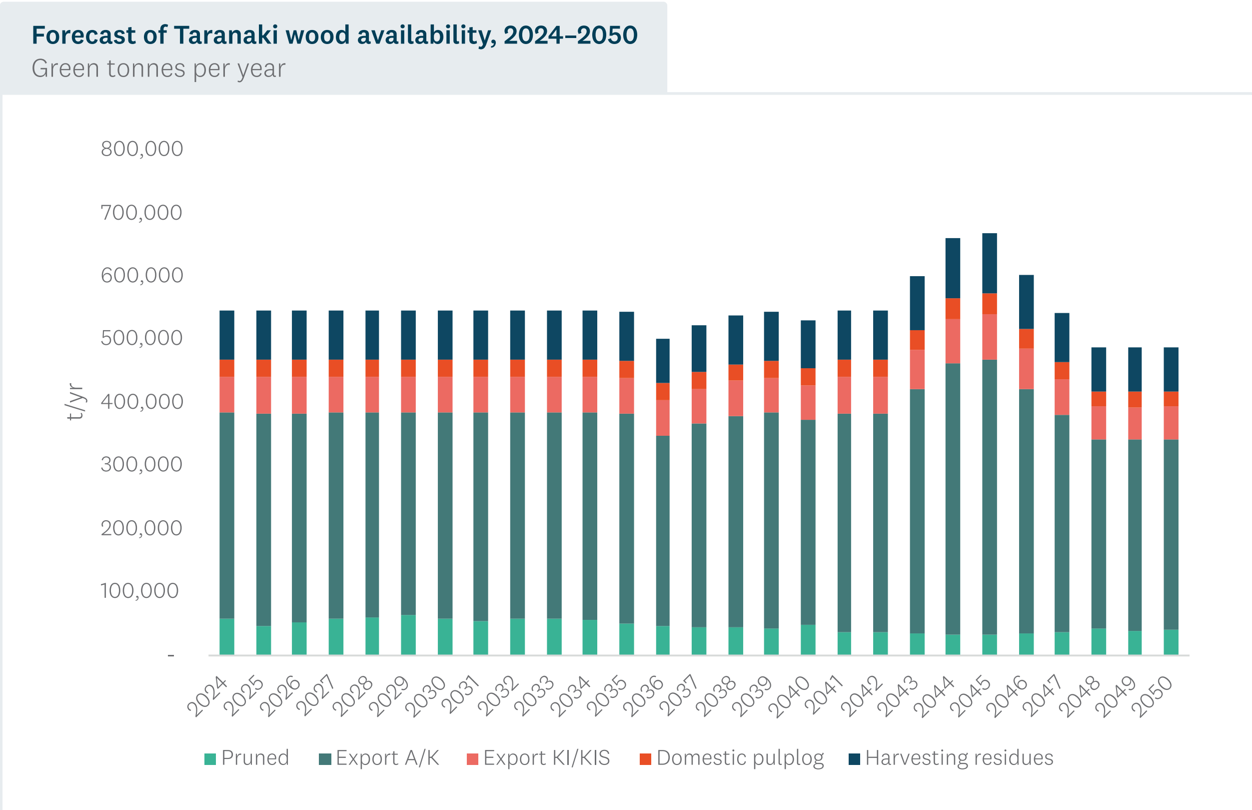
66 This is data for 2023.

67 We note this site has now ceased operations and whether it will become operational in the future is unknown.

68 Specifically, WAF unpruned category corresponds to large sawlog (A) and small sawlog (K); WAF pulp log category corresponds to the totality of industrial (KI), Industrial small (KIS), and domestic pulp. A new category is added for harvesting residues, which is absent in WAF.

Export grade volumes are sent to Port of Taranaki. Domestic grades are utilised in Taranaki by local processors.

Figure 36 – Forecast of Taranaki Wood Availability, 2024-2050. Source: Forme



As can be seen from Figure 36, there is some annual variation in total available wood resource particularly in the second half of the RETA period, with a visible increase in Export A/K volumes (sawlog) over the 2043-2046 period compared to today. The annual variation occurs due to the age distribution of the existing forests, and yield assumptions combined with assumptions on how forests are harvested.

That said, a model can only predict how wood flows may occur subject to assumptions that drive individual forest harvest. It is important to recognise that forests are normally managed in a way that maximises the benefits to the owners. Such benefits are not easily modelled particularly as prevailing market conditions will change. Each owner has their own harvesting strategy based on the wood flow objectives and forest revenue. Any change in harvesting strategies by forest owners will affect the age structure and maturity of the forests they own and, in turn, future wood availability.

Unlike other RETA regions, small-scale owners hold most of the modelled resource (65% of total planted forests). A key issue, therefore, is the timing of harvesting by small-scale forest owners. The harvest age can vary markedly even between neighbouring properties. The volumes forecasted by larger forest owners are subject to alteration because of changes in harvesting intentions or changes in the resource description (for example, areas and yields). But a higher level of confidence can generally be assumed for these owners than for small-scale owners, whose harvest intentions are less clear due to being more reactive, and with less accurate resource descriptions.

8.5 Insights from interviews with forest owners and processors

The results of the wood availability modelling are complemented with a set of detailed interviews and surveys of the major forest owners and processors. This provides a richer picture of the potential resource available for bioenergy.

8.5.1 Processing residues

Six processors in the region were interviewed to better understand both the potential residues from processing, as well as the current demand for these residues for bioenergy.

Table 7 shows the types of processing residues readily available from three Taranaki processors.[69] There are no residual residues available from the remaining three processors.[70]

Table 7 – Products readily available for bioenergy from processors in Taranaki

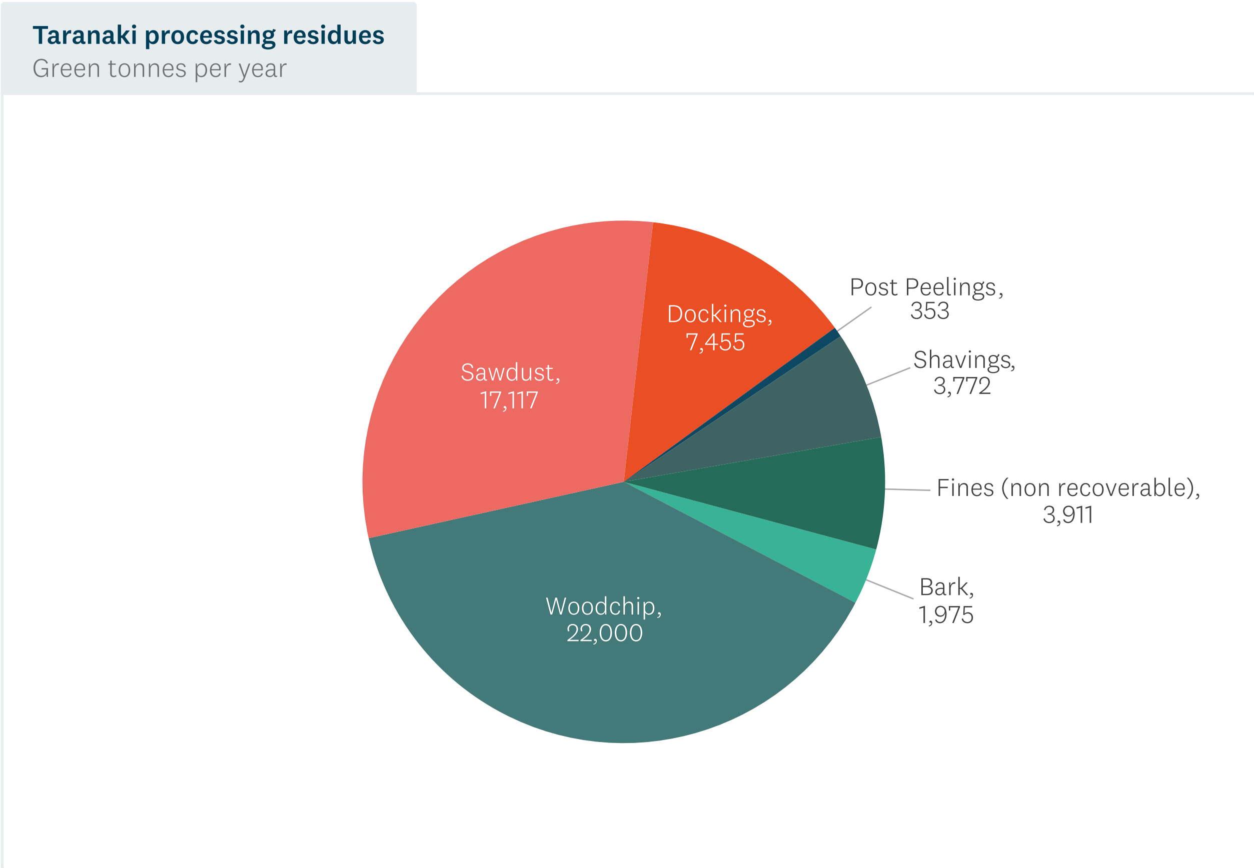
	Woodchip	Sawdust	Bark	Shavings	Post peelings	Dockings
Taranaki Pine		x				
Value Timber Post & Pole						x
Cleland Timber						x

The interviews conducted suggest that there are, on average, 53kt per year of processing residues created in Taranaki, the majority of which is woodchip (Figure 37). Sawmill woodchip is the highest value, large quantity residue. It is in demand from the pulp sector due to its density characteristics and consequent high pulp yield. Each year, 24kt of processor residues are already being utilised by Taranaki processors for their own bioenergy needs. Most of the woodchip is exported to a pulp mill in Central North Island.

69 Definitions of the different types of residues can be found in Appendix D

70 The remainder processors are Value Timber, Kaimata Sawmill and Inglewood Timber Processors.

Figure 37 – Taranaki processing residues, tonnes per annum (15-year average). Source: Forme



8.5.2 In-forest recovery of biomass

In-forest residue volumes were estimated by Forme. Based on forest owner surveys, Taranaki forest residues have been split into three categories.[71]

- **Binwood** accounts for an average of 1.5% of total available wood volumes (8,040t per annum on average over the 2024-2050 period).
- **Salvage wood** accounts for an average of 0.9% of total available wood volumes (4,710t per annum on average over the 2024-2050 period).
- **Cutover** accounts for an average of 11.9% of total available wood volumes (65,200t per annum on average over the 2024-2050 period).

Based on interviews with forest owners, all binwood and salvage wood volumes are assumed to be recovered, given they are relatively easy to access. By contrast, no cutover volumes are currently recovered in Taranaki. The issues faced with in-forest residue recovery include:

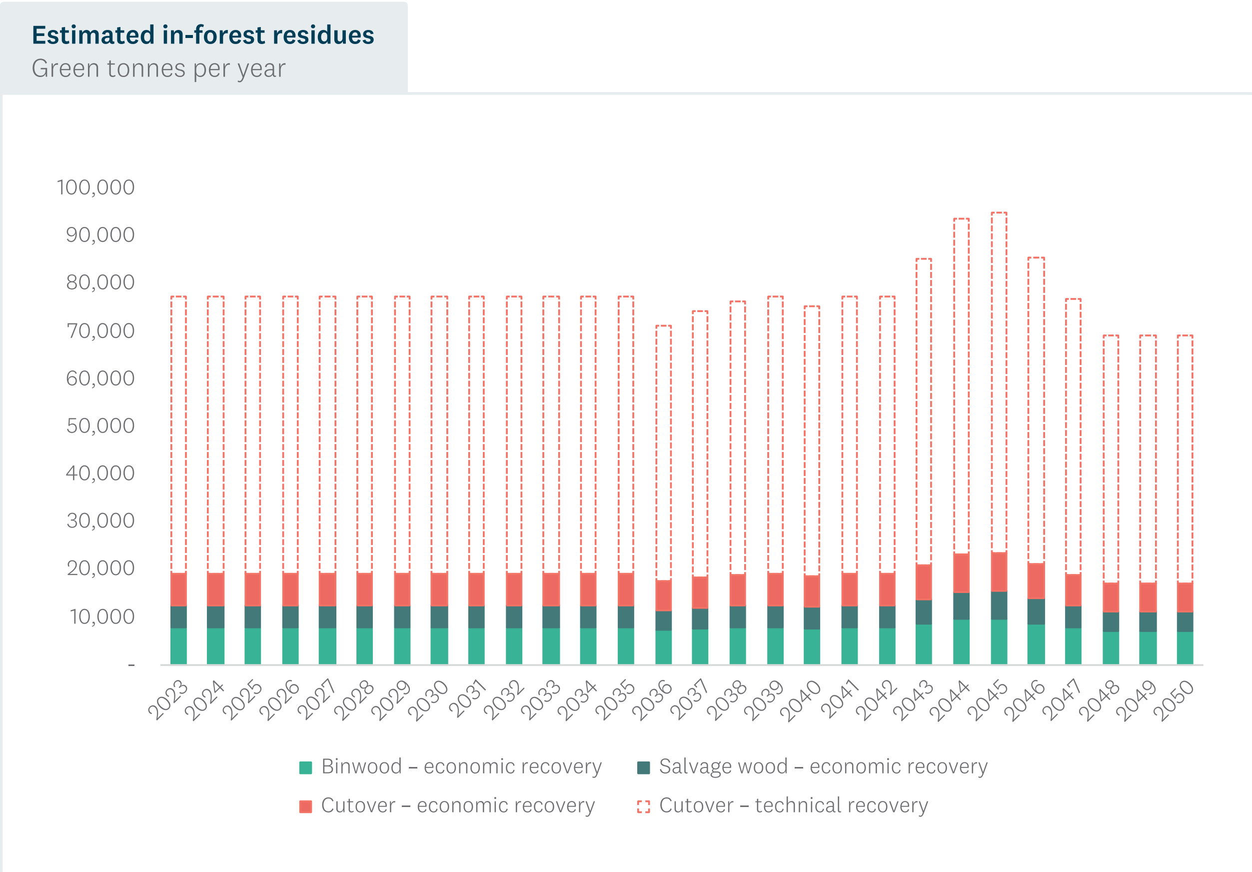
- Land accessibility can be difficult due to steep terrain, which also makes recovery of cutover residues more difficult and costly to extract. As the proportion of steep terrain increases, the overall practical level of residue recovery drops.
- Commentary from foresters suggests that even some of the roadside volumes gets left behind because the market price would not exceed to cost of collection and distribution.

[71] See definitions in Appendix D.

Furthermore, cutover residues provide important nutrient value for plantations, which is of increasing importance given the environmental pressures against the use of synthetic fertilisers in New Zealand's agricultural sector. For these reasons, only 10% of total cutover residues (6,520t) are deemed recoverable.

Figure 38 below compares the technical and economic potential of harvest residues. The analysis of available volumes for bioenergy includes economic recovery only.

Figure 38 – Estimated in-forest residues – technical potential vs economic recovery



8.5.3 Existing bioenergy demand

The interviews highlighted that a large proportion of processing residues are currently being used internally by Taranaki wood processors as boiler fuel, totalling 23.6kt per annum.

In the following analysis we assume that these bioenergy demands continue in the foreseeable future.

8.6 Summary of availability and existing bioenergy demand

Figure 39 shows our overall assessment of the forest (and forestry by-product) resources in Taranaki.

Figure 39 – Wood resource availability in the Taranaki region, Forme

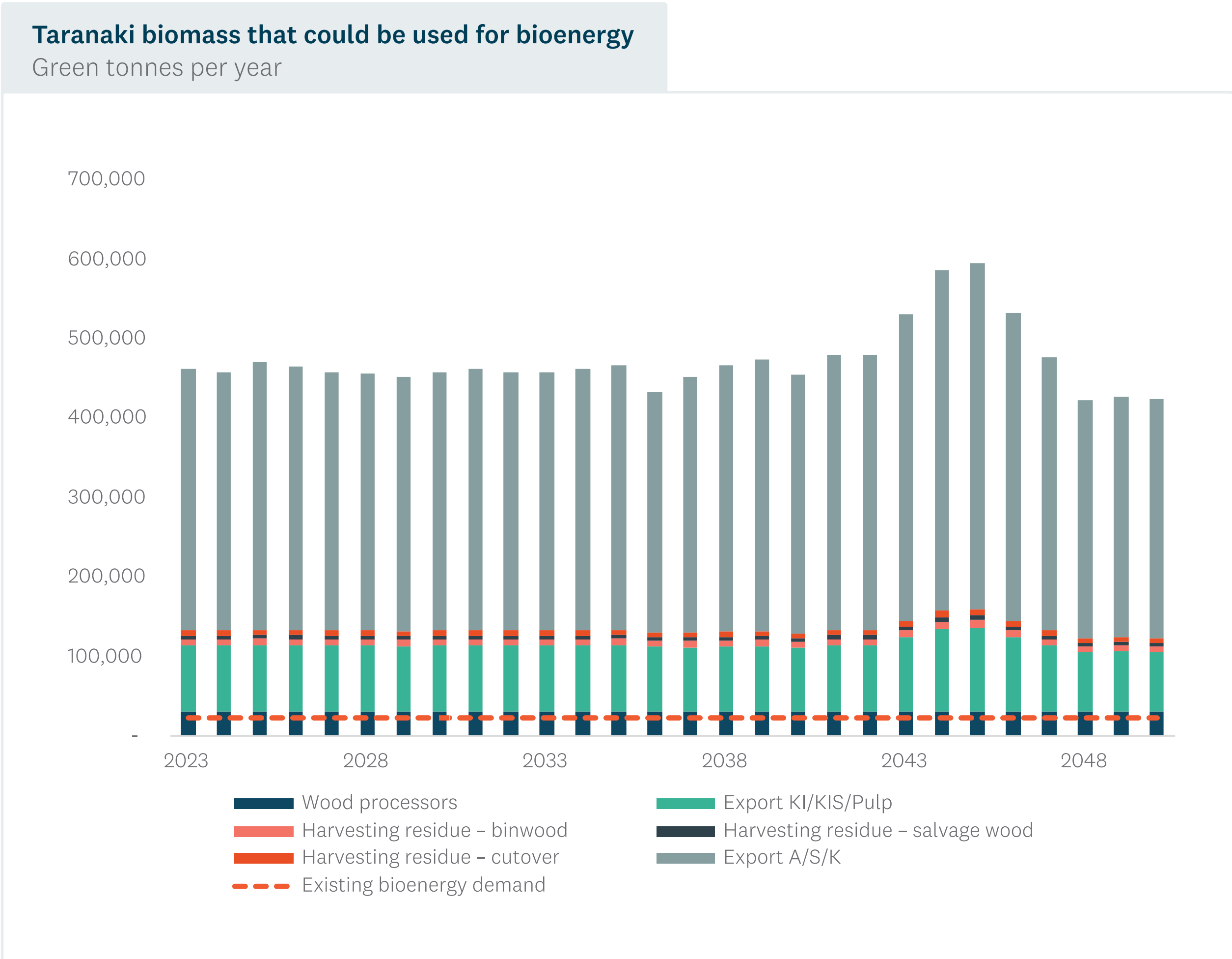


Figure 39 shows there is significant scope to increase the within-region use of bioenergy from the level today (~23,600t, or 170TJ). We note that domestic pulp is included because, in the Taranaki region, a lot of the pulp is left on the cutover or landing edges, therefore serving as a potential source of bioenergy. We also include export A/S/K grades because, as it will be shown later, these volumes would be required to meet the significant increase in biomass demand in 2050 in two pathways (MAC Optimal and Biomass Centric).

We now turn our attention to the likely cost of the potential bioenergy resources identified above.

8.7 Cost assessment of bioenergy

Since bioenergy markets are very much in their infancy, the approach is to base prices on either an estimate of the costs of extracting the resource, or to 'shadow price' to the value of resources in other markets (where these markets existed). For example, shadow pricing uses export prices for wood, to imply a price that must be 'matched or beaten' if users are to divert their wood resources away from that market to bioenergy.

8.7.1 Cost components

A key cost component is the cost of transporting the material from source to a hypothetical processing location, which for the Taranaki Region has been assumed to be located at Stratford, 60km distance from the forest gate on average. Depending on the source, prices have been determined as follows:

- **Wood processing residues** – The price for the wood processing residues is the sum of the cost of the material at the processing mill plus the cost of transporting it to the hub. It is assumed that the material is already in a form that could be consumed for energy production, hence only storage, handling, and hub margin costs are added.
- **In-forest binwood, salvage wood and cutover volume** – A forest owner's costs (collection, loading, transport from forest to biomass hub) are added to the biomass hub costs of chipping, storage, and handling.
- **Diverted export volume** – All the export volume from Taranaki is assumed to be transported to Port of Taranaki at present. The difference between the transport cost to the port and to the biomass hub is subtracted from the at-wharf gate export price. The biomass hub costs of chipping, storage and handling the biomass is then added to the price.

8.7.1.1 Estimated costs of bioenergy

Table 8 and Figure 40 show these costs in terms of mass ($/t of wet wood) and energy equivalent ($/GJ). This requires an assumption about the moisture content of the underlying fuel. We use calorific value associated with a moisture content of 55%; in reality, the moisture content will vary between the different sources listed in Table 8; this will need more detailed consideration by process heat users contemplating conversion to biomass.

Table 8 – Sources and costs of biomass resources in the Taranaki region. Source: Forme (2024)

Bioenergy source	Cost of biomass source ($/t)	Harvesting and collection ($/t)	Chipping and storage ($/t)	Transport to biomass hub ($/t)[72]	Total cost delivered to user's site ($/t)	Total cost delivered to user's site ($/GJ)[73]
Processor residues (excl woodchip)	$12.5	$0	$10	$20.74	**$43.24**	**$6.02**
Harvesting residues – binwood	$10	[included]	$25	$23.93	**$58.93**	**$8.21**
Harvesting residues – salvage wood	$3	$12.5	$25	$23.93	**$64.43**	**$8.97**
Harvesting residues – cutover	$3	$25.04	$25	$35.89	**$88.93**	**$12.39**
Domestic pulp	$44	[included]	$25	$20.74	**$89.74**	**$12.50**
Export grade KIS logs	$56.5	[included]	$25	$20.74	**$101.74**	**$14.17**
Export grade KI logs	$64.5	[included]	$25	$20.74	**$110.20**	**$15.35**
Export grade K logs	$74.5	[included]	$25	$20.74	**$120.20**	**$16.74**
Export grade A logs	$97.2	[included]	$25	$20.74	**$142.90**	**$19.90**

The figures in the far-right column of Table 8 only include the cost of primary transport from the forest to a hub that is assumed to be 60 km from the forest gate.[74] We also note that our analysis (and Figure 39) of biomass supply excludes woodchip as it is currently exported to a pulp mill in the Central North Island.[75]

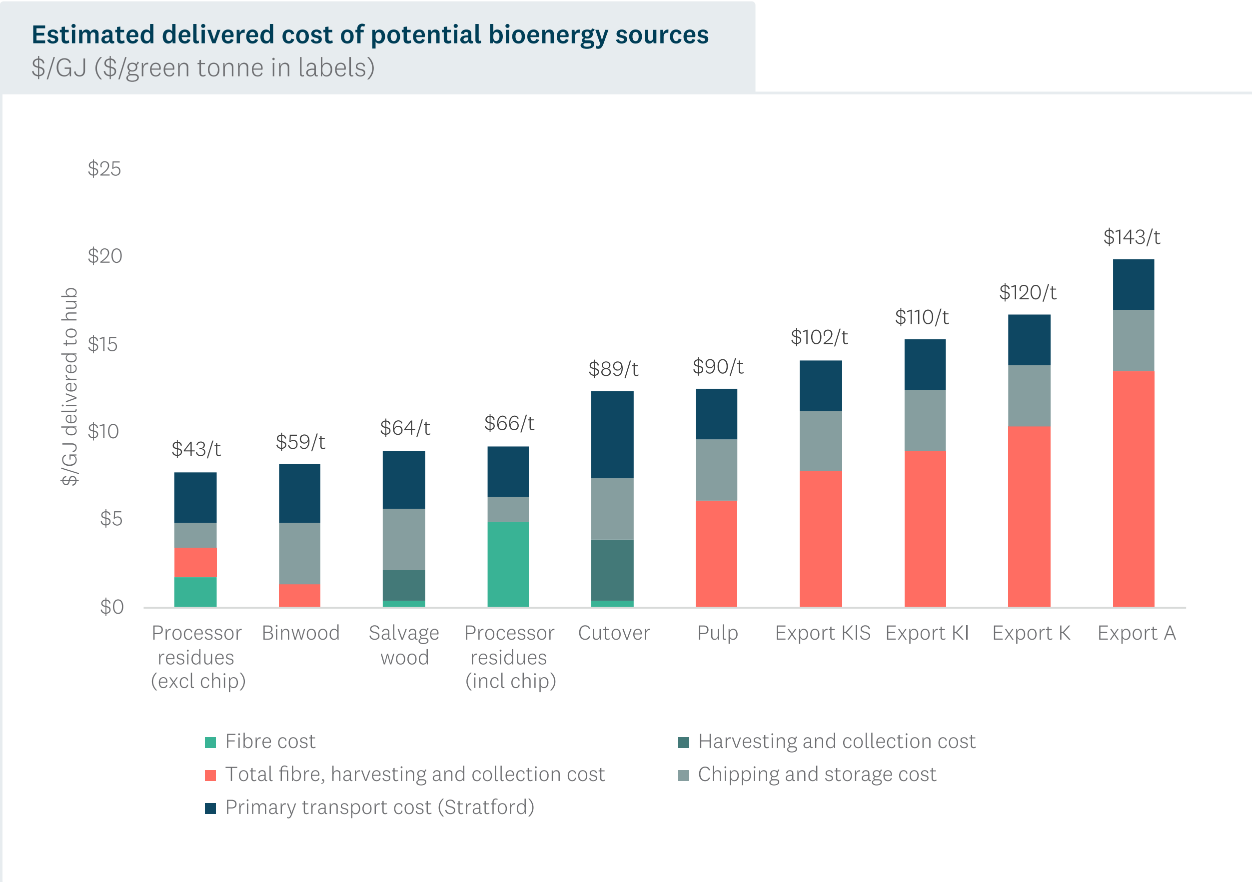
72 We note that on annual basis, the transport cost varies depending on the location of the forest.

73 Conversion in energy equivalent assumes a net calorific value of 7.184 MJ/kg (55% moisture content), and 1m³ = 1,000kg. We also note that this is a price of energy as delivered to the gate and is therefore not directly comparable to an electricity price, due to the relatively lower biomass boiler efficiency compared to an electrode boiler (or a high temperature heat pump, where applicable).

74 'Secondary' transport from the hub to the process heat user are used in the MAC calculations, assuming $1.67/GJ over 35km from the hub.

75 We note this site has now ceased operations and whether it will become operational in the future is unknown.

Figure 40 – Estimated delivered cost of potential bioenergy sources. Source: Forme (2024)



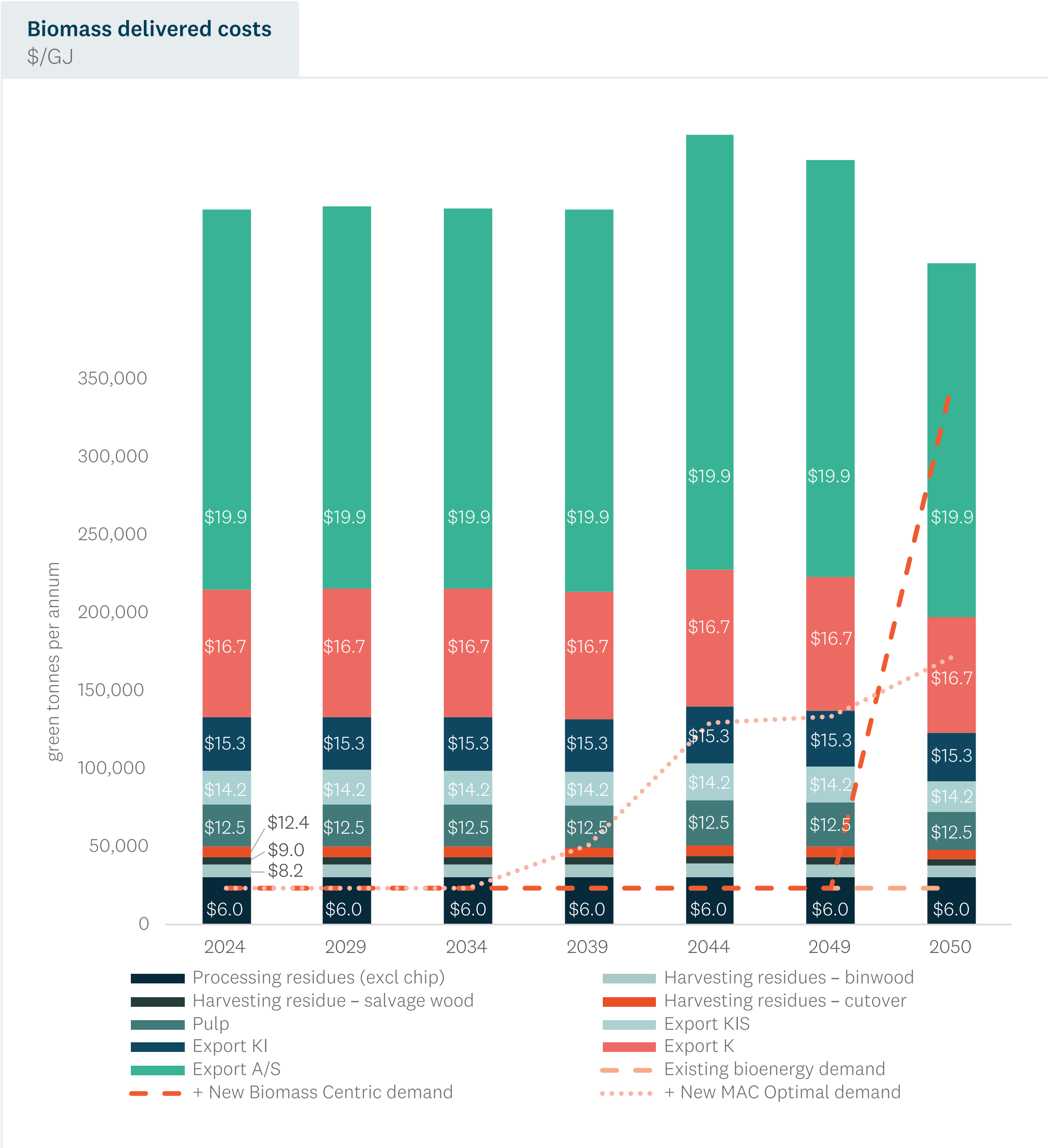
8.7.2 Supply curves

To convert these costs into an indicative market supply curve, we use the corresponding volumes for each category of resource from the analysis in Section 8.6.

Figure 41 provides a summary of available biomass volumes and the total delivered cost of each type of biomass. Note that the costs shown here do not include secondary transport costs from the processing hub to the final user, they only include transport costs from the forest to the hypothetical hub. Furthermore, the cost of harvesting residues may change through time once a market is established for this type of biomass.

The figure shows that the significant increase in 2050 of biomass demand in the MAC Optimal and Biomass Centric pathways would only be matched by the supply of higher-grade export K or A/S Logs. On this basis, we assume we assume that the long-term biomass price (delivered at hub) in the Taranaki region is set by the average of the K-grade and A-grade log prices, i.e. $18.3/GJ.

Figure 41 – Biomass supply curves through to 2050, five-year average volumes Source: Forme (2024)[76]



[76] Note the volumes for Export A/K logs have been cropped to help with the chart visualisation.

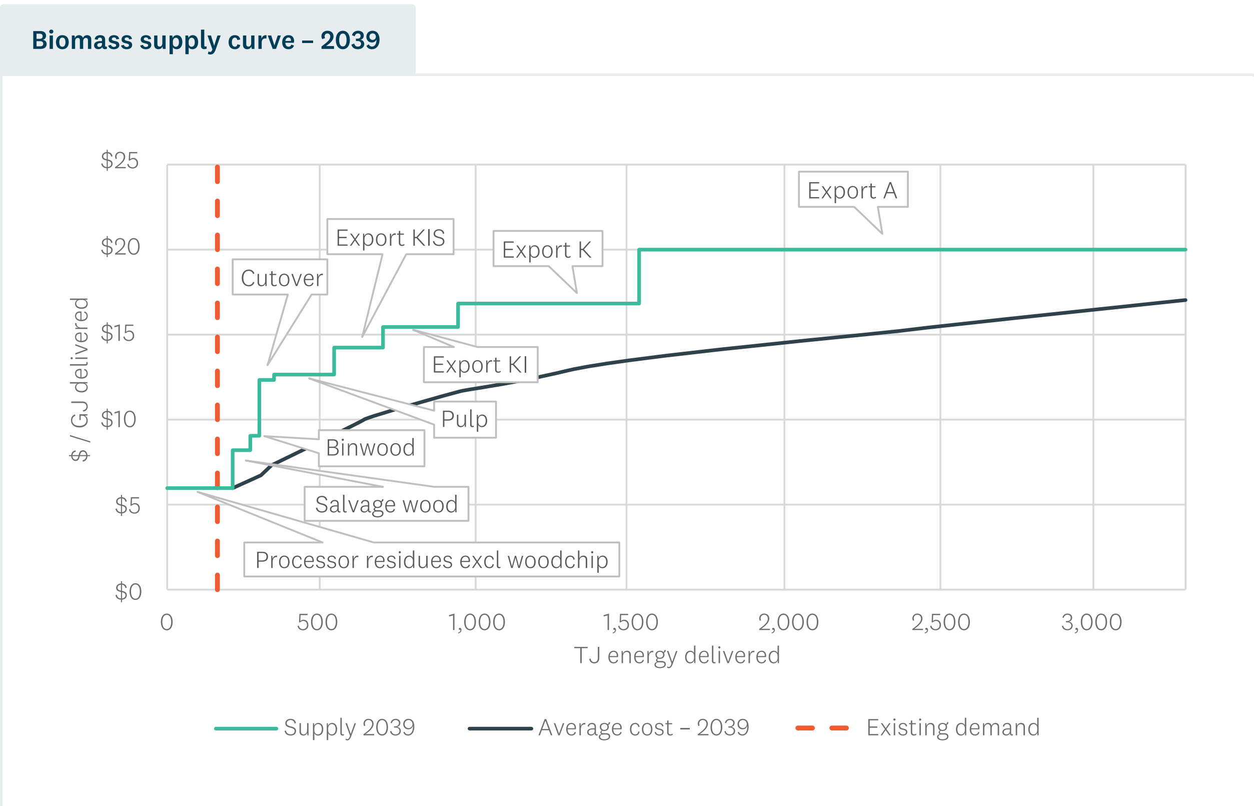
As an example, Figure 42 shows the biomass supply curve and average prices for 2039.

The supply curves have three dimensions: volume, cost, and time. The cost shown by the solid line for each increment in supply is the marginal cost for the most expensive resource required to meet that level of demand. This is higher than the (volume-weighted) average cost paid by the market overall at any point in time (which would include the lower cost resources). It allows us to think about the price bioenergy users may face in any year in two ways:

- If early biomass customers secure long-term contracts for lower cost processor residues or in-forest residues (indicated by the dashed lines), they will still have access to those resources, at the agreed price, for the duration of those contracts. This is regardless of what is happening in the rest of the market. As each subsequent process heat user switches fuels, they will contract for the lowest cost resource that has not already been secured by an earlier adopter. Hence the supply curves in Figure 42 indicate the price faced by the next increment of demand, assuming that all cheaper biomass resources have been fully contracted, at least for the remaining period of the chart.
- Alternatively, the biomass market may operate on a 'spot' basis, without any long-term contracting. Every year, aggregators of bioenergy resources suitable for process heat will secure the supply, and all users will pay a price approximating the average cost across all the resources.

Reality will likely lie somewhere between these two scenarios, depending on how the arrangements for long-term supply of bioenergy evolve.

Figure 42 – Biomass supply curve, 2039



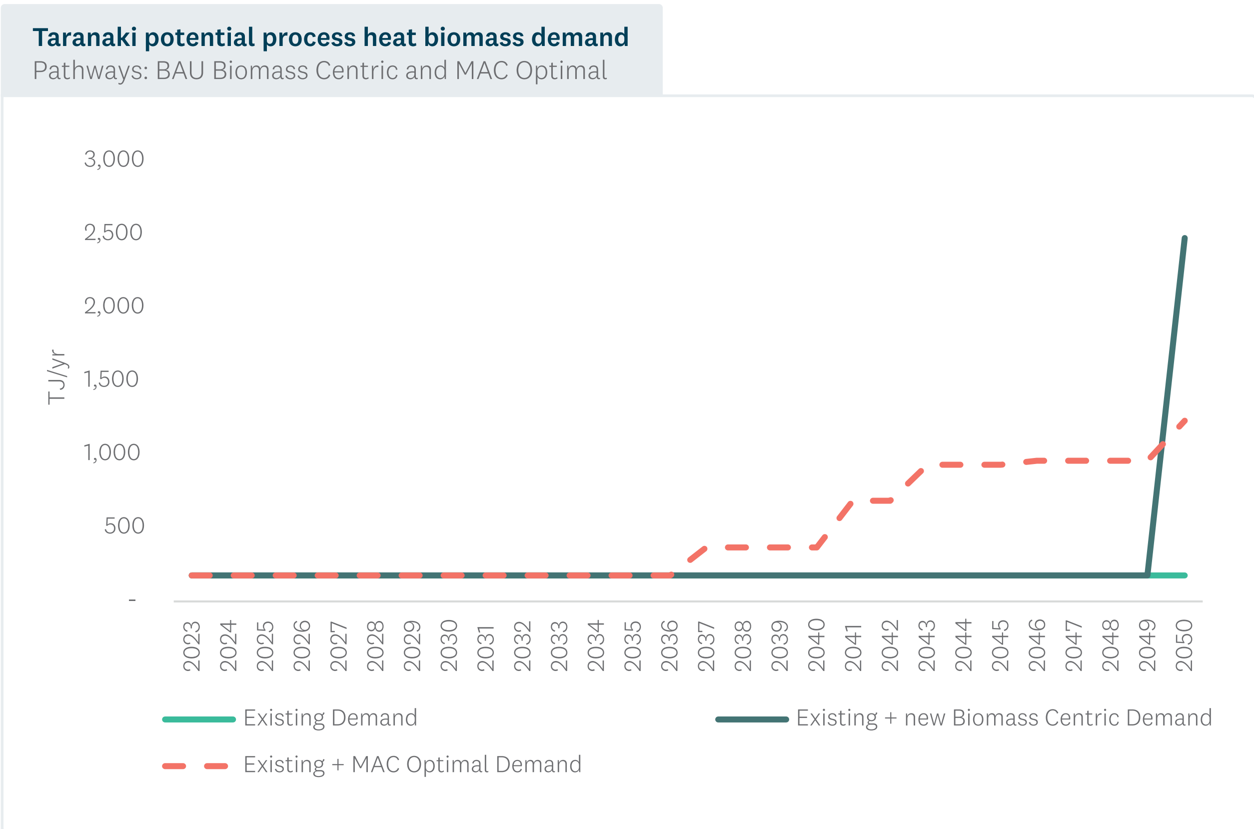
8.7.3 Scenarios of biomass costs to process heat users

With a nascent bioenergy market, there is no price history to draw on to use to calibrate price forecasts. To get an indication of what prices may be, we overlay plausible demand scenarios on top of each year's supply curve. Recall that these supply curves are based on a forecast of the costs of accessing these resources in 2024, with no additional margin applied, which is only intended to provide a proxy for potential future price scenarios.

These demand scenarios include the total present consumption of bioenergy (~23,600t per annum), and assumes this continues throughout the 2024-2050 period.

Our demand curves through time illustrate a scenario where biomass is selected as the fuel for every boiler conversion in the RETA study,[77] i.e. it is a conservative forecast of biomass demand. The timing of each conversion (and hence when each increment will arise) is set by when it is optimal to switch to biomass given the expected ETS prices or, in the case where no date is set, 2050. The figure shows that, in the MAC Optimal pathways, unconfirmed biomass conversions across the RETA projects are gradually occurring over the 2034-2050 period, whereas in the Biomass Centric pathway all conversions take place in 2049.

Figure 43 – Pathways of Taranaki region bioenergy demand for process heat to 2050. Source: EECA



[77] Note committed switches to electricity are excluded.

In the following figure we overlay the various increments in Taranaki demand on six supply curve periods.

Figure 44 – Biomass supply and demand in 2029, 2034, 2039, 2044, 2047 and 2050. Source: Forme, EECA.

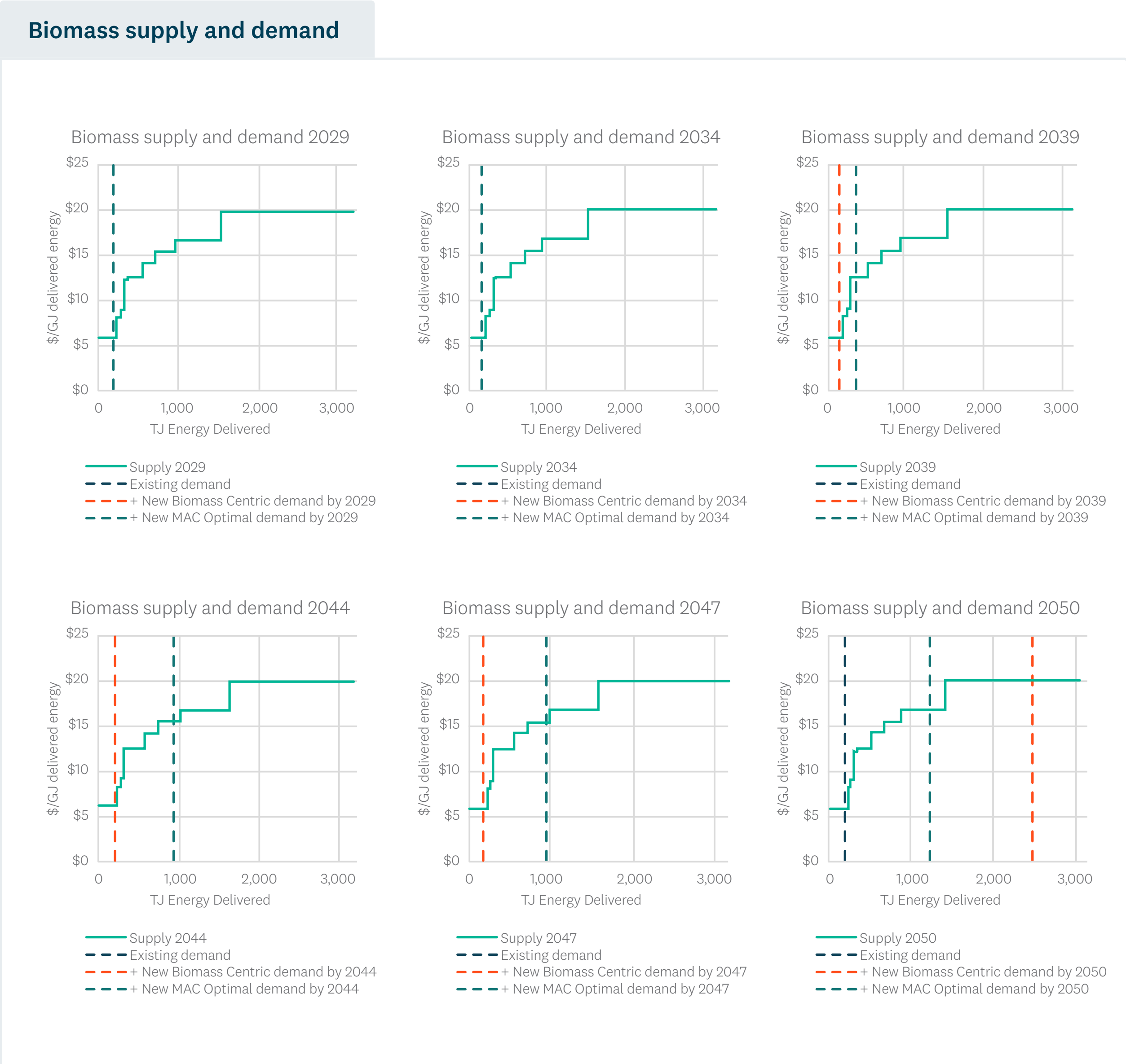


Figure 44 illustrates that from 2039 there is an increase in biomass demand, over and above existing demand. In 2039, demand in the MAC Optimal pathway (367 TJ pa, including existing demand) is double present demand, using all processing residues (excl. woodchip), all harvest residues, and 7% of pulp. In 2044, demand in the MAC Optimal pathway (928 TJ pa, including existing demand) is five times higher than current demand, using all processors (excl. woodchip) and harvest residues, all pulp and export KIS-grade logs, and 70% of KI-grade logs. In 2050, demand in the MAC Optimal pathway (1,230 TJ pa, including existing demand) is seven times higher than current demand, using all processors (excl. woodchip) and harvest residues, all pulp, all KIS and KI-grade logs, and 64% of K-grade logs. In 2050, demand in the Biomass Centric pathway increases from 170TJ pa (current demand) to 2,480TJ pa, using all log-grades to Export K in the merit order, plus 65% of Export A-grade logs.

On this basis and recognising that not all users will be paying the same equilibrium price (as shown for the MAC Optimal pathway), we assume that the long-term equilibrium biomass price is determined by the average of the K-grade and A-grade log prices, i.e. $18.3/GJ at the biomass hub.[78]

Photo credit: Taranaki Pine

[78] This is the base biomass price assumed over the RETA period.

9 Taranaki electricity supply and infrastructure

This section considers the impact of the electrification of process heat on the electricity system.

The availability of electricity generation to meet the demand from process heat users is largely determined at a national 'wholesale' level, from a network of power stations around the country. This supply is transported to an individual site through electricity networks – a transmission 'state highway' grid (owned by Transpower), and a distribution 'local roads' network (owned by Electricity Distribution Businesses (EDBs)) that connects individual consumers to the boundary of Transpower's grid. The points on the grid where EDBs (and potentially some large consumers, such as Fonterra) interface with Transpower's grid are referred to as Grid Exit Points (GXPs).

Unlike biomass, where markets for the supply and delivery of wood for bioenergy are only starting to emerge, the electricity industry evolved a market and set of institutional arrangements in the 1990s to govern how competing supply resources meet energy demand. These arrangements and rules have led to a range of market participants who compete to provide generation and negotiate a variety of commercial arrangements for the supply of electricity to consumers. These institutional arrangements include a framework embedded in legislation that governs the activities of monopoly transmission and distribution networks. Overall, these arrangements strongly influence (and often constrain) how prices are calculated, revenue earned, and assets that are invested in (including timing).

Electrification of process heat often leads to significant increases in demands on local electricity networks. Networks are primarily concerned with any increase in the highest level of instantaneous electricity demand – known as 'peak demand'. This is what EDBs design their networks to cope with. In some cases, increases in electricity demand will be beyond the existing capability of the local distribution network, and possibly beyond the capacity of Transpower's high-voltage transmission network.

On the assumption that process heat users have reduced their demand as much as possible through demand reduction and heat pump projects, then for this analysis the primary questions for a process heat user considering electrification are:

- What is the price of electricity likely to be, including the costs of wholesale generation, electrical losses, transmission, and distribution?[79]
- Is the existing capacity in Transpower and the EDBs' networks sufficient to transport electricity to their electricity-based process heat location at all points in time?[80]
- If the networks do not have sufficient spare capacity, what is the cost, and ability of network companies' ability to deliver any upgrades required to accommodate the peak electricity demand of process heat users (as well as any other consumers looking to increase electricity demand in that part of the network)?
- To what extent can a process heat user use any inherent flexibility in their consumption to reduce the cost of upgrades or electricity?

This section covers these four topics.

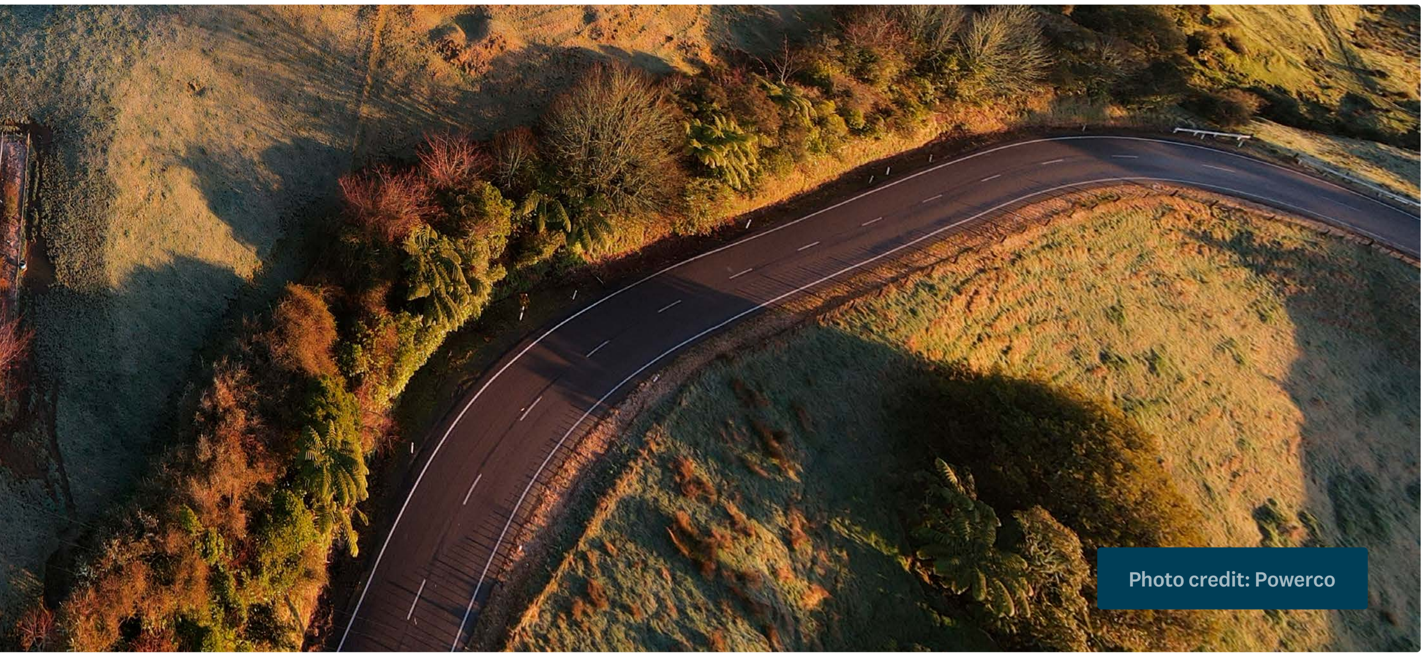


Photo credit: Powerco

[79] As explained below, this includes metering, regulatory levies and other costs which consumers pay for.

[80] The site's spare capacity also has to be considered, of course.

9.1 Overview of the Taranaki electricity network

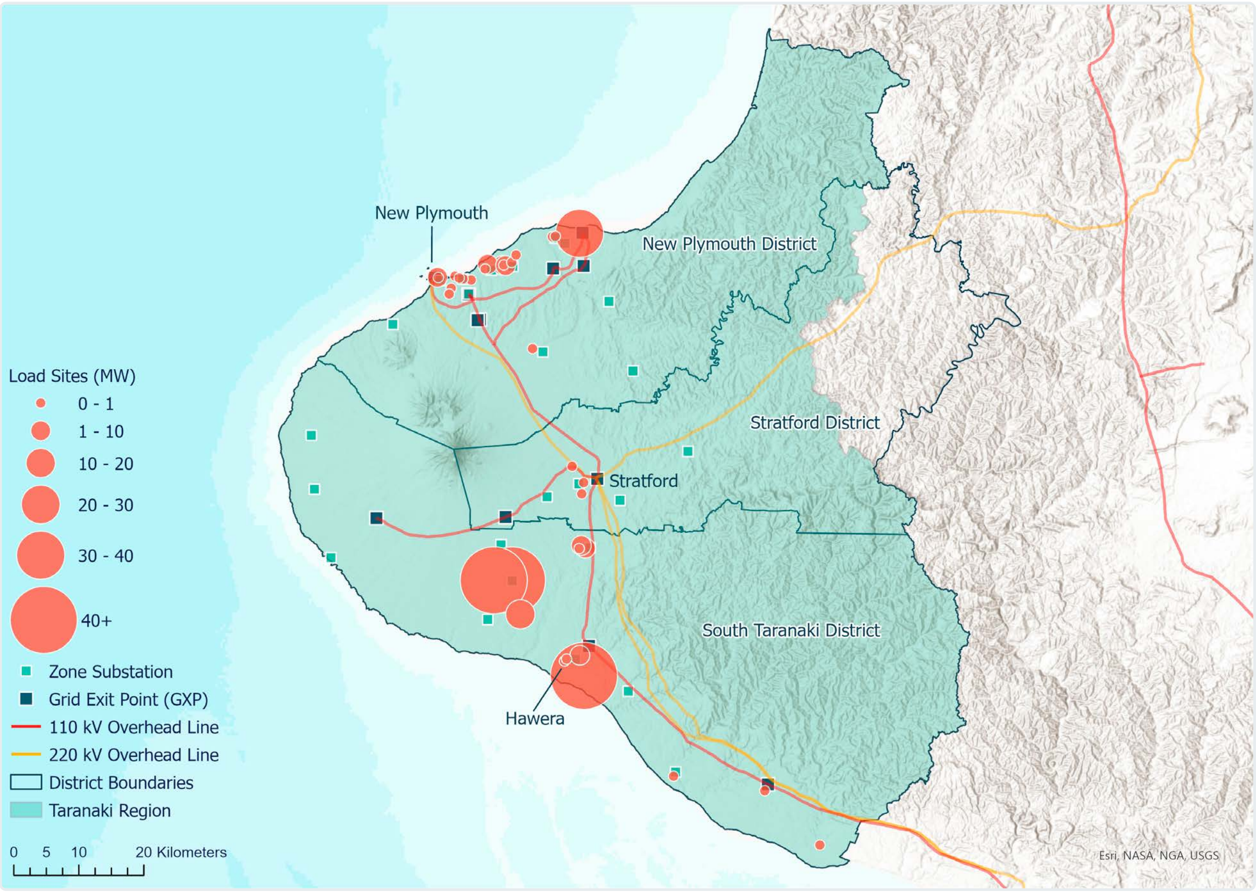
Figure 45 shows the region's high-voltage grid (owned by Transpower), including the nine grid exit points (GXPs). Six of the GXPs connect the national grid to the local distribution network of the local EDB (Powerco) to supply households and businesses in the Taranaki zone (and a section of the Whanganui zone) of Powerco's Western network.[81]

The remaining three GXPs connect large industrial consumers and/or generation:

- Hāwera 110kV GXP connects Fonterra Whareroa demand and co-generation[82]
- Motunui GXP connects the large industrial Methanex and OMV production loads, and
- Kāpuni GXP supplies the Fonterra Kāpuni load and allows for connection of the Kāpuni generation. The Kāpuni GXP is owned by Nova Energy instead of Transpower.

In addition to GXPs, Figure 45 shows the sub-transmission zone substations that are owned and operated by Powerco, alongside the 33 process heat demand sites where electrification of process heat could be considered (see Table 6).

Figure 45 – Map of the Taranaki process heat demand sites showing transmission grid, GXPS, and substations



[81] Powerco's Western region comprises of four network zones – Taranaki (including Egmont), Whanganui (including Rangitīkei), Palmerston (Manawatū-Tararua) and Wairarapa.

[82] A system that produces heat and electricity simultaneously in a single plant, powered by just one primary energy source (e.g. gas). The process heat can be used onsite, and the electricity can be used to supply on site demand or be exported into the local network.

Powerco's Taranaki network zone includes some heavy industry, oil/gas production and agricultural loads as well as the city of New Plymouth and other large towns.[83] The mix of residential, rural, commercial and industrial loads are split between winter peaking, with a daily morning and evening peak, and summer peaking. The latter are heavily influenced by the large rural/tourism areas and agricultural loads with typical summer morning and evening peaks. As outlined further below, the geography of the area and the associated characteristics of the assets alongside the types of consumers connected leads to some differences across Powerco's network zones.

The Taranaki region consumed 1,048GWh of electricity in 2023.[84] The maximum instantaneous ('peak') demand for the region is 234MW.[85]

Generation capacity in the region comprises of approximately 1,065MW[86] including:

- Piped natural gas - Taranaki Combined Cycle[87] (383MW), Junction Road (98MW), McKee (94MW), Mangahewa (9MW), Stratford Austral Pacific (1MW) and Stratford Peakers (220MW)
- Hydro - Patea (32MW), Mangorei (5MW) and Motukawa (5MW)
- Wind – Waipipi (130MW)
- Gas fired co-generation – Kāpuni (24MW) and Whareroa (64MW)
- Taranaki has a small but increasing amount of solar generation (11 MW).[88]

Together, the local grid connection generation (natural gas, wind and hydro) alongside the other local embedded[89] generation (hydro, solar and co-generation) produce around 2,420 GWh[90] per year, which represents approximately 230% of the region's annual consumption. Many of the generation plants in the area (particularly the natural gas plants) are peaking plants, meaning they are typically used only when required – for example when electricity prices are high, or when there are network constraints. Due to the high total generation capacity in the region, depending on the load and generation levels at a given time, the region may import or export electricity from/to the national grid.

83 Powerco operates its electricity network in two parts. The first being referred to as the Western Region (Taranaki, Egmont, Whanganui, Rangitīkei, Manawatū, Tararua & Wairarapa) and the second being referred to as the Eastern Region (The Valley: Coromandel to South Waikato and Bay of Plenty: Tauranga-Mt Maunganui). Noting that Powerco's AMP and disclosure information relates to the Western Network (including Taranaki, Egmont, Whanganui, Rangitīkei, Manawatū, Tararua & Wairarapa), this creates a discrepancy with the area defined as Taranaki for the RETA analysis. Therefore, in this report, where possible when referencing Taranaki, we have tried to use sources that assist in delineating Whanganui-Rangitīkei, Manawatū & Wairarapa so as to provide an accurate picture of the region as defined under RETA.

84 See emi.ea.govt.nz

85 Transpower's 2023 Transmission Planning Report

86 Transpower's 2023 Transmission Planning Report

87 Taranaki combined cycle generation plant is expected to be decommissioned at the end of 2024 – see Contact Energy, Interim Results Presentation, 19th February 2024, page 28.

88 See emi.ea.govt.nz Installed distributed generation trends.

89 By embedded we mean it is connected to the distribution network, rather than connected directly to Transpower's network.

90 See emi.ea.govt.nz generation trends and Powerco 2023 information disclosure documentation.

With the growing shift toward a lower carbon, more electrified way of life and forecast electrification of process heat and transportation, demand for electricity in the region is expected to increase. Transpower's 2023 Transmission Planning Report[91] forecasts Taranaki's regional demand will grow by an average 1.8% each year for the next 15 years, which is lower than the national average growth rate of 2% for the same period.

Major oil and gas facilities and a strong dairy industry all rely on the transmission system to varying degrees. Unlike other regions, due to natural gas resources, Taranaki also hosts a significant portion of the country's remaining thermal generation. In addition, there has been significant interest in solar and wind generation opportunities in the region, including offshore wind developments.

With the increase in renewable generation being proposed to be connected in the region, Transpower has identified some potential adverse impacts on the transmission system at times of high generation and low local electricity demand. As such Transpower has several replacement and refurbishment projects planned for the Taranaki region over the next 15 years to enable identified system issues to be resolved, some of which are covered in more detail in Table 9 in Section 9.3.3.

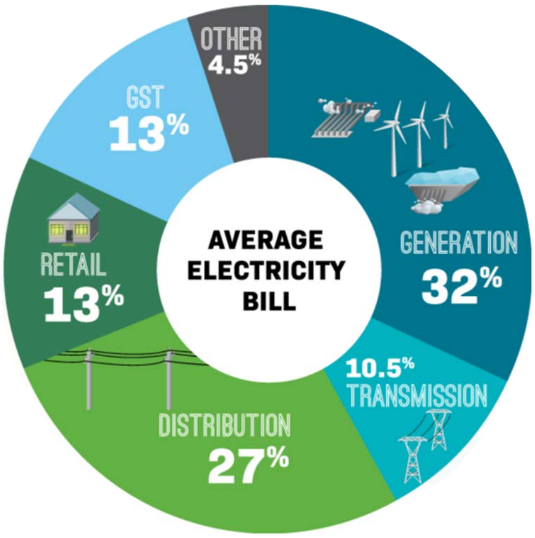
Photo credit: Powerco

[91] Table 12-1: Forecast prudent annual peak demand (MW) at Taranaki grid exit points to 2038, 2023 Transmission Planning Report

9.2 Retail electricity prices in Taranaki

Retail electricity prices, that would be faced by most of the sites,[92] reflect the average wholesale cost of electricity plus the network charges levied by Powerco and Transpower for the use of the existing network. The Electricity Authority publishes the image below showing how the total cost of electricity to a residential household is broken down:

Figure 46 – Components of the bill for a residential consumer. Source: Electricity Authority



While all of the components in Figure 46 are also present for large commercial and most industrial consumers, the breakdown will be different, and can vary substantially depending on the size of the facility (in terms of electricity demand), its proximity to a grid exit point, and its location in the country.

In terms of location, the Ministry of Business, Innovation and Employment (MBIE) periodically publish average domestic (i.e. household) electricity prices for 42 locations around the country. This can give us a sense of the cost of electricity in the Taranaki region relative to other parts of the country, and the role that the major components in Figure 46 play.

[92] Unless the site connects directly to Transpower's network, in which case it may not use a retailer to interpose between the wholesale market and its purchases. Also, some users may request a 'wholesale' or 'spot' rate from their retailer, where the retailer passes through the half-hourly wholesale price (plus a margin). While this is almost exactly like being a grid connected customer, we consider it a retail arrangement here, due to the potential for margins or re-packaging of network charges by the retailer.

Figure 47 – Quarterly domestic electricity prices in New Zealand, including GST. Source: MBIE.

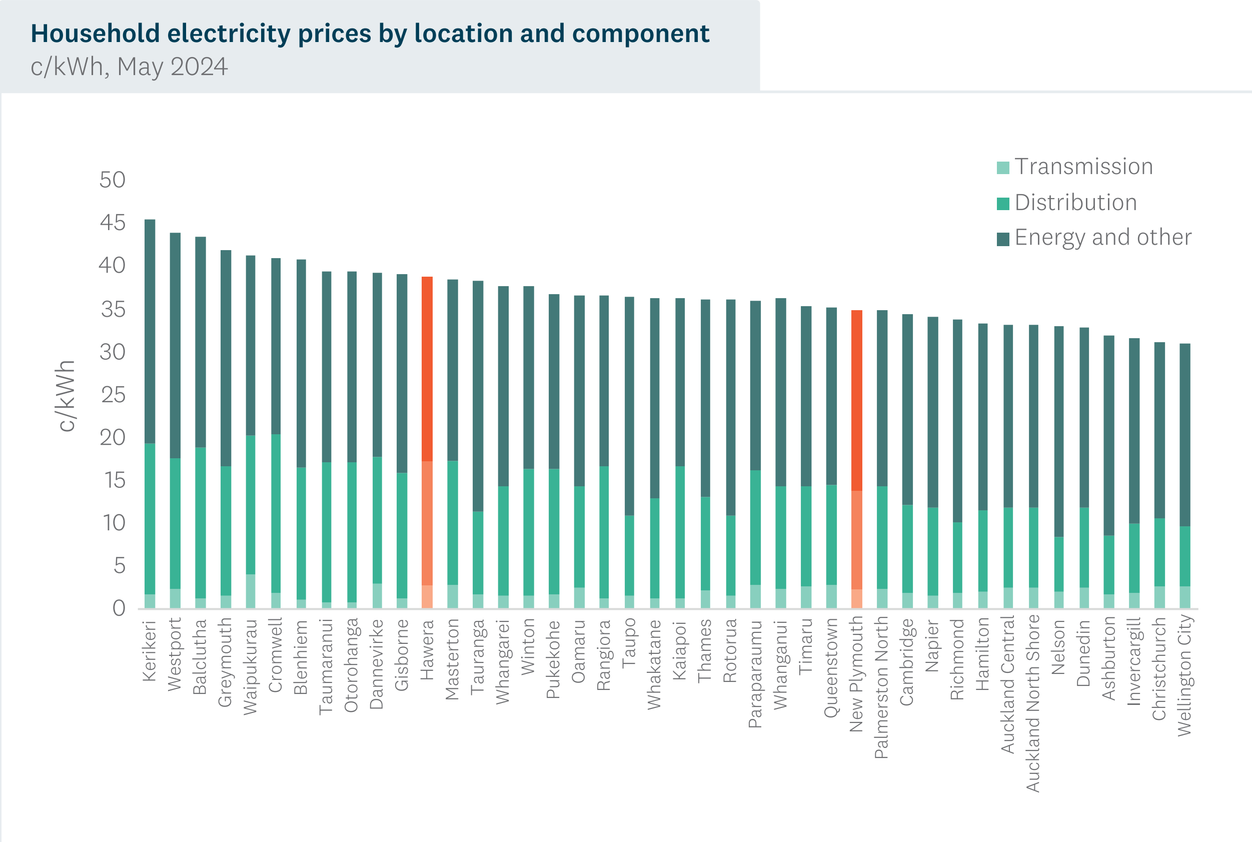


Figure 47 shows that the Taranaki region has a spectrum of residential prices, ranging from lower-range costs (New Plymouth) to higher than median costs (Hāwera).[93] These differences are likely driven by the different population densities of the two centres illustrated, electricity loss factors set by the EDB, as well as each urban centre experiencing different levels of retail competition.

These factors will also be present for commercial and industrial electricity consumers, such as potential process heat users considering electric boilers. However, the methodologies that determine the charges paid by commercial and industrial consumers may see these factors manifest differently.

This section provides general guidance on the generation, retail, distribution, and transmission components, but it is important that process heat users considering electrification engage with electricity retailers and Powerco to obtain tailored estimates relevant to their project.[94]

[93] Note that 'energy and other' in the chart relates to the generation, retail, and other components of Figure 49. The high level of transmission losses will be included in the generation component, rather than the transmission component, which reflect the charges for access to the transmission grid.

[94] On top of this, process heat sites will also pay charges for metering and Electricity Authority levies ('other' in the chart above)

9.2.1 Generation (or 'wholesale') prices

The generation or 'wholesale' cost of electricity is the result of electricity prices that arise from a market that clears supply and demand every half hour of the year. In order to derive a forecast of future retail electricity prices that can be used to assess the economics of electrification projects, ideally New Zealand needs a model that reflects the likely interaction of supply and demand, and therefore prices, in the wholesale market.

EECA engaged EnergyLink, an electricity market modelling firm, to use its sophisticated modelling of the electricity market to produce such a price forecast. Details of EnergyLink's model and simulation approach are discussed in Appendix C. Due to the range in potential future supply and demand outcomes in the electricity industry, and their impact on the wholesale electricity price, three wholesale price scenarios – low price, central and high price scenarios – were included in the EnergyLink modelling. Given the announcement in May 2024 that the Tiwai Pt smelter will remain open until 2044, the low-price scenario is no longer considered informative and, for the purposes of sensitivity analysis (see Section 7.4), we have developed an alternative low price scenario.

9.2.2 Retail prices

Today, most large users of power do not elect to face the half hourly varying wholesale price, and instead prefer the price stability in multi-year retail contracts. These contracts contain a schedule of fixed prices that each apply to different months, times of week and times of day (generally referred to as 'time of use' contracts).[95]

To reflect the estimated difference between the wholesale price and the retail price that would be faced by consumers, EnergyLink converted their wholesale price scenarios into time-of-use contract price scenarios. This provides a plausible guide (based on historical trends) as to what customers might expect if they were to seek this type of retail contract.

EnergyLink prices include the effects of high-voltage transmission losses to the nearest GXP in the Taranaki region, but do not include distribution network losses to the customer's premises.

As part of their pricing methodology, Powerco sets 'loss factors' to account for distribution losses, and these loss factors are applied by retailers to the GXP-based price. In the case of Taranaki, the distribution losses for sites connecting at or below 11kV are around 1.07 for Powerco's Western network.[96]

Each site contemplating electrification should engage with electricity retailers to obtain more refined estimates and potential options relevant to their operational requirements.

95 Common contracts are often referred to as '144 part' contracts, reflecting the fact that the prices are specific to 12 months, two-day types (weekday and other day) and six time periods within the day.

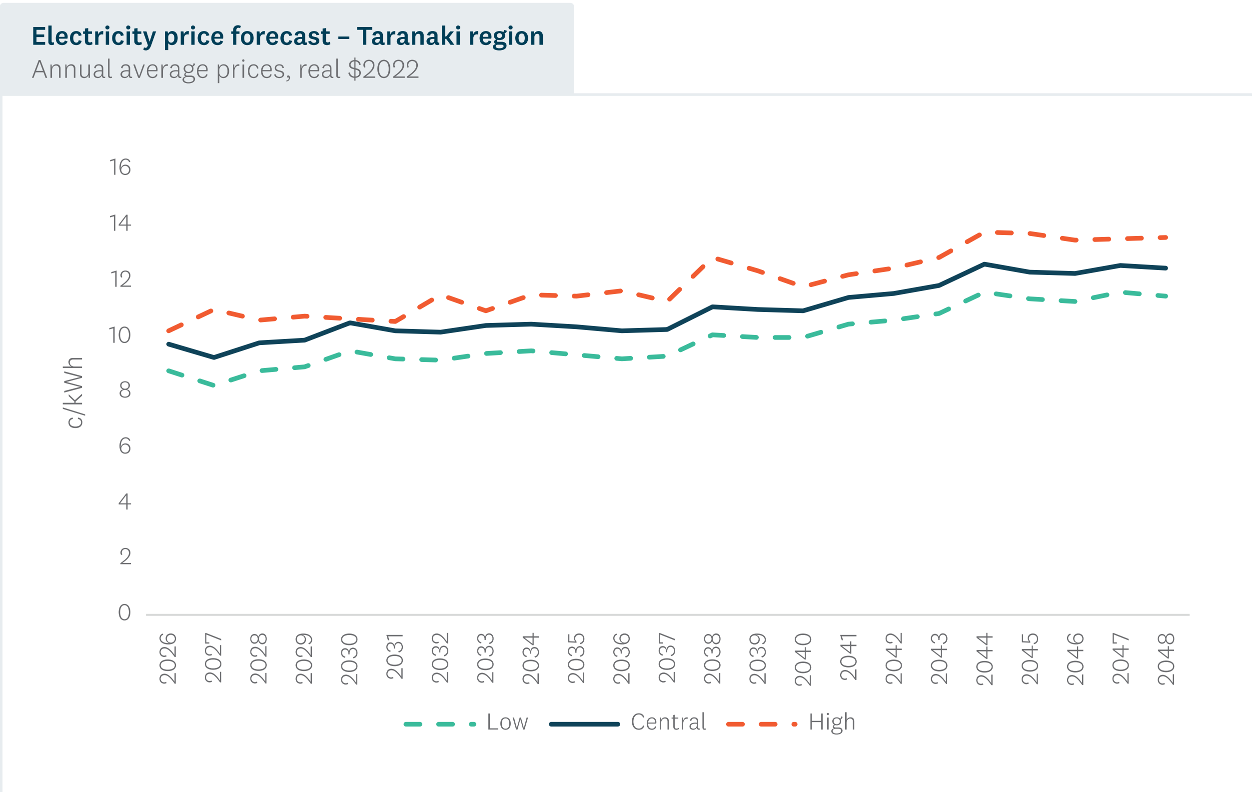
96 EDBs publish network loss factors for different parts of the network, usually as part of their pricing schedule. An individual customer can find their loss factor by entering their ICP number (found on a recent power bill) in https://www.ea.govt.nz/consumers/your-power-data-in-your-hands/my-meter/. The distribution loss factor for that site can then be found under the 'Network Pricing' section.

9.2.3 Retail price forecasts

Annual average (nominal) price forecasts are presented below for the period 2026-2048. Three retail price scenarios have been provided, and the detailed assumptions behind these can be found in Appendix C. We reiterate that the prices discussed in this section do not include network charges.

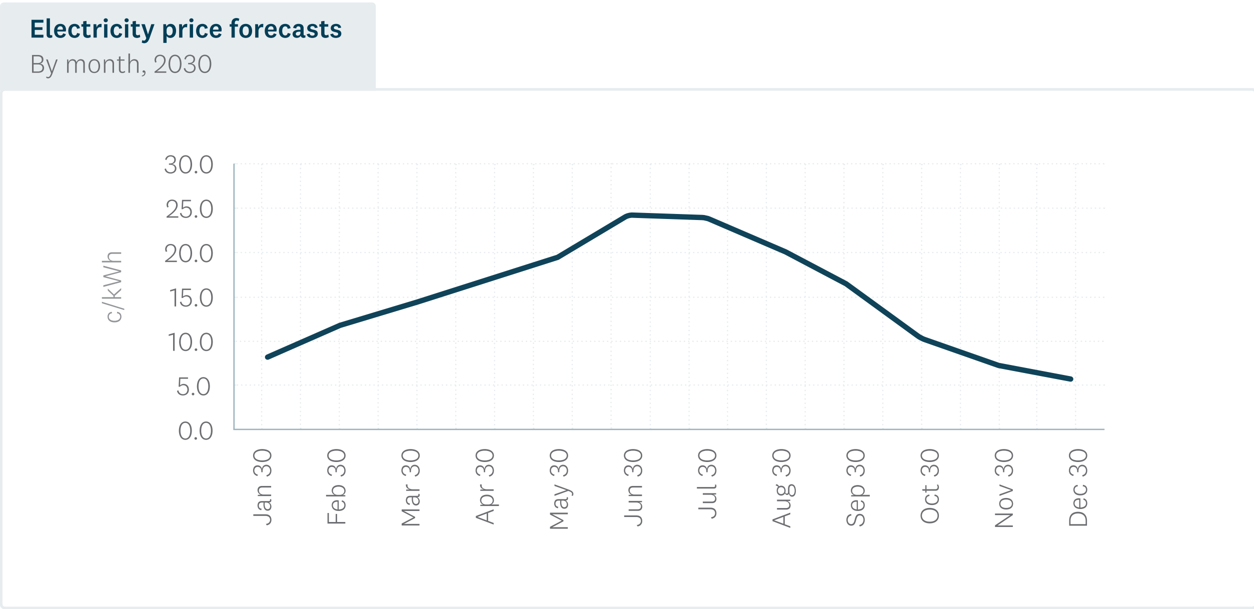
For the central scenario, real electricity prices increase by 12% between 2026 and 2040 for the Taranaki region. Beyond 2040, the forecast sees more significant increases in electricity prices. However, it is difficult to predict pricing beyond this period. Some New Zealand market analyses suggest real prices may remain constant after 2035, due to the downward pressure on generation costs (especially solar and wind) as technology and scale increases. Other analyses see continued increases. We cannot be definitive about electricity prices 20 years into the future and suggest any business cases consider a range of scenarios.

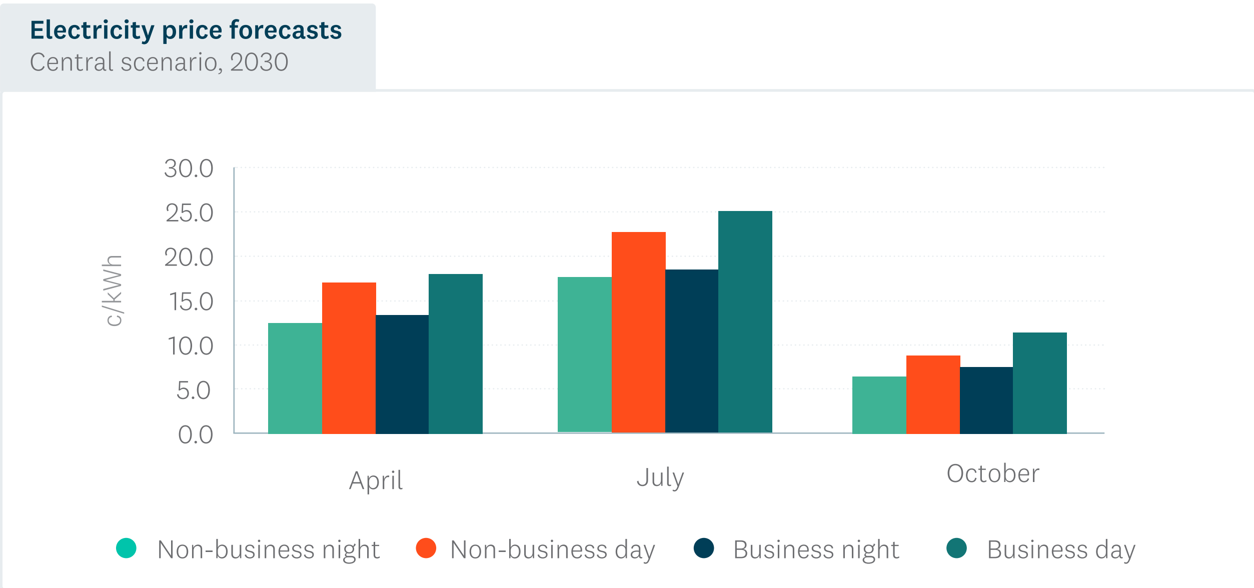
Figure 48 – Forecast of real annual average electricity prices for large commercial and industrial demand in the Taranaki region Source: EnergyLink



As outlined earlier, the price forecasts are provided at a finer resolution than the annual average series in Figure 48. Figure 49 zooms in on 2030, showing (a) the variation over the year, and (b) the variation between day and time of day.

Figure 49 – Electricity price forecasts (a) by month and (b) by time block in April, July, and October 2030. Source: EnergyLink





The shape of electricity prices over the year reflects the expected nature of national winter demand (winter peaking – lighting and heating) coupled with lower winter inflows into alpine lakes. However, this is somewhat inversely correlated with some of the sites considered in this study, particularly dairy, who experience the lowest levels of demand during winter. The volume-weighted price paid for electricity at these sites could be materially different from the annual average prices shown in Figure 49. Our modelling considers each process heat user's profile of thermal load across the day, week, and year.

As noted above, the prices that a retailer will charge a process heat user will include a network loss factor which is specific to where the customer is located in Powerco's network. EnergyLink's prices do not include this component, but they are incorporated into our modelling in Section 7. Network loss factors are discussed in Appendix C.

9.2.4 Distribution network charges

EDBs levy charges on electricity customers for the use of the distribution network, except for those large customers who connect directly to one of Transpower's GXPs. These charges are in addition to the generation and retail ('energy') component of a customer's tariff.[97] As monopolies, EDBs are permitted under the Commerce Act to recover the cost of building and operating the distribution network plus a regulated return. The total amount of revenue EDBs can earn is regulated by the Commerce Commission,[98] while the way they charge customers (generally referred to as 'distribution pricing')[99] is overseen by the Electricity Authority.

The magnitude of charges for any individual customer depends on each EDB's 'pricing methodology'. This methodology describes how each EDB will convert its allowable revenue into prices for different customer groups, while meeting the principles set by the Electricity Authority for efficient pricing. Each year, these prices – for each customer group – are published by each EDB in a 'pricing schedule'. Powerco's charges for both distribution and transmission are based on their 2024-2025 pricing methodology.[100] Most businesses considering electrification of process heat would likely fall into a 'large commercial and industrial' or medium voltage (11kV) category of charging. The main components used by Powerco for pricing in these categories are:

i. Fixed daily charges.
ii. Peak Coincident Demand (PCD) charges (related to the consumer's average demand during the top 100 peak periods observed on Powerco's network, usually measured in kW or MW).
iii. Capacity charges (related to the full capacity of the connection provided by Powerco, measured in kVA or MVA).
iv. Average Demand Level (ADL) charges (related to the consumer's average level of kW demand across a 12-month period)

Powerco set their distribution charges for large commercial and industrial customers based on the size of the connection (kVA) and peak coincident demand (kW). As such distribution prices will vary per site. In addition, transmission charges (refer section 9.2.5) are a combination of capacity (kVA) and average demand (kW) charges.

It is important that each business considering electrification of process heat engages with Powerco to discuss the exact pricing that would apply to them.

97 This is generally the costs we have discussed above, relating to generation plus transmission losses and retailer margin, insofar as the latter is included in variable (c/kWh) charges. Some components of retailer margin may also be included in fixed daily charges from the retailer.

98 At least, those EDBs who are covered by price-quality regulation. Consumer-owned EDBs do not fall into this category, and hence their revenue is not regulated by the Commerce Commission.

99 By this we mean how they allocate their costs amongst different customer groups, what variables they use to charge customers (e.g. capacity, peak demand, volumetric consumption) and other principle-based oversight. For more information see https://www.ea.govt.nz/projects/all/distribution-pricing/

100 Powerco's 2024-2025 electricity pricing schedules and methodologies for the Western Network can be found on their website.

9.2.4.1 Contributions to the capital cost of accommodating new demand

In Section 9.3, we provide estimates of the capital costs that Powerco (and - for some large users - Transpower) would incur to upgrade their network to accommodate a particular process heat user's electrification decision.

The charges in that section are presented as total capital costs. Precisely how the process heat user pays for these upgrades, however, is usually more complex than a simple up-front payment. There are a variety of ways that EDBs can recover these costs (assuming that it is Powerco that constructs the new assets rather than a third party).[101] These are contained in Powerco's 'capital contribution' policies, which recognise that new demand is subject to the cost-recovery charges and hence – over time – a component of the cost of new assets may be recovered through these charges. Powerco may elect to calculate an up-front capital contribution that is only a portion of the total cost of the required upgrades or, in some situations, may design customer-specific charges (often including a fixed component), tailored to the process heat user's expected demand and location in the network.

The exact methodology used to determine the quantum of capital contribution required from new electricity demand varies between EDBs. It is important that process heat users contemplating electrification meet with Powerco to discuss how this will work in their situation. For the pathway modelling outlined in Section 7.2, we assume that Powerco contributes 50% of the capital costs associated with distribution network upgrades required to connect process heat users.

9.2.5 Transmission network charges

Where a consumer connects directly to the grid, Transpower will charge this consumer directly for use of the national grid. Otherwise, Transpower's charges are passed through by the local EDB Powerco. As noted previously approximate transmission charges for Powerco's Western Network vary with the size (kVA) of the connection and are a pass-through of Transpower's charges based on Powerco's 2024-2025 pricing methodology.[102]

The rules governing how Transpower charges its customers (distributors, directly connected industrials and generators) are determined by the Electricity Authority. These rules are known as the 'Transmission Pricing Methodology' (TPM).

A major revision to the TPM guidelines was concluded by the Electricity Authority in 2022. These changes came into effect for the 2023/24 pricing year.[103]

The TPM is incredibly complex, and it is not possible to present the methodology in any detail here. To help process heat users understand these changes, we provide a commentary in Appendix C on what the TPM is trying to achieve, and what that might mean for charges that are passed through by EDBs to process heat users. We also provide a worked example.

[101] Electricity Network Association information on EDB connection pricing

[102] Powerco 2025 Electricity Pricing Methodology

[103] A pricing year begins on 1st April for all network companies.

9.2.6 Electricity pricing summary

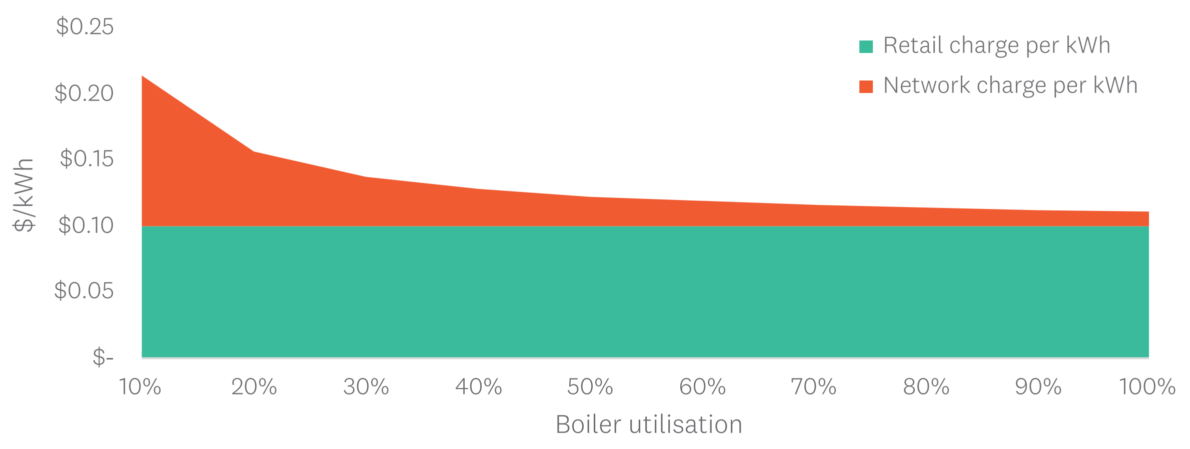
In summary this section has shown that process heat users considering electrification in the Taranaki region would face the following charges for electricity consumption:

- A retail tariff (including wholesale market and retail costs) which would **average around 11.5c/kWh over the 20 year project life**, including losses of approximately 7% for the region. We note the effective average tariff will differ between process heat users depending on the way their consumption varies over the year. Further, industrial process heat users may be able to secure special retail rates being offered by electricity retailers which may be significantly lower.
- A network charge which comprises components relating to the use of the existing distribution network, and Transpower's transmission network. These charges are structured in a range of different ways. Powerco's charges for its Western network include a combination of a fixed daily charge, a peak coincident demand charge and a capacity charge. We strongly recommend process heat users engage with Powerco to obtain pricing that is specific to their location, operating profile, and desired capacity.

Combining these two types of charges (retail and network) into a single overall cost of electricity, to allow comparison with other fuels, requires an estimate of the utilisation of the heat plant (electrification projects). As discussed above, distribution charges are typically calculated as a function of variables that are often fixed (once the new connection is completed) – e.g. connection capacity (kVA). As a result, for a given connection capacity, an electrification project which has a high utilisation over the year will have a lower overall per-kWh cost of electricity than a site which only uses its boiler, furnace or heat pump for a shorter period (e.g. winter). This is illustrated in Figure 50, for example parameters of retail[104] and network charges.[105]

Figure 50 – Illustrative example of how overall cost of electricity varies with heat plant utilisation.

Overall cost of electricity ($/kWh) for different boiler utilisation
Retail charge $0.10/kWh; Network charge $100,000/MW



[104] As noted above, the retail rate itself will, in many situations, vary over the year under a 'time of use' retail plan. For simplicity, we have assumed a fixed retail rate over the year.

[105] The network charges used in Figure 49 are not a reflection of Powerco's charges for the Western Network (which are customer specific), rather they are illustrative only for the purposes of the example.

This doesn't mean that distribution charges can't be reduced. Rather, it means that opportunities to reduce them exist primarily at the design phase – optimising the size of the connection capacity and enabling flexibility in heat plant operation so that peak demand charges can be minimised. Appendix C discusses the opportunities and benefits from enabling flexibility in more detail.

The next section considers the third component of costs, which is the potential for individual sites to need upgrades to the distribution network to accommodate the electrification of their process heat. This would require a capital contribution from the process heat user.

Photo credit: Powerco

9.3 Impact of process heat electrification on network investment needs

EECA engaged Ergo to complete an assessment of the potential costs of transmission and distribution upgrades required to accommodate electrification of each identified process heat demand site, given the current capacity of the Taranaki networks. It is important to understand that this analysis was conducted to a level of accuracy commensurate with a 'screening' analysis and, necessarily, required Ergo to make several judgments and estimates. Each site contemplating electrification should engage with Powerco to obtain more refined estimates and potential options.

Further, accommodating new demand for electricity from process heat is not purely a matter of building new network assets. The degree to which network expansion is required can be influenced by the process heat user's willingness to be flexible in *when* they consume electricity and/or their willingness to have supply briefly interrupted on those very infrequent occasions when a network fault occurs. There are a range of ways that process heat users can benefit from being flexible, and EDBs are exploring ways in which customer response can be reliably integrated into their networks via operational arrangements and pricing incentives.[106]

These opportunities are not included in Ergo's assessment of connection costs, and process heat users should engage with Powerco early to understand how their use of flexibility can reduce the cost of connecting, and what the operational implications are (see Appendix C for a fuller discussion on flexibility).

As described in Section 9.1 the maximum demand for Taranaki is 234MW.[107] If all identified process heat sites electrified their process heat demand, the region would experience an increase of 230MW. However, if two potential hydrogen electrolyser projects also proceeded, this would add an additional 302MW of peak demand. Given the significant size of one of the hydrogen electrolyser projects, it would require bespoke electricity transmission and generation arrangements that are beyond the scope of this analysis. The remainder of this section therefore excludes this potential demand. The increase in demand grows regional Taranaki peak demand to 464MW, i.e. 98% increase on the 2023 regional peak demand. However, this is considered a conservative assessment, as we expect there to be some diversity between when each of the individual sites reach their peak demand.

We stress that the assessment of spare network capacity, costs, and lead times presented below is changing all the time. The policy and regulatory space for the electricity sector is in a state of change as it incorporates decarbonisation and the emergence of new technologies. This in turn is leading to a greater number of consumers considering the technology they buy and how they reduce their consumption of fossil fuels. Hence Transpower and EDBs exist in a context which is changing far more quickly than it did in the recent past.

Specifically, Transpower and the EDBs are experiencing an increasing need for investment as a result of continued population and business growth, distributed generation, and the electrification of transport and process heat. While this RETA analysis only examines demand from process heat electrification, this broader context of potentially rapid growth in demand is important to understanding the challenges associated with accommodating new load.

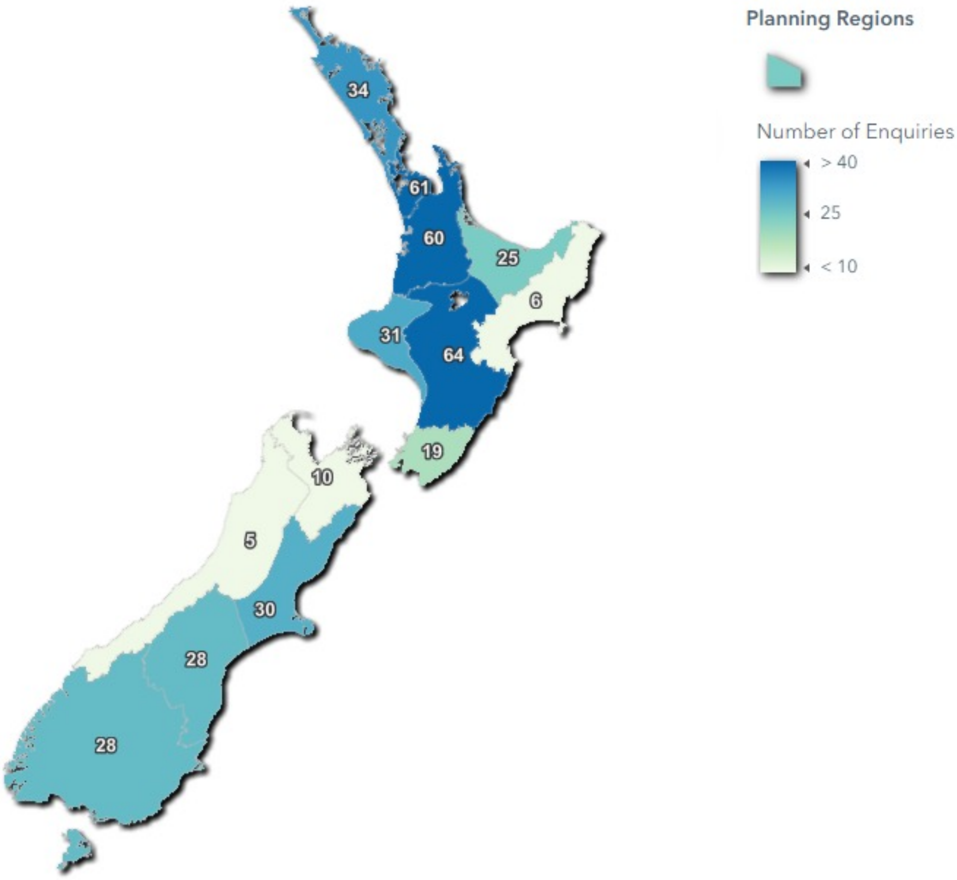
106 This is part of a broader development of 'non-network alternatives' by EDBs and Transpower – demand response from consumers, distribution-scale batteries, and distributed generation – to defer the need for more capital-intensive upgrades.

107 Transpower's 2023 Transmission Planning Report

Specifically, Transpower and the EDBs are experiencing an increasing need for investment as a result of continued population and business growth, distributed generation, and the electrification of transport and process heat. While this RETA analysis only examines demand from process heat electrification, and public EV charging facilities where this information is available to EECA, this broader context of potentially rapid growth in demand is important to understanding the challenges associated with accommodating new load.

As an illustration of this, Figure 51 below shows the number of enquiries Transpower alone is facing in each of its planning regions. Of the 401 enquiries they face nationally, 60% have need dates prior to 2025.[108] Transpower reports that of the 53 enquiries in the Taranaki region, 11 are for demand-side needs including network upgrades and Powerco/Transpower demand connections.[109] The remainder are for asset transfer or other transaction (1), and supply-side needs including grid-connected generation (30) and Powerco connected generation (11).

Figure 51 – Number of grid connection enquiries per region, June 2024. Source: Transpower



It is going to be challenging for Transpower and EDBs to scale up their resourcing to cater to this new demand and proposed generation in the region.

The implication for the material presented in this section is that it is a snapshot in time, in an electricity industry that is rapidly changing – both on the supply (generation) side, and for consumers as they consider electrification.

108 As at June 2024.

109 The regional figures on Transpower's map excludes any enquiries that are only prospects, commissioned, or 'Enquiries that have been assessed as unlikely to proceed to commissioning'. Our figures in the text report the total number of enquires.

9.3.1 Non-process heat demand growth

The assessment of spare capacity at each point in the network is based on near term estimates of peak demand published by network companies, combined with knowledge of peak demand at each identified process heat demand site. Should some of the sites proceed to electrification, a number of years may pass between now and when the connection and fuel switch is finally commissioned. In this intervening period, some degree of demand growth (outside the sites considered in this RETA) will occur due to:

- Increased residential demand from new houses.
- Increased business demand from business growth and/or smaller scale fuel-switching away from fossil fuels.
- Increased transport demand from the electrification of private and public transport vehicles.
- Other potential new large electricity demands, such as data centres.

Powerco will have developed peak demand forecasts over the next 10+ years that account for these factors. EECA understands these forecasts are shared with Transpower, as they develop their peak demand forecasts for each GXP.

Depending on the magnitude of growth in electricity demand, some of the spare capacity identified may be absorbed by the time each site finalises its connection arrangements. Hence the above analysis is a snapshot in time and has not considered the degree to which future demand growth may change which investments trigger an upgrade.

9.3.2 Network security levels – N and N-1

Before discussing the current state of the electricity network in the Taranaki region, it is important to define the security standards that are used to define the capacity of the network.

Electricity networks use a convention to describe the level of connection security they provide all customers at a particular connection point. Broadly, this convention distinguishes three levels of security:

- **N-1 security** – Where N-1 security is present, forecast peak demand can be met and, furthermore, any 'credible' failure of a single component of the network (e.g. transformer or circuit) will also leave the system in a satisfactory state.[110]
- **N security** – A failure of any single component of the network at forecast peak demand may result in a service interruption that cannot be restored until the fault is repaired.
- **Switched security** – Some EDBs also use a concept of 'switched' security where the EDB responds to a network event by switching a customer across to an alternative network asset. This switching may result in a short interruption, which may or may not suit the customer.

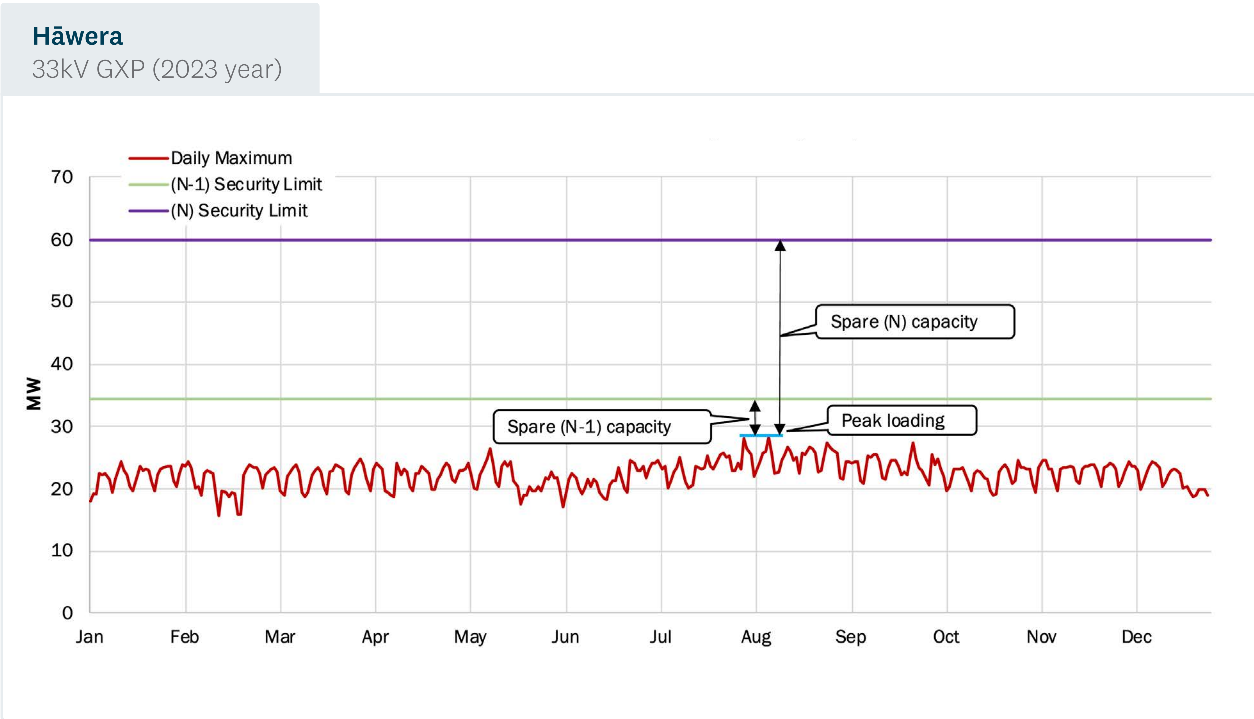
N-1 is generally provided through building redundancy into network assets, relative to the expected (peak) demand. It is the standard that applies on the 'interconnected' parts of Transpower's high-voltage transmission grid, due to the scale of bulk power flows affecting a large part of the population.

110 This means that undue interruptions in supply or the spreading of a failure must not occur. Furthermore, the voltage must remain within the permitted limits and the remaining resources must not be overloaded.

In the distribution networks, the lower scale, coupled with higher network density, means providing the redundancy for N-1 to every customer would be very expensive. Hence, many parts of the distribution network only experience N security. This is discussed further in Appendix C.

Figure 52 illustrates the difference between the available capacity for N and N-1 security for Hāwera 33kV grid exit point which supplies five zone substations in Powerco's network.

Figure 52 – Illustration of spare N and N-1 security capacity at Hāwea 33kV GXP substation. Source: Ergo



If a customer agrees with Powerco to utilise N security capacity,[111] there may be operational measures that would need to be put in place to ensure network security is managed in the event of a network fault. These operational measures will likely include a physical arrangement which automatically interrupts supply to the process heat user when a network fault occurs.

As discussed in Appendix C, current spare capacity may be more efficiently utilised through new process heat users enabling flexibility in their production processes (i.e. increasing load diversity). Such flexibility can either be made available to network companies should a network failure occur (i.e. the '1' in N-1) or could be used systematically to avoid breaching the N-1 limit in real-time (through, for example, demand shifting).

111 This includes situations where N-1 security is currently being provided to existing customers (often the case in urban centres), but the connection of a new process heat demand exceeds the spare N-1 capacity. To continue providing N-1 security to existing customers, an arrangement between the new process heat user and the EDB could be that the new process heat uses spare N capacity on the understanding that the EDB can automatically interrupt supply in the event of a network fault. This ensures that continuity of supply (i.e. N-1) is maintained to the existing customers, whilst at the same time limiting the investment required to accommodate the new process heat user.

9.3.3 Impact on transmission investment

As part of its annual Transmission Planning Report, Transpower works with EDBs and other stakeholders to produce long-term grid enhancement strategies for each network area to address capacity issues that are expected to result from the forecast load growth and proposed new generation in the area. In doing this, Transpower considers investment in additional interconnecting and supply transformers, circuits, and voltage support equipment, as well as using operational measures such as special protection schemes and generator runback/constrained-on schemes.

The electrification of the identified process heat demand sites will increase the electricity demand at seven of the ten regional GXPs shown on Figure 45. This has implications for both regional and GXP demand.

Regional considerations

As previously noted, the load forecast for Taranaki over the next 15 years, is lower than the expected national average of 2.0% per annum. However, as noted by Transpower,[112] there has been significant interest in solar and wind generation opportunities in the region, including offshore wind developments. To supply the forecast demand, and to facilitate the connection of new generation in the region, may require investment in the distribution network as well as the transmission network.

From a transmission perspective, Transpower is responsible for maintaining and upgrading the national grid to ensure continuity of supply, which includes the management of voltage stability. Many of the transmission capacity issues in the region relate to capacity for new/excess generation connections, and as such, the region may be an optimal location for additional electrical demand. Many of the transmission capacity issues in the region can be managed in the short-term with special protection schemes (SPS) or transformer overload protection schemes (TOPS), and in the longer-term with planned equipment replacements or upgrades.

Transpower is working with Powerco and other stakeholders to operationally manage the existing grid asset capability within the Taranaki region, during particular system conditions (e.g. high demand coinciding with low generation).

The inherent assumptions in our analysis for the Taranaki region are that:

- Transpower's investment programme will address the Taranaki thermal and voltage stability issues noted over the next 15 years.[113]
- There is always sufficient local generation to supply the demand within the region.
- The transmission lines connecting the region to the national grid have sufficient capacity, at all times, to export any excess generation produced.

GXP, Sub-transmission substation level connection considerations

The available spare capacity for different security levels (N and N-1), at each of the Taranaki GXPs is shown in Figure 53.[114] For the avoidance of doubt, Figure 53 shows the capacity headroom at each GXP, that is, the difference between Transpower's prudent demand forecast (for 2023) and the N or N-1 capacity at the GXP (as published by Transpower).

112 Refer section 12.1 Transpower 2023 Transmission Planning Report.

113 2023 Transmission Planning Report: section 12.3.2.

114 Hāwera 110kV GXP is not included as Transpower has not reported on the spare HV capacity of this GXP.

Figure 53 – Spare capacity at Transpower's Taranaki's Grid Exit Points (GXPs). Source: Ergo

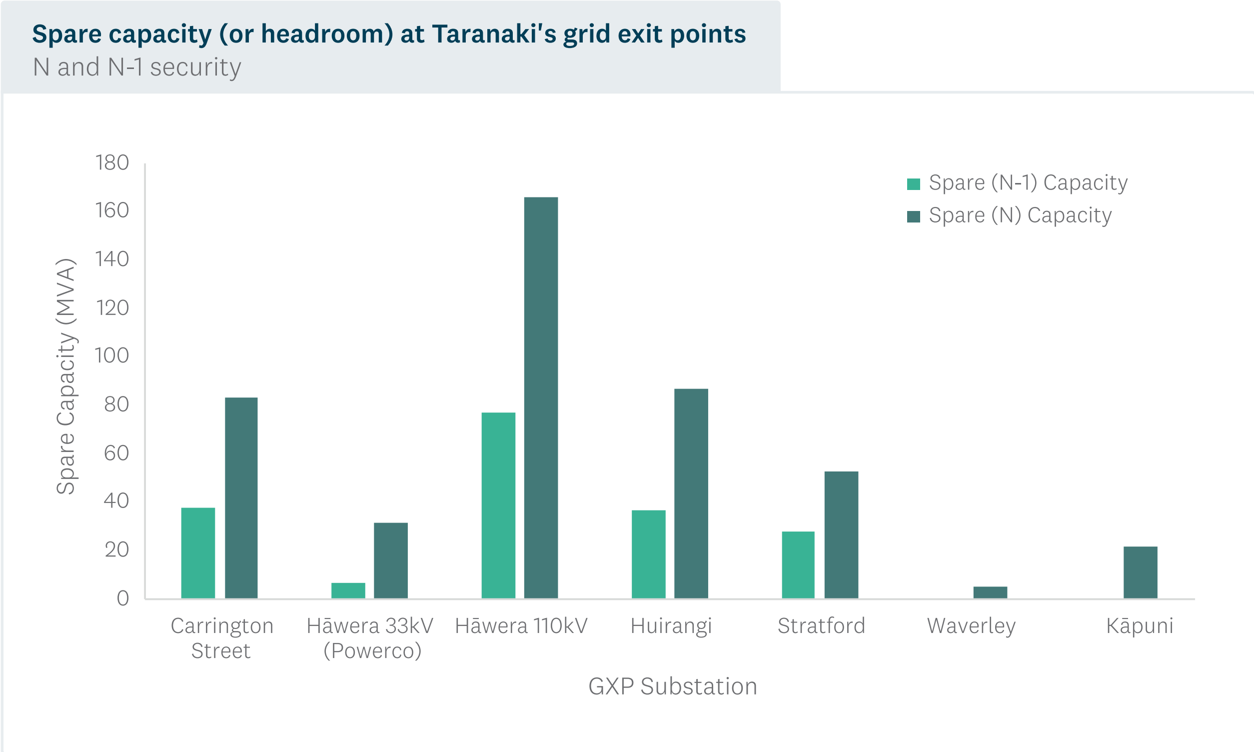


Figure 53 infers that based on the 2023 forecast demands for the region,[115] there are modest levels of spare N-1 capacity at Carrington St, Hawera 33kV (Powerco), Hāwera 110kV,[116] Huirangi, and Stratford. Waverley is connected via a single transformer, and Kāpuni is supplied via a single 110kV circuit. Therefore, these GXPs have no spare N-1 capacity as it can only operate at N security.

As previously noted, Taranaki is home to considerable generation with a point of connection to the grid (which includes grid connected sites and network embedded generators with a large enough impact on GXPs to be subject to Transpower requirements), which has the following impacts on spare capacity:

- **Carrington St GXP** – Local generation includes the Mangorei hydro station (5MW) the output of which feeds directly into the Powerco network at Carrington GXP.
- **Huirangi GXP** – Local generation includes Motukawa hydro station (5MW) and the gas fired Mangahewa (9MW) peaker plant. As the latter is a peaker plant, it can contribute to supplying the local load during situations where there is a mismatch in supply and demand, low hydro supply or network constraints. The production output of both stations feed directly into the Powerco network at Huirangi GXP.
- **Waverley GXP** – Waipipi wind generation is grid connected to Transpower's 110kV network via a single 110kV transmission line to Waverley GXP. As the generation is intermittent (wind), the output from the scheme varies with a maximum capacity of 133MW, producing ~455GWh per annum.[117]
- **Hāwera GXP** – Local generation includes Pātea hydro station (32MW) and Whareroa gas fired co-generation station (64MW). These stations connect into Transpower's 110kV network at Hāwera GXP.

115 From demand forecasts included in Transpower's 2023 TPR, and Powerco's 2023 AMPs.

116 As it relates to the supply to the Whareroa site via two 110kV circuits from Hāwera 110kV bus, calculated by Ergo. Transpower did not provide the spare N or N-1 capacity of Hāwera 110kV at the HV side.

117 https://www.mercury.co.nz/about-us/renewable-energy/wind-generation/waipipi-wind-farm

- **Kapuni GXP** – Kapuni load and generation is connected to the grid through a single 110kV circuit (owned by Nova Energy) which is tee-connected to Transpower's 110kV Opunake-Stratford 2 circuit.
- **Stratford GXP** – The gas fired Taranaki Combined Cycle (383MW) and Stratford Peaker Plant (220MW) connect to the national grid at Transpower's Stratford GXP. Taranaki Combined Cycle provides base load generation, whereas the Stratford Peakers production contributes to supplying energy where there are high electricity prices due to is a mismatch in supply and demand, low hydro supply, and/or network constraints.

Transpower and Ergo's assessment of spare capacity does not consider any additional small 'embedded generation' (e.g. rooftop solar) connected at, or downstream of, each GXP. Insofar as all the local and embedded stations are generating at the time that peak demand occurs at the various GXPs, this will reduce the demand on Transpower's assets 'increasing' the effective spare capacity at that GXP.

In addition to the generation above, the Junction Road and McKee open cycle gas turbine plants are directly connected to the transmission network in the area via Grid Injection Points (GIPs).

Given the number of generation plants in Taranaki the production output from the combination of these often exceeds the demand offtake, with the result that power is exported out of the region into the North Island Grid

The spare capacities shown in Figure 53 relate to the supply transformer capacities and do not include any voltage constraints or upstream transmission constraints, which would need to be confirmed by Transpower or Powerco.[118]

For those sites with limited spare capacity left, we comment below on any planned transmission upgrades.[119] These are summarised in Table 9.

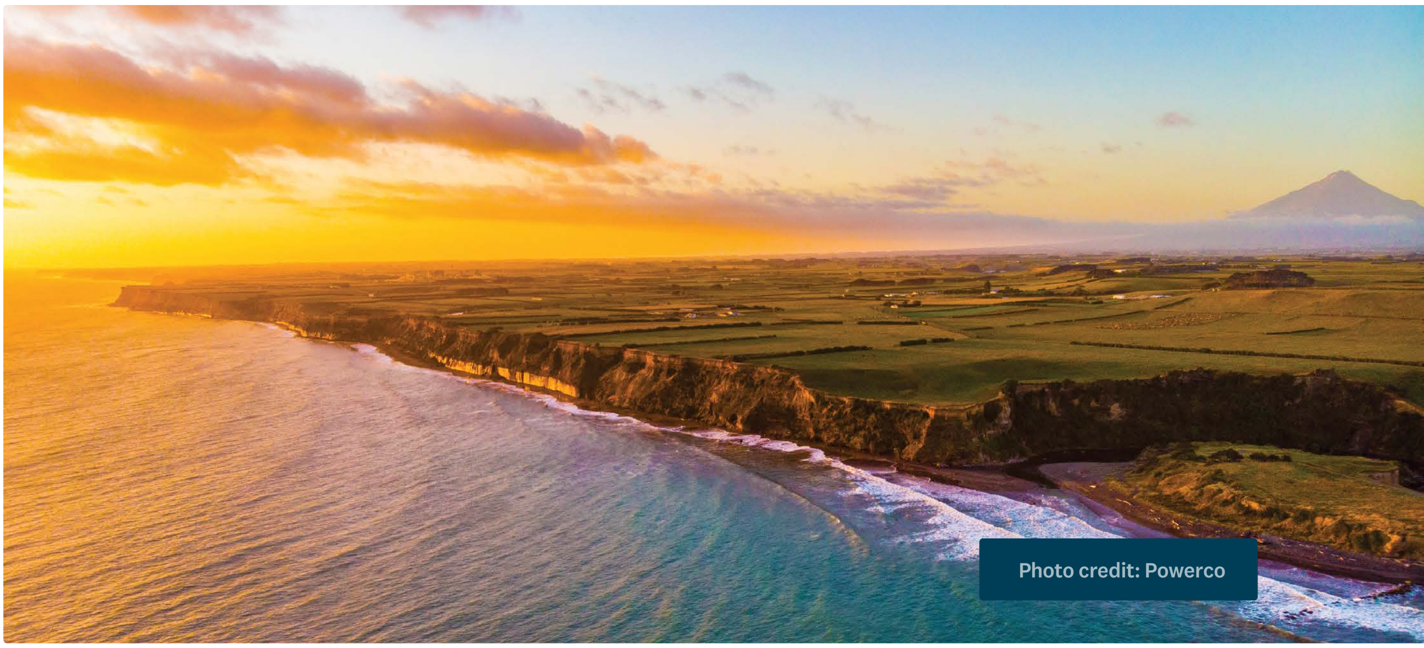


Photo credit: Powerco

118 Refer to Transpower's Transmission Planning Reports

119 These are upgrades that are specifically planned by Transpower in their 2022 Transmission Planning Report (TPR). Future potential upgrades are also contemplated by the TPR, and may be the subject of discussions with EDBs, but are not costed or formally planned.

Table 9 – Spare Grid Exit Point (GXP) capacity in Taranaki and Transpower and Powerco's currently planned grid upgrades.

GXP	EDB	RETA sites analysed	Spare N-1 GXP capacity	Planned Transpower GXP upgrade
Carrington St	Powerco	• Downer New Zealand Ltd New Plymouth Asphalt • New Plymouth District Council Wastewater treatment plant • Downer New Zealand Ltd New Plymouth Bitumen • Technix Bitumen Technologies Limited • Tegel Bell Block Feedmill • Ministry of Health Taranaki Base Hospital • Western Institute of Technology in Taranaki (WITT) Taranaki • New Plymouth District Council Todd Energy Aquatic Centre • New Plymouth District Council Puke Ariki • New Plymouth District Council Civic Centre • State-integrated school Francis Douglas Memorial College • New Plymouth District Council Len Lye Centre	38MW	None
Hāwera 110kV	Transpower	• Fonterra Ltd Whareroa	77MW[120]	None

[120] As it relates to the supply to the Whareroa site via two 110kV circuits from Hāwera 110kV bus, calculated by Ergo. Transpower did not provide the spare N or N-1 capacity of Hāwera 110kV at the HV side

GXP	EDB	RETA sites analysed	Spare N-1 GXP capacity	Planned Transpower GXP upgrade
Hāwera 33kV(Powerco)	Powerco	• Taranaki By-Products Hawera • Silver Fern Farms Limited Hawera • Little Knoll Greenhouses Ltd Patea • Balance Agri-Nutrients Ltd Kapuni	7MW	Hāwera outdoor to indoor (ODID) switchyard project will remove the current bus limit caused by the existing 33kV outdoor switchgear. Discussion with Powerco is required for longer term options to address the overload issue post 2028.
Huirangi	Powerco	• Mckechnie Aluminium Solutions Limited Bell Block • ANZCO Foods Waitara • La Nuova Inglewood • Poppas Peppers 2009 Limited New Plymouth • Tegel New Plymouth • Van Dyck New Plymouth • New Plymouth District Council Waitara Pool	37MW	None
Stratford	Powerco	• Fonterra Brands Ltd Eltham Bridge St • Fonterra Limited Eltham Collingwood St • Taranaki Abattoir Stratford • ANZCO Foods Eltham • Ministry of Education Stratford High School • Taranaki Galvanizers Stratford	28MW	Two 220/110 kV interconnecting transformers enable the Taranaki region loads to be supplied by the 220 kV lines which connect to Stratford GXP. The interconnecting transformers are rated at 200 MVA and 100 MVA. The following issues relate to the interconnecting transformers: An outage of the larger transformer during low generation and high load may cause the smaller transformer's capacity to be exceeded and may also result in low voltages (below 0.95 p.u.) in the Taranaki region.

Assessing the transmission grid implications of connecting RETA sites against current spare capacity is only part of the story:

- In some of the cases above where no spare capacity exists today, the planned upgrades in Table 11 will accommodate the connection of new electrified process heat users.
- At GXPs where there are no planned upgrades, the connection of multiple process heat sites may be so significant that an upgrade – not currently planned by Transpower – is triggered.
- There may be some situations where there is insufficient spare N-1 capacity, but a process heat user may be able to either connect at N security – requiring it to be able to reduce demand should a contingency occur – or be able to reduce its demand at peak times to avoid breaching the existing N-1 limit.

For the Taranaki region, Ergo's analysis concluded that the electrification of Taranaki By-Products would, by itself, trigger the need for transmission upgrades. Similarly, on the assumption that gas fired cogeneration plants (on-site and locally supplied) would not remain should the sites decarbonise, then Fonterra Whareroa and Fonterra Kāpuni would also, by themselves, trigger the need for transmission upgrades. Section 9.4 considers whether the collective connection of a number of the other process heat demand sites may also lead to a need for transmission investment.[121]

9.3.4 Analysis of impact of individual process heat demand sites on Powerco's investment

Most identified process heat demand sites will connect to the distribution (rather than Transpower's transmission network). Here we present an analysis of whether the existing distribution network can currently accommodate each site, and, if not, what the options are to upgrade the network sufficiently.

It is important to emphasise that the analysis undertaken here is preliminary and not intended as a detailed guide to the scope of works required to connect each site. The intended purpose is to provide a high-level 'screening' of process heat sites and the likely magnitude and complexity of their connection arrangements, should they choose to electrify. Further, the connection costs below approximate the total capital cost of constructing the connection assets, which may overstate the cost faced by the process heat user due to the potential for capital contributions from Powerco. It is imperative that process heat owners seek more detailed assessments from Powerco (and potentially Transpower) should they wish to investigate electrification further or develop more robust budgets.[122]

121 Where grid upgrades are triggered by the collective decisions of multiple organisations (potentially generators and consumers), it falls into the realm of the TPM, which is discussed in more detail in Section 13.3

122 Cost estimates have a Class 5 accuracy - suitable for concept screening. See https://web.aacei.org/docs/default-source/toc/toc_18r-97.pdf?sfvrsn=4

Below we present the results of Ergo's analysis of the RETA sites in three sections, reflecting the potential connection complexity of each site:

- **Minor** – The 'as designed' electrical system can likely connect the site with minor distribution level changes and without the need for substantial infrastructure upgrades. Some connections may require infrastructure which takes additional time to procure from international suppliers or implement (e.g., transformers, underground cabling).
- **Moderate** – The 'as designed' electrical system requires some infrastructure upgrades including new connections into the local zone substation, upgrades at the local zone substation, and/or upgrades to the sub-transmission network.[123]
- **Major** – The 'as designed' electrical system requires large upgrades at both the transmission and distribution level, likely requiring substantial investment, potentially with lead times beyond 36 months.

All estimates exclude the timeframes required for consenting and easements, if required. The categorisation of the projects does reflect the complexity of the potential work required and actual costs may differ from the indicative figures provided here. Also, since the assessment of upgrades required are limited to those that the process heat user would pay Powerco for directly (i.e. they are customer-initiated investments) there is no need for approval from the Commerce Commission. Were this not the case, the timelines for regulatory approval would need to be added to the timelines below.

Given the speed at which information is changing, the information presented below is indicative, and is a snapshot in time. Estimates are conservative. Each individual site should be re-considered when more detail is available.

In particular, the nature of information available at the time of this assessment, and the complexity of the task, necessitated a set of assumptions about how the various sites could be accommodated within the network. Detail pertaining to these assumptions can be found in the Appendix 14.1.6.

It should be noted that the cost estimates provided by Ergo only include the incumbent network operator's distribution/transmission equipment up to the customer site boundary and do not include onsite equipment that may be required to supply each site (for example, switchboards/cables within the respective sites are not included).

The magnitude of these additional onsite costs depends on whether the new process heat equipment can be accommodated within the site's existing connection capacity. For larger installations (>1MW), it is unlikely that any current spare onsite capacity will be sufficient, and an allowance is made for these costs in the estimated boiler or heat pump cost (rather than in the table below). However, for smaller sites (the majority of which appear on the 'minor' complexity table), it is possible that existing spare capacity can accommodate the new plant without significant additional expenditure.

However, there is no practical way, as part of this planning phase analysis, to discover whether smaller sites have spare onsite connection capacity, or whether that spare capacity is sufficient to accommodate new electrical loads for process heat. In the cost tables below, we indicate the potential for these costs to arise by having a minimum network upgrade cost of <$0.3M.

[123] The network infrastructure which connects local zone substations to Transpower's GXP.

Table 10 lists the connections that are categorised as 'minor' in nature.

Table 10 – Connection costs and lead times for minor complexity connections. Source: Ergo

Site	Transpower GXP	Network	Peak site demand (MW)	Total network upgrade cost ($M)[124]	Timing[125, 126]
Downer New Zealand Limited New Plymouth Asphalt	Carrington St	Powerco	3.37	$1.3	12-18 months
New Plymouth District Council Wastewater treatment plant	Carrington St	Powerco	2.70	$1.9	12-18 months
Downer New Zealand Limited New Plymouth Bitumen	Carrington St	Powerco	2.10	$0.58	12-18 months
Technix Bitumen Technologies Limited	Carrington St	Powerco	1.23	$0.58	12-18 months
Tegel Bell Block Feedmill	Carrington St	Powerco	0.64	<$0.3	12-18 months
Ministry of Health Taranaki Base Hospital	Carrington St	Powerco	0.47	<$0.3	3-6 months
Western Institute of Technology in Taranaki (WITT) Taranaki	Carrington St	Powerco	0.36	<$0.3	3-6 months
New Plymouth District Council Todd Energy Aquatic Centre	Carrington St	Powerco	0.23	<$0.3	3-6 months
New Plymouth District Council Puke Ariki	Carrington St	Powerco	0.12	<$0.3	3-6 months
New Plymouth District Council Civic Centre	Carrington St	Powerco	0.10	<$0.3	3-6 months
State-integrated school Francis Douglas Memorial College	Carrington St	Powerco	0.09	<$0.3	3-6 months
New Plymouth District Council Len Lye Centre	Carrington St	Powerco	0.06	<$0.3	3-6 months
Little Knoll Greenhouses Ltd Patea	Hāwera 33kV (Powerco)	Powerco	0.28	<$0.3	3-6 months

124 We reiterate that for sites with increases over 1MW, these costs do not include costs associated with the installation of distribution transformers/switchgear on the site. These costs are included as part of the assumed overall capital cost of boiler installation (see Section 7.1).

125 If a distribution transformer and/or switchgear is required, the lead time is expected to be around 9-12 months.

126 Estimated timing relates to plan, design, procure, construct and commission.

Site	Transpower GXP	Network	Peak site demand (MW)	Total network upgrade cost ($M)[124]	Timing[125, 126]
Mckechnie Aluminium Solutions Limited Bell Block	Huirangi	Powerco	4.59	$1.2	12-18 months
ANZCO Foods Waitara	Huirangi	Powerco	0.80	<$0.3	3-6 months
La Nuova Inglewood	Huirangi	Powerco	0.73	<$0.3	3-6 months
Poppas Peppers 2009 Limited New Plymouth	Huirangi	Powerco	0.71	$1.6	12-18 months
Tegel New Plymouth	Huirangi	Powerco	1.30	$0.96	12-18 months
Van Dyck New Plymouth	Huirangi	Powerco	0.07	<$0.3	3-6 months
New Plymouth District Council Waitara Pool	Huirangi	Powerco	0.06	<$0.3	3-6 months
Fonterra Brands Limited Eltham Bridge St	Stratford	Powerco	5.79	$0.7	12-18 months
Fonterra Limited Eltham Collingwood St	Stratford	Powerco	2.69	$1.3	12-24 months
Taranaki Abattoir Stratford	Stratford	Powerco	0.94	<$0.3	3-6 months
ANZCO Foods Eltham	Stratford	Powerco	1.80	$1.3	12-24 months
Ministry of Education Stratford High School	Stratford	Powerco	0.25	<$0.3	3-6 months
Taranaki Galvanizers Stratford	Stratford	Powerco	0.15	<$0.3	3-6 months
Silver Fern Farms Limited Waitotara	Waverley	Powerco	0.54	<$0.3	3-6 months

Table 11 lists the connections that are categorised as 'moderate'. These connections are more significant, both in terms of cost and the estimated time required to complete.

Table 11 – Connection costs and lead times for moderate complexity connections. Source: Ergo

Site	Transpower GXP	Network	Peak site demand (MW)[127]	Total network upgrade cost ($M)[128]	Timing[129]
Fonterra Limited Whareroa - Total (N) Stage 1	Hāwera 110kV	Transpower	22.00	$3.5	12-24 months
Fonterra Limited Whareroa - Total (N) Stage 2	Hāwera 110kV	Transpower	44.00	$7.0	12-24 months
Fonterra Limited Whareroa - Total (N) Stage 3	Hāwera 110kV	Transpower	66.00	$10.5	12-24 months
Fonterra Limited Whareroa - Total (N) Stage 4	Hāwera 110kV	Transpower	88.14	$3.5	12-24 months
Fonterra Limited Whareroa - Total (N-1) Stage 1	Hāwera 110kV	Transpower	22.00	$3.5	12-24 months
Fonterra Limited Whareroa - Total (N-1) Stage 2	Hāwera 110kV	Transpower	44.00	$7.0	12-24 months
Fonterra Limited Whareroa - Total (N-1) Stage 3	Hāwera 110kV	Transpower	66.00	$10.5	12-24 months
Fonterra Limited Whareroa - Total (N-1) Stage 4	Hāwera 110kV	Transpower	88.14	$36.8	36-48 months
Silver Fern Farms Limited Hawera	Hāwera 33kV (Powerco)	Powerco	1.47	$6.72	24-36 months

The cost associated with Fonterra Whareroa's electrification is substantially higher than other 'moderate' connections. Fonterra presently has 64MW of cogeneration connected to the 110kV bus at the site. This generation typically supplies the whole site load, and the surplus is exported to the national grid. As the cogeneration is dependent upon existing fossil fuel energy supply (natural gas), the analysis presented here assumes that the cogeneration is decommissioned as the site decarbonises. The costs noted in the table above are cumulative, as each latter stage is dependent on the prior stages being completed.

[127] Where sites have a number of stages of electrification, the peak demand figures represent the cumulative increase in peak demand, including any previous stages

[128] Where sites have a number of stages of electrification, the total network upgrade costs represent the cumulative increase in costs, including any previous stages

[129] Estimated timing relates to plan, design, procure, construct and commission.

The electrification of Fonterra Whareroa has therefore been broken into four stages:

- Stages 1-3 (22MVA each) at a total additional load of 66MVA can be accommodated within the N-1 spare capacity of Hawera 110kV GXP, with the installation of a dedicated switchboard (at each stage) for the new 11kV load assuming the transformers which presently connect to the generators could be reused for connection of the new load. It is anticipated that the existing generation switchboard would remain partially in operation and would not be suitable for the 11kV load.
- Stage 4 (22.14MVA). The fourth stage of Fonterra Whareroa expansion adds an additional 22.14MVA onto the Stage 3 load, for a total of 88.14MVA. As with previous stages a new 11kV switchboard is required.
- For an N-1 supply at Stage 4, a new11kV switchboard and an additional 110kV circuit would be required between Hāwera GXP and Stratford GXP.

Table 12 shows the two connections that are categorised as ‘major’. These connections are significant, in terms of cost, complexity and the estimated time to complete.

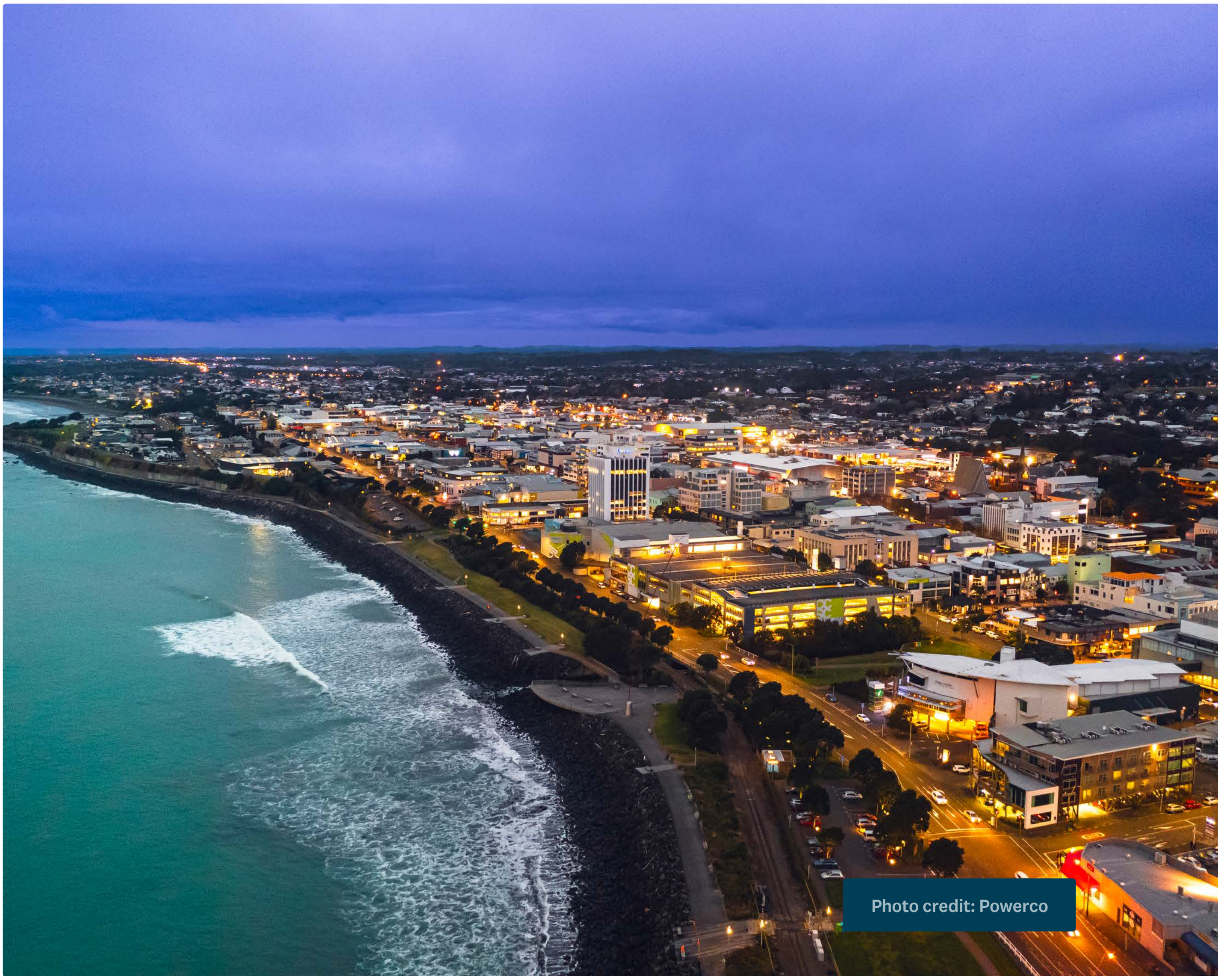


Photo credit: Powerco

Table 12 – Connection costs and lead times for major complexity connections. Source: Ergo

Site	Transpower GXP	Network	Peak site demand (MW)[130]	Total network upgrade cost ($M)	Timing[131]
Taranaki By-Products Hawera (N)	Hāwera 33kV (Powerco)	Powerco	12.47	$3.25	24-36 months
Taranaki By-Products Hawera (N-1)	Hāwera 33kV (Powerco)	Powerco	12.47	$16.35	36-48 months
Fonterra Limited Kapuni - (N) Stage 1	Kāpuni	Powerco	11.00	$12.1	12-18 months
Fonterra Limited Kapuni - (N) Stage 2	Kāpuni	Powerco	22.00	$16.6	36-48 months
Fonterra Limited Kapuni - (N) Stage 3	Kāpuni	Powerco	33.00	$28.6	36-48 months
Fonterra Limited Kapuni - (N) Stage 4	Kāpuni	Powerco	45.91	$28.6	3-6 months
Fonterra Limited Kapuni - (N-1) Stage 1	Kāpuni	Powerco	11.00	$33.80	12-18 months
Fonterra Limited Kapuni - (N-1) Stage 2	Kāpuni	Powerco	22.00	$38.2	36-48 months
Fonterra Limited Kapuni - (N) Stage 3	Kāpuni	Powerco	33.00	$82.3	36-48 months
Fonterra Limited Kapuni - (N-1) Stage 4	Kāpuni	Powerco	45.91	$82.3	24-36 months

Fonterra Kāpuni is presently supplied by the Kāpuni GXP near the site via a tee connection to the 110kV Ōpunake-Stratford 2 circuit. The Kāpuni GXP is presently equipped with a single 30MVA transformer. With a maximum demand of 8MVA, the GXP presently has ~22MVA of spare N capacity. There is also 24MW of natural gas cogeneration connected to Kāpuni GXP that supplies energy to Fonterra Kāpuni. The analysis presented here assumes Fonterra decarbonises by substituting the cogeneration supply with renewable energy sourced via the transmission network. The costs noted in the table above are cumulative, as each latter stage is dependent on the prior stages being completed.

130 Where sites have a number of stages of electrification, the peak demand figures represent the cumulative increase in peak demand, including any previous stages

131 Estimated timing relates to plan, design, procure, construct and commission.

Due to the size of the load, analysis focussed on a staged approach as follows:

- Stage 1 (11MVA). The first stage of Fonterra Kāpuni expansion adds an additional 11MVA onto the existing load. For an N security supply, it is expected that a new 110kV line from the Kāpuni GXP to the Fonterra site would be required, along with one 110/11kV transformer at the Fonterra site, and associated switchgear.
- For an (N-1) security supply at Stage 1, additional to the upgrades required for an (N) security supply, it is expected that a 110 kV line to Fonterra from the Ōpunake-Stratford 110 kV lines (similar to the one supplying Kāpuni GXP) would also be required. This line would likely tee off the other Ōpunake-Stratford line from the existing tee connection and is expected to be ~15 km long. Additionally, two transformers would be required at the Fonterra site, rather than the single one required for an (N) supply. NB: Any new transformers should be sized for the final stage of site development
- Stage 2 (11MVA). The second stage of Fonterra expansion adds an additional 11 MVA onto the stage 1 load, for a total addition load of 22 MVA. For both an (N) and an (N-1) supply, replacement of the existing 110/11 kV transformer at the site would be required. NB: Any new transformers should be sized for the final stage of site development
- Stage 3 (11MVA each) The third stage of Fonterra expansion adds an additional 11 MVA onto the stage 3 load, for a total additional load of 33 MVA. For both an (N) or (N-1) security supply, the existing 110 kV line suppling Kāpuni would require replacements/thermal upgrades.
- For an (N-1) security supply, upgrades of the Ōpunake-Stratford 110 kV lines between the Kāpuni tee and Stratford (~20 km per line) would be required.
- Stage 4 (12.91MVA). The fourth stage of Fonterra Kāpuni expansion adds an additional 12.91MVA onto the Stage 3 load, for a total of 45.91MVA. Assuming that the previous stages' transformer installations considered this final load, no further upgrades are expected for an (N) or (N-1) security supply.

This example highlights the complexity associated with connecting large demands, as well as deciding on the level of security required. Network investment can be very 'lumpy' – small increments in demand, or accepting lower security levels, can sometimes be accommodated at relatively low cost. However, there is a point where substantial investment is triggered; and this investment – once committed – can accommodate quite large load increments.

By way of example the costs associated with providing N-1 to Fonterra Kāpuni 11MVA Stage 1 are ~$33.8m; once this network investment is committed, the additional cost to double this demand to 22MVA is only $4.5m.

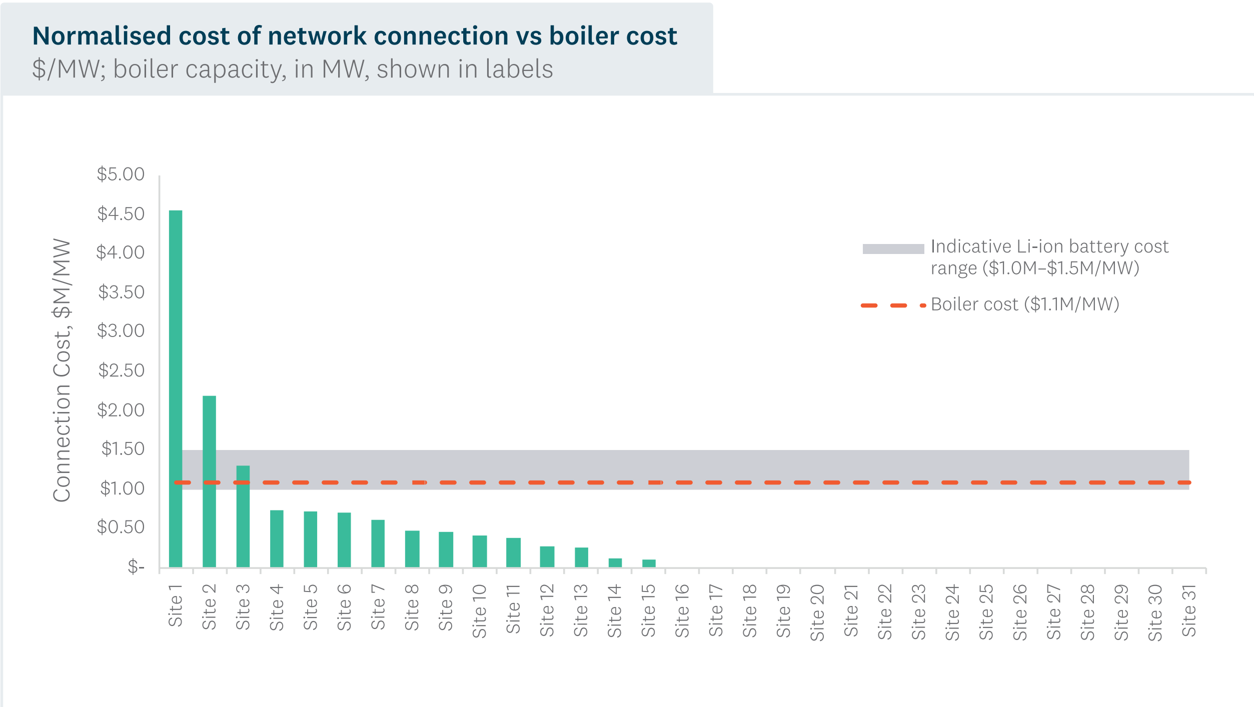
Similarly, the additional costs associated with providing N-1 to Fonterra Kāpuni Stage 3 (for a total of 33MVA supply) are ~$44m; however, once this second large network investment is committed, there is no additional cost to increase the demand to 45.91MVA.

Noting the complexity of the Fonterra site above and the likely impact on both the distribution and transmission networks, this underscores the importance of early and regular communication between process heat users, distributors and Transpower. Powerco and Transpower will be in a better position to optimise network investment when they have a more complete picture of the intentions of process heat users. This leads to cost savings which are likely to improve the business case for converting process heat to electricity.

9.3.5 Summary

The network connection costs presented above vary in magnitude. It is worth viewing these costs through the lens of the size of the boiler installation. Figure 54 shows each site's connection costs expressed in per-MW terms, i.e. relative to the capacity of the proposed boiler, and to a lithium-ion battery solution.

Figure 54 – Normalised cost of network connection vs boiler cost. Source: Ergo, EECA



The red dashed line in Figure 53 compares these per-MW costs to the estimated cost of an electrode boiler ($1.1M per MW).[132] The blue shaded area indicates the estimated cost range for a 1MW lithium-ion battery. Figure 53 shows not only a wide variety of relative costs of connecting electrode boilers, but that for two cases, the connection cost more than doubles the overall capital cost associated with electrification and three are within (or exceed) the indicative cost range for a battery energy storage solution (BESS).

Process heat users could potentially deploy battery energy storage solutions – or any other suitable storage solution (e.g. hot water, ice slurry, thermal energy storage etc) – to defer the need for transmission or distribution network investments by meeting peak demand with energy that was stored onsite during lower-demand periods. This helps reduce congestion and improves overall transmission and distribution asset utilisation.

We would note that while storage solutions (such as batteries, hot water, ice slurry etc) are highly valuable in managing peak periods, they can only do this for a limited period (e.g. a BESS generally has storage capability of a small number of hours depending on battery size, characteristics and configuration).

[132] This is the estimate used in the development of the marginal abatement costs and pathways presented in Section 7.

For sites where the cost of a battery is nominally less that the possible connection costs, consideration should be given to investigating battery energy storage solution options, especially if the load profile has a peak that coincides with the relevant network daily peaks. In these situations, the use of a BESS could not only reduce network connection costs,[133] but also provide an opportunity for the RETA site to offer (and contract) the operation of the BESS as a network peak management service to Powerco (or Transpower), such that the need for transmission or distribution investment is deferred.

We note, as explained above, the connection costs developed in this section and used in Figure 54, may not reflect the capital costs incurred by the process heat user. Powerco may only charge the user a share of these costs, as per their capital contributions policies.

While the estimates of connection costs provided here are of an accuracy commensurate with this screening analysis, it does demonstrate how connection costs can have a significant effect on the final decision. It also shows that, particularly for smaller electrification projects, reductions in connection cost of only $50,000 could have a significant effect on the economics of fuel switching decisions.

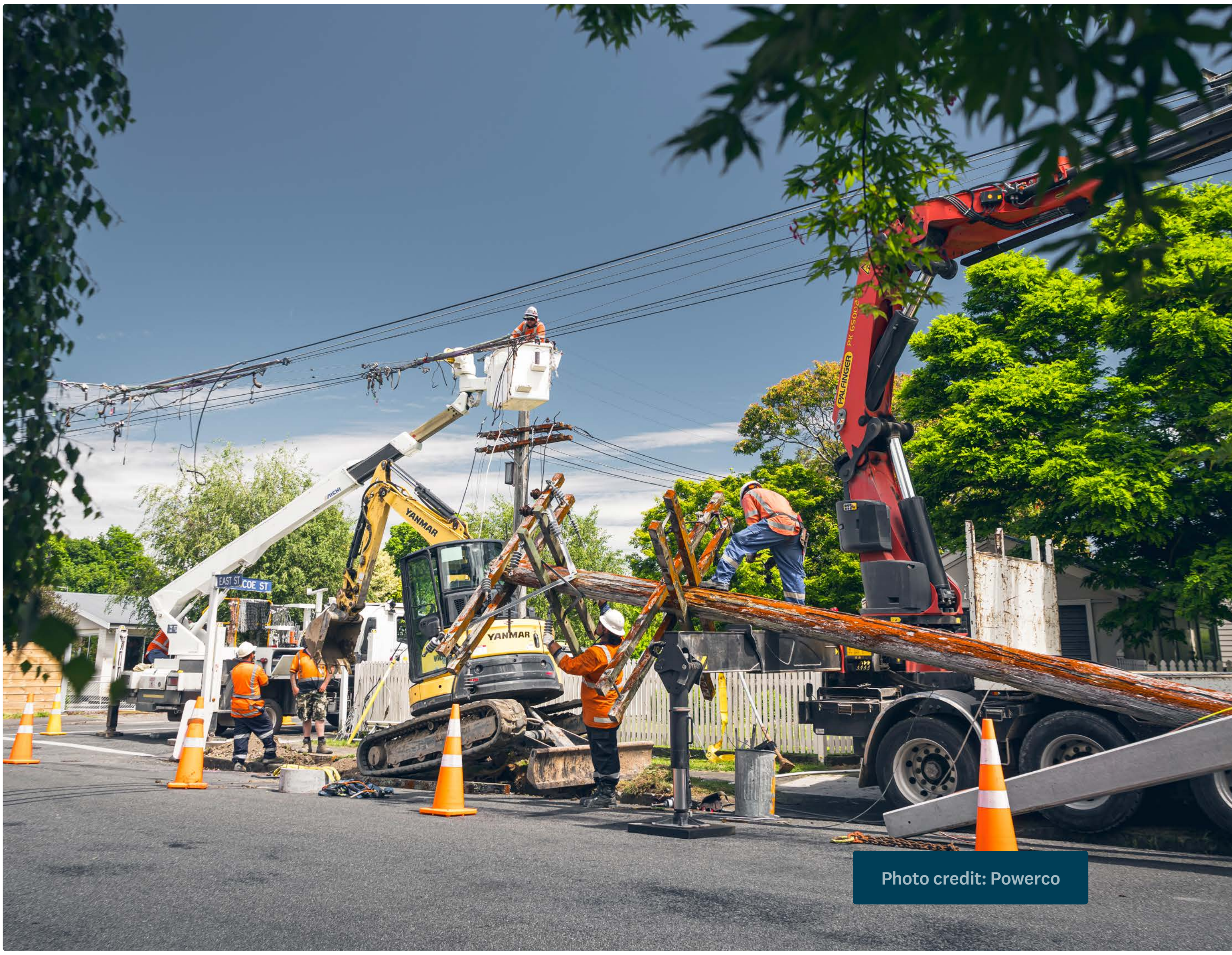


Photo credit: Powerco

[133] The degree to which a battery can do this depends on the demand profile of the site. If, as discussed above, the site reaches its peak demand for very short periods (30-60 minutes), a BESS may be suitable. However, if it sustains its peak load for a number of hours, batteries may be less economic than network upgrades.

9.4 Potential for flexibility to reduce process heat electricity-related costs

Process heat flexibility can improve system resilience and reduce both electricity system costs and process heat electricity-related costs.

Not only does flexibility in process heat demand reduce the need for expensive peaking generation and storage, the ability for process heat to be able to respond to system and network conditions (when system asset failures occur) increases resilience. The technology and communications systems are commercially available to allow this instantaneous response, where the underlying heat process allows.

In addition to benefits to the overall costs in the electricity system, process heat users can also financially benefit from using flexibility.[134] The RETA analysis highlights how the use of flexibility in the process heat user's electricity demand – e.g. by changing its electricity consumption profile over the day – can help reduce or avoid electricity charges targeted at peak network or system periods. Our analysis allows us to estimate the potential value of three elements of the flexibility 'value stack':

- **Energy arbitrage** – Retail electricity charges are likely to be higher during 'peak' periods – mornings and evenings during business days – than off-peak periods. Shifting some electricity consumption from peak to off-peak periods would reduce the total retail charges faced by the process heat user.[135]
- **Network pricing arbitrage** – Charges for the use of the existing transmission and distribution network vary depending on the size (kVA) of the process heat demand. In addition, a significant component of these charges related to what the process heat user was demanding at peak network times.[136]
- **Connection pricing** – Finally, for most process heat users who convert to electricity, some degree of investment would be required to increase the capacity of the network. For smaller sites, or sites connecting to Powerco's network with sufficient pre-existing capacity, the amount of network investment is relatively modest. However, some require moderate or major investment in the distribution network. For sites that could smooth their consumption profile, or invest in onsite batteries, the quantum of investment required could potentially be reduced.[137]

[134] In fact, this is inherent in the design of the market – the financial benefits to the system, from flexibility, will be shared with the organisations that are providing the flexibility when the underlying retail and network prices are an efficient reflection of market prices. However, today, New Zealand is at an early stage in developing the market systems that allow electricity consumers to participate in the 'flexibility' market. This discussion focuses on financial benefits that process heat users should be able to access today, noting that New Zealand will continue to make progress in this regard. See https://flexforum.nz

[135] Using the retail price forecasts EECA procured for the RETA workstream, the 'energy' component of retail electricity charges during weekday days is expected to average 11c/kWh between now and 2030, while weekday nights are expected to average 7.6c/kWh. Businesses that can shift 1MWh of consumption from day to night, every weekday, would save the process heat user $8,000 per annum.

[136] Powerco's published tariffs include capacity based daily fixed charges, congestion period demand charges and connection capacity charges. It is challenging to make a definitive assessment of how much of these charges could be avoided by deploying flexibility. Our analysis below conservatively assumes only 50% of the overall charges could be avoided.

[137] Our analysis of each of these sites suggests the average construction cost of these investments was $588,000/MW. However, we also assumed that the capital contribution by the process heat user would be 50%.

By enabling flexibility in their process heat demands, Taranaki process heat users could reduce their electricity procurement costs by up to $56,000 per MW of flexibility deployed every year. In addition, at the planning stage, they could also reduce costs associated with the size of their connection to the electricity network – the investment required in the physical connection, as well as any network charges from Powerco that relate to the size of the connection.

Figure 55 – Estimates of the value of flexibility in Taranaki RETA. Source: EECA

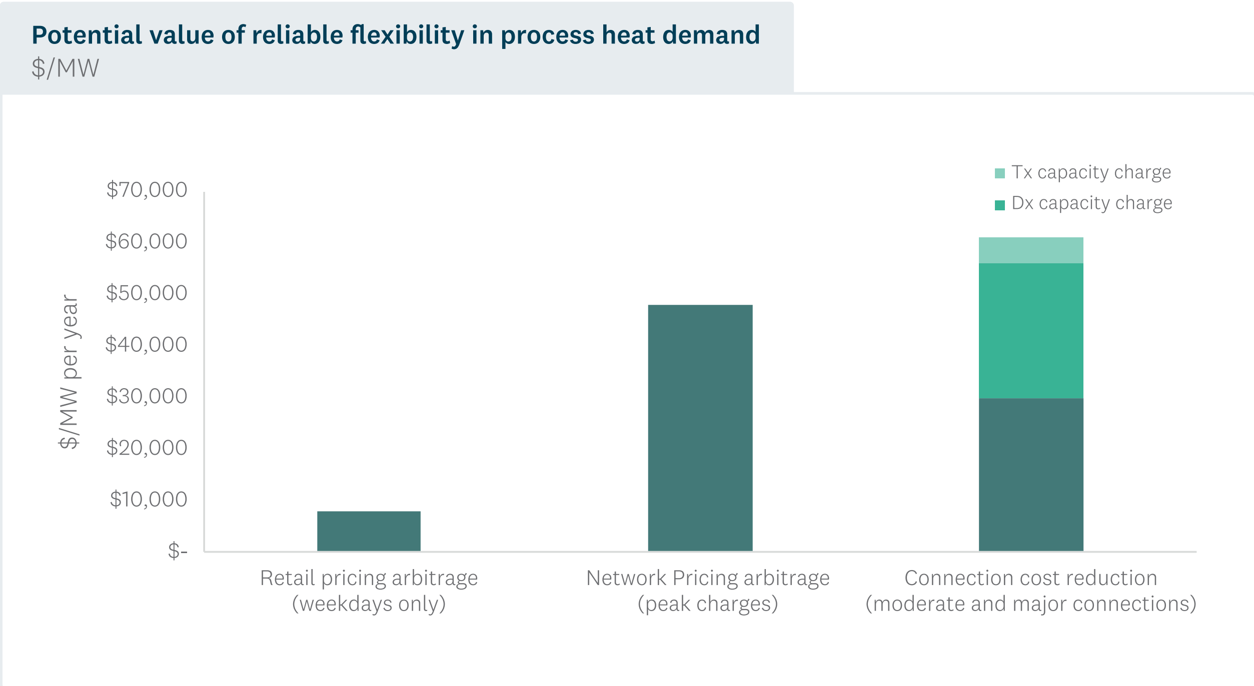


Figure 55 uses plausible estimates from the Taranaki RETA analysis of what this flexibility could be worth to a process heat user, per MW of demand that can be shifted into an off-peak period. We note that, in reality, the estimate for reducing connection costs may vary significantly, as the underlying equipment underpinning network investment comes in standard sizes – varying peak process heat demand by a relatively small amount may not change the connection costs.

A process heat user that has sufficient flexibility in their underlying process could obtain, up to $61,000 (annualised) if it allows them to reduce the size of their connection to the network.

Some process heat users may find it challenging to alter their underlying process to achieve this. Even then, onsite batteries could be used to extract these cost savings. Over a 20-year timeframe, the cost savings above could be sufficient to underwrite an investment in a battery. Onsite battery storage also provides extra resilience in network failure scenarios. EECA is working with process heat users to better understand the value streams associated with batteries that are integrated into their electrification plans.

9.5 Collective impact of multiple RETA sites connecting

The above analysis considered each site in isolation from each other, and whether it could fit into the spare capacity available in existing network infrastructure. This may underestimate the need for wider network upgrades; should a number of sites choose to electrify, this could collectively have a more significant impact on peak network demand.

9.5.1 Diversity in demand

In considering scenarios where multiple sites electrify their process heat and connect to common network infrastructure, we must first consider what the resulting collective peak demand is with the expectation that there will be some diversity between when each of the individual sites reach their peak demand. A simplistic approach would be to sum the individual peak demands of each site and add them to the existing peak demand on the network. However, sites may have quite different patterns of demand over the year – some peak in winter (swimming pools, schools) while others (e.g. dairy) peak in summer. In other words, not all individual site 'peaks' happen at the same time. Further, they may not occur at the same time as the existing demand peaks. Hence a better approach is to consider the diversity in the operational requirements of each site considered, which may see each site:

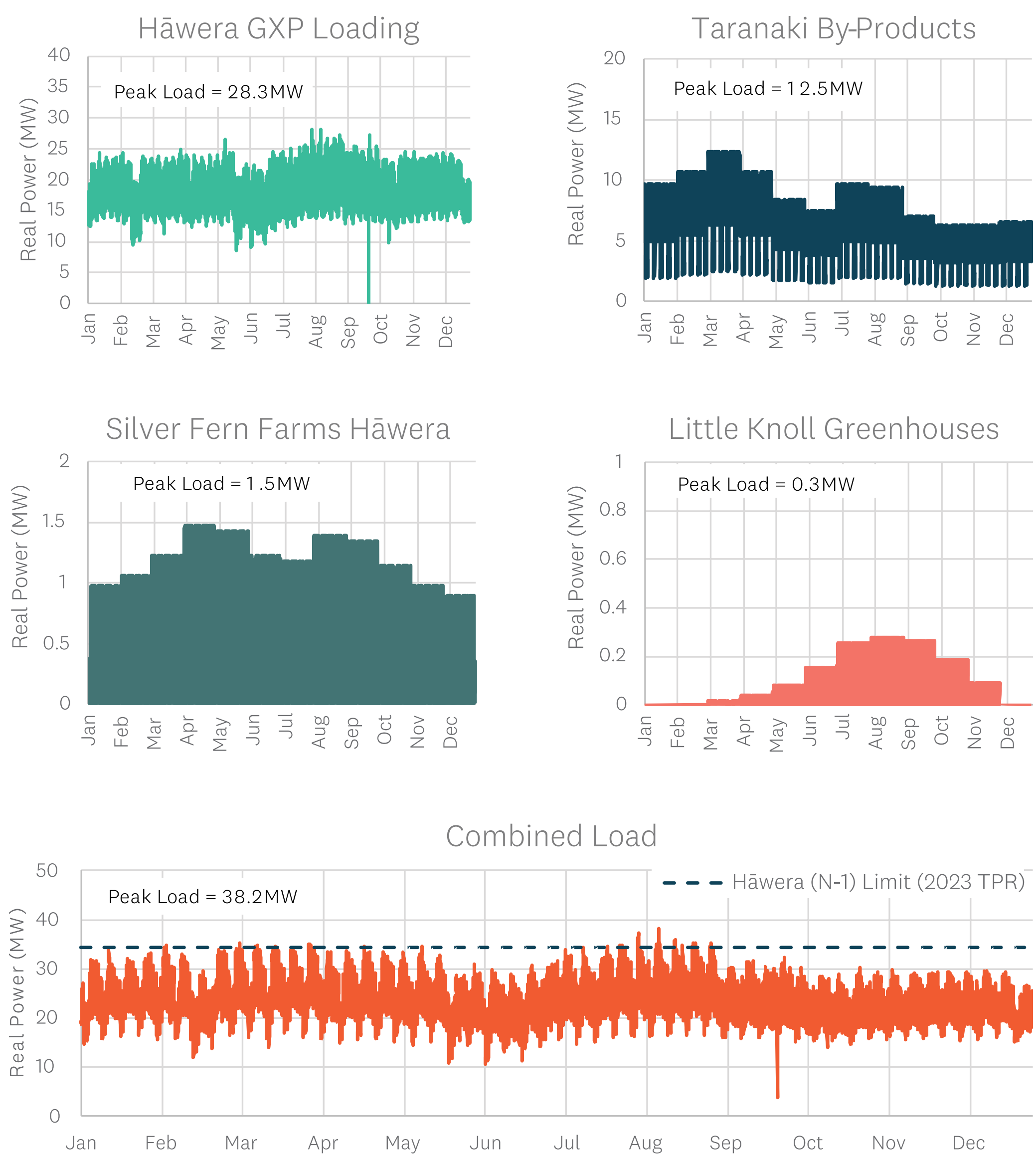
- Reach its peak demand at a different time to the other RETA sites; and/or
- Reach its peak demand at a different time to existing network demand.

If we can simulate the operational profiles of each site, we can approximate the extent to which diversity in peak demands leads to a lower overall peak demand on the network than the simple addition of each site's peak.

Determining the collective impact on peak demand requires detailed data on the profile of existing demand over the year, as well as similarly detailed data for each individual site. Ergo obtained half hourly historical demand data for each GXP in the Taranaki region for 2023, as well as simulated individual site profiles based on other similar sites. This allowed a simulation of what half-hourly demand at each GXP would have looked like in 2023, had all identified sites been electrified.

Figure 56 illustrates this approach for the Hāwera GXP. The top-left chart shows the half hourly demand at Hāwera 33kV over the 2023 year. Below that, we show the simulated half-hourly demand profile of each RETA site, should they choose to electrify their process heat. The bottom chart shows the simulated resulting demand at Hāwera 33kV, should these sites electrify their process heat. We reinforce that this more detailed analysis is a simulation based on 2023 data, hence is only indicative of the collective effect of these sites connecting, as though that happened in 2023. A more robust analysis would require consideration of future changes to half-hourly demand at Hāwera 33kV transmission substation, including underlying growth from sources other than RETA sites.

Figure 56 – Simulation of impact on Hāwera 33kV GXP demand from all RETA site electrification



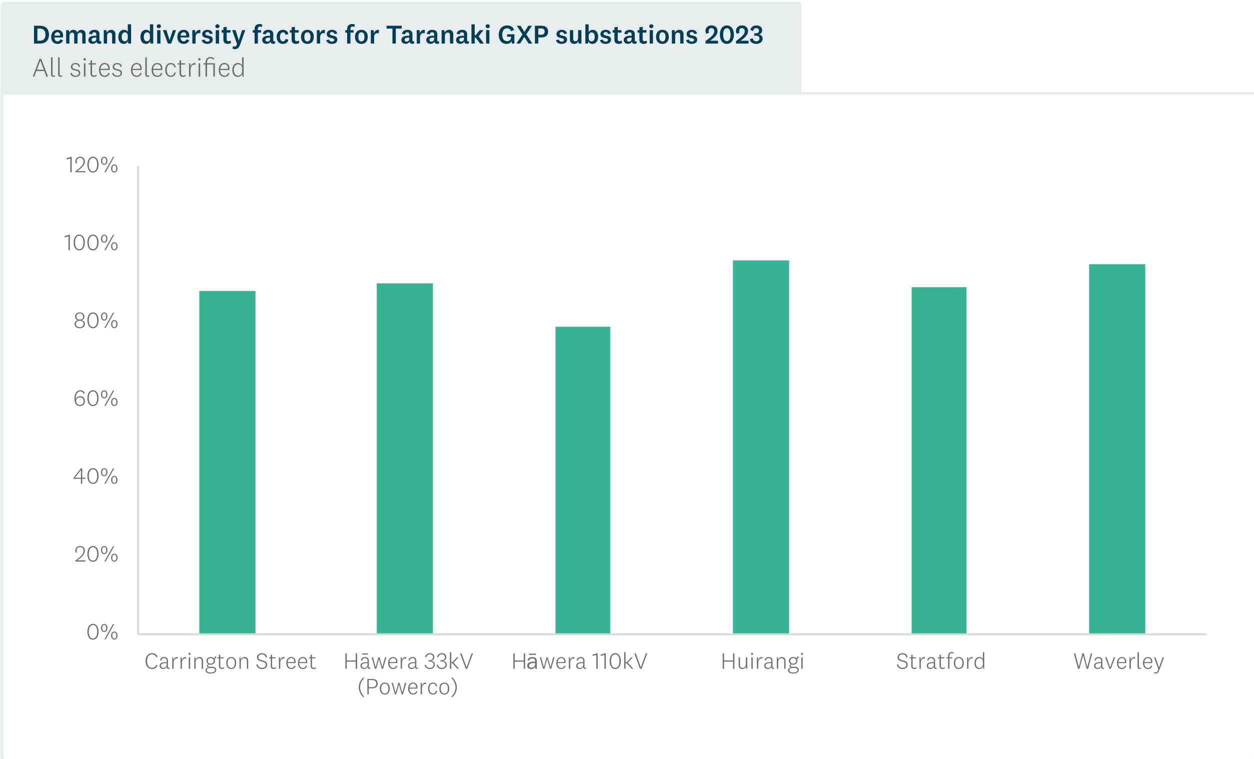
Importantly, the resulting peak GXP demand observed is 38.2MW, which is lower than the simple addition of all individual RETA site peaks (14.3MW) to the 2023 Hāwera 33kV peak demand (28.3MW), which would have suggested the new peak is 42.6MW. The effect of demand diversity amongst the different Hāwera 33kV RETA sites is that the combined peak is 90% of what a simple addition would have suggested. We refer to this as a diversity 'factor'.

Taking this approach shows that the combined demand from all individual RETA sites would cause the Hāwera 33kV assets to exceed their N-1 rating in only a small number of instances over the year. This relatively low risk of interruption may be more acceptable to connecting customers, Powerco and Transpower than investing in additional capacity.

Ergo repeated this analysis across six of the ten GXP.[138] The resulting demand diversity factors are shown in Figure 57.

[138] Kāpuni and Motunui have single loads connected, while Ōpunake and Hāwera 33kV (Kupe) have no RETA sites connected, so no diversity analysis was required for these GXPs.

Figure 57 – Demand diversity factors for Taranaki GXPS. Source: Ergo



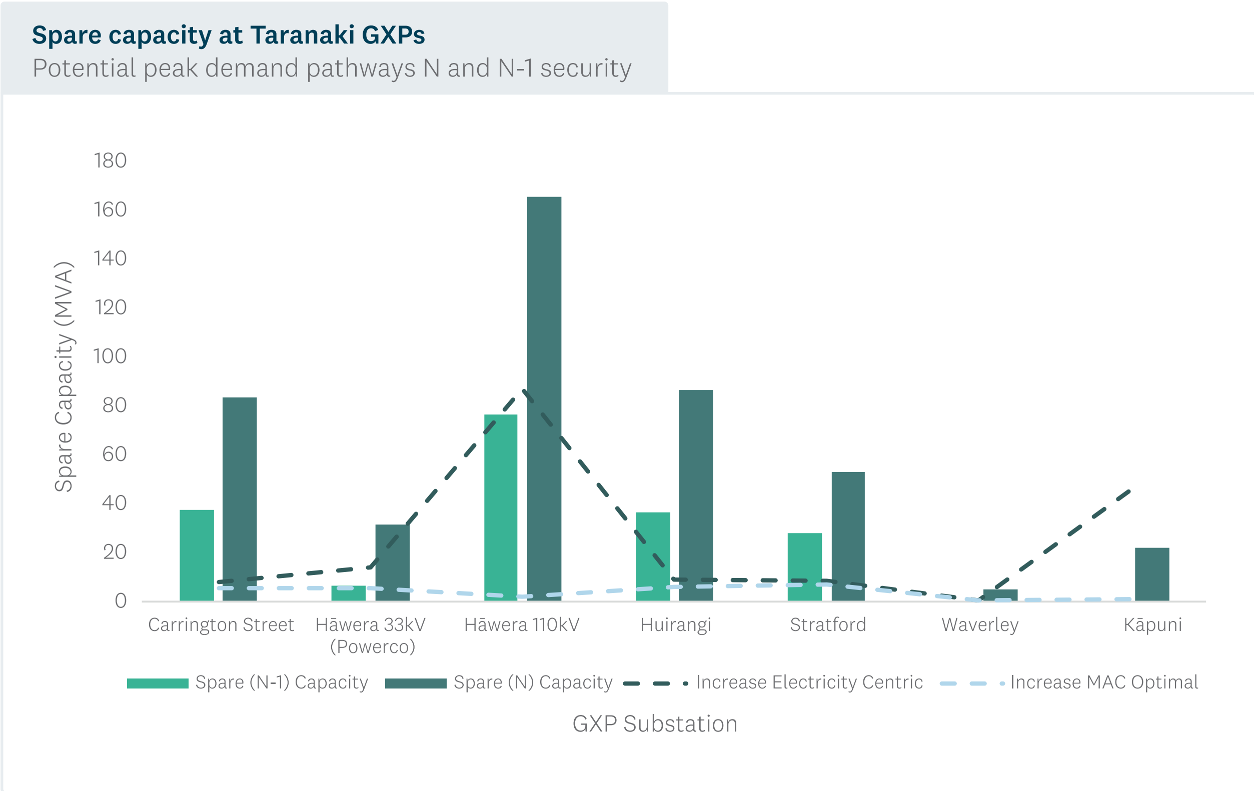
9.5.2 Assessment against spare capacity

We can use these diversity factors to determine the impact of all sites electrifying on spare capacity. Figure 58 shows the amount of spare capacity at each GXP if that would be used under two scenarios:

- The 'Electricity Centric' pathway, where all unconfirmed Taranaki identified process heat demand sites choose to electrify (orange dashed line).
- A 'MAC Optimal' pathway, where only those unconfirmed sites that have lower marginal abatement costs than biomass (see Section 7.1) electrify (blue dashed line).

Section 7.2 describes these scenarios more fully. Note that the dashed lines in Figure 58 assume that none of the sites actively manage their demand to avoid system peaks; again, this is a conservative view of peak demand. Note, as mentioned earlier, these graphs exclude the 300 MW hydrogen electrolyser project.

Figure 58 – Potential combined effect of site decisions at each GXP on spare capacity. Source: Ergo



On this analysis:

- In the Electricity Centric scenario, Carrington St, Huirangi and Stratford have sufficient N-1 capacity to accommodate the RETA demand. Hāwera 33kV (Powerco) and Hāwera 110kV have insufficient spare N-1 capacity with RETA demand using up a large portion of the spare N capacity. Waverley and Kāpuni have no N-1 spare capacity (as they operate at N), Waverley has sufficient N capacity, but RETA demand at Kāpuni is greater than available N capacity.
- However, in the MAC Optimal scenario, at Carrington St, Hāwera 33kV (Powerco), Hāwera 110kV, Huirangi and Stratford GXPs, there is sufficient N-1 spare capacity to accommodate the increase from RETA demand. Waverley and Kāpuni operate at N, so the RETA demand under the MAC Optimal scenario at these locations would use up a small amount of spare N capacity.

However, as outlined earlier, our spare capacity metric is based on the difference between N-1 (and N) capacity at the GXP and Transpower's conservative prudent demand forecast. This forecast is a '90th percentile' forecast – that is, a somewhat worst-case assessment of peak demand. This forecast will, in many cases, be above the 'expected' peak demand. We note that any confirmed increase in demand from the electrification of RETA sites may trigger or accelerate some of the potential upgrades noted in Table 11 above, including any which are noted as 'customer driven investments'.

Process heat users contemplating electrification at all nodes should engage early with Powerco to ensure that this assessment of spare capacity aligns with their expectations. Powerco will have a broader perspective of other demand growth (and distribution generation) expected to occur at the various GXPs, transmission substations and zone substations.

9.5.3 Zone substations

The assessment of the two RETA pathways against spare GXP capacity suggested that most of the process heat decarbonisation projects were unlikely to trigger transmission upgrades that were not already planned for - the exceptions being Taranaki By-Products, as well as Fonterra Whareroa (should they decarbonise the site and decommission the on-site gas fired cogeneration plant) and Fonterra Kāpuni (should they decarbonise the energy supply to site).

In addition, some potential network upgrades to Powerco's Eltham zone substation were identified. The three RETA sites considering connecting to the Eltham zone substation are Fonterra Eltham Bridge St, Fonterra Eltham Collingwood St and ANZCO Foods Eltham. The combined peak demand of these loads is 10.28MVA, which the zone substation does not have (N-1) capacity for. If all three loads were to connect, or the two Fonterra loads only, it is possible that replacements of the Eltham transformers would be required, at an estimated cost of $4.6m.

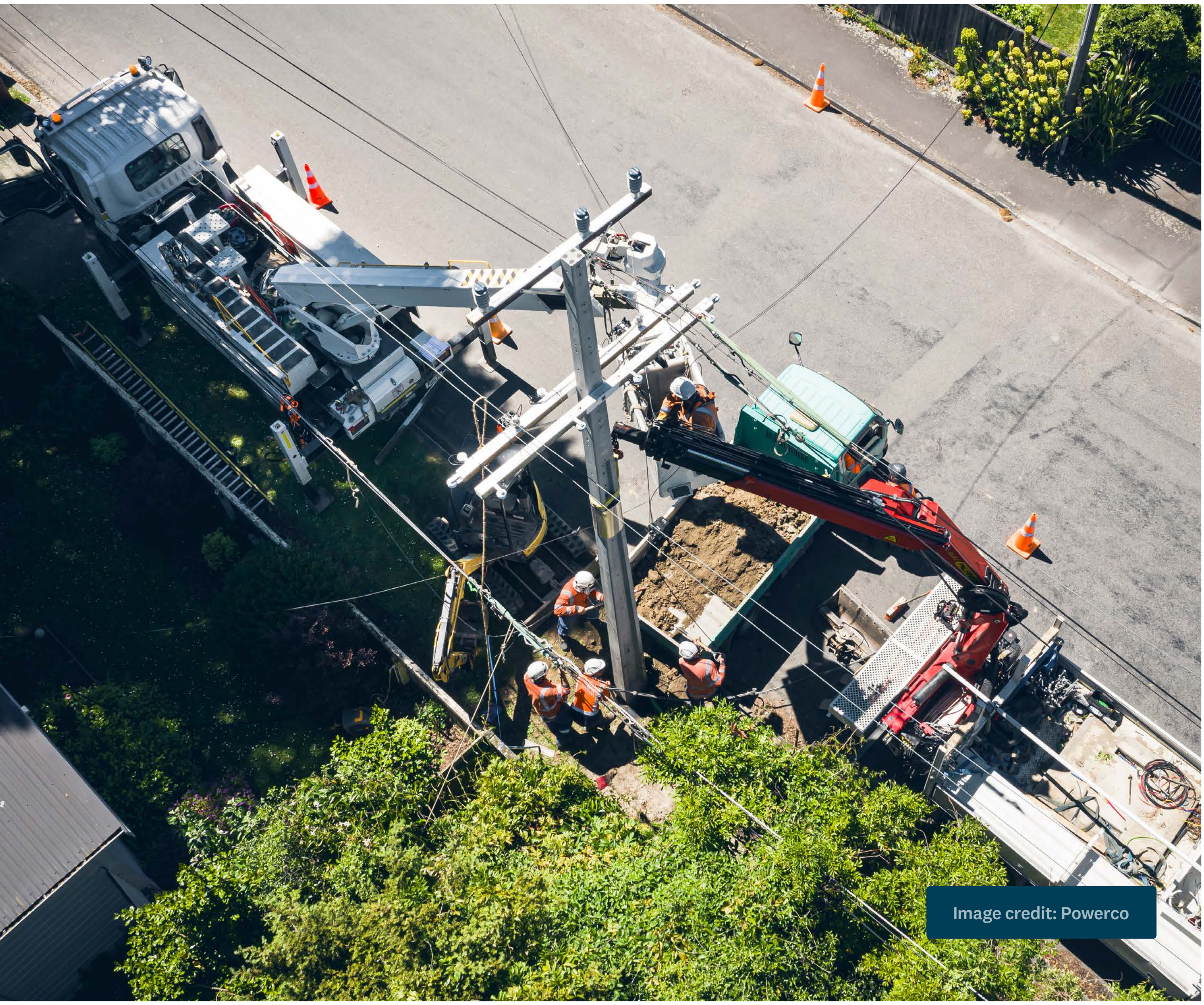


Image credit: Powerco

10 Taranaki RETA Insights and Recommendations

The RETA programme aims to develop an understanding of what is needed to decarbonise a region through a well-informed and coordinated approach. The focus is to understand unique region-specific opportunities and barriers when developing regional energy transition roadmaps.

Our analysis of energy requirements in Taranaki uses year 2022 as baseline. We note that since then, constraints in gas supply have affected prices for natural gas, and as a result have altered natural gas consumption patterns, particularly for sites using natural gas as feedstock.

Our analysis focuses on the energy use for process heat only, and we recognise the decisions are more complicated for organisations that also use natural gas as feedstock.

This report has considered several organisations facing the decision of how to reduce their fossil fuel process heat consumption.

The aim of this report, which is the culmination of the RETA planning stage for the Taranaki region, is to:

- Provide process heat users with coordinated information specific to the region to make more informed decisions on fuel choice and timing.
- Improve fuel supplier confidence to invest in supply side infrastructure; and
- Surface issues, opportunities, and recommendations.

The report is premised on the observation that, while individual organisations may be able to obtain information pertinent to their own decarbonisation decision, some of the most important factors require a collective, regional view. Only with a regional view can 'system-level' challenges and opportunities be evaluated. If these challenges can be addressed, and opportunities pursued, process heat consumers and fuel suppliers can make better decisions.

This report has illustrated a range of decarbonisation pathways, all of which demonstrate how the combined decisions of a range of process heat users may lead to common infrastructure challenges from a supply perspective. The pathways illuminate different decision-making frameworks that might be used by process heat organisations to decide on which fuel to switch to. Hence the pathways give a sense of the diversity of outcomes that might be expected.

In this section, we will present our findings from the work undertaken and recommendations about how the identified challenges can be resolved.

A 'whole-of-system' perspective would go further than this RETA report to incorporate other sectors. The transport sector is likely to decarbonise through a combination of sustainable fuels (including bioenergy and electricity), and in some situations process heat and transport will compete for the same sources of fuel. The nature of the decarbonisation technologies that underpin these decisions is changing quickly, and a system-level view – even at a regional level – will allow decision makers and policy makers to be able make informed choices and identify challenges, gaps, and opportunities. This makes the analysis more complex, but more insightful in identifying system challenges and solutions.

10.1 Biomass – insights and recommendations

The analysis undertaken shows that the estimated volumes of unutilised harvesting and processor residues (after existing bioenergy demands are removed) are not sufficient to meet the biomass demand in any pathway and are exhausted by 2037 in the MAC Optimal pathway. Meeting demand beyond 2039 would mean tapping into the higher-valued logs from the Taranaki region (export K/A), and/or exploring opportunities for importing residues from other regions.

Cutover residues may be more complex and more expensive to recover than modelled here, although we have used a pragmatic assessment based on expert opinion.

Our analysis suggests there are likely to be 14 process heat users seeking biomass as a fuel (including confirmed fuel switching projects). There needs to be a high degree of coordination between these organisations and forestry companies to ensure all parties – on the supply side and demand side – have the confidence to extract, process and consume residue-based biomass as a long-term option. There are a number of opportunities to increase this coordination and confidence.

- More analysis, pilots and collaboration with existing forestry organisations extracting residues to understand costs, volumes, energy content (given the potential susceptibility of these residues to high moisture levels) and methods of recovering residues.
- Work should be undertaken in tandem with forest owners to understand the logistics, space and equipment required for harvesting residues.
- The development of an E-grade would greatly assist in the development of bioenergy markets. Further, clarity regarding the grade and value of biomass should help the 'integrated model' of cost recovery, outlined above, achieve the best outcomes in terms of recovery cost and volumes.
- Mechanisms should be investigated and established to help give confidence over prices, volumes and contracts for example regular (e.g. annual) updates to the biomass analysis in this RETA, encouraging use of industry-standard long-term contracts for process heat service-level biomass supply and greater transparency about (anonymised) prices and volumes being offered or traded.[139] The analysis for Taranaki showed that the cost of biomass can significantly affect investment decisions; given the significant potential demand for biomass relative to available residues in the region (processing and harvest), process heat users would benefit from a mechanism that could help identify opportunities for inter-regional trade of biomass resources.
- Analysis is also required to determine the impact of recovering these residues on soil quality, carbon sequestration, the risk of forest fires and what actions may be required to offset this.
- Undertake research into the likely competing demands for wood fibre from other emerging markets, such as biofuels and wood-derived chemicals.

[139] See https://www.bioenergy.org.nz/documents/resource/Technical-Guides/TG06-Contracting-to-deliver-quality-wood-fuel.pdf for a guide developed by the Bioenergy Association to assist the sellers and purchasers of solid biofuels trade and contract these materials for the production of energy.

10.2 Electricity – insights and recommendations

Electricity has a more established delivery infrastructure, and a market for securing medium-term supply of electricity at relatively stable prices through retail contracts.

Process heat users will make the best decarbonisation decisions if they clearly understand the potential costs and how enabling flexibility in their consumption will help reduce those costs (see Appendix C). Transpower and Powerco can only make the best decisions about upgrades if they have the best information about process heat organisations' intentions, and realistic levels of flexibility that process heat organisations can offer.

This RETA assessment has sought to increase the level of information shared, but we acknowledge that the world is changing quickly and this needs to be a continued process. The more up-to-date information is, the better able organisations are to adapt to a changing world. Electricity industry participants need to find ways to increase the pace of information exchange.

The analysis undertaken for this report indicates that it appears unlikely that the conversion of RETA process heat to electricity will trigger significant transmission upgrades. However, there are some potential situations where Powerco will need to upgrade zone substations to accommodate some scenarios of fuel switching. It is critical that process heat users engage with Powerco early, and often, about their plans.

10.2.1 The role for Powerco to play

Given the pace of change, Powerco should proactively engage with process heat users in order to:

- Stay abreast of process heat users' intentions regarding timing of, and capacity required for, electrification decisions. This will enable Powerco to accommodate their intentions in their network plans and demand forecasts, to make efficient use of network resources.
- Help Transpower and other stakeholders (as necessary) receive information from process heat users relevant to their planning at an early stage.
- Provide process heat users with timely advice and a good understanding of network investment, and network security levels, that can be incorporated into process heat business cases.

10.2.2 Information process heat organisations need to seek from Powerco

- **What their likely electricity consumption means for network upgrades.** The screening-level estimates provided in Section 9 provide a starting point, but more detailed discussions and engineering studies are required to firm these up. An important piece of information here is how the process heat user's demand (see below) aligns with existing demand patterns on the relevant parts of the network.
- **The risks and cost trade-offs of remaining on N security relative to N-1 (or switched N-1 if available).** Powerco will have sufficient history of network outages to provide a realistic expectation of the frequency of network interruptions, as well as the duration of any interruption to supply.
- **Network charges and network loss factors relevant to their connection location.** As outlined in Section 9, we have calculated each RETA sites network charges based on Powerco's pricing schedule Process heat user should gain an understanding of the degree to which Powerco charges will reward the process heat user for enabling and using flexibility in their demand.

- **A clear process, timeframes and information required for obtaining or upgrading network connection.**[140] These processes should have realistic timeframes and the nature of the information that each stage of the process will provide the process heat user, and the data and information network companies need from the process heat user at each stage (see below). The recommendation above regarding a connection feasibility information template should be explored as part of this.
- **How flexibility in their electricity consumption and/or the level of network security they desire could impact the cost of connecting them to the network.** Like network charges and loss factors, the degree to which Transpower and Powerco can be flexible with network security and therefore the extent of network upgrades required depends on the connection location.
- **How upgrade projects could be accelerated, for example through:**
  - Early and bulk procurement of critical long lead time equipment (items such as transformers, switchboards, cable, conductors etc).
  - Consideration of expedited delivery (often suppliers will expedite for a premium or offer air freight options).
  - Paralleling design and build activities where possible to reduce durations; and/or
  - Using commercial levers in contracts to expedite (i.e. delivery incentives or similar).

10.2.3 Information process heat organisations need to seek from electricity retailers

- **What tariffs are available that lock in a fixed set of prices over multiple years.** This avoids process heat organisations being exposed to unexpected price rises.
- **What tariffs are available that reward process heat organisations for using flexibility in their electricity consumption.** While retailers will be able to provide tiered pricing (e.g. different prices for peak periods vs off-peak periods), they should be developing more sophisticated arrangements which can lower their wholesale costs, the benefits of which should be shared with organisations who provide them flexibility. This should include tariffs which give the process heat user more exposure to the underlying wholesale price, but retailers need to explain the nature of the risks of operating under such a tariff.

10.2.4 Information that process heat users need to provide retailers, EDBs

To obtain good advice, process heat users need to develop and share a good understanding of:

- The nature of their electricity demand over time (baseload and varying components), especially what time of day and time of year their demand is likely to reach its maximum level.
- The flexibility in their heat requirements, which may allow them to shift/reduce demand, potentially at short notice, in response to system or market conditions.
- The level of security they need as part of their manufacturing process, including their tolerance for interruption.
- Any spare capacity the process heat user has onsite.

140 Transpower's web-based guide to the connection process is a good example. See https://www.transpower.co.nz/connect-grid/our-connection-process

10.2.5 The need for electricity industry participants to encourage and enable flexibility

This RETA assessment has highlighted some situations where costs could be significantly reduced if process heat users enable flexibility. However, New Zealand is currently lagging other electricity jurisdictions (e.g. the United Kingdom) in establishing a mature set of arrangements where electricity consumers can, if they wish, provide their consumption flexibility to electricity industry participants, and share in the benefits that flexibility creates. This lowers the costs of electrifying new process heat.

The FlexForum has developed a 'Flexibility Plan' for New Zealand, endorsed by MBIE, drawing on the expertise of over 20 members across a wide spectrum of the electricity and technology industries. The Flexibility Plan outlines 34 practical, scalable and least-regrets steps that help households, businesses and communities maximise the benefits from the flexibility inherent in their electricity consumption.

Part of these benefits stem from the wholesale market, which creates the wholesale prices used to calculate electricity purchase costs incurred by retailers and large consumers who connect directly to the national grid. A future electricity system, with a higher penetration of renewables, will experience greater benefit from demand-side flexibility. It is likely that the retail market will evolve to reward customers who are able to respond dynamically. This does not necessarily imply that customers need to be fully exposed to wholesale prices. Customers may be able to remain on a stable retail contract, but one that has a lower tariff as a quid pro quo for assigning some degree of control over demand to an intermediary.

For process heat users to be able to assess the benefits of process flexibility, they will need an improved level of information from electricity industry participants. EECA recommends better and more transparent information be published by EDBs, retailers and the FlexForum about the benefits to process heat users from enabling flexibility in consumption, and the types of commercial arrangements (between electricity consumers and retailers/EDBs) that should exist to provide these benefits.[141]

141 We note that, in its recent 'Price discovery in a renewables-based electricity system – options paper' the Electricity Authority's Market Development Advisory Group has included a preferred option C13 that recommends "Provide info to help large users with upcoming DSF investment decisions". See https://www.ea.govt.nz/documents/1247/MDAG-Library-of-options-FINAL-1.pdf, page 64.

10.3 Pathways – insights and recommendations

The pathways provided in this report illustrated how different assumptions about how and when process heat organisations make decarbonisation decisions can impact the resources and networks that provide the fuels.

Although the pathways have their limitations, and EECA will continue to enhance these in future RETA assessments (e.g. through more sensitivity analysis), they have illustrated the uncertainty faced by biomass and electricity suppliers. A lot of this uncertainty relates to the timing of decarbonisation decisions by users of process heat, and thus speaks to the pace of demand growth. Specifically:

- Given the assumed expectations of carbon prices, the MAC Optimal pathway suggests that the bulk of emissions reductions can already be achieved economically through demand reduction, electrification (boilers and heat pumps), and particularly through conversion to biomass. Given the likely lead times of bringing new biomass resources (particularly forest residues) and/or network capacity to market, it suggests that **planning by forest owners, aggregators, and network companies needs to begin immediately, including the types of information sharing highlighted above.**
- The pathways highlighted that the extent to which process heat users are aware of, and incorporate, expectations of future carbon price trajectories into their decision making will have a significant effect of investment timing. Rigorous, publicly available long-term scenarios of carbon prices, and guidance for how process heat organisations can incorporate these into investment decisions, is not easily accessible. An easily accessible centralised portal should be created that publishes up-to-date carbon price assumptions that are used to guide policy and regulatory decisions, e.g. Treasury's shadow carbon prices used for cost-benefit analysis, Treasury's ETS price assumptions for fiscal forecasting etc.

The pathways do not incorporate the potential for the growth in bioenergy and electricity for transport to compete with process heat. EECA will continue to develop the analysis to incorporate this in future analyses.

Photo credit: Methanex

10.4 Summary of recommendations

In summary, our recommendations are:

- More analysis, and potentially pilot studies, are conducted to understand different methods of recovering harvesting residues and the associated costs, volumes, energy content of the resources (given the potential susceptibility of these residues to high moisture levels).
- The development of an E-grade would greatly assist in the development of bioenergy markets. Further, clarity regarding the grade and value of biomass should help the development of an 'integrated model' of cost recovery, achieving the best outcomes in terms of recovery cost and volumes.
- Mechanisms should be investigated and established to help suppliers and consumers within and between regions to see biomass prices and volumes being traded and have confidence in being able to transact at those prices for the volumes they require. These mechanisms could include standardised contracts which allow longer-term prices to be discovered, and risks to be managed more effectively.
- National guidance or standards should be developed, based on international experience tailored to the New Zealand context regarding the sustainability of different bioenergy sources, accounting for international supply chain effects, biodiversity, carbon sequestration and the risk of forest fires.
- Powerco develop and publish clear processes for how it will handle connection requests in a timely fashion, opportunities for electrified process heat users to contract for lower security, and how costs will be calculated and charged, especially where upgrades may be accommodating multiple new parties (who may be connecting at different times).
- Powerco and process heat users to engage early to allow Powerco to develop options for how the process heat user's new demand can be accommodated, what the capital contributions and associated lines charges are for the process heat user, and any role for flexibility in the process heat user's demand. This allows both Powerco and process heat user to find the overall best investment option.
- To support this early engagement, Powerco to explore, in consultation with process heat users and EECA, the development of a 'connection feasibility information template' as an early step in the connection process. This template would include a section for process heat users to provide key information to Powerco, and a network section where Powerco provides high-level options for the connection of the process heat user's new demand. Information provided by Powerco would include the potential implications of each option for construction lead times, capital contributions, network tariffs and the use of the customer's flexibility.
- Powerco should ensure Transpower and other stakeholders (as necessary) are aware of information relevant to their planning at an early stage.
- Retailers, Powerco and the Electricity Authority should assist by sharing information that helps process heat consumers model the benefits of providing flexibility.
- Powerco and retailers should ensure that the tariffs they offer process heat users are incentivising the right behaviour.
- EECA expand future iterations of regional analyses to include transport as a decarbonising decision that will compete for electrical network capacity and biomass.
- EECA to work with Treasury and Ministries (such as Ministry for the Environment) to create an easily-accessible centralised portal that publishes up-to-date carbon price assumptions that are used to guide policy and regulatory decisions, e.g. Treasury's shadow carbon prices used for cost-benefit analysis, Treasury's ETS price assumptions for fiscal forecasting etc.

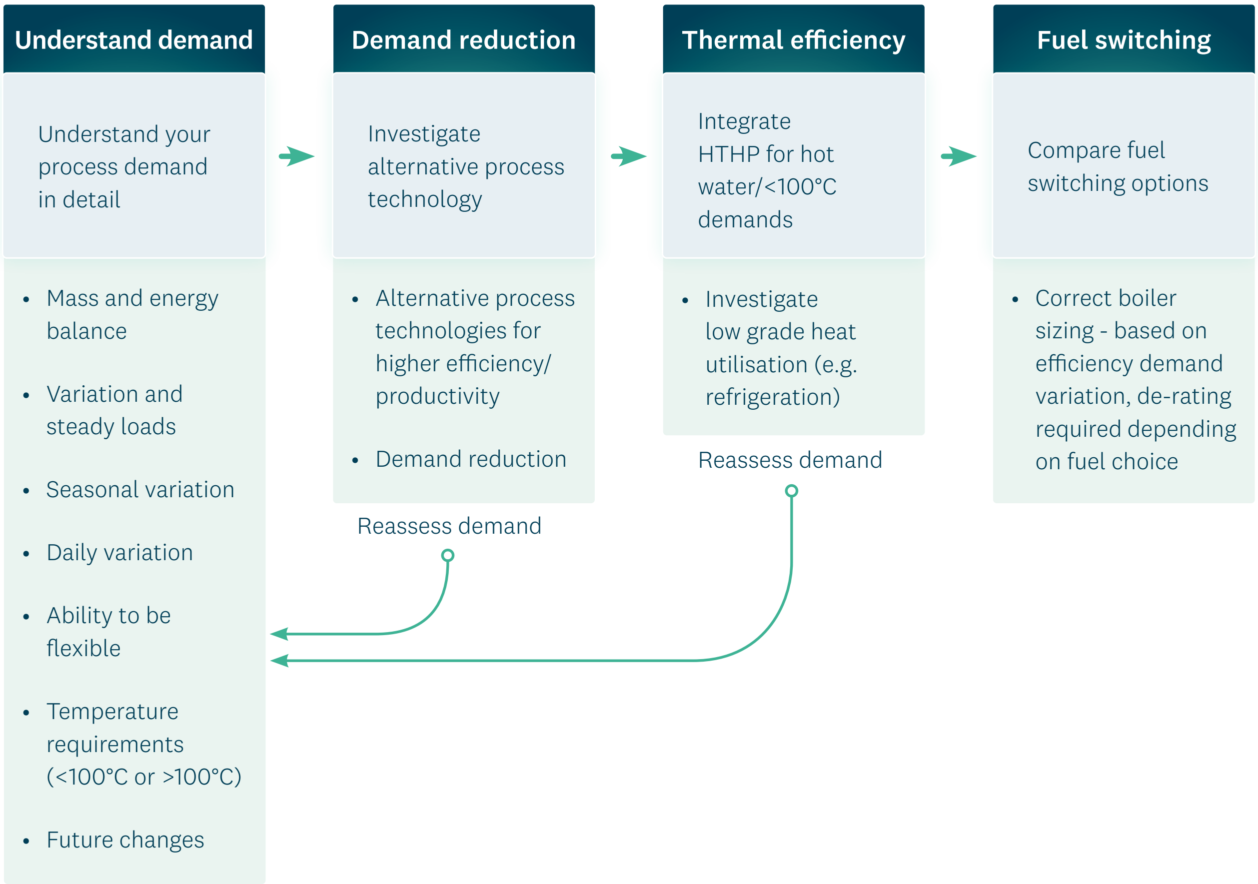
Photo credit: Venture Taranaki

11 Appendix A – Overview of the process heat decarbonisation process

For an individual process heat user, decarbonisation is a series of interconnected decisions. While the 'fuel' decision will usually be the most financially significant aspect of the project, a number of initial steps in the decision-making process can reduce energy consumption and emissions before the major fuel switch decision is made. These steps are usually commercially attractive in and of themselves, but also may result in reducing the capital cost associated with the fuel switching decision.

Figure 59 provides an overview of the main steps in the decarbonisation decision making process.

Figure 59 – Key steps in process heat decarbonisation projects. Source: EECA



As part of the fuel switching step above

Electricity

- Electrode boiler
- Network capacity increase required?
- Ability to flex demand to minimise cost
- Long-term electricity tariff
- Long-term carbon price

Biomass

- Age of boiler - conversion or new boiler?
- Long-term fuel supply and price – pellets, chip, hog
- Operational requirements for different fuels
- Fuel storage requirements for different fuels
- Long-term carbon price

11.1.1 Understanding heat demand

The importance of understanding the nature of a site's demand for process heat cannot be overstated. This includes an understanding of how it varies on an hourly, daily, weekly, and seasonal basis. A comprehensive understanding of heat requirements will underpin all subsequent decisions regarding efficiency, demand reduction, and fuel switching. An important aspect here, especially if electrification is to be considered properly, is the ability to be flexible in heat demand – can heat demand be interrupted or reduced for short periods of time (e.g. through utilising hot water storage). This flexibility can reduce the cost associated with any electricity network upgrades required to accommodate the project. It can also mean a financial reward for the process heat user through a variable ('time-of-use') electricity tariff. Similarly, this applies to biomass options as it may reduce the size of a boiler, which reduces the capital outlay required if a new boiler is contemplated.

There are four primary ways in which emissions can be reduced from the process heat projects covered by the Taranaki region RETA. For any given site, the four options below are not mutually exclusive and a number of options could be executed. Some of the options below are precursors for others – for example, to minimise the cost of a new boiler, demand reduction projects should precede commitment to the new boiler size.

11.1.2 Demand reduction and efficiency through heat recovery

Demand reduction includes projects such as heat recovery, temperature optimisation, equipment replacement, thermal insulation, and water flow reduction. These projects often have lower capital costs than fuel switching, providing a good return on investment and marginal abatement cost. The ability for a site to reduce demand is specific to its operations, so sites within the same sector usually have similar project opportunities. Opportunities in the meat industry include UV sterilisation, heat recovery, washdown optimisation, and pipe insulation.[142] For the dairy sector, opportunities could include waste heat recovery (including through use of heat pumps), conversion to mechanical vapor recompression, or preheating boiler feed water. These are often the best actions when considering energy productivity and the best use of limited funding.

It is critical to understand the full potential of demand reduction and best integration. Tools such as pinch analysis could play a key role in utilising the demand reduction to its full potential.

142 See https://www.eeca.govt.nz/insights/eeca-insights/international-tech-scan/

11.1.3 Fuel switching to biomass – boiler conversions or replacements

Large-scale conversion to biomass will most typically draw on wood as a source of bioenergy. Within that, there is a range of options where wood is used to generate heat in a boiler.

Two primary and interrelated decisions when switching to biomass are:

- Whether the existing boiler will be replaced with a new biomass specific boiler, or the existing boiler will be converted from a coal supply chain to a wood-based one. The decision to convert an existing boiler will depend on its type, age, and condition, and may require a particular type of biomass fuel.
- What type of fuel will be used – for example, wood pellets, chip, or hog.

These two decisions involve a range of technical and financial considerations:

- If the site is converting an existing coal boiler, it may be able to be retrofitted to burn wood pellets or chip as a fuel. If a new boiler is contemplated, wood pellets, chip and hog are potential fuels.
- Wood pellets are a higher quality fuel and are more expensive, while wood chip and hog are lower quality fuels, but are more easily produced. Wood pellets require substantially more processing than other wood fuels, and bioenergy processing plants (e.g. pellet production) will likely have minimum levels of scale to be economic and may take time to be developed in the region.
- EECA has not considered in detail the logistical and emissions impact of transporting biomass but notes that wood pellets will have lesser transport requirements due to their higher energy density.
- Wood fuel must have a moisture content as specified in the fuel supply contract according to the design of the boiler. Out of specification fuel may impact the performance of the boiler and the overall process.
- Hog fuel is cheaper than wood pellets and chip but may require greater modification of existing storage and handling facilities which have been designed around coal. Due to the lower energy density of hog fuel compared to coal, more space (and likely a higher number of deliveries) is required to store it onsite.
- The available space on site is also important. Biomass fuel should be kept dry so larger, covered, storage facilities may be required compared to existing coal storage.

Photo credit: Methanex

11.1.4 Fuel switching – electrification through high temperature heat pumps for <100°C requirements

Significant improvements in thermal efficiency can be achieved through the installation of high temperature heat pumps (HTHPs).[143] As a result of their high efficiency, opportunities to use HTHPs where heat requirements are lower than 100°C are highly likely to be economically preferable to existing sources. These projects vary from site to site, but can provide heating for process water, potable water on industrial sites or HVAC on commercial sites.

Where a site has a range of heat requirements, heat pump projects should generally be considered prior to fuel switching as existing site heat can be utilised to decrease the required capacity of the new boiler. Depending on the site operations, a coefficient of performance (CoP) of three to five can typically be achieved.[144] While not yet used in New Zealand, high temperature steam heat pumps producing 150°C heat have the potential to decarbonise much of New Zealand's industry within the 15 year timeframe contemplated by EECA's RETA decarbonisation pathways for the Taranaki region (outlined in Section 7).[145]

11.1.5 Fuel switching – electrification through electrode boilers

Electrification sees electrode (or similar) boilers installed to generate heat. Compared to biomass boilers, electric boilers generally have a lower capital (purchase and installation) cost, but grid-sourced electricity is more expensive than biomass as a fuel at the current time. Operationally these boilers are ~25% more efficient than biomass, with highly flexible output and low maintenance costs.[146]

A key consideration when assessing electrification projects is whether the increase in electricity demand from the site requires upgrades to the local or regional electricity network. The potential cost of such upgrades is considered in Section 9.

Finally, and as indicated above, while electrode boilers are more efficient, the electricity price is likely to be higher (on a $ per unit of energy basis) than biomass. However, electricity retailers can structure prices in a way that rewards the heat user for shifting its demand (to the extent possible) to periods where the electricity price is lower. This use of flexibility may also lower the cost of any electricity network upgrades triggered by the electrification of the process heat.

143 See EECA's industrial heat pump fact sheet at https://www.eeca.govt.nz/insights/eeca-insights/industrial-heat-pumps-for-process-heat/

144 This means that one unit of electricity consumption can generate 3-5 units of heat. Heat pump systems coupled to refrigeration systems can achieve Coefficient of Performance (COPs) of 8 or more. Mechanical vapour recompression (MVR) technology can achieve significantly higher COP again.

145 Fonterra is planning to trial these heat pumps. See https://www.nzherald.co.nz/business/fonterra-could-build-giant-heat-pumps-for-factories-as-1-billion-dollar-sustainability-drive-continues/LTIMLRIC2VGSVOBXTXYYHJZRGE/

146 See https://genless.govt.nz/assets/Business-Resources/Electrode-electric-resistance-steam-generators-hot-water-heaters-for-low-carbon-process-heating.pdf


Photo credit: Methanex

12 Appendix B – Sources, assumptions and methodologies used to calculate MAC values

12.1.1 Sources and assumptions

The modelling that sits behind the simulated pathways relies on an array of assumptions about the decisions individual organisations will make. Some of these relate to the individual characteristics of each process heat organisation in the Taranaki RETA, other estimates use the costs produced in Section 8 and 9.

Where possible we have used actual data for this analysis and the main sources of data include:

- Energy Transition Accelerators (ETAs)
- Energy audits
- Feasibility studies
- Discussions with specific sites
- Published funding applications
- Process Heat Regional Demand Database
- School coal boiler replacement assessments
- Online articles

The emissions profiles and reduction opportunities of all the major sites have been covered off using these sources, covering most emissions from the Taranaki RETA sites.

However, for sites where individual ETA data was not available, estimates based on other data available to EECA were made. We outline this data below.

Demand reduction and low temperature heat opportunities

For demand reduction and low temperature heat (<100°C) opportunities, if ETA data is unavailable, the information in Table 13 is used:

Table 13 – Assumptions regarding heat pump hot water and demand reduction opportunities where ETA information unavailable. Source: Worley

Sector	Sub-sector	Proportion of total heat demand < 100°C	Peak demand reduction (%)
Dairy	Dairy	11%	11%
Industrial	Wood	10%	10%
Commercial	Buildings	10%	10%
Industrial	Meat	18%	18%
Industrial	Other industrial	25%	25%
Commercial	Schools	10%	10%

The following general rules have also been applied to each site, which reflect the decarbonisation decision making process outlined in Section 7.3:

- Demand reduction or efficiency projects are assumed to proceed, and will proceed first, so that boiler sizing decisions are based off the post-efficiency/demand reduction requirements.[147]
- If a site only demands hot water at less than 100°C, there is the potential to replace the entire boiler load with heat pumps (depending on opportunities for heat recovery on site). If a site contains both <100°C water and >100°C heat requirements, a mixed approach may be adopted, using heat pumps for the hot water demands and a boiler conversion or replacement for higher temperature needs.

147 As a result, the total boiler demand from sites post-fuel switching decisions is lower than the demand implied from the process heat regional demand database.

Heat delivery efficiency

While information on the current consumption of fossil fuels is available, investment in new process heat technology will invariably lead to increased efficiency and thus a reduction in the energy required to deliver the required heat. Where ETA information is not available, we used the parameters in Table 14 to represent the efficiency of the new process heat equipment.

Table 14 – Assumed efficiency of new process heat technology, where ETA information is unavailable. Source: EECA

Existing boiler efficiency	78%
New boiler efficiency	80% (biomass) 99% (electricity)
Heat pump efficiency	400%

12.1.2 Our methodology for simulating commercially driven decisions

As outlined above, some of our pathways make simplifying assumptions about process heat user decarbonisation decisions. Other pathways seek to reflect more realistic, commercially driven decisions by process heat users. Here, we focus on how we simulate these commercial pathways.

There are a range of factors organisations face when deciding when to invest in decarbonisation, and which fuel to choose. These factors will invariably include the financial cost of the decision, but also may include confidence in future fuel supply, competitor behaviour, funding and financing or consumer expectations.

However, the softer factors are harder to model quantitatively. As a result, the methodology used here focuses on the financial components of the investment decision that can be modelled with available data. To a large extent, these are the factors relating to efficiencies and costs listed above, as well as known information about the current annual consumption of heat at each of the RETA sites.

Our simulated 'optimal' decision making framework presumes that the decision regarding which fuel to switch to, and when, is purely about the change in capital and operating expenditure arising from the project, using the information outlined above. Using discounted cashflows analysis, at an appropriate discount rate, we can determine the 'net present value' (NPV) of the combination of up-front capital costs and changes in ongoing operational costs (including the cost reduction from not consuming fossil fuels), tailored to each type of technology (heat pump or boiler) and fuel (electricity or biomass). We then assume that the process heat user would choose the option with the best (highest) NPV.

For an indicative set of parameters, Figure 60 illustrates the NPV for three different fuel choices.

Figure 60 – Illustrative NPV for different heat technology options.

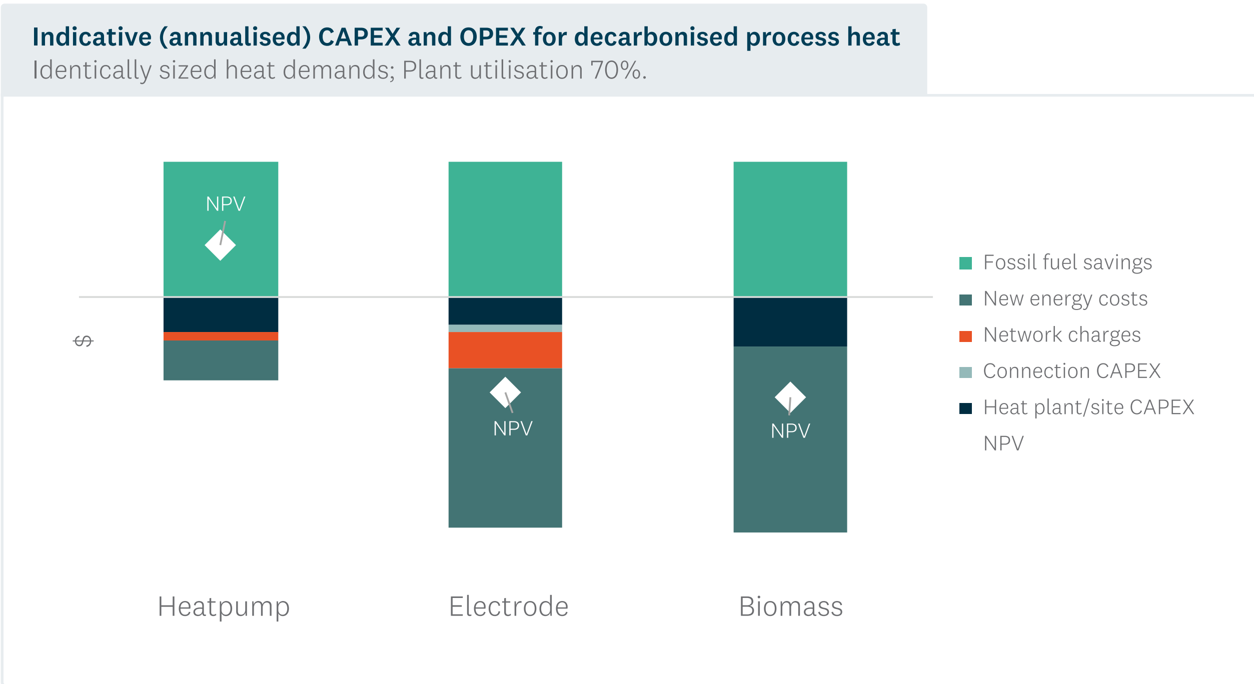


Figure 60 shows that, if the process heat site is using low temperature (<100°C) heat, a heat pump has the highest NPV. In fact, it would have a positive NPV, as the cost of the heat pump option would be more than offset by the savings in fossil fuels. This is a result of the significantly higher efficiency of the heat pump, compared to other options.

For heat requirements over 100°C, the NPV for both electricity and biomass is negative at current fossil fuel prices. As carbon prices rise, the price of fossil fuels will increase, as will the savings from switching to low emissions fuel. An increasing carbon price will eventually result in the NPV becoming positive for several sites – we explore this further below.

Figure 60 also illustrates the relative cost components of electricity vs biomass investments:

- The variable costs of fuel are lower for electricity (retail charges) than biomass. In this illustrative case, this is principally due to the boiler efficiencies – an electrode boiler is ~25% more efficient than a biomass boiler.
- While the capital costs of an electrode boiler are assumed to be around half that of a new biomass boiler, electricity also faces upfront capital costs (associated with upgrades to the network) as well as annual network charges which are a function of connection capacity and peak demand. These network charges can potentially be reduced by reducing electricity consumption during peak periods, as outlined later.

The impact of fixed costs on the economics of an investment is heavily influenced by the utilisation of the boiler. Because fixed costs don't change with the usage of the plant, the economics of high utilisation plant (such as dairy factories) will generally be better than low utilisation plant (for example, schools). This is why the economics of low utilisation process heat sites tend to favour biomass – in a range of situations, the fixed costs are lower for biomass, due to the absence of network upgrade costs and charges.

To illustrate this point, Figure 61 illustrates the relative economics with the same parameters as Figure 60, except we have lowered the utilisation of the plant from 70% above, to 20%.

Figure 61 – Illustrative NPV for different heat technology options, low (20%) utilisation.

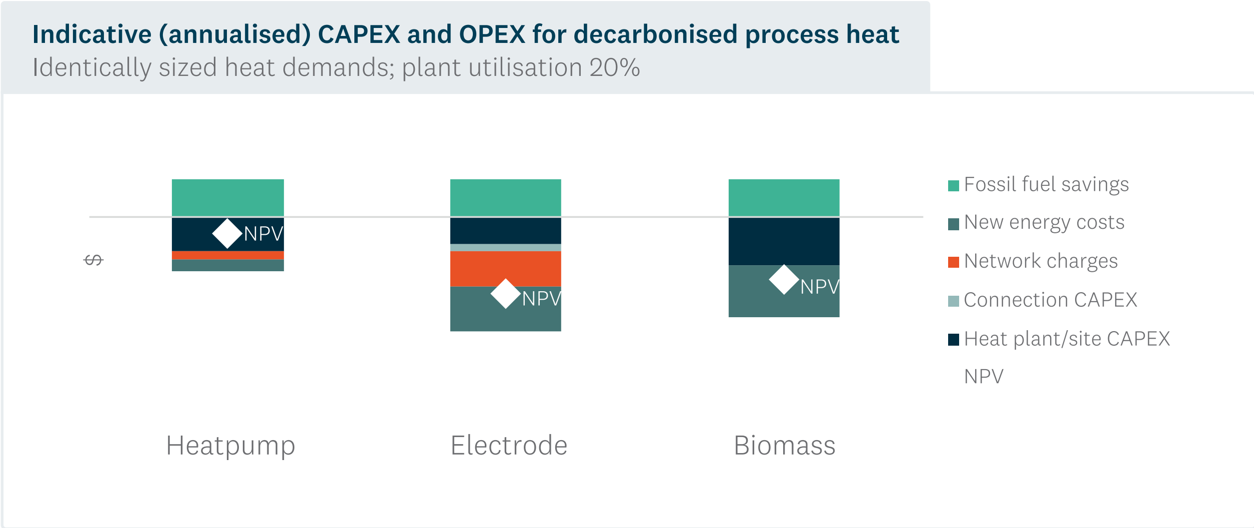


Figure 61 shows that the economics now favour biomass (if the process heat user requires heat greater than 100°C). This is because the consumption-related costs (retail electricity or biomass) have reduced, but the fixed network costs for both options remain the same. Since the biomass had lower fixed costs, it now outperforms electricity.

12.1.3 Comparing economics from a decarbonisation perspective

Whilst comparing NPVs is a useful commercial approach, the example above highlighted that an important factor is the impact of an increasing carbon price on the cost of continuing to use fossil fuels for process heat. Although today the carbon price may not be sufficiently high to result in a positive commercial outcome from decarbonisation, the carbon price is expected to increase in the future. At some point, projects that are currently uneconomic are likely to become economic. At this point, the cost of continuing to use fossil fuels (effectively the green bars in Figure 60 and Figure 61) will exceed the cost associated with reducing emissions (via investment in electricity or biomass).

Understanding when this point might occur requires us to calculate a ‘levelised cost of emissions reduction’ for each project and fuel type (biomass or electricity), also known as a ‘marginal abatement cost’ (MAC).

MACs are just another way of viewing the NPV of the project, except that it is ‘normalised’ by the tonnes of emissions reduced by the investment. MACs are calculated as follows:

$$MAC\left(^{\$}/_{CO_2e}\right) = \frac{NPV(Project\ Costs\ (\$))}{NPV(emissions\ reduced\ (tCO_2e))}$$

The NPV in the formula differs in one major respect from that illustrated in Figure 60 and Figure 61 above – it must not include the future estimated carbon price. As a result, it provides the underlying average cost of reducing emissions as though there was no carbon price. This can then be correctly compared with the current and future carbon price.

MAC values can then support a process heat user's investment decision in two ways:

- **Fuel choice** – As discussed above, since it incorporates the underlying NPV of the project, the MAC gives a relative ranking of the options (heat pump, electrode, or biomass boiler), just expressed per-tonne of CO_2e. A high MAC value suggests that project's cost of reducing a tonne of carbon dioxide is higher than a project with a low MAC value.
- **Investment timing** – Having determined the option with the lowest MAC, it then can be used as an indication of the best time to invest in decarbonisation by comparing it with likely carbon prices. Ultimately, carbon prices flow through to the fossil fuels used by the RETA organisations via the price of the fuels they use. If the national carbon price is expected to be higher than the MAC value (the 'cost of carbon reduction'), then the organisation will have lower costs in the future by investing in decarbonisation and reducing its exposure to future carbon prices.

New Zealand's carbon price is set primarily through the Emissions Trading Scheme (ETS); however, the quarterly carbon auctions which determine this price only reflect the current supply of, and demand for NZUs.

Comparing the optimal fuel's MAC value against today's carbon price doesn't fully capture what the business will be paying for coal, diesel and LPG in the future. This is especially important when considering investments in boilers – that will avoid the cost of carbon – that have a life of 20 years (or more). Put another way, decarbonising process heat doesn't just avoid today's cost of carbon, it avoids it over the life of the investment.

If the carbon price was expected to rise, then the investment would be more attractive than if only today's price of carbon was used. The challenge for many organisations is how to form a view on the carbon price (and its impact on the business) *in the future*, should it continue to consume fossil fuels.[148] Unfortunately, there are few publicly available forecasts of carbon prices through which a process heat user can get confidence that carbon prices will reach a level which makes the investment economic. Even if these forecasts were available, it is entirely understandable that an investor might 'wait and see' if the increases materialise, before committing investment.

A view on future carbon prices can be informed by the Treasury's assumptions as follows:

- For the first four years in the RETA period, we have used ETS price assumptions as per Treasury's ETS fiscal forecasting.[149]
- For the longer term, we have used shadow carbon price projections used by central agencies to inform policy decisions, and which are published by the Treasury.[150]

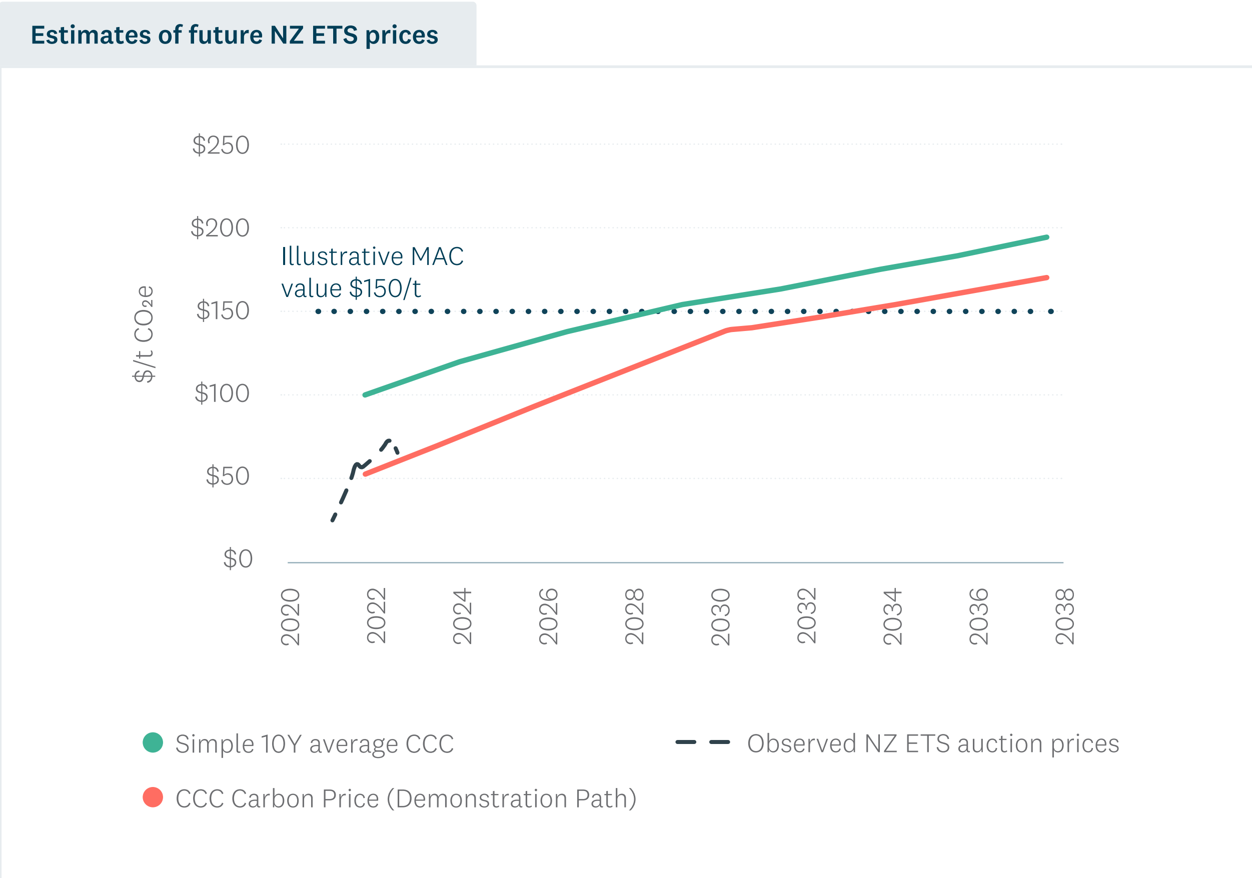
Whether or not ETS prices follow these prices depends largely on whether government policies and resulting decisions by consumers and businesses are aligned with the 'emissions budgets' recommended by the CCC.

148 To some extent, this is no different to an organisation considering the future prices of any of their major input costs, except that the carbon price is often already packaged into the cost of the fossil fuel they consume (coal, gas, or diesel) and may not be itemised separately by the fuel supplier.

149 https://www.treasury.govt.nz/sites/default/files/2023-08/cefa23-technical-appendix-1.pdf

150 See Table 1 in https://www.treasury.govt.nz/sites/default/files/2023-12/cbax-tool-climate-environmental-impacts.pdf

Figure 62 – Future views of carbon prices



Recognising that it is the carbon prices over the lifetime of the investment that represent the carbon costs that the organisation will face, we have used the 10-year future average of the CCC's demonstration pathway. This is the green solid line in Figure 62.

The black dashed line shows the outcomes of actual New Zealand ETS auctions (held each quarter). These are the result of the bids by organisations that need to purchase NZUs, cleared against the volumes made available by the government (at reserve prices). The NZ ETS sets a minimum auction price that needs to be met for an auction to be accepted. During 2023, clearing prices did not meet this minimum criterion, so there were not successful bids.

We have also included one broker's clearing prices of NZU contracts being traded up to five years in the future – this offers another view of the market's expectation of carbon prices, as at March 2024.[151]

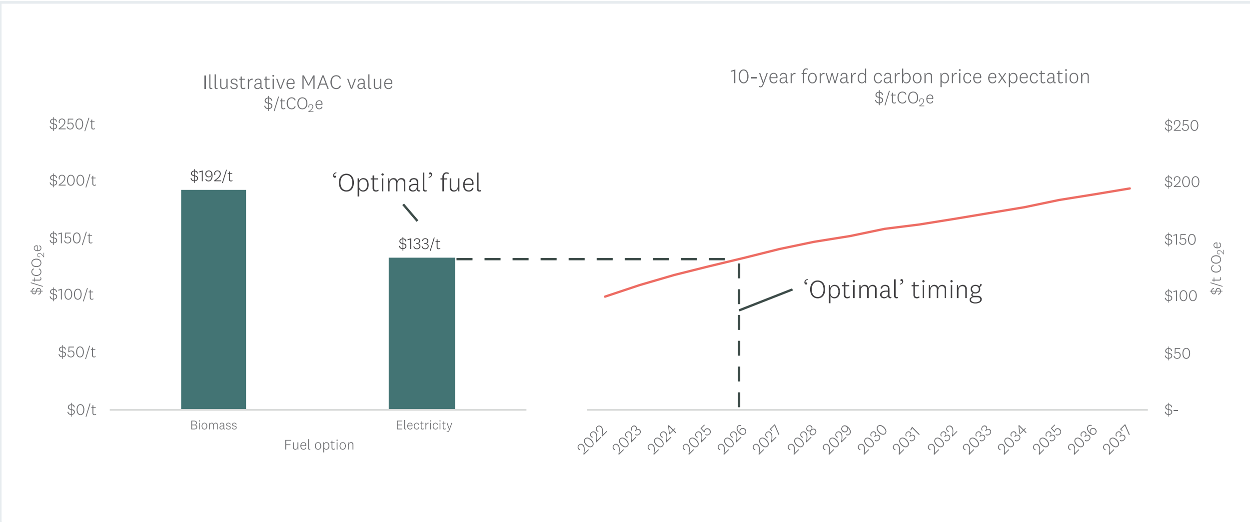
Different future views on carbon prices, and different ways of using those views, could have quite different impacts on the timing of decarbonisation projects proceeding. Assuming that the Treasury's shadow prices are a good forecast of carbon prices, Figure 65 shows that a project with a $150/t MAC value would not be committed until 2031 if the decision maker used the current carbon price to trigger the decision, but would proceed earlier – in 2027 – if they used the simple average of the next 10 years of carbon prices implied by the Treasury's carbon prices.

151 Because NZUs can be purchased today and stockpiled/held for the future, these forward prices contain very limited information about future carbon prices other than the cost of carry (i.e. working capital/interest rates. If, however, the only way to meet NZU obligations in – say – 2026 was to purchase 2026 vintage NZUs, then forward contracts would have significant signalling value.

For this report, we have chosen to use the 10-year forward average of the Treasury's shadow prices (central scenario) to determine the investment timing, as we believe this is a better reflection of the actual financial impact of *future* carbon prices on a long-term investment than just using the solid red line in Figure 65.[152]

The overall framework for how we use MAC values to create the 'MAC Optimal' pathway below is shown in Figure 63.

Figure 63 – Illustration of how MAC's are used to determine optimal decision making



152 This is not the only correct way to determine investment timing. There are a range of other frameworks for decision making, which could result in earlier or later investment timing.

12.1.4 The impact of boiler efficiency on the 'cost of heat'

The MAC analysis implicitly trades off all the costs – capital, operating and fuel – to provide a single analysis of the lowest-cost fuel (from an emissions reduction perspective). This (necessarily) incorporates the different efficiencies of the boiler technologies chosen. For sites that can contemplate both biomass and electricity as fuel switching options, the delivered cost of biomass (to the 'gate' of the site) cannot be directly compared with the delivered cost of electricity (or any other fuel) without accounting for the fact that, biomass boilers have approximately 80% efficiency, whereas electrode boilers have close to 99% efficiency. On the same basis, heat pumps have coefficients of performance that are four or higher. The cost per unit of heat received by the process is therefore different from the cost per unit of the energy delivered to site.

In Figure 64, we illustrate the difference between these cost concepts using the bioenergy supply curve from Section 8.7 (for a biomass decision) and the electricity price path from Section 9.2 (for an electrode boiler, and heat pump decision). Note that these are only the variable costs of the fuel, and do not incorporate the fixed costs associated with different investment decisions (which are considered with the MAC calculation). The biomass price does not account for any margin that suppliers may seek on the various bioenergy resources, which we expect would add $3/GJ to the biomass figure, nor secondary transport from the hub to a process heat user's site (assumed to be $3/GJ).

Figure 64 – Comparison of the variable costs of biomass and electricity from a delivered heat perspective. Sources: Worley, Forme, EnergyLink, EECA.

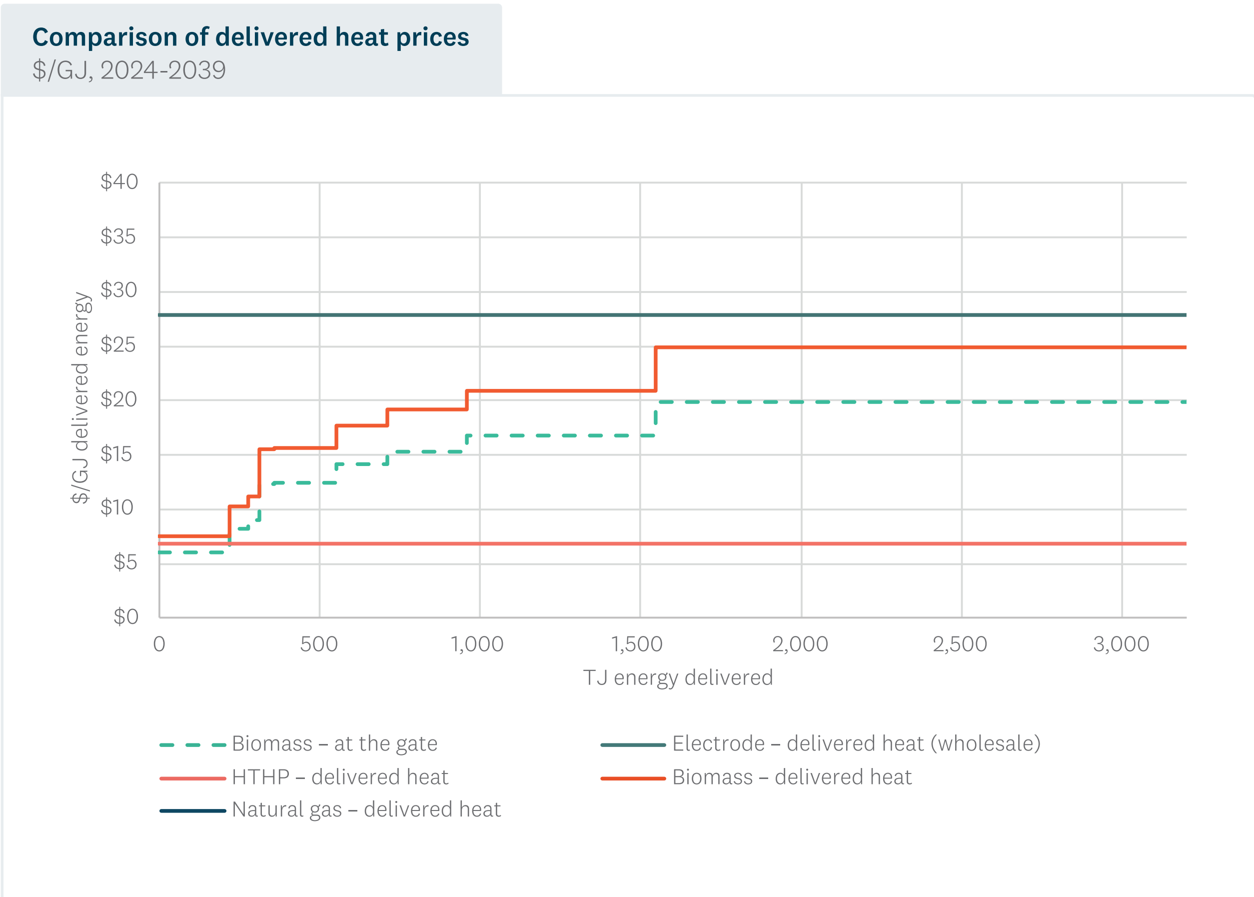


Photo credit: Methanex

13 Appendix C – Electricity Supply and infrastructure explanatory information

The following sections provide detailed information on technical and complex aspects of electricity supply and infrastructure referred to in Section 9.0 of this report.

13.1 Pricing

13.1.1 Energy pricing – wholesale

As noted in Section 9.2 the generation or 'wholesale' cost of electricity is the result of electricity prices that arise from a market that clears supply and demand every half hour of the year. In order to derive a forecast of future retail electricity prices that can be used to assess the economics of electrification projects, ideally New Zealand needs a model that reflects the likely interaction of supply and demand, and therefore prices, in the wholesale market.

EECA engaged EnergyLink, an electricity market modelling firm, to use its sophisticated modelling of the electricity market to produce such a price forecast. EnergyLink's model simulates the interaction of wholesale electricity supply and demand, and produces wholesale market prices, in a way that closely resembles the mechanics of the actual half hourly market. This includes the way the New Zealand electricity market incorporates transmission losses into the wholesale price observed at each of the ~250 locations (GXPs or GIPs) around the country where power is traded and reconciled.[153] Finally, it also includes the impact of varying inflows into hydro reservoirs, which remains critical given New Zealand's reliance on hydro generation (~55% of total generation) will remain for some time yet.[154]

However, to produce these prices over a multi-decadal timeframe, assumptions need to be formed about the future wholesale supply of, and demand for, electricity over this period. Given the significant uncertainty facing the electricity industry presently, EnergyLink developed three scenarios of supply and demand, including fuel costs, carbon costs and investment costs associated with new supply (as shown in section 14.1.2.1).

153 Grid Exit Points (where electricity leaves the grid) and Grid Injection Points (where electricity enters the grid from power stations).

154 There is some evidence from climate analyses that, at least on average, inflow patterns into the major hydro storage lakes (Lakes Tekapo and Pukaki, which represent ~70% of New Zealand's controllable storage) will change over the coming decades. The principal effect is that less precipitation will fall as snow as the globe warms, which has the effect of increasing winter inflows into these alpine lakes. EnergyLink have not included these effects in the scenarios produced for this project.

13.1.2 Energy pricing – retail

Most large users of power do not elect to face the half-hourly varying wholesale price, and instead prefer the stability of multi-year retail contracts that contain a schedule of fixed prices, that each apply to different months, times of week and times of day.[155] The three wholesale price scenarios were adjusted to reflect the observed difference between the wholesale price of power, and how large user retail contracts are typically priced. This is an approximation based on historical evidence but should be a plausible guide (based on historical trends) to what customer should expect if it sought this type of retail contract. Each site contemplating electrification should engage with electricity retailers to obtain more refined estimates and potential options.

The retail electricity prices scenarios produced by EnergyLink are relevant to process heat users, reflecting what would be expected from a retailer that was pricing a large commercial contract. It is important to understand that:

- The Energylink price is only forecast for the generation and retail ('energy') component of the customer's tariff, that is, they do not include network charges (use of the existing transmission and distribution network, which is in addition to the costs of any upgrades considered above) which will vary from customer to customer.[156] The network component of the bill is discussed in Section 9.2.4 and 9.2.5.
- Energylink prices include the effects of high-voltage transmission losses to the nearest GXP in the Taranaki region, but do not include distribution network losses to the customer's premises. Loss factors are set by EDBs companies to account for distribution losses, and these loss factors are applied by retailers to the GXP-based price. In the case of Taranaki, distribution losses for sites connecting at or below 11kV are around 1.07 for Powerco's Western network.[157]
- Energylink produce prices for four time 'blocks' each month – business day daytime, business day night-time, other day daytime and other day night-time. Different arrangements with a retailer may allow for different granularities of pricing and may also allow for the site to be rewarded for responding to, for example, high wholesale prices by shifting demand.

This is a relatively orthodox approach to modelling the electricity tariffs that process heat users may be presented with by their retailers. However, some electricity retailers are evolving their tariffs to provide incentives for large process heat consumers to convert to electricity, and these tariffs have begun to emerge in the New Zealand industry.[158] As part of this RETA analysis, we have incorporated currently available special offers for process heat decarbonisation to be representative of retail prices for the first 10 years of a fuel switching project, after which we revert to EnergyLink's forecasts.

155 Common contracts are often referred to as '144 part' contracts, reflecting the fact that the prices are specific to 12 months, two-day types (weekday and other day) and six time periods within the day.

156 This is generally the costs we have discussed above, relating to generation plus transmission losses and retailer margin, insofar as the latter is included in variable (c/kWh) charges. Some components of retailer margin may also be included in fixed daily charges from the retailer.

157 EDBs publish network loss factors for different parts of the network, usually as part of their pricing schedule. An individual customer can find their loss factor by entering their ICP number (found on a recent power bill) in https://www.ea.govt.nz/consumers/your-power-data-in-your-hands/my-meter/. The distribution loss factor for that site can then be found under the 'Network Pricing' section.

158 For example, Meridian's process heat electrification programme pricing.

13.1.2.1 Scenarios considered

The three scenarios are characterised by assumptions that represent a 'Central' price scenario plus:

- **High Price scenario** – Assumptions that would lead to higher electricity prices than the Central scenario, for example, higher demand, higher fuel costs or more restrained investment in new power stations.
- **Low Price Scenario**[159] – The low price scenario originally provided by EnergyLink reflected an exit of the Tiwai Point aluminium smelter. During the course of this RETA project, this scenario became moot, as Tiwai confirmed that it had secured electricity supply arrangements. EECA has therefore constructed its own low price scenario by simply varying prices below the "Central" scenario by approximately the same amount that the high price scenario is above the central scenario.

The three scenarios used are outlined in Table 14 below. More detail on these assumptions is available in EnergyLink's report.[160]

Table 14 – Electricity market scenarios considered. Source: EnergyLink

Scenario driver	Central price scenario	High price scenario
NZAS at Tiwai Pt	Remains	Remains
Demand growth[161]	46TWh by 2032; 63TWh by 2048	50TWh by 2032, 70TWh by 2048
Coal price	USD85/t	>USD100/t
Gas price	Medium	High
Initial Carbon price[162]	NZD75/t	NZD75/t
Generation Investment behaviour[163]	Neutral	Lagged/Conservative
Generation disinvestment	Huntly Rankines dry year and retired by 2030 Huntly CCGT retired 2037	Huntly Rankines dry year and retired by 2030 Huntly CCGT retired 2037

159 We would note that with the confirmation the Tiwai Pt smelter will remain open until 2044, the low-price scenario is no longer relevant

160 EnergyLink (2022), 'Regional Electricity Price Forecasts: EECA Regional Energy Transition Accelerator Program', May 2022.

161 EnergyLink did not provide sufficient data to perform a direct comparison, but their Low scenario appears slightly lower than the CCC's Demonstration Path (which included a Tiwai exit). EnergyLink's Central Estimate in 2032 looks ~3TWh lower than the CCC's 'Tiwai Stays' sensitivity.

162 Note that the impact of the cost of carbon on the electricity price reduces over time as the electricity supply chain decarbonises and wholesale electricity prices become less sensitive to the cost of electricity generation that has a carbon component.

163 Specifically, EnergyLink assume that a neutral approach would be an investor seeking to time construction such that target EBITDA is reached within two years of construction. A more aggressive approach would see investors build earlier (tolerating an undershoot of EBITDA by 10%), whereas a lagged approach would see investors delay construction to ensure 10% more than target EBITDA is achieved two years after construction.

EnergyLink also model the 'levelised cost of energy' (LCOE) associated with generation investment classes (e.g. wind, solar) into the future.[164] The degree to which these forecasts of LCOE affect investment are then a function of these costs, the way the projects are assumed to be financed, and the cost of debt.

Noting that the Low and High scenarios are not necessarily designed to be the most plausible storylines, but instead to apply assumptions that would deliberately lead to high and low-price outcomes.[165] As with many scenario analyses that involve mathematical models, there is a tendency for these models to understate the true range of potential prices as they cannot incorporate all of the real-world factors (including human decision making) that drive price. EnergyLink's scenarios provide information on what a range of price outcomes might look like. It is also important to note that the Low and High scenarios assume the variables in the table persist every year for 25 years. In reality, the market could periodically 'switch' from one scenario to another and remain there for a number of years.

The following assumption in EnergyLink's modelling are also relevant:

- The scenarios assume that the national electricity system reaches the Climate Change Commission's target of 95% renewable generation by 2030.
- The scenarios have not factored in the proposed pumped storage scheme at Lake Onslow. They do assume that the remaining thermal peaking plant can be switched (if deemed economic) to a low emissions fuel and has fuel storage large enough to support the system through extended periods of low inflows.[166]
- EnergyLink apply different inflation assumptions to the various assumptions in the table above, each of which imply different rates of decline from its current level of 7% to a long-term rate of 2%.

164 "In real terms, the cost of building, owning, and operating new wind generation falls at rates calibrated against actual wind projects in New Zealand, with adjustments for the cost of financing projects. The cost of grid-scale solar farms also falls in real terms, but as there are no such projects in New Zealand, the rate at which costs fall is calculated from a combination of information that is in the public domain in New Zealand, along with data from overseas." EnergyLink, p 14, footnote 20

165 For example, in the Low Scenario, Tiwai is assumed to exit but other decarbonisation demand is also assumed to be muted. However, it is the Tiwai exit scenario that is mostly likely to accelerate initiatives to decarbonise, not least because the price of electricity will be suppressed for quite some period of time, making electrification attractive.

166 Studies into future electricity supply are also considering the emergence of 'dunkelflaute' conditions, which are extended periods of cloud and low wind. These periods, potentially of weeks, such as that observed in continental Europe in 2021, would be beyond the capability of lithium-ion batteries and would also benefit from the presence of flexible generation such as peakers.

13.1.3 Network charges – distribution

As noted in section 9.2.4, EDBs levy charges on electricity customers for the use of the distribution network, except for those large customers who connect directly to one of Transpower's GXPs. As monopolies, EDBs are permitted under the Commerce Act to recover the cost of building and operating the distribution network plus a regulated return. The total amount EDBs can earn is regulated by the Commerce Commission, while the way they charge (generally referred to as 'distribution pricing') is overseen by the Electricity Authority.[167]

The magnitude of charges for any individual customer depends on each EDB's 'pricing methodology'. This methodology describes how each EDB will convert its allowable revenue into prices for different customer groups, while meeting the principles set by the Electricity Authority for efficient pricing. Each year, these prices – for each customer group – are published by each EDB in a 'pricing schedule'.[168]

The difference in prices between EDBs can reflect a variety of characteristics of each network – their pricing methodologies (which determines how costs are allocated between domestic, commercial, and industrial consumers), the nature of their network (e.g. proportion of high-density urban environments versus sparse rural areas) and where they are in their investment cycle.

When considering a business case for an investment that will last many years, a very important factor is the potential changes in how EDBs might structure their prices, and the degree to which these charges will be reflected in retail electricity contracts.[169] The Electricity Authority is working with EDBs to move their pricing approaches, over time, towards more efficient pricing structures, with five focus areas:

- Planning for future congestion
- Avoiding first mover disadvantage for new/expanded connections
- Transmission pricing pass through (see below)
- Increased use of fixed charges
- Not applying use-based charges (e.g. Anytime Maximum Demand) to recover fixed costs

More detail is available on the Electricity Authority's website.[170]

167 By this we mean how they allocate their costs amongst different customer groups, what variables they use to charge customers (e.g., capacity, peak demand, volumetric consumption) and other principle-based oversight. For more information see https://www.ea.govt.nz/projects/all/distribution-pricing/

168 The 2023-24 pricing schedules and methodologies for each EDB can be found on their websites.

169 Having these charges passed directly through to the process heat customer is only one way to incentivise flexibility. Since retailers ultimately pay these charges to distributors, another way is for retailers to work with the process heat users to reduce demand at high price times, this reducing the retailer costs, and share this benefit with the process heat user in any number of ways.

170 See https://www.ea.govt.nz/projects/all/distribution-pricing

13.1.4 Network charges – transmission

Where a consumer connects directly to the grid, Transpower will charge this consumer directly. The rules governing how Transpower charges its customers (distributors, directly connected industrials and generators) are determined by the Electricity Authority. These rules - known as the 'Transmission Pricing Methodology' (TPM) - have been a contentious topic since Transpower was separated from ECNZ in the early 1990s. Over the past 10 years, the Electricity Authority has conducted a number of phases of consultation in an effort to create a more enduring TPM, less subject to litigation.

A major revision to the TPM guidelines was concluded by the Electricity Authority in 2022. These charges come into effect for the 2023/24 pricing year.[171] Alongside the new TPM, the Authority released guidelines for EDBs as to how to pass through the new transmission charges to their customers (which will include the majority of process heat users covered by this RETA).[172]

The TPM is incredibly complex, and it is not possible to present the methodology in any detail here. But it is materially different from the TPM that has been in place for a number of years. In order to help process heat users understand these changes, we provide below a commentary below on what the TPM is trying to achieve, and what that might mean for charges that are passed through by EDBs to process heat users. An outline of the TPM and more detail is provided below in Section 14.3.

13.1.5 Network security levels

While highly reliable, there is a small chance that components within electricity networks may fail. The conventional approach to maintaining supply to customers in a scenario of network failure is to consider the degree to which parts of the network have an in-built degree of redundancy in order to provide customers security of supply.

Like most infrastructure, electricity networks are sized to accommodate the very highest levels of expected demand ('peak demand'). In electricity, these peaks are often only a small number of hours per year and can occur at predictable times. Hence the overall level of 'secure capacity' is defined by the degree of redundancy that is available at peak times. At other times, more capacity is available. The level of secure capacity available to an individual site is a function of both:

- The available secure capacity at the point in time that the overall demand on the network reaches its highest level; and
- The degree to which the site adds to that peak at the time it occurs (usually referred to as 'coincident demand').

171 A pricing year begins on 1st April for all network companies.

172 We note that these guidelines did not include direction as to how EDBs or retailers present the transmission charges on the customer's bill. Process heat users (and any other customers) may not see any detail about what component of their new bills relates to the new transmission charges, although we expect distributors and retailers will want to explain any material increases in the overall bill.

Generally N-1 is the standard that applies on the 'interconnected' parts of Transpower's high-voltage transmission grid, due to the scale of bulk power flows affecting a large part of the population. However, on some more remote parts of Transpower's grid, the economic trade-off between N-1 and the cost to local consumers of the investment to accommodate demand growth may mean lower security is more efficient, and/or there are other ways to provide N-1 (see below) and better balance affordability.

The extent to which an EDB provides (or preserves, in the face of increasing demand) N-1 is a risk-based assessment which considers, amongst other things, the proportion of time that a particular part of the network would exceed N-1 capacity; the economic and risk profile of the existing customers; and the trade-off between the costs of extra capacity versus increased risk of interruption. For this reason, N-1 is often provided by EDBs in urban areas where there is high density of households and businesses. Approaches to determining where N-1 will or won't be provided are typically detailed in the EDB's asset management plans (available on their websites), and process heat users should engage with their EDB to determine how this applies to their site.

For the purposes of this report, Ergo determined the amount of spare capacity by using Transpower's prudent peak demand forecast for the 2023 year, rather than actual observed peak demand as inferred by Figure 51.[173] The use of a prudent forecast recognizes that there are a range of variables that can determine what happens on a given day or time, such as weather and the decisions of individual consumers which may see a drop in load diversity for a short time.

13.1.6 Impact on network investment from RETA sites

The majority of RETA sites will connect to the distribution network (rather than the transmission network), therefore it is necessary to analyse whether the existing distribution network to which the site is connecting, can accommodate each RETA site, and if not, what the network upgrades may be required to facilitate the connection at the agreed security level for the site (e.g. N or N-1).

To undertake analysis given the nature of the information available and the complexity of the task necessitates developing a set of assumptions about how the various sites could potentially be accommodated within a network. Exploring these assumptions with the relevant EDB may indicate where opportunities for cost reductions exist. Specifically, process heat users need to discuss the following aspects with EDBs and Transpower (where relevant):

- Confirm the spare capacities of both the GXP and Zone substations.[174] The analysis presented in this report calculated these based on the **publicly disclosed loading and capacity information** in Transpower's 2022 Transmission Planning Report and the EDBs 2023 Asset Management Plans.

173 Transpower's description of a prudent demand forecast is as follows: 'For the TPR we use a 'prudent' demand forecast to recognise the significant risks associated with investing too late to address grid issues. In effect, we add extra demand growth in the first seven years of the forecast to account for potential high levels of growth. After the first seven years we assume expected levels of growth. We determine the amount to add by calculating in our stage 1 models both the expected level of base demand and the 'prudent' 10% probability of exceedance base demand. The ratio of the stage 1 prudent base growth to expected base growth is then used to scale up the final demand from the stage 2 output to give the final 'prudent forecast.' Transmission Planning Report (2022), page 20.

174 Zone substations are large substations within the distribution network.

- The degree to which the process heat user's demand is **coincident with peak demand on the network**, for the purposes of assessing the amount of spare capacity each site absorbs. More detailed modelling of the pattern of site demand, and potential flexibility in that pattern, versus the timing of (typical) peak loadings on the network, may yield further opportunities to reduce upgrade costs. Further, the opportunity for the site to provide short-term demand response (e.g. by utilising hot water storage to pause boiler operation for a small number of hours) in peak demand situations or following a network fault should be considered, as this may have a material impact on cost.
- **The current level of network security to the site, and whether that should be maintained**. The analysis completed assumes that – for example - if the site currently has (N-1) security, infrastructure upgrades are recommended to maintain this. Ergo's report highlights where upgrade costs could be reduced by allowing for a lower level of security. Adopting a lower level of security should be considered in consultation with Transpower and the EDB but enabling the site to provide flexibility (i.e. rapid reduction) in demand in response to a failure on a network could save significant amounts of money where expensive upgrades are required to maintain N-1 security.[175]
- The extent to which the upgrades are affected by the decisions of **other process heat sites regarding electrification in a similar part of the network**. There are some parts of the transmission and distribution network where the collective effect of different upgrades and costs would be optimal should a number of sites simultaneously decide to electrify, or – more practically – coordinate their decisions in a way the gives the network owner confidence to invest. In Section 9.4, we consider the collective impact on a GXP should a number of sites choose to electrify.
- The costs associated with **land purchase, easements and consenting for any network upgrades**. These costs are difficult to estimate without undertaking a detailed review of the available land (including a site visit) and the local council rules in relation to electrical infrastructure. For example, the upgrade of existing overhead lines or new lines/cables across private land requires utilities to secure easements to protect their assets. Securing easements can be a very time consuming and costly process. For this reason, the estimates for new electrical circuits generally assume they are installed in road reserve and involve underground cables in urban locations and overhead lines in rural locations. Generally, 110kV and 220kV lines cannot be installed in road reserve due to width requirements. In some locations the width of the road reserve is such that some lines cannot be installed. This issue only becomes transparent after a preliminary line design has been undertaken.
- The estimates of the **time required to execute the network upgrades**. The estimates in the analysis exclude any allowance for consenting and landowner negotiations and are based on Ergo's experience. There is likely to be significant variance depending on the scope of the project and the appetite for expediting.

175 The most common way to do this is a 'Special Protection Scheme' whereby the network owner allows demand to exceed N-1 on the condition that, should a fault occur, demand is quickly (automatically) reduced to the N-1 limit.

13.2 The role of flexibility in managing costs

13.2.1 Why flexibility?

At its simplest, demand-side flexibility is a consumer's ability to be flexible about when they consume electricity. By modifying usage in response to a range of 'triggers' (changing price, a network constraint or failure) sites may be able to reduce costs and/or generate revenue. This response can be manual (i.e. determined by the consumer in real time) or automated via technology.

In the context of the electrification of process heat, demand side flexibility can have many benefits as outlined below:

- It can help improve the commercial viability and business case of transition projects by reducing upfront capital costs (e.g. optimise the network connection capacity to reduce or prevent a network upgrade).
- It can reduce ongoing electricity procurement costs (e.g. by consuming less at times of high retail rates or network charges, i.e. winter morning and evening peaks).
- It can unlock a new revenue stream to help offset project costs.

13.2.2 How to enable flexibility

The analysis above (in Section 9.3.4) has assessed the cost implications of the electrification of process heat, assuming that:

- Each site operates in a way that suits its own production schedule; and
- The investment in the network is required if the connection of the electrified process causes network security to fall below its current level (i.e. from N-1 to N).

However, control of even very complex production processes can be 'smart', in that the process can respond dynamically to signals from the electricity network and market.

Control technology, automation, predictive algorithms, and communications have evolved over recent years to make these mechanisms smarter and more precise. In the vernacular of the electricity market, it allows consumers of almost any scale to provide 'flexibility services' to network companies and the electricity market, whereby their consumption of electricity adapts continuously, or in specific situations, to what is happening on the network and market. Consumers should be rewarded for providing these flexibility services, either through reduced costs, or through sharing in the benefits captured by EDBs or retailers.

In the context of the electrification of process heat, this creates a number of opportunities for sites to lower their electricity procurement costs, or – in some scenarios – earn additional revenue from the electricity market. Specific opportunities include:

- Wholesale market response
- Minimising retail costs
- Dry year response
- Minimising network charges
- Reducing capital costs of connection, and
- Other market services, such as Ancillary Services.

More detail about these opportunities is laid out in Appendix 14.2.

Of course, altering the production of process heat in order to provide flexibility services (i) – (v) above has consequences (and potentially cost implications) for the site. Lost production during high priced periods, for example, must be recovered at another time – depending on the nature of the process, the flexibility may be limited.

However, there are a number of ways in which thus flexibility can be enabled. If the site can increase its use of thermal storage (e.g. hot water), this can enable flexibility.[176] Alternatively, a secondary standby fuel could be maintained. Responses could be optimised around production constraints and be automated to reduce labour costs associated with manual decision making.

13.2.3 Potential benefits of flexibility

Enabling flexibility in these ways will incur some costs but may be more than offset by the reduction in electricity consumption costs or the capital contribution to network upgrades. The benefits of enabling flexibility – in terms of reduced consumption costs and capital requirements for network upgrades - could be significant. Further, as the electricity system reduces its use of fossil fuels (coal, natural gas and diesel) in line with emissions prices, and instead builds lower cost wind and solar, the system will require more flexibility from other sources, including consumers. This flexibility could well become a premium product.

There have been a range of analyses of the potential value (to the system) of demand flexibility in the New Zealand system. These range from $150,000 - $300,000 per year for every MW of demand that can be reliably moved away from the overall network peak.[177] This may not necessarily reflect the reduction in electricity cost that a RETA site may be able to realise. Further information on estimated electricity cost reductions can be found in Appendix 14.2.6

As previously noted, electricity transmission and distribution networks must be sized to meet peak demand, which may only occur over a few hours of the year. When anticipated growth in peak electricity demand exceeds the existing network capability, costly investments are needed to upgrade the network and/or develop new infrastructure. Process heat users with flexibility that can be enabled in their use of process heat – even for a short period – through the use of interruptible processes or thermal load, may be able to provide highly valuable support to the EDBs and/or Transpower in managing transmission and distribution voltage and thermal constraints affecting the Taranaki region.

Process heat users are encouraged to seriously consider if they have demand flexibility (including storage solutions such as battery, hot water, ice slurry etc) that they can enable, and if so, how much, and share this information with EDBs and retailers to ensure that they (the process heat user) get the maximum benefit from enabling this.

176 Other methods include ice slurry storage, hot oil storage, steam accumulators.

177 See *Reeve, Stevenson, Comendant (2021), Cost-benefit analysis of distributed energy resources in New Zealand*. Available here: https://www.ea.govt.nz/documents/1742/Sapere_CBA.pdf; Orion (2023), 1 March 2023; Boston Consulting Group (2022), *The Future is Electric*.

13.2.4 Who should process heat users discuss flexibility with?

RETA sites should consider their ability to provide flexibility, as well as the potential associated costs and implications.

Once process heat users have assessed the degree to which they can be flexible with their electricity consumption, or the security level they require from their connection, they should approach:

- **EDBs** to assess whether the flexibility can reduce the cost of connecting the new electric boiler to the network. EDB's may also be willing to pay for a process heat user's flexibility in order to defer wider network upgrades (sometimes referred to as a 'non-network alternative').
- **Electricity retailers** to determine the extent to which they will incentivise the process heat user to be flexible in their consumption through the electricity tariff the retailer provides through, e.g. peak and off-peak pricing.
- **Electricity retailers, flexibility service providers[178] and consultancies** to assess the degree to which the site's response to these signals can be automated.

13.2.5 The FlexForum[179]

The FlexForum is a pan-industry collaboration which is striving to help New Zealand households, businesses and communities maximise the value of distributed flexibility. In its Flexibility Plan 1.0, FlexForum outline a set of practical, scalable, and least-regrets steps that should achieve a significant increase in consumers' use of flexibility. A critical component in the Flexibility Plan is 'learning by doing' – supporting organisations (such as process heat users) piloting and trialling flexibility.

13.2.6 Value of flexibility

At its simplest, demand-side flexibility is a consumer's ability to be flexible about when they consume electricity. By modifying usage in response to a range of 'triggers' (changing price, a network constraint or failure) sites may be able to reduce costs and/or generate revenue. This response can be manual (i.e. determined by the consumer in real time) or automated via technology.

In fact, some of this technology has existed for decades – for example, the ripple relays that allow domestic hot water elements to be switched off, or frequency relays that allow large industrial processes to participate in the instantaneous reserve market.[180] More recently, though, the control technology, automation, predictive algorithms, and communications have evolved to make these mechanisms smarter and more precise. In the vernacular of the electricity market, it allows consumers of almost any scale to provide 'flexibility services' to network companies and the electricity market, whereby their consumption of electricity adapts continuously, or in specific situations, to what is happening on the network and market.

178 Examples of flexibility providers include Enel X and Simply Energy.

179 See https://www.araake.co.nz/projects/flexforum/

180 This is part of New Zealand's wholesale market design, whereby large loads and generation are paid to be on standby if a large system component fails, thus causing frequency to fall.

In the context of the electrification of process heat, this creates a number of opportunities for sites to lower their electricity procurement costs, or – in some scenarios – earn additional revenue from the electricity market. Specific opportunities include:

i. **Wholesale market response** – Section 9.2.1 outlined how the wholesale market is dynamically adjusting to supply and demand conditions in real time, and thus wholesale prices are constantly changing. Sites that choose to be exposed to this wholesale price and that can respond to these prices dynamically will lower their overall procurement cost by consuming less when prices are high, and more when prices are low.

ii. **Minimising retail costs** – Section 9.2.3 outlined how sites that choose to face a more stable retail tariff (rather than direct exposure to wholesale prices) will likely be provided with a set of 'shaped' prices that (at the very least) reflect time of year, weekdays vs other days, and day versus night (see Figure 48). Some pricing arrangements may have more granular prices (e.g. different prices for each four-hour 'block' of the day). This provides incentives for site operators to schedule production in a more predictable way (compared with a volatile wholesale price), again lowering electricity procurement costs by scheduling production away from high priced periods.

iii. **Dry year response** – It is relatively well known that, due to the dominance of hydro in New Zealand's electricity system, the system occasionally experiences 'dry years' where low inflows persist for weeks and potentially months. This can raise wholesale market prices significantly for a prolonged period, and electricity retailers may be willing to incentivise consumers to reduce demand for this period. This obviously would have significant consequences for manufacturing processes, although sites with dual-fuel capability (e.g. electricity and coal) could switch from electricity to coal during these periods with little impact on their operations.

iv. **Minimising network charges** – As discussed in Section 9.2.4, EDBs may price some component of network charges based on the consumption of the site at peak network demand times (e.g. weekday morning and evening peaks). By reducing demand at these times, network charges may be able to be reduced.

v. **Reducing capital costs of connection** – Similarly, when considering the capital cost associated with accommodating newly electrified processes, Section 9.3 outlined that a key factor is the current spare capacity at peak times in the existing network. Flexibility in electricity consumption can potentially reduce the cost of network upgrades in two different ways:

   - Ensuring demand from the site is reliably lower during the times of peak network demand (when spare capacity is at its lowest), thus reducing the amount of network investment required from the network company;[181] and/or
   - Allowing the site's demand to be reliably interrupted should a part of the network fail (known as a 'Special Protection Scheme'). The network company may, based on a risk assessment, allow network security to drop from N-1 to N-0.5, or N at peak times (see Section 9.3.2), thus requiring a lower level of investment in network upgrades, on the understanding that should a component of the network fail , the site will immediately reduce demand so that the network remains stable and thus doesn't affect other consumers connected to the network.[182]

181 This would have to be sufficiently reliable to give the network company the confidence to scale back its investment.

182 Depending on the nature of the security limitation, this may be required to be instantaneous, or may permit up to 15 minutes for the response to occur.

vi. **Other market services** – Finally, there are a number of 'ancillary services' that Transpower, as the electricity 'system operator' must procure which help it manage the whole system's stability and resilience. A reliably responsive demand site may be able to provide services into these markets and earn revenue from them. Participation can be as little as one to two response events per year that require a load drop of only a number of minutes. We note that the industry is currently discussing how these services may evolve as the amount of intermittent wind and solar increases on the system, including new types of ancillary services that may arise.[183]

13.2.7 Flexibility benefits

As previously noted, there have been a range of analyses of the potential value (to the system) of demand flexibility in the New Zealand system. These range from $150,000 – $300,000 per year for every MW of demand that can be reliably moved away from the overall network peak.[184] While this may not necessarily reflect the reduction in electricity cost that a RETA site may be able to realise, the Electricity Authority's independent Market Development Advisory Group (MDAG) have estimated the electricity cost reductions that an existing process heat site could realise in a future system with a very high degree of renewables.[185] Notably:

- It estimated that a process heat site using expanded hot water storage could save between 8% and 18% of its electricity procurement costs if it responded dynamically to wholesale prices (option (i) above).
- It also estimated that a process heat site that maintained an additional standby supply of fuel and boiler that could substitute for its electric boiler in a dry year could save around 16% of its electricity procurement costs (again if it were exposed to wholesale prices).

These figures do not include any benefits associated with reduced network charges, or the capital costs of upgrades to the distribution network in order to facilitate an increase in electricity demand, if this process heat demand had been new (i.e., (iv) and (v) above). These would be in addition to the savings noted above.

We note that, while MDAG's simulations assumed the process heat site was exposed to wholesale prices, this need not be the case for savings to be realised. If the site purchases power through a retailer, then the retailer would save the wholesale costs if the site responded and should share those savings with the site. Of course, this requires an arrangement between the retailer and the site as to when the alternative fuel needed to be switched in, how much notice was given, and what savings would be shared.

MDAG's figures do not include any benefits associated with reduced network charges, or the capital costs of upgrades to the distribution network in order to facilitate new process heat demand had they been new (i.e. (iv) and (v) above).

183 See https://www.araake.co.nz/projects/flexforum/. Note that, in some situations, process heat organisations may be able to receive revenue for a number of demand side flexibility services.

184 See *Reeve, Stevenson, Comendant (2021), Cost-benefit analysis of distributed energy resources in New Zealand*. Available here: https://www.ea.govt.nz/documents/1742/Sapere_CBA.pdf; Orion (2023), 1 March 2023; Boston Consulting Group (2022), *The Future is Electric*.

185 See https://www.ea.govt.nz/documents/299/Distribution_pricing_practice_note.pdf, specifically the Demand Side Flexibility case studies available at https://www.ea.govt.nz/documents/1254/DSF-case-studies-FINAL-1.pdf

13.3 Overview of the TPM

In essence, the TPM attempts to identify, amongst its customers (distributors, generators, direct connects), who the beneficiaries are of each of Transpower's assets, and allocate charges to those beneficiaries. This is a similar intent to the pricing methodologies of EDBs discussed in Section 9.2.4 above.

There are three basic components of the new TPM, plus a range of adjustments that are outlined further below. The three components are:

i. **Connection charges** – There are some assets owned by Transpower which are only there for the benefit of a very small number of users. These are known as 'connection assets', as they tend to exist solely to connect an EDB's network, and/or a large industrial consumer, and/or a generator, to the national grid. In these situations, Transpower's costs – capital returns and operating expenses – are shared amongst that very small group of users in a relatively simple way.

ii. **Benefit-based charges (BBC)** – These charges relate to specific investments where the beneficiary identification is more complex than for connection assets, but the beneficiaries have been established by the Authority (and allocations of charges calculated accordingly).[186] This analysis will occur for grid investments going forward, but also includes seven relatively recent grid upgrades that were approved by a regulator under the current market design, and hence were subject to a range of cost-benefit assessments. Should grid upgrades occur in the Taranaki region (see Section 9.3), the associated transmission charges would be calculated in accordance with the BBC methodology. It is difficult to estimate now what the likely quantum of charges would be, as the Authority won't determine the allocations amongst the various beneficiaries until the investment is formally considered.

iii. **Residual charges** – For the remainder of the existing transmission network not covered by BBC charges, it is too difficult to identify specific beneficiaries of each asset.[187] Charges for these network assets are referred to as the Residual Charge (RC) and are spread across all loads (EDBs and grid connected industrial consumers). Generators don't pay the RC. RC is principally spread across loads in proportion to their anytime maximum demand. An important consideration for new grid-connected electricity demands, such as that arising from electrification of RETA process heat sites, is that they do not receive an RC charge for the first four years of operation; after that, the RC allocation steps up linearly over a four-year period. As a result, these new grid-connected demands (which include demands from distribution networks) do not face their full RC allocation for eight years. Equally, RCs for grid-connected demands take eight years to reduce to the new level.

The intent and essence of the three types of charges may appear relatively straightforward, but the methods by which they will be determined (especially the BBC) is complex. To aid understanding, we have included a worked example for a stylised process heat consumer in Section 14.3.2 of this report.

[186] These more complex assets are referred to as 'interconnection assets', reflecting the fact that the tend to be part of the meshed grid, and the use of these assets can relate to a wide range of customers at different times. The residual charge also relates to interconnection assets.

[187] Pre-2019 grid assets, not including the seven relatively recent grid upgrades listed in Appendix A of the TPM.

Further, the Electricity Authority has included an additional set of mechanisms in the TPM that anticipate, and attempt to correct for, some undesirable outcomes that could occur with a customer's transmission charges. These include:

- **Transitional cap** – A transitional cap on prices to avoid 'rate shock'. The cap is inflation adjusted; hence, with prevailing rates of inflation in early 2023, the cap is unlikely to have any material effect on charges.
- **Adjustments to charges** – Adjustments for things like new connections to the transmission network, customers disconnecting from the transmission network, and substantial changes in circumstance leading to substantial changes in consumption (increased or decreased). This is especially important for the connection of new electrode boilers, which – as they are replacing coal – would in some cases lead to material increases in demand taken by EDBs from Transpower's grid. Equally, some large sites may decide, upon electrification, to switch from being connected to the distribution network to direct grid connection – this would cause a drop in the EDB's peak demand.
- **Prudent discounts** – The TPM provides for discounting transmission charges where, based on an economic framework, a customer is 'overcharged' as a result of the TPM. Overcharging has a specific meaning, namely that the customer's TPM charges would lead them to inefficiently bypass the grid e.g. by building a self-supply and disconnecting from the grid, or building a line to a different part of the grid. Transpower has published a draft prudent discount manual. There is a significant amount of analysis that is required to prove that an individual customer's TPM charges are a genuine case of 'overcharging'.

We note that – since Transpower is entitled to recover a fixed amount of revenue from its customers – any reduction to one set of Transpower's customers, using the mechanisms above, results in an increase in charges to Transpower's other customers.

13.3.1 What does the TPM mean for RETA sites?

As noted above, our various references to 'customers' of Transpower, and payers of transmission charges, relate to EDBs, generators and grid connected industrial consumers. The majority of RETA participants do not fall into these categories, as they are connected to a local EDB's network, rather than Transpower's.

EDBs, however, will pass through transmission charges to their customers (i.e. electricity consumers). The exact mechanism by which each EDB 'repackages' TPM charges will vary across the country, but the Electricity Authority has published guidance on how they expect EDBs to do this.

Fundamentally, the Electricity Authority expects that an EDB will pass the TPM charges on consistently with how they are derived in the TPM:

- The BBC and RC to be passed on as a daily fixed charge; and
- Connection charges will probably be on-charged substantially as done previously.

The EDBs will need to do some form of categorisation and averaging to allocate the transmission charges. The methods used in the TPM for categorising, averaging, and lagging measures of 'usage' of the grid give EDBs some discretion to how costs will fall.[188] For example, an averaging method based on energy consumption will tend to move charges from residential towards industrial consumers and vice versa for averaging based on peak demand.[189] EDBs may also base charges on historical periods that, in their view, are a better reflection of the party's consumption that created the need for transmission capacity in the first place.

188 Either energy usage over time, or peak demand, for example.

189 Residential demand tends to be more 'peaky' than many forms of non-residential demand.

EDBs have published their pricing schedules for the 2023/24 pricing year – the first year that the new TPM applies. However, even without any new grid investments, we strongly caution against using these figures as a guide. Transpower's indicative transmission charges for 2023/24 show that the majority of charges accruing to EDBs are the residual charges. As outlined above, the intent of these charges is to recover the sunk costs of grid where individual beneficiaries haven't been identified. As such, they are intended to be unavoidable charges which should not change marginal operating or investment decisions. Defining these as per-MW charges accruing to newly electrified load will tend to overstate their magnitude, depending on the degree to which EDBs rebalance charges across their customer bases.

13.3.2 A worked TPM example

For this example, we are using a practical example based on a stylised. While the example is based on the process heat user, the results should be treated as indicative only for the purpose of illustrating the transmission charges.

The process heat user has an existing demand connected to the EDB, who in turn connect the process heat user to the grid at one of Transpower's GXPs. For the avoidance of doubt, we are only looking at the transmission charges that would be applicable to the process heat user under the new TPM, not the distribution charges. Note also that there may be some averaging of charges that means that the EDB does not pass on the charges as outlined here.

The process heat user is also investigating replacing its coal boiler with an electrode boiler, which will substantially increase both its peak demand and total energy consumption.

We are only going to evaluate the three main components of the transmission charges, CC, BBC, and RC. As we discuss above there are a number of smaller adjustments that might also apply to ensure that Transpower's costs are recovered, we cannot anticipate all of these. The one that we would have had to adjust for, the transitional price cap, is inflation adjusted but, with very high inflation, the cap now barely applies.

We look at each charge individually for the starting point of how the new charges would apply to the process heat user's current load and then how those charges would change for the electrode boiler investment. We also estimate future charges for both scenarios. The initial prices are based on Transpower's Excel spreadsheet 'TPM indicative pricing model August 2022'.

13.3.2.1 Connection Charges

The GXP is a grid node, not a connection node, and there is no Transpower spur line to the EDB. However, there is equipment at the GXP substation that is only there to connect the EDB to the grid. In addition to circuit breakers and other switchgear this includes two 220/33kV transformers as the GXP grid bus is 220,000 volts while the EDB takes supply at 33,000 volts. The annualised cost of these connection assets is assessed as $457k for the 2023/2024 pricing year. As the EDB is the only customer at the GXP these connection costs are all allocated to the EDB.

Where there are multiple customers on one connection then connection charges are allocated to customers on the basis of their Anytime Maximum Demand (AMD) to the total of all customer's AMDs. This is a way in which the EDB could allocate connection charges to their customers that is consistent with the TPM. We can't know what the total of all AMDs within the EDB's network is (behind the GXP) and so we will simply assume that the AMD of the combined network is the total of all AMD.[190] This gives a worse case allocation for the process heat user. AMD is the average of the twelve highest half-hour peaks in the given year or other time period. We have assessed the AMD for the process heat user based on data provided to us, which gives 18.1 MW. We assume that the process heat user peak demand will remain constant unless they physically invest in new plant. For the GXP demand we use the peak demand forecast from Transpower's 'Transmission Planning Report 2021'.

This gives a forecast of connection charges for the process heat user's current demand in Table 15.

Table 15 – Forecast CC for the process heat user current demand

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
EDB AMD	110	113	115	118	120	122	125	127	129
Process heat user AMD	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Allocation	16.5%	16.0%	15.7%	15.3%	15.1%	14.8%	14.5%	14.3%	14.0%
Process heat user CC	$0.08M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.06M

To assess the increase in charges for the addition of the electrode boiler we add 24MW to the process heat user's current AMD and to the EDB AMD but make no other alterations. Again, this is the worst case for the process heat user and gives the connection charges forecast in Table 16.

Table 16 – Forecast CC for the process heat user demand and new boiler

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
EDB AMD	134	137	139	142	144	146	149	151	153
Process heat user AMD	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1	42.1
Allocation	31.4%	30.7%	30.3%	29.7%	29.2%	28.8%	28.3%	27.9%	27.5%
Process heat user CC	$0.14M	$0.14M	$0.14M	$0.14M	$0.13M	$0.13M	$0.13M	$0.13M	$0.13M

190 The network's AMD can be different to the sum of customers AMD as customer's AMD can occur at different times.

13.3.2.2 Benefit Based Charges

The Benefit Based Investments (BBIs) that are allocated to the EDB at the GXP are all 'TPM Appendix A' BBIs. This means that they are the pre-2019 investments chosen and assessed by the Electricity Authority for the guidelines given to Transpower. As the Electricity Authority had already determined these allocations, Transpower was instructed to use these allocations, which are attached in the TPM as Appendix A.

The investments and allocations that apply for the GXP are given in Table 17.

Table 17 – BBI projects and allocations for the GXP

Benefit-based investment	Allocation
Bunnythrope Haywards	5.34%
HVDC	1.38%
LSI Reliability	10.57%
LSI Renewables	6.33%
NIGU	0.38%
UNIDRS	0.38%
Wairakei Ring	0.35%

Once these allocations have been made to the recovery costs of the above projects then the BBC charges that apply to the EDB for the GXP for the 2023/2024 pricing year are $1.07M.

When it comes to allocating the process heat user a share of these charges, the EDB could consider three methods that are consistent with the TPM. These methods are:

- Attempt to recreate the Authority's original method for allocation.
- Attempt to apply the standard method from the TPM.
- Apply the simple method from the TPM.

It would not be feasible for a distributor to use the first two methods. They don't have the input information or models to replicate the results. The simple method models the beneficiaries by regions of the transmission network and then allocates these benefits to connection locations using Intra-Regional Allocators (IRA). The calculation method for IRAs is the most practical method, consistent with the TPM, for allocating BBIs.

There is a further complication, though. Different IRA calculations apply according to the nature of the investments. We think it unlikely that a distributor's methodology would be considered inconsistent with the TPM by simply picking one of the methods to apply to the total BBC. Both methods use the same calculation period being three years of data lagged by two years, i.e. n-4 to n-2 inclusive, in this case 2018 to 2021.[191] The allocation would then be based either on peak coincident demand over that period or total consumption over that period. the process heat user has a very low-capacity factor for an industrial user at 32%. This means that the two approaches yield very different allocations. Using peak coincident demand (using our assumptions from above) would give 16.5% and using consumption would give 3.6%. Given the peaking requirements for the process heat user and that most of the TPM Appendix A BBIs could be described as investments to meet peak demand, we think that the EDB might use 16.5%. This would give the process heat user a starting BBC allocation of $175k (i.e. prior to the 25MW increase from the new electrode boiler).

As TPM Appendix A BBIs are fixed allocations then the EDB is likely to treat the starting allocation for the process heat user as a fixed allocation. This gives the outcome in Table 18.

Table 18 – Worst case BBC allocation to the process heat user

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
Allocation	16.5%	16.0%	15.7%	15.3%	15.1%	14.8%	14.5%	14.3%	14.0%
Process heat user BBC	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M

TPM Appendix A BBIs are fixed allocations but do change for adjustments made for new customers, exiting customers, and substantial changes in consumption. We can't possibly predict what these changes might be and so we assume that these charges apply for the foreseeable future. The adjustments made for the new electrode boiler at the process heat user will help illustrate what could happen.

The GXP's BBC will also change if they are allocated charges for new BBIs. Again, we will not attempt to predict what these are and how they would be allocated but we will illustrate the potential impact of an imaginary investment on the charges for illustrative purposes.

The definitions for the events that cause an adjustment under the BBC are confusing. On consulting the Electricity Authority's original decision paper on the intent of the adjustments we believe that the proposed electrode boiler would be considered a 'Benefit-based Charge Adjustment Event: Large Plant Connected or Disconnected'. This event requires the large plant connection to be treated as if it's a new customer at the connection location but with the BBI allocation added to the relevant transmission customer, i.e. the EDB. Then all customers allocations must be reduced by a factor to keep the adjustment revenue neutral. The adjustment formulae for calculating the adjustment seems to have a logic error in that the same term used for the adjustment factor solution is used as an input to a formula where the solution is used as an input to the adjustment formula, i.e. prima facie a circular reference.

[171] Here, 'n' refers to the current year.

The formulae gross up the BBC at the connecting location based on the consumption assessed by Transpower against the same capacity period as residual charges 2014-2017 inclusive. As the new electrode boiler is going to increase the consumption at the GXP by 138GWh and the 2014-2017 average consumption is 452GWh, then the gross increase in charges at the GXP will be 30.5%, which is $325k for the 2023/2024 pricing year. All customers who pay for the BBIs relevant to the GXP get a slight reduction in charges to ensure revenue neutrality. However, as the change in charges is $325k in a set of projects with annual cost of $211M then the adjustment is negligible.

It is worth noting that, if the BBC for the GXP had included post-2019 BBIs the calculation of the increase in charges would have been more complicated. Although, it is also worth noting that the significant drivers on the BBC are two of the TPM Appendix A BBIs, the HVDC ($116M of BBC) and North Island Grid Upgrade (NIGU - the new Pakuranga to Whakamaru 400/220kV line - $68M).

Once the EDB's charge have been adjusted for the new electrode boiler then this becomes a new fixed allocation of charges. If the new boiler's consumption proves to be more than 25% higher, then it might trigger a 'Benefit-based Charge Adjustment Event: Substantial Sustained Increase' event. There is no commensurate sustained decrease provision.

As the increase in the EDB's charges is attributable to the process heat user if the electrode boiler goes ahead then the resulting charges are shown in Table 19.

Table 19 – BBC for the process heat user with electrode boiler

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
Process heat user BBC	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M
+ boilers	$0.325M	$0.325M	$0.325M	$0.325M	$0.325M	$0.325M	$0.325M	$0.325M	$0.325M
Total	**$0.500M**	**$0.500M**	**$0.500M**	**$0.500M**	**$0.500M**	**$0.500M**	**$0.500M**	**$0.500M**	**$0.500M**

We have seen above that the addition of other new connections, unless very large or there are a large number, can make little difference to BBC.

To illustrate how new BBIs might affect the process heat user's charges we take the example of a potential upgrade of the HVDC (say a fourth cable across the Cook Strait). If this project were to cost $80M, which gives a very approximate $5M in additional costs per year, and the benefits flowed through as per the TPM Appendix A HVDC allocations, then the process heat user would attract a further $25k per year in BBC.

13.3.2.3 Residual charge

Residual charges are the largest charges that are passed through. They are passed through initially as lagged peak charges and then adjusted based on lagged consumption. The RC assessed for the EDB for the 2023/2024 pricing year are $4.6M.

The AMD that is applied for $AMDR_{baseline}$ is different to the one that applies for CC.[192] However, we will assume the same allocation factor for AMD applies for the $AMDR_{baseline}$, i.e. that the process heat user will get 16.5% of the RC. . If we assume there is no significant difference in total EDB consumption, then there will be no significant difference in the allocation of RC to the process heat user. In practice, this will depend on many factors including changes in consumption within the GXP network and elsewhere. This gives RC for the process heat user as shown in Table 20.

Table 20 – RC for the process heat user without boiler

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
Allocation	16.5%	16.0%	15.7%	15.3%	15.1%	14.8%	14.5%	14.3%	14.0%
Process heat user RC	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M

If the boiler is added there will be no immediate impact on the EDB's RC due to the adjustment factor being based on lagged consumption. After four years then consumption is based on four years of average consumption lagged by four years. Assuming that the new electrode boiler adds 138 GWh per year starting in the 2023/2024 pricing year, then the adjustment in charges is shown in Table 21.

Table 21 – RC for the process heat user with boiler

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
Adjustment factor	1.00	1.00	1.00	1.00	1.00	1.08	1.16	1.24	1.32
EDB charges	$4.60M	$4.60M	$4.60M	$4.60M	$4.60M	$4.97M	$5.35M	$5.72M	$6.09M
Increase for boiler	$0.00M	$0.00M	$0.00M	$0.00M	$0.00M	$0.37M	$0.75M	$1.12M	$1.49M
Process heat user with boiler	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$1.13M	$1.50M	$1.88M	$2.25M

The charges reach their fully adjusted value in 2031.

[172] Anytime Maximum Demand for Residual Charges baseline.

13.3.2.4 Summary of charges

Table 22 summarises the outputs of Table 15, Table 19, and Table 20 to give the forecast allocation of transmission charges to the process heat user without the proposed electrode boiler.

Table 22 – Forecast allocation of transmission charges to the process heat user

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
Connection charges	$0.08M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.06M
Benefit-based charges	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M
Residual charges	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M
Total	**$1.02M**	**$1.01M**	**$1.01M**	**$1.01M**	**$1.01M**	**$1.01M**	**$1.01M**	**$1.01M**	**$1.00M**

Table 23 summarises the outputs of the three tables above to give the forecast allocation of transmission charges to the process heat user with the proposed electrode boiler.

Table 23 – Forecast allocation of charges to the process heat user with boiler

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
Connection charges	$0.14M	$0.14M	$0.14M	$0.14M	$0.13M	$0.13M	$0.13M	$0.13M	$0.13M
Benefit-based charges	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M
Residual charges	$0.76M	$0.76M	$0.76M	$0.76M	$0.76M	$1.13M	$1.5M	$1.88M	$2.25M
Total	**$1.40M**	**$1.40M**	**$1.40M**	**$1.40M**	**$1.39M**	**$1.76M**	**$2.13M**	**$2.51M**	**$2.88M**
Increase	**$0.39M**	**$0.40M**	**$0.40M**	**$0.40M**	**$0.39M**	**$0.76M**	**$1.13M**	**$1.51M**	**$1.89M**

Table 23 also shows the increase in transmission charges after the boiler is installed. The charges are fully increased by 2031 to $2.88M, a $1.89M increase from what would happen without the boiler (ceteris paribus). Calculating the present value of 10 years (at 8% discount rate) of increased transmission charges gives $5.53M.

14 Appendix D – Additional information on bioenergy

Wood processing residues are generally categorised as:

- **Sawdust** is the residues from sawing logs and is one of the more difficult products to sell. It can be mixed with other residues and sold as animal bedding. It could also be made into wood pellets but needs to be dried beforehand.
- **Bark** is mostly created at the port when handling, storing, and loading logs but small volumes are also available from processors.
- **Woodchip** is created onsite from all viable offcuts and is sold for landscaping, animal bedding or to MDF.
- **Shavings** are created when dressing the timber which creates a finished product smooth and clean. Shavings are usually created after the timber has been dried so it is light and dry and is good boiler fuel.
- **Post peelings** are the residues created from making round posts (fencing, poles, lamppost) and are thin and long in shape making them difficult to handle. Additional processing may be necessary to create a more uniform product for bioenergy.
- **Slabwood** is produced from the offcuts of milling and is sold as firewood.
- **Dockings** are lumber offcuts and may be green (which will normally be fed back into the chipper), or from a drymill in which case they may be sent to a boiler, chipped, or sold as firewood.

Harvesting residues are categorised as.

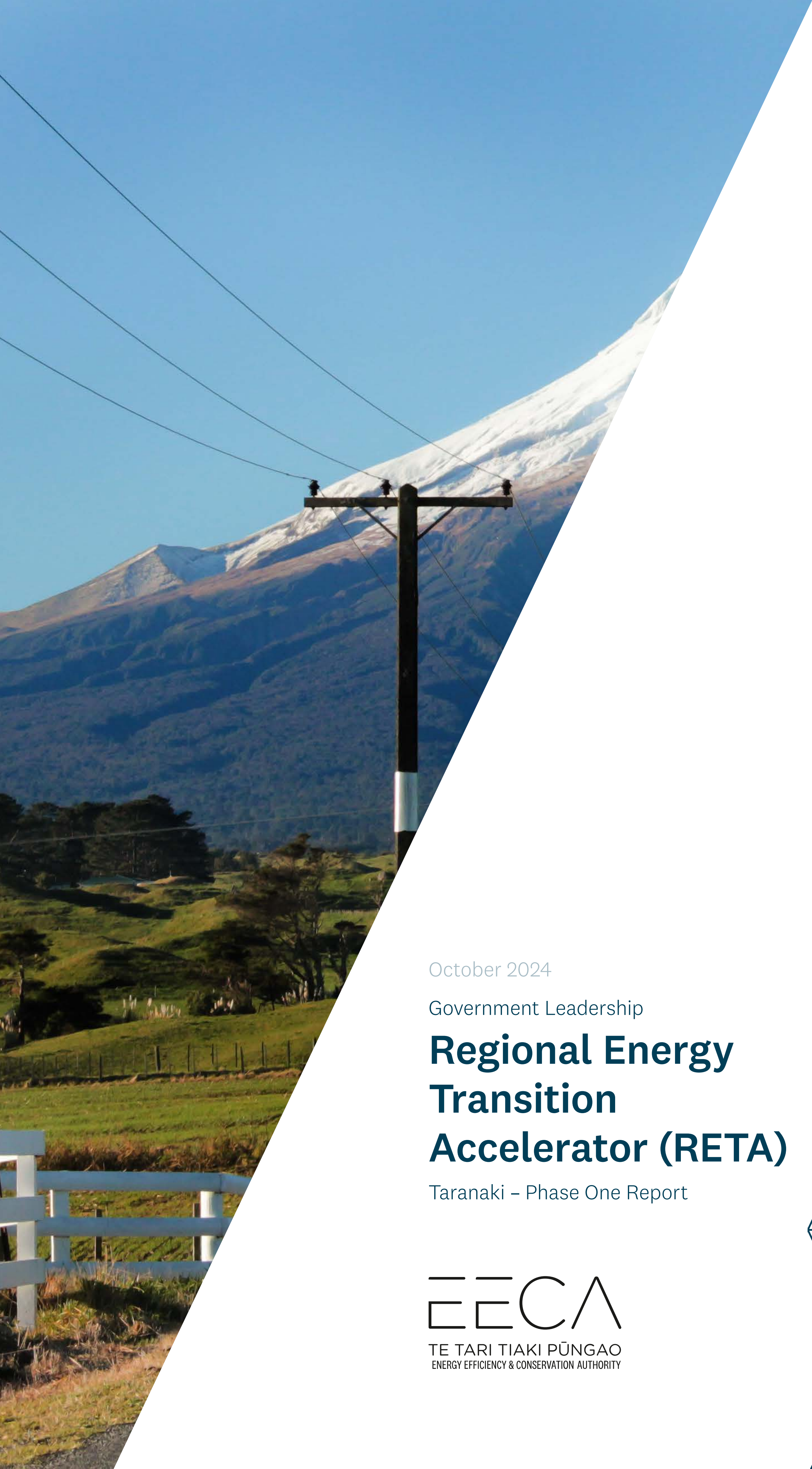
- **Billets** are shorter pulp logs (minimum length 1.8m).
- **Binwood** shorter than billets and is easily accessible residues that are collected by a truck with a bin.
- **Salvage wood** is described as salvageable biomass that is collected using a 'log reach excavator'.
- **Cutover** refers to residues from stems and branches left in the area that has recently been felled and cleared and is not as easy to access. This volume is technically recoverable but at a higher cost due to the additional effort required.

Photo credit: Methanex

15 Index of figures

Index of figures

Photo credit: Venture Taranaki



October 2024

Government Leadership

Regional Energy Transition Accelerator (RETA)

Taranaki – Phase One Report

TE TARI TIAKI PŪNGAO
ENERGY EFFICIENCY & CONSERVATION AUTHORITY