Government Leadership

Regional Energy Transition Accelerator (RETA)

Manawatū-Whanganui — Phase One Report

May 2025

TE TARI TIAKI PŪNGAO
ENERGY EFFICIENCY & CONSERVATION AUTHORITY

He kupu whakataki

He mahi nui te whakatutuki i te whāomoomo ā-pūngao kaitā me te tautoko i ngā kora mā, heoi anō, he waiwai. Waihoki, me whai pārongo horopū, me pakari anō hoki te mahi tahi a ngā rohe.

E whakaatu ana te Manawatū–Whanganui Regional Energy Transition Accelerator (RETA) i tētahi tūāoma waiwai i tēnei ara, e tuku ana i te māramatanga whānui mō ngā mahi me mātua mahi ki te whakapiki i te whāomoomo ā-pūngao, ki te whakahaukaha i te whakaratonga, me te whakaheke mārika i ngā tukunga puta noa i te rohe.

Ko te rohe o Manawatū–Whanganui he pokapū tuari matua mō Te Ika-a-Māui, he kāinga anō hoki ki tētahi ahumahi pāmu kararehe pakari e whakaputa ana i te huamiraka me te kiko. Kei tēnei pūrongo tētahi aromatawai ā-rohe whānui, e tūhura ana i ngā arawātea me ngā wero anō hoki i te rohe i roto i tōna haerenga whakawhiti pūngao. Mā ēnei pārongo e mātau ai, e rīrā ai anō hoki ngā whakatau a ngā pakihi me ngā kaiwhakarato e pā ana ki ō rātou matea ā-pūngao.

E kitea ana i te hōtaka RETA i te mana o ngā whakatau takitini, e whakaatu ana i ngā hua o te mahi tahi a ngā kaiwhakamahi pūngao huhua, arā, ko ngā urupare ki ngā wero tūāhanga, i te tirohanga whakarato me te popono anō hoki.

Ko tētahi o ngā aronga matua o tēnei pūrongo nei ko te wāhi hirahira ki te papatipu koiora whakahou hei kāinga rua utu-ngāwari, horopū anō hoki ki ngā kora mātātoka mō te pōkākā tukatuka tū i te ahumahi. Ka whakarārangi tēnei tātaritanga i ngā ara rau e whakawhiti ai ngā kaiwhakamahi pōkākā tukatuka o te rohe ki ngā puna pūngao whakahou. Ka whakamuramuratia ngā arawātea o te rohe – arā, te ngāwari o te utu me te mātotorutanga o te kora koiora.

E tō mai ana te hōtaka RETA i ngā kaupapa kua whakaritea kētia i te rohe, e whanake ana i ngā kokenga kua kitea kētia ki Manawatū–Whanganui ki ngā kāinga rua whāomoomotanga ā-pūngao, tukuwaro iti anō hoki. He huhua ngā pakihi, i te taha o EECA, kua whakamahere kē, kua whakauru kē rānei i ngā ara waro-iti, e whakaatu ana i ngā ahatanga ka taea. Mei kore ake rātou i tuari i ngā mōhiotanga ki te whakaahua i tēnei pūrongo nei.

Ko tēnei puka te whakakapitanga o te tūāoma whakamahere o RETA, e tuku ana i ngā matapae, e whakamahere ana i te popono pūngao pōkākā tū i te rohe i te taha o ngā aromatawai whakarato pūngao whakahou. Kua whakawhanaketia ēnei mōhiotanga i runga i te āta mahi tahi ki ngā pakihi tuku hiko – The Lines Company, Powerco, Electra, me Scanpower – waihoki ngā kamupene ngahere ā-rohe, ngā kaitukatuka rākau, ngā kaiwhakaputa hiko me ngā kaihoko, otirā, ngā kaiwhakamahi pūngao waenga ki te rarahi i te ahumahi.

I a mātou ka neke whakamua, e ū tonu ana mātou ki te tautoko i te rohe ki te tūhura i tōna pitomata whakawhiti pūngao whānui. Ka whakaū hoki i tā te tauritetanga o te whakarato me te popono whāngai i te whakamaru ā-pūngao, te ngāwari o te utu me te whāomotanga.

1 Foreword

Achieving large-scale energy efficiency and supporting clean fuels is a complex, yet essential task, one that demands both reliable data and strong regional collaboration. The Manawatū–Whanganui Regional Energy Transition Accelerator (RETA) represents a vital step forward in this journey, providing a comprehensive understanding of the actions necessary to enhance energy efficiency, bolster supply security, and significantly reduce emissions across the region.

The Manawatū–Whanganui region is a key distribution hub for the North Island and home to a robust pastoral industry in both dairy and meat production. This report offers a complete regional assessment, revealing both the opportunities and challenges the region faces in its energy transition journey. Armed with this information, businesses and suppliers can make informed, future-proof decisions about their energy needs.

The RETA programme underscores the power of collective decision-making, illustrating how collaboration among multiple energy users can lead to shared solutions for infrastructure challenges, from both a supply and demand perspective.

A central focus of this report is the pivotal role of renewable biomass as a cost-effective and reliable alternative to fossil fuels for industrial stationary process heat. This analysis outlines various pathways for transitioning the region's process heat users to renewable energy sources, highlighting region-specific opportunities — particularly the affordability and abundance of biofuel.

Building on the significant progress already made in Manawatū–Whanganui toward energy efficiency and low-emissions alternatives, the RETA programme draws on the region's existing initiatives. Many businesses, in partnership with EECA, have already mapped out or implemented low-carbon pathways, proving what is possible. Their willingness to share insights has been indispensable in shaping this report.

This document marks the completion of RETA's planning phase, offering forecasts and mapping regional stationary heat energy demand alongside renewable energy supply assessments. These insights have been developed through close collaboration with local electricity distribution businesses — The Lines Company, Powerco, Electra, and Scanpower — as well as regional forestry companies, wood processors, electricity generators and retailers, and medium-to-large industrial energy users.

As we move forward, we remain committed to supporting the region in unlocking its full energy transition potential while ensuring the balance of supply and demand contribute to energy security, affordability and efficiency.

Dr Marcos Pelenur
Chief Executive, EECA

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 Manawatū–Whanganui region
- Manawatū–Whanganui electricity distribution businesses — The Lines Company, Powerco, Electra, and Scanpower
- 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:

- **DETA** — process heat demand-side assessment
- **Whirika and Margules Groome** — biomass availability analysis
- **Ergo Consultants** — electricity network analysis
- **EnergyLink** — electricity price forecast
- **Sapere Research Group** — report collation, publication, and modelling assistance

> *A central focus of this report is the pivotal role of renewable biomass as a cost-effective and reliable alternative to fossil fuels for industrial stationary process heat.*

Dr Marcos Pelenur, Chief Executive, EECA

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Manawatū–Whanganui is the focus for New Zealand's thirteenth Regional Energy Transition Accelerator (RETA).

4 Executive summary

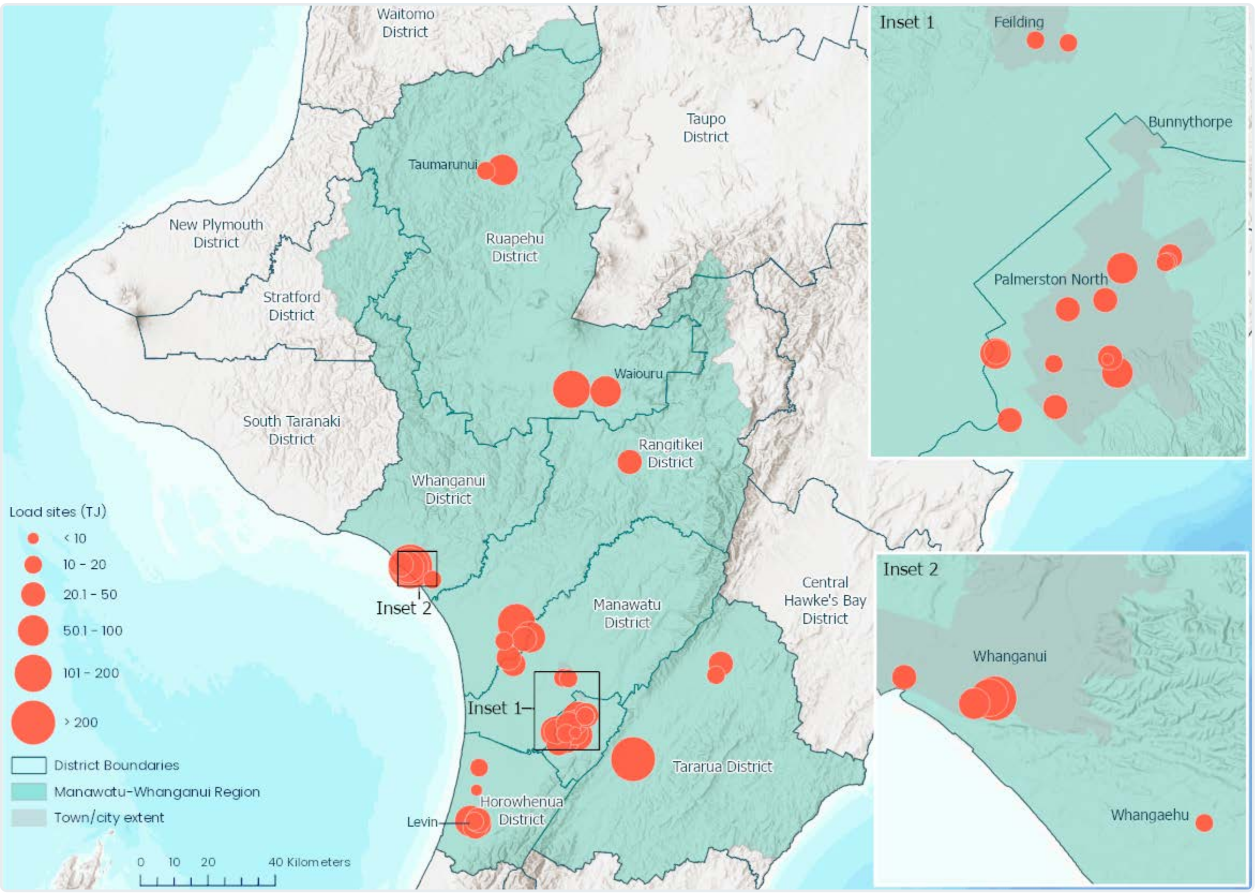
This report summarises the results of the planning phase of the Manawatū-Whanganui Regional Energy Transition Accelerator.

The report brings together information on the demand for fossil fuels for process heat in Manawatū-Whanganui, along with information on electricity network and biomass availability in the region, to:

- Provide process heat users with coordinated information specific to the region that can be used to make more informed decisions on fuel choice and timing.
- Improve fuel supplier confidence to invest in supply side infrastructure (including electricity and biomass).
- Surface issues, opportunities, and recommendations.

The region covers the area shown in Figure 1.

Figure 1 – Process heat demand sites in the Manawatū-Whanganui region.



4.1 Regional fuel use and emissions

There are 42 sites covered in this report, at locations shown by the red dots in Figure 1, spanning the industrial and commercial sectors.[1] These sites either have fossil-fuelled process heat equipment larger than 500kW or are sites (e.g. hospitals) for which EECA has detailed information obtained from various programmes.

In 2022, the baseline year for this analysis, these sites collectively consumed 2,611 TJ of process heat energy, primarily in the form of fossil gas, producing 142kt per year of carbon dioxide equivalent (CO_2e) emissions from the fossil fuels used for process heat. We note that since then, constraints in gas supply have affected prices and availability of fossil gas, and as a result have altered fossil gas consumption patterns.[2] However, 2022 has been retained as the base year to ensure consistency across the RETA regional analyses.

Table 1 – Summary of Manawatū-Whanganui RETA sites process heat demand and emissions (2022).

Sector	Sites	Thermal capacity (MW)	Thermal fuel consumption (GWh/yr)	Thermal fuel demand (TJ/yr)	Thermal fuel emissions (kt CO_2e/yr)
Dairy	6	117	313	1126	60
Meat	14	56	146	527	28
All other industrial	13	78	154	555	28
Commercial	9	65	112	403	25
Total	**42**	**316**	**725**	**2611**	**142**

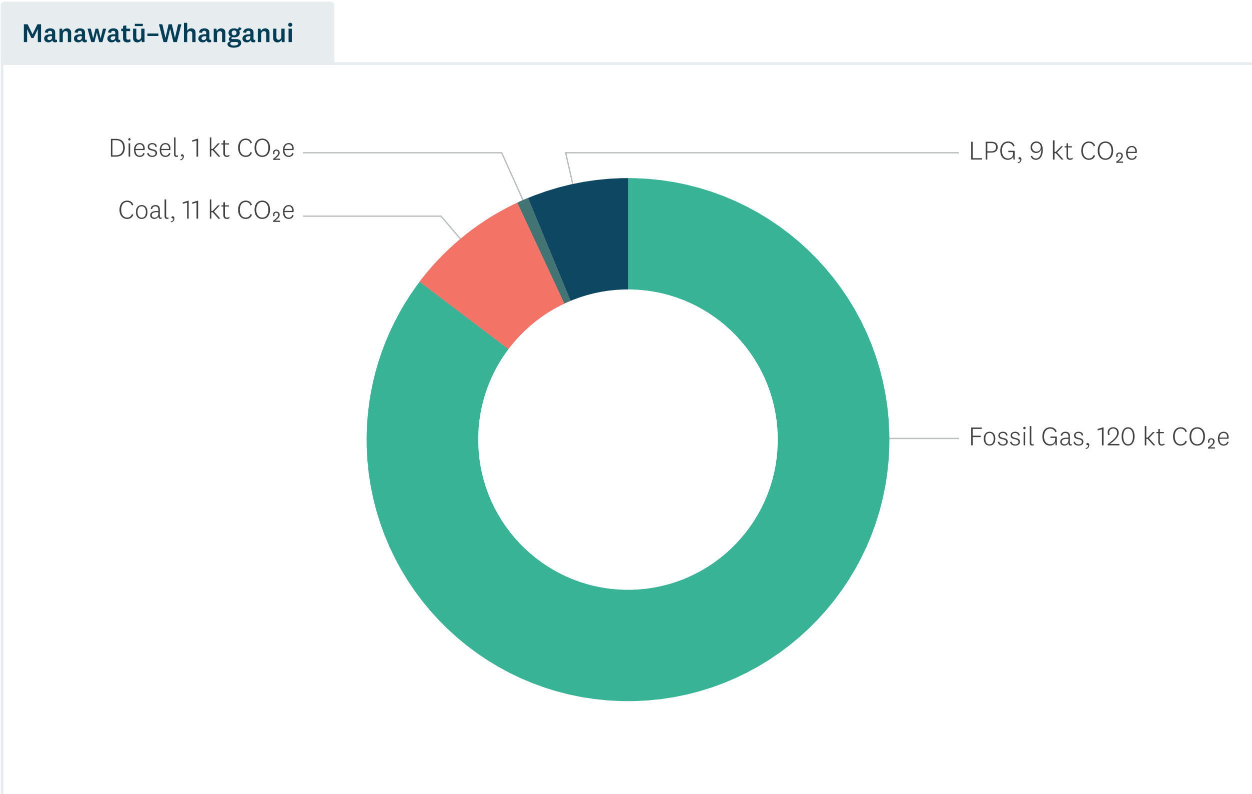
Photo credit: Whanganui & Partners

[1] The industrial sectors include dairy, meat, food & beverage, and wood processors; the commercial sector includes schools, hospitals and accommodation facilities.

[2] 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 of Manawatū–Whanganui process heat emissions come from piped fossil gas, followed by coal (Figure 2).

Figure 2 – 2022 annual emissions from fossil fuel process heat.

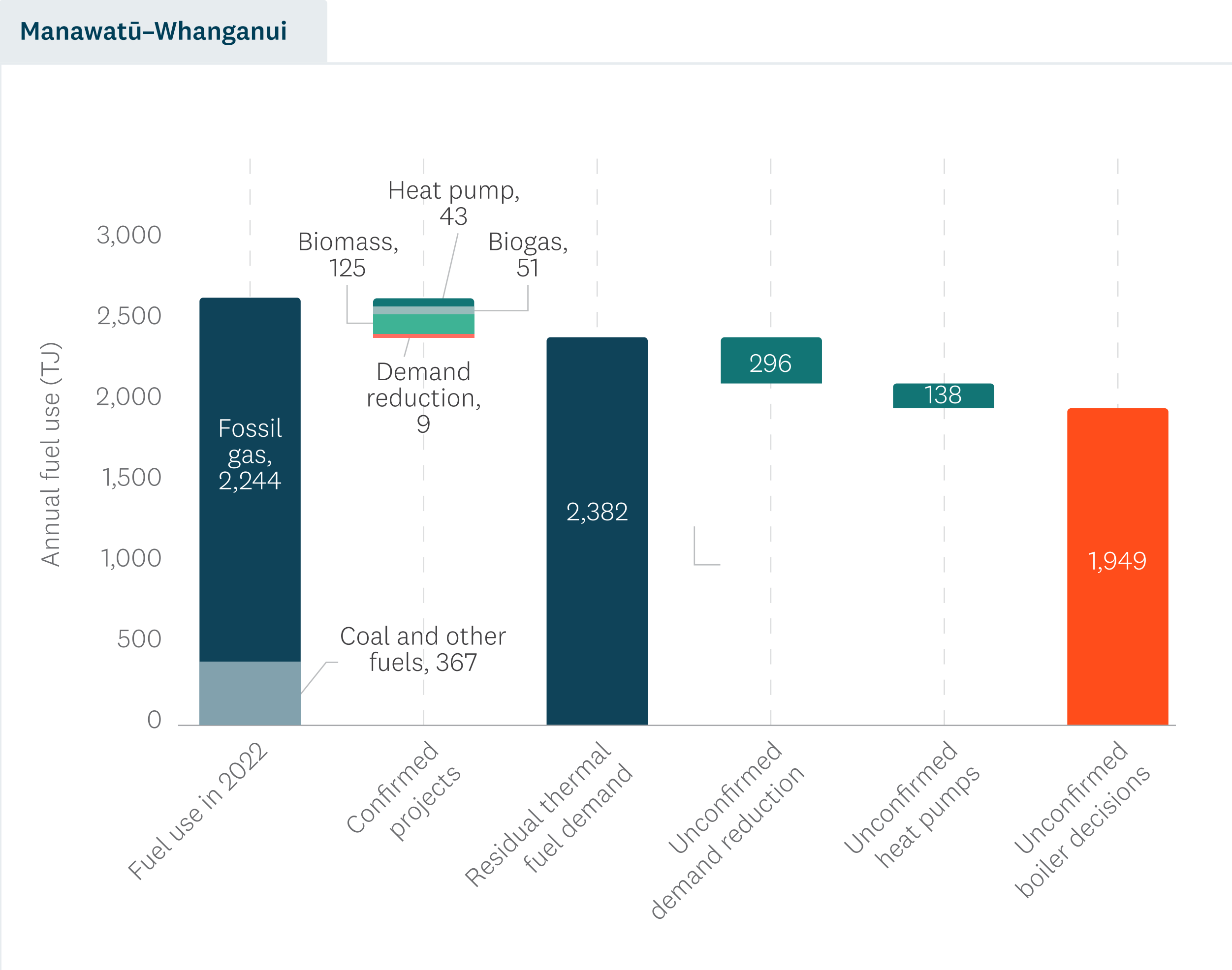


The objective of the Manawatū–Whanganui RETA is to demonstrate pathways which eliminate as much of these process heat emissions as possible. It does this by supporting organisations in their consideration of:

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

Figure 3 illustrates the potential impact on regional fossil fuel demand of process heat 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 demand reduction and fuel-switching on Manawatū–Whanganui fossil fuel usage.



The analysis shows that there is 2,382 TJ per year of residual fossil fuel thermal demand in Manawatū–Whanganui. While demand could be reduced by 296 TJ per year, with a further 138 TJ per year of demand being met by heat pumps, it is estimated that around 1,949 TJ per year used in boilers would need to be replaced by biomass or electricity to fully displace fossil fuels for process heat in Manawatū–Whanganui.

Gaseous biofuels, derived from organic waste materials from households, industry and/or agricultural sources, landfills and wastewater treatment plants, are an alternative, renewable supply of gaseous fuel that can be produced on an individual site or added to the existing gas network as a replacement for fossil gas. Most biogas currently produced is associated with wastewater treatment or landfills, and is commonly used for electricity generation. There are some locations where biogas is being used for process heat, for example at Nelson Hospital and at the Turners and Growers Reporoa site. However for the purposes of this analysis there is insufficient information about the potential volume and cost of biogas available in the region, therefore it has not been considered as an alternative fuel in this report's modelling. We note that the Bioenergy Association is working with EECA and other industry stakeholders to identify opportunities to esatablish and grow the biogas market in New Zealand.

4.2 Simulating fuel-switching decision making

This report has assessed the indicative economics of 130 potential emissions reduction projects across the 42 Manawatū–Whanganui sites identified — covering demand reduction, heat pumps for low temperature heat, and fuel-switching projects. It also investigates the regional availability of biomass and electricity to replace fossil gas and coal. Combining these two analyses — demand-side and supply-side — we can provide the indicative economics of each of the 130 potential projects.

There are a range of decision criteria that individual organisations may use to determine the timing of their 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' (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.

Where sites can choose to switch to either biomass or electricity, we assume that the process heat user would choose the option with the lowest MAC. Applying this selection reduces the potential emissions reduction projects in the region from 130 to 95 (noting that most sites have multiple potential projects). Figure 4 shows the MACs associated with each of these 95 projects, and the emissions reduced by these projects, based on the cost estimates outlined in this report.

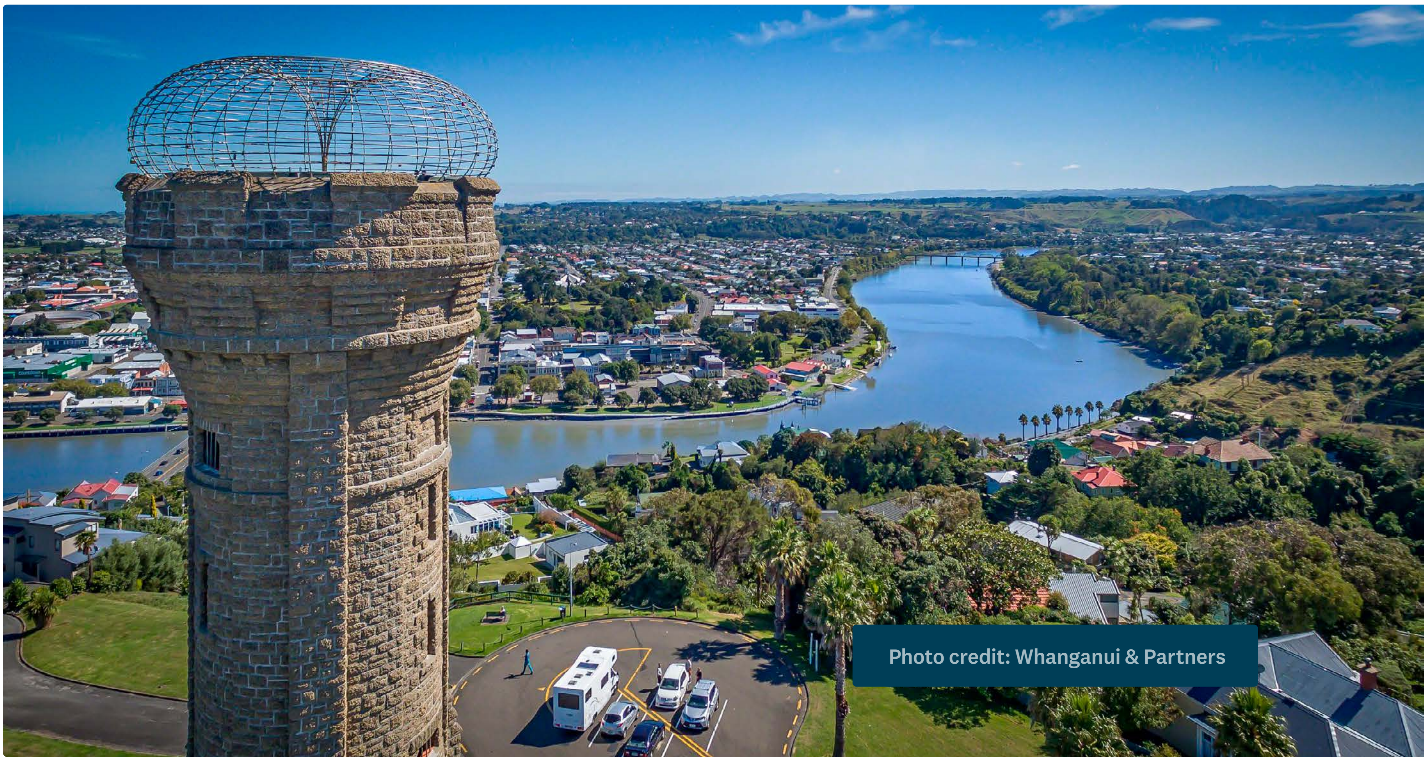
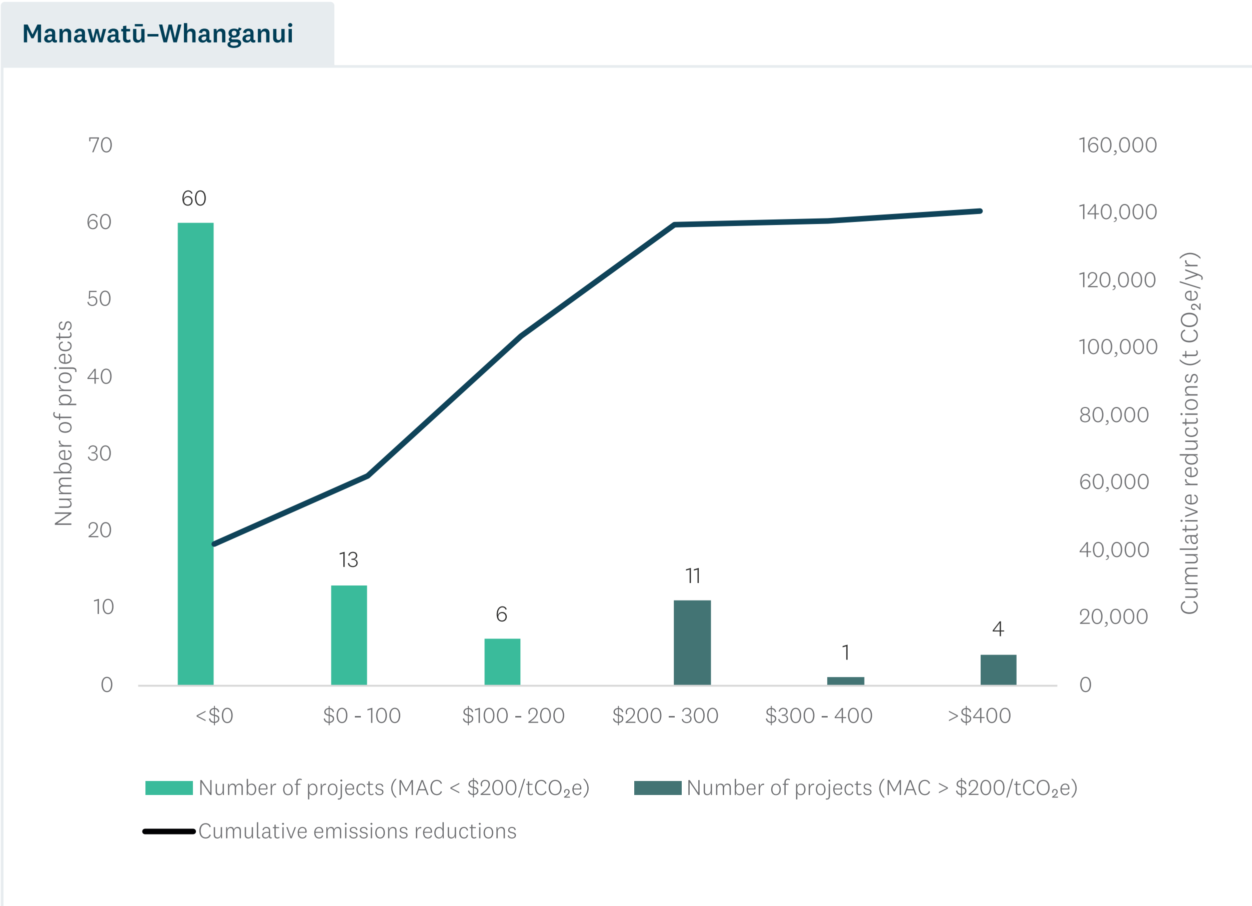


Photo credit: Whanganui & Partners

Figure 4 – Number of projects and cumulative emissions reductions by range of MAC value.



Out of 142kt of process heat emissions from Manawatū–Whanganui RETA sites, 103kt CO_2e (72%) have MACs less than $200/t$CO_2$e. Using a commercial MAC decision-making criteria, combined with expected future carbon prices, it would be commercially favourable to execute these projects over the next eight years.

Even without a carbon price, 60 potential projects (making up 42ktCO_2e (30%) of Manawatū–Whanganui process heat emissions) have a MAC less than zero, meaning they are economic now, and 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, at the assumed trajectory of carbon prices.

4.3 Indicative Manawatū–Whanganui pathways

4.3.1 Comparing emissions reductions across four pathways

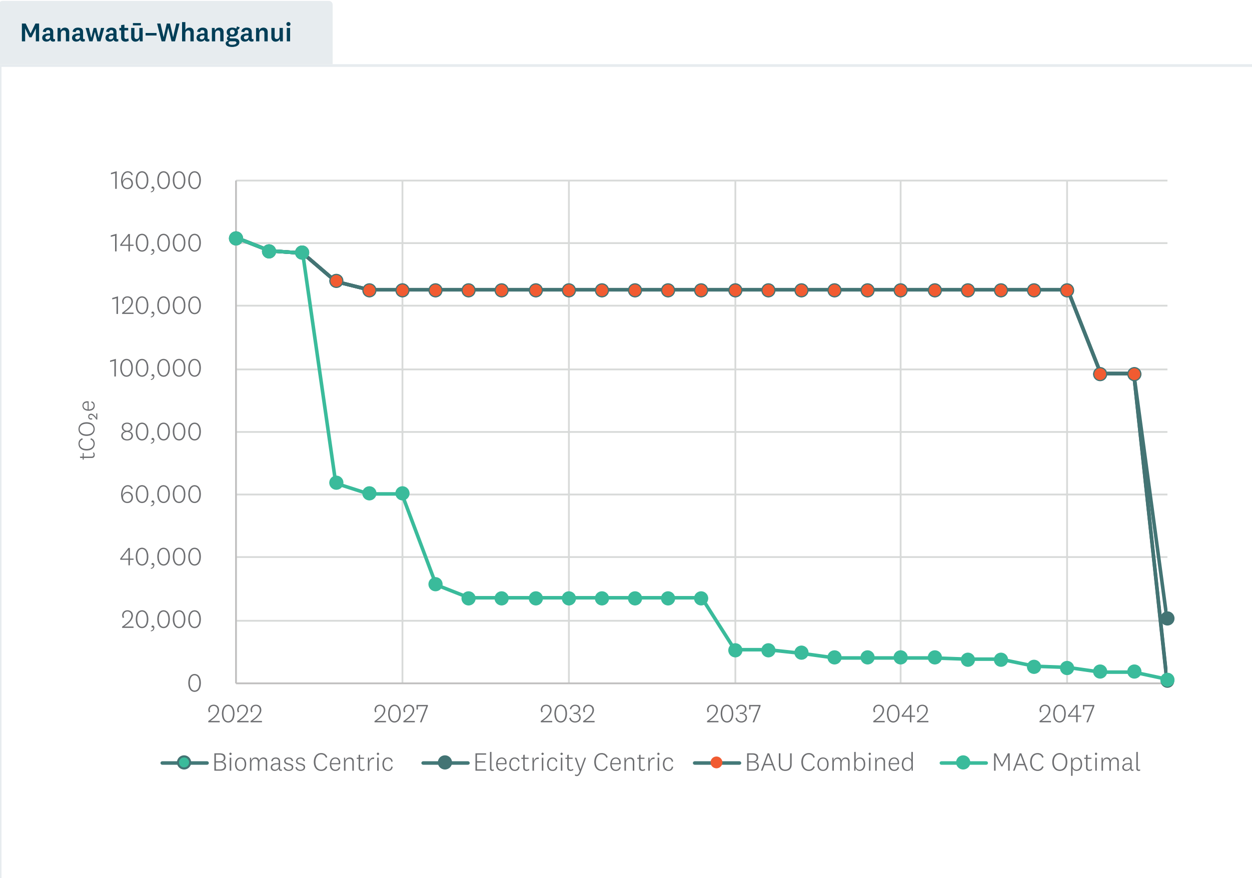
Four indicative scenarios, referred to as fuel-switching pathways, have been considered in the analysis. In three of the pathways, it is assumed that all unconfirmed emission reduction projects occur either in 2036, for existing coal boilers, or in 2049 in line with New Zealand's target of net zero greenhouse gas emissions by 2050 in the Climate Change Response (Zero Carbon) Amendment Act. As only two of the sites used coal, and both have since switched fuels, all the unconfirmed fuel switches in this region are therefore assumed to occur in 2049. It is acknowledged that this is an artificial scenario, but in the absence of information about confirmed plans, it serves to provide an indication of the possible total future fuel demand for each type of fuel considered.

- In a Biomass Centric pathway, all unconfirmed site fuel-switching decisions proceed with biomass where possible in 2049.
- In an Electricity Centric pathway, all unconfirmed fuel-switching decisions proceed with electricity where possible in 2049
- In a BAU Combined pathway, all unconfirmed fuel-switching decisions (i.e. biomass or electricity) are determined by the lowest MAC value for each project in 2049.
- 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 the Treasury's central estimate of carbon shadow prices. If the MAC does not drop below the 10-year rolling average of future carbon prices, then the project is assumed to start in 2049.

Figure 5 shows the potential cumulative reduction in emissions under each pathway. Note that the Electricity Centric and Biomass Centric pathways are obscured in the chart by the BAU Combined pathway, because the project timings and therefore the emissions reductions are identical.

Compared to a BAU Combined pathway, the MAC Optimal pathway would accelerate decarbonisation, and reduce the cumulative release of emissions by 2,500kt between 2025 and 2050 (Figure 5).

Figure 5 – Simulated emissions under fuel-switching pathways.



By 2037, the economical pathway will have reduced the region's process heat emissions by 131kt CO_2e, a 93% reduction compared to the emissions in 2022 from the sites considered in the study. This pathway would see 17 large heat pump installations, and 25 biomass boilers installed by 2037. Supporting these installations will require only minor modifications to local EDB networks and would increase electricity demand by 26 GWh per year, and the demand for biomass by 265kt per year in 2050. All of these projects and ongoing energy requirements present opportunities for employment in the region.

For the 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 (CAPEX), and ongoing operational costs (OPEX), of the investments.

The difference in total 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 and electrode boilers) are reasonably similar but electricity-related projects may incur connection costs, which, depending on the level of security required, can be very high (per MW of demand).
- Both heat pumps (if they can be used) and electrode boilers are more efficient than biomass boilers, thus require less energy to achieve the same reduction in fossil fuel consumption than biomass boilers.

- The level of utilisation of the heat plant, or both electricity and biomass, has a significant impact on the capex component of MAC values. Therefore, a heat plant with low utilisation will need to recover its capital costs over a small amount of emissions reductions relative to a plant that has high utilisation; this implies a higher capex proportion out of total MAC for the low-utilisation heat plant.
- 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. 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 – for example 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.

4.3.2 Testing for sensitivities

We tested a range of sensitivities on this modelling including fossil gas, electricity, biomass and carbon prices. We found that:

- **Electricity prices.** Retail electricity price reductions of both 20% and 60% accelerated one project, and the 60% reduction caused two projects to switch from biomass to electricity. However, the overall impact on emissions reductions was insignificant in both sensitivity tests.
- **Electricity network upgrade costs.** Neither a 50% increase nor decrease in network upgrade costs changed the optimal fuel-switching decisions for the Manawatū–Whanganui sites.
- **Biomass prices.** A 20% reduction in the 'wholesale' biomass fibre price (excluding any margin at the hub),[3] from \$12.9/GJ to \$11.6/GJ, caused one project to switch from electricity to biomass, and accelerated four projects, delivering an additional 254kt of CO_2e emissions reductions by 2050. A 50% reduction in the biomass price changed two projects to biomass and accelerated four projects with a cumulative additional emissions reduction of 423kt CO_2e by 2050.
- **Carbon prices.** The 'high' carbon price trajectory delivers 211kt CO_2e more emissions reductions cumulatively through to 2050, compared to a 'central' case. By contrast, a 'low' carbon price trajectory delivers 397kt CO_2e fewer emissions reductions. Lastly, the very low path (\$49/tCO_2e by 2050) delivers 1,211kt CO_2e fewer emissions reductions by 2050 on a cumulative basis, compared to the base case.
- **Fossil gas prices.** As shown in Figure 6, we found that halving the annual increase in the price for fossil gas from 3% to 1.5% resulted in 406kt CO_2e of additional emissions on a cumulative basis through to 2050 and decelerated 11 fuel-switching decisions. By contrast, doubling the increase to 6% accelerated four projects, delivering an additional 425kt of CO_2e emissions reduction by 2050. A significant increase in the fossil gas price to \$45/GJ by 2035 (excl. ETS) for all users accelerated four projects with a cumulative additional reduction of 451kt CO_2e by 2050.

[3] This is the underlying cost of fibre, assumed to be set by the roadside residues in our base case scenario. This cost excludes any margin for the biomass provider and excludes additional processing and transport costs. Our base case biomass pricing assumptions for process heat users once these other costs are included are \$19.2/GJ, \$20.2/GJ, and \$23/GJ for hog fuel, wood chip, and wood pellet, respectively, delivered to their site.

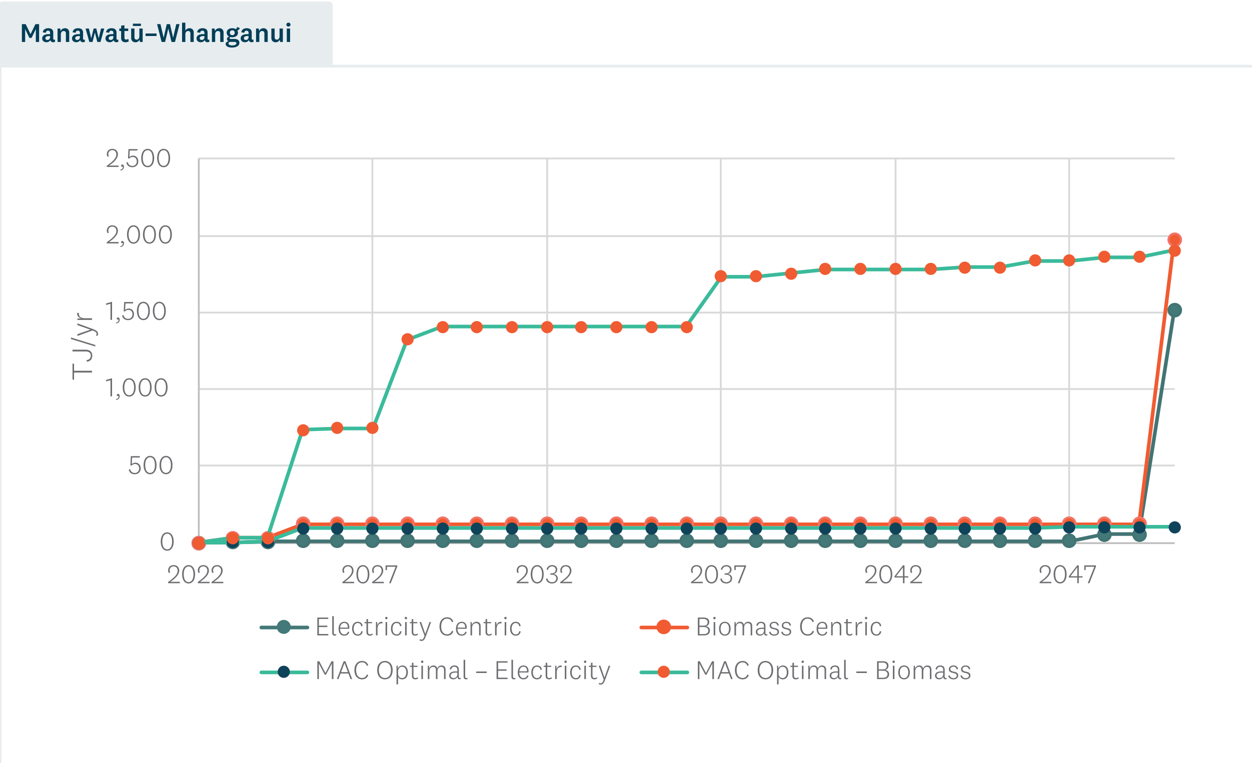
Figure 6 – Sensitivity of emissions reduction pathways to different gas price assumptions.

The sensitivity analysis shows that the optimal timing of decarbonisation decisions across Manawatū–Whanganui RETA sites is very sensitive to future prices of piped fossil gas. Therefore, it is recommended that fossil gas users in the Manawatū–Whanganui understand their existing gas pricing, when their contract term expires, and engage suppliers early to understand what their future gas pricing could be.

4.4 Implications for fuel use

From a supply-side perspective, the MAC Optimal pathway results in 95% of the process heat energy being supplied by biomass, and 5% by electricity by 2050 (Figure 7). The sheer dominance of biomass reflects its lower overall cost (compared to electrode boilers) as a fuel for large industrial projects which require high temperature boilers (over 100°C) for their process heat, so cannot switch to heat pumps alone.

Figure 7 – Electricity and biomass demand under fuel-switching pathways.



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 has on the overall picture of the Manawatū–Whanganui region's process heat decarbonisation. Figure 3 shows that investment in demand reduction could meet around 12% of the total process heat demand of the Manawatū–Whanganui RETA sites. This would reduce the necessary fuel-switching infrastructure required. Thermal capacity required from new biomass or electric boilers would be reduced by around 22MW if these projects were completed. We estimate that demand reduction would avoid investment of between $25m and $27m in electricity and biomass infrastructure.[4]

[4] On the assumption that the capital cost of electrode boilers is $1.1m and biomass boilers is $1.2m. The electrode boiler cost does not consider the connection costs, which average $1.8m/MW for the Manawatū–Whanganui, but are very site specific.

4.4.1 Biomass

The modelling shows that net residues alone will not be sufficient to meet biomass demand in the MAC Optimal pathway from 2029 onwards. In the Biomass Centric and BAU Combined, supply of net residues will fall short of biomass demand from 2049. To fill the gaps, pulp/export KIS grades will need to be used.

We also note that the wood availability forecast may differ to what will occur in reality. Discussions with forestry industry stakeholders as part of this RETA programme indicate that the peak volumes of harvesting modelled for years 2024 and 2025 are not being realised. Therefore, actual harvest volumes — and corresponding harvest residue volumes — are expected to be lower in the near term, allowing for additional volumes being available to fill some of the troughs in the mid-2030s.

Figure 8 – Growth in biomass demand under fuel-switching pathways, and available residues.

Manawatū–Whanganui

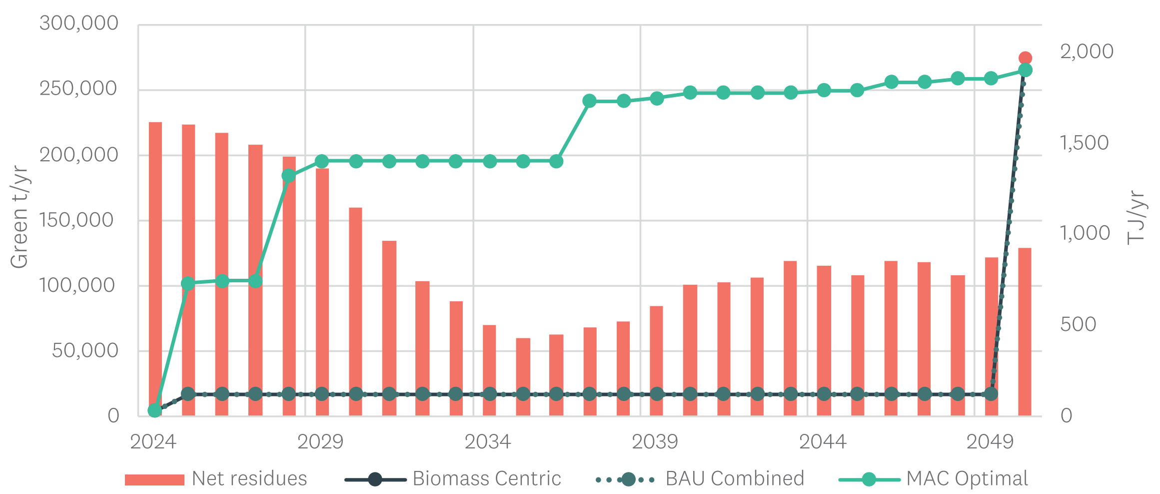
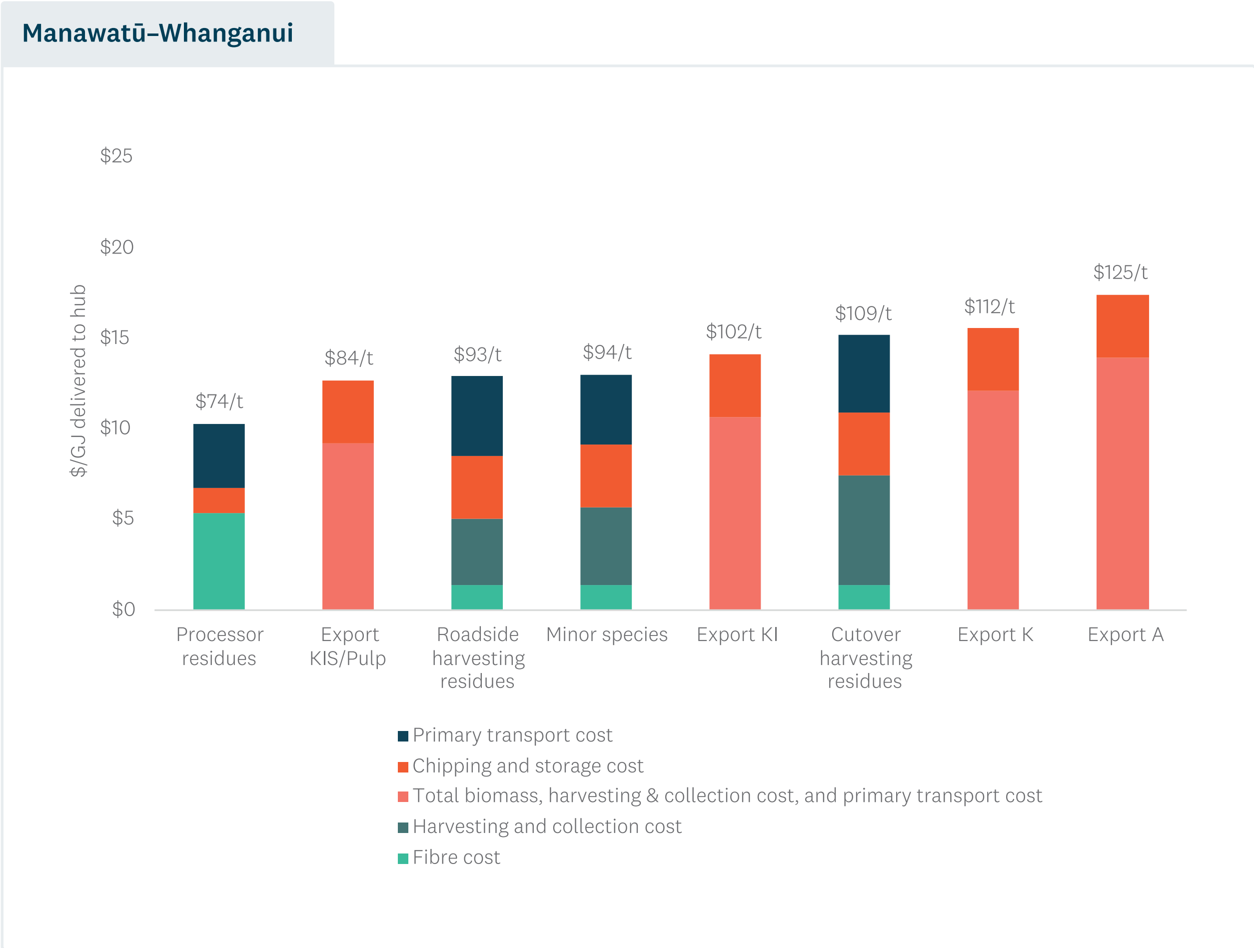
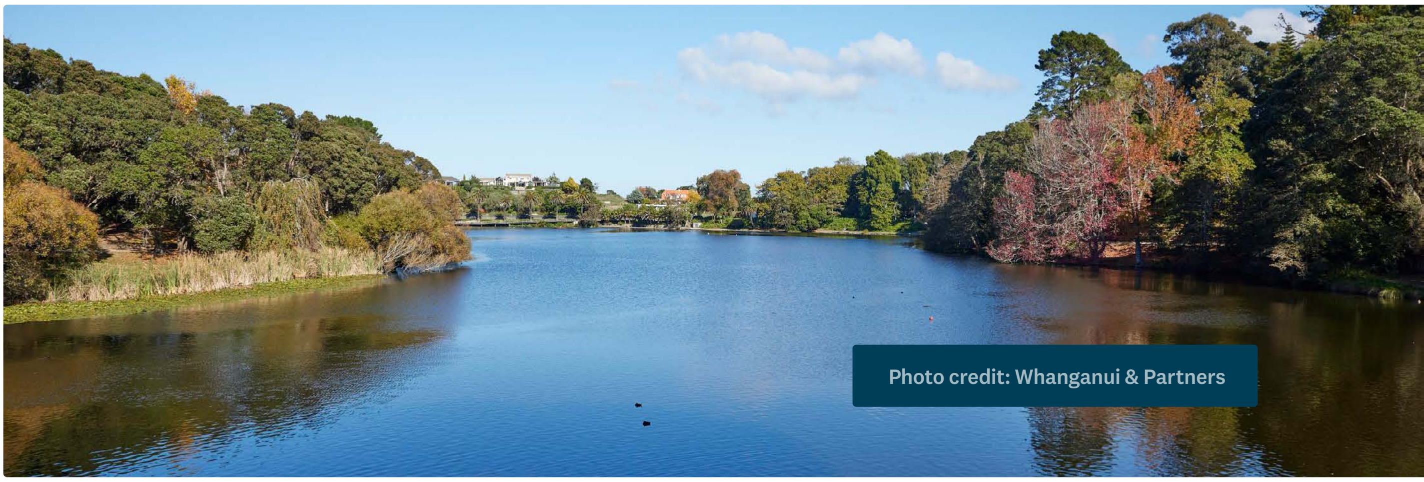


Figure 9 shows costs of collection and delivery per tonne of green tonnes and GJ. In our modelling, we assume that the available volumes in Figure 8 can be processed into woodchip and delivered to process heat users for $20.2/GJ ($254/t of dried woodchip), while pellets will cost $22.9/GJ ($400/t of pellets).

Figure 9 – Estimated delivered cost of potential bioenergy sources. Source: Whirika and Margules Groome (2024).





4.4.2 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 Manawatū–Whanganui region is home to four EDBs – Electra, The Lines Company, Powerco and Scanpower – which maintain myriad assets that connect consumers to Transpower's national grid and also work with Transpower to ensure that the national transmission grid is sufficient to cope with increased demand.

The precise way in which EDBs calculate distribution charges (and pass-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 some sites considering electrification, the 'as designed' electrical system can likely connect the site with minor distribution level changes without the need for substantial infrastructure upgrades. Most of these upgrades would have connection costs under $300,000 and experience connection lead times of less than six months.

More substantial upgrades to the distribution network are required for 21 of the sites, with higher costs (up to $20m, dependent on the level of security) and longer lead times (up to 36 months).

Seventeen sites may require major distribution and transmission upgrades, depending on level of network security required. The cost of the upgrades can exceed $30m and 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 (in $/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.
Note: boiler capacity in MW shown in labels. Sites with an asterisk may trigger additional upgrades depending on the security level required (described in Section 9).

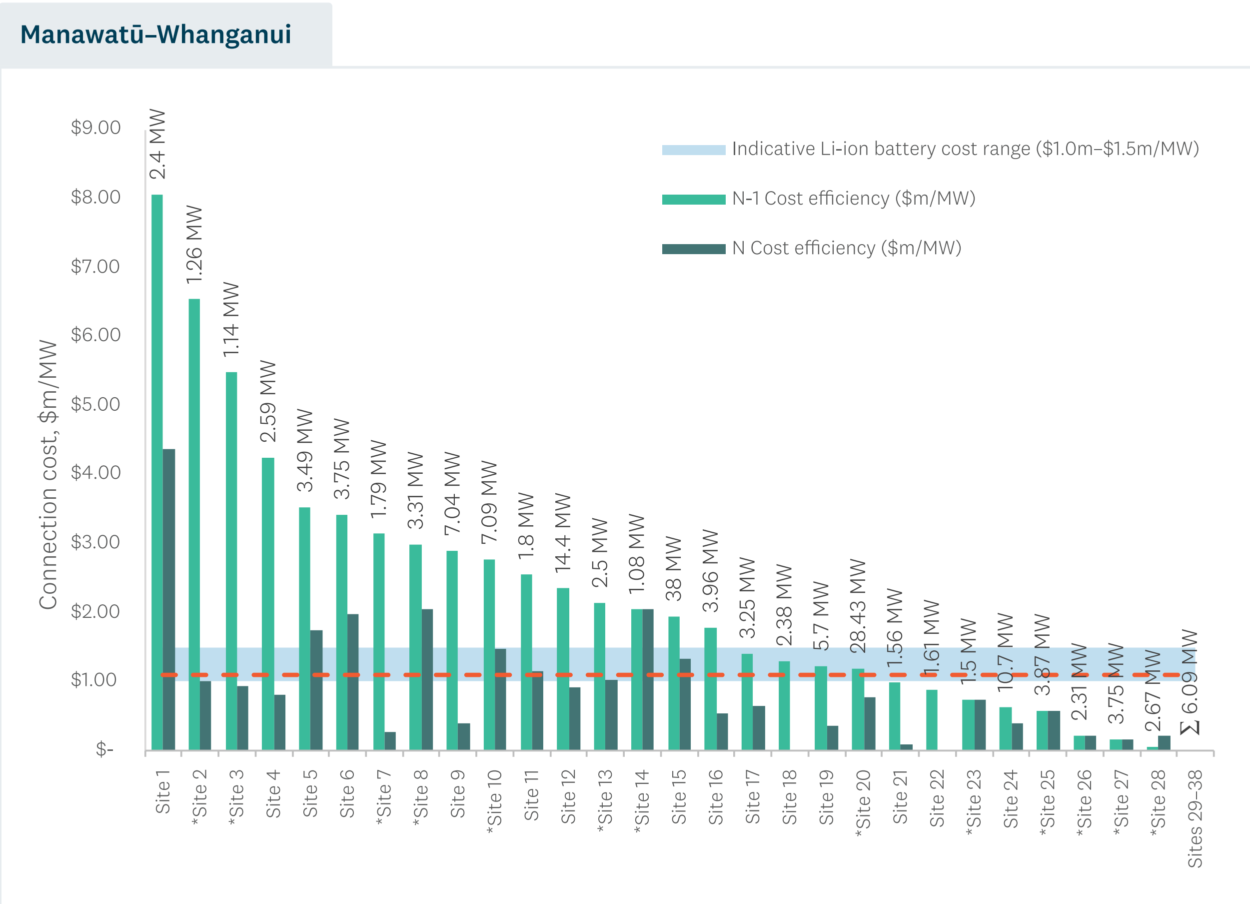


Figure 10 also provides a comparison between connection options that provide N-1 security, and options that provide N security.[5] For a number of sites, the N security option is substantially lower cost than N-1; whether that is an acceptable level of security will be an agreement between the process heat user and the relevant EDB.

Based on the various electricity cost parameters, including a 50% contribution to the cost of network upgrades, only 5% 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.

[5] Sites marked with an asterisk (*) are sites whose N-1 option would by itself trigger a transmission upgrade (as discussed in 9.3.3), but given multiple sites are proposing to connect to the same GXP(s), the direct transmission costs have been excluded from the chart on the expectation that any GXP transmission upgrade costs would be shared among all the sites connecting to that GXP.

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 Manawatū–Whanganui peak electricity demand under pathways.

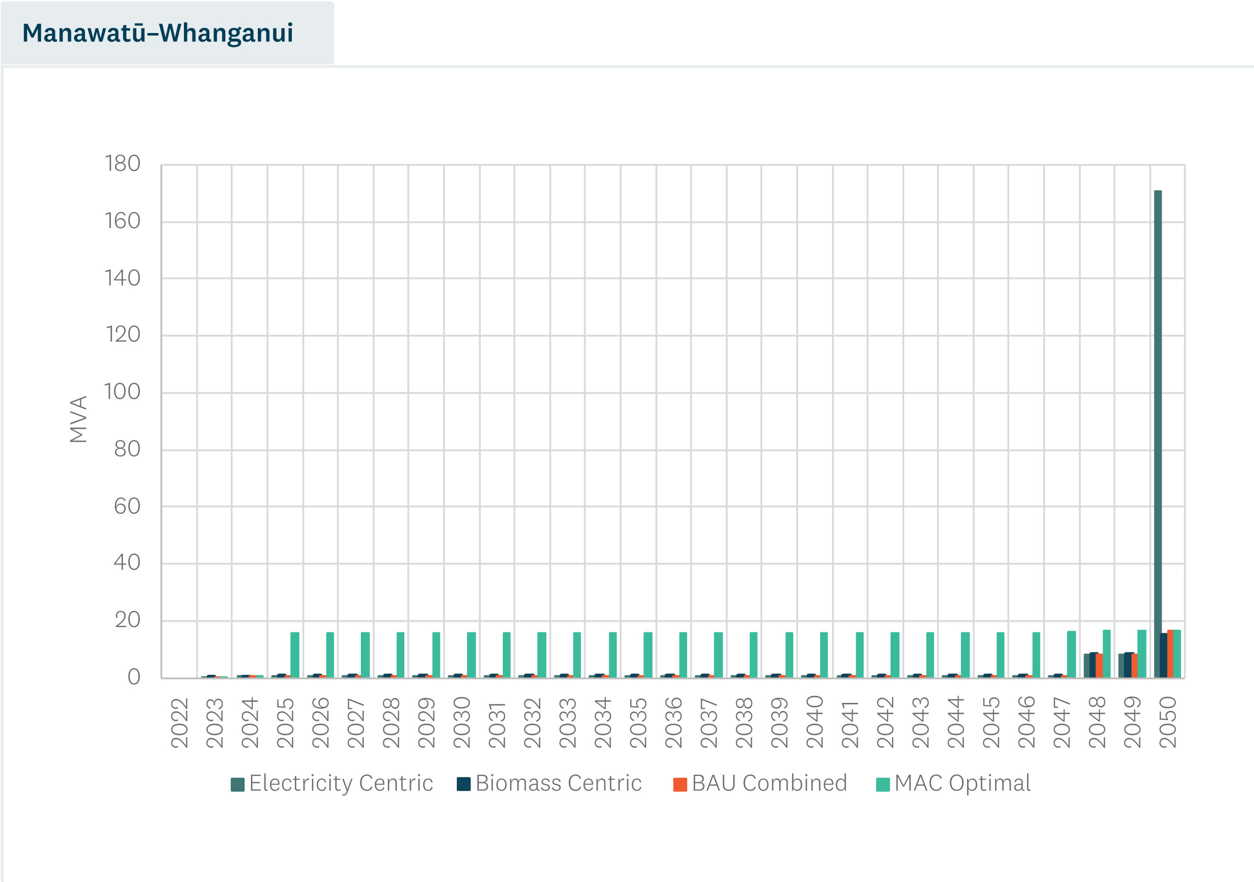


Figure 11 shows that should all unconfirmed process heat users in Manawatū–Whanganui convert to electricity (the Electricity Centric pathway), the increase in demands could be significant — an increase in peak demand of 171MVA by 2050, or 51% compared to today. While this chart shows the cumulative increase 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 lower peak demand requirement from the networks.

EDBs are responsible for any upgrades required to accommodate process heat users who electrify.

Table 2 breaks down these costs under the two pathways.

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

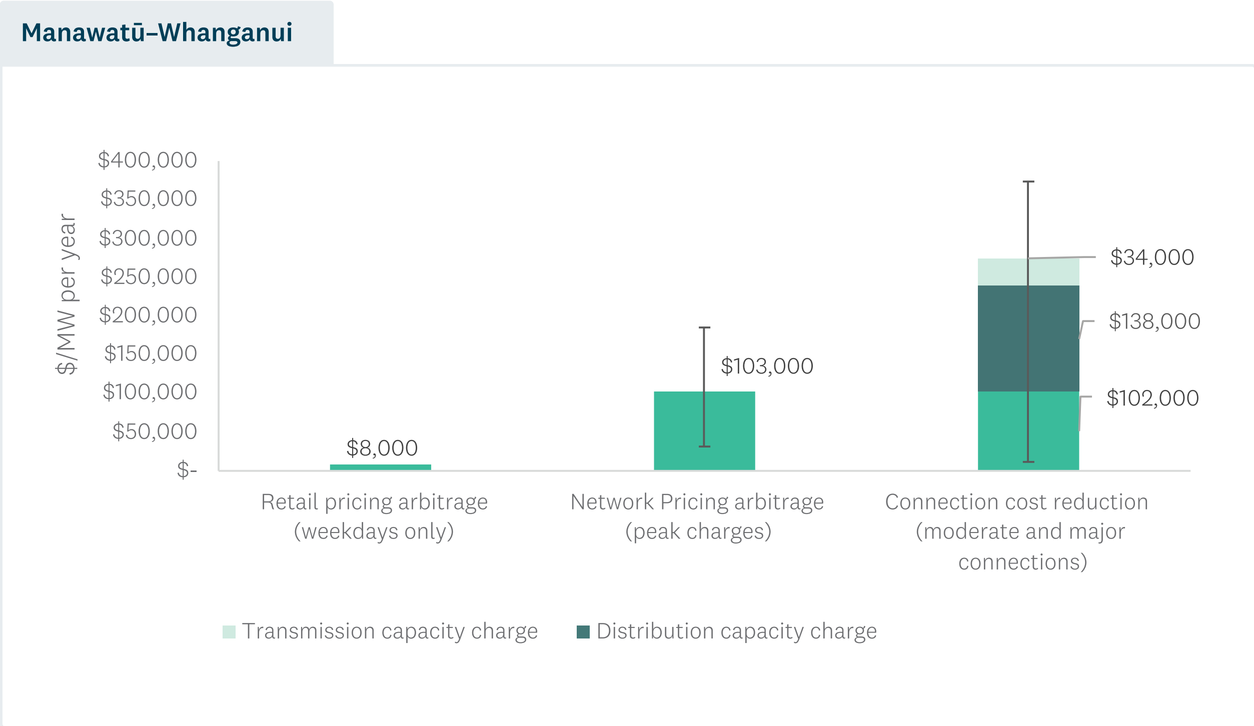
EDB	New connections — Electricity Centric pathway		New connections — MAC Optimal pathway	
	Connection Capacity (MVA)	Connection Cost ($)	Connection Capacity (MVA)	Connection Cost ($)
Electra	13	$51.6m	0.26	$1.3m
PowerCo	147	$279m	11.3	$29.1m
Scanpower	2.7	$3.1m	0.35	-
The Lines Company	8.0	$17m	0.05	-

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 they 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 each EDB's network depends on several factors, such as existing spare capacity and security of supply requirements.

By enabling flexibility in their process heat demands, Manawatū–Whanganui process heat users could reduce their electricity procurement costs by up to $111,000 per MW of flexibility deployed every year, as shown in Figure 12. 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, and also any network charges from the relevant EDB that relate to the size of the connection

Figure 12 – Estimates of the value of flexibility for Manawatū–Whanganui RETA sites.
Note: the error bars indicate the 10th and 90th percentile values calculated across different projects.



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.

Photo credit: Transpower

4.5 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 commencement 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.
- 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.
- EECA should collaborate with forest managers in the region to progress biomass supply.
- EECA should collaborate with process heat users to develop their biomass options.
- 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:

- EDBs should 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. EDBs should ensure Transpower and other stakeholders (as necessary) are aware of information relevant to their planning at an early stage, especially since, in Manawatū–Whanganui, Bunnythorpe and Marton may need to be upgraded as a result of process heat decisions.
- Process heat users should proactively engage with EDBs, keeping them abreast of their plans with respect to decarbonisation, 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.

- EDBs should 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, EDBs should 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 EDBs, and a network section where EDBs provide high-level options for the connection of the process heat user's new demand. Information provided by EDBs 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, EDBs 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.
- EDBs and retailers should ensure that the tariffs they offer process heat users are incentivising the right behaviour.
- EECA should work with process heat users to better understand the value and operability associated with batteries that are integrated into their electrification plans.

We note that many aspects of these recommendations are currently being considered through the Electricity Authority's network connections project.

Recommendations to assist process heat users with their decarbonisation decisions:

- EECA should 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.

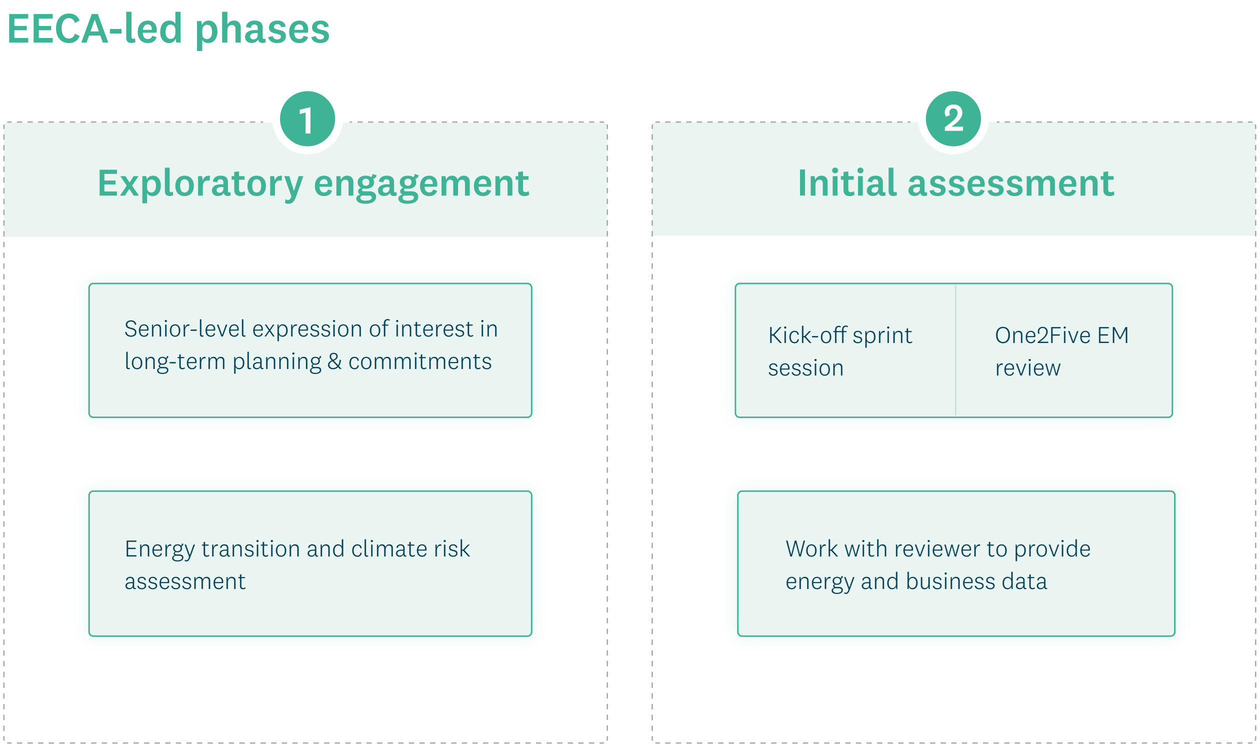
Photo credit: ManawatuNZ

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 13, while the key components of a process heat decarbonisation analysis for an individual organisation are described in Appendix A.

Figure 13 – Overview of the Energy Transition Accelerator programme.



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).

Information gained from the individual ETAs completed to date has been used to inform the potential process heat decarbonisation pathways and identify the process heat challenges that are common to many users, 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 Manawatū–Whanganui Region Energy Transition Accelerator

There are two stages of the RETA programme — planning and implementation. This report is the culmination of the RETA planning stage in the Manawatū–Whanganui 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 programme does not focus in any detail on 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.

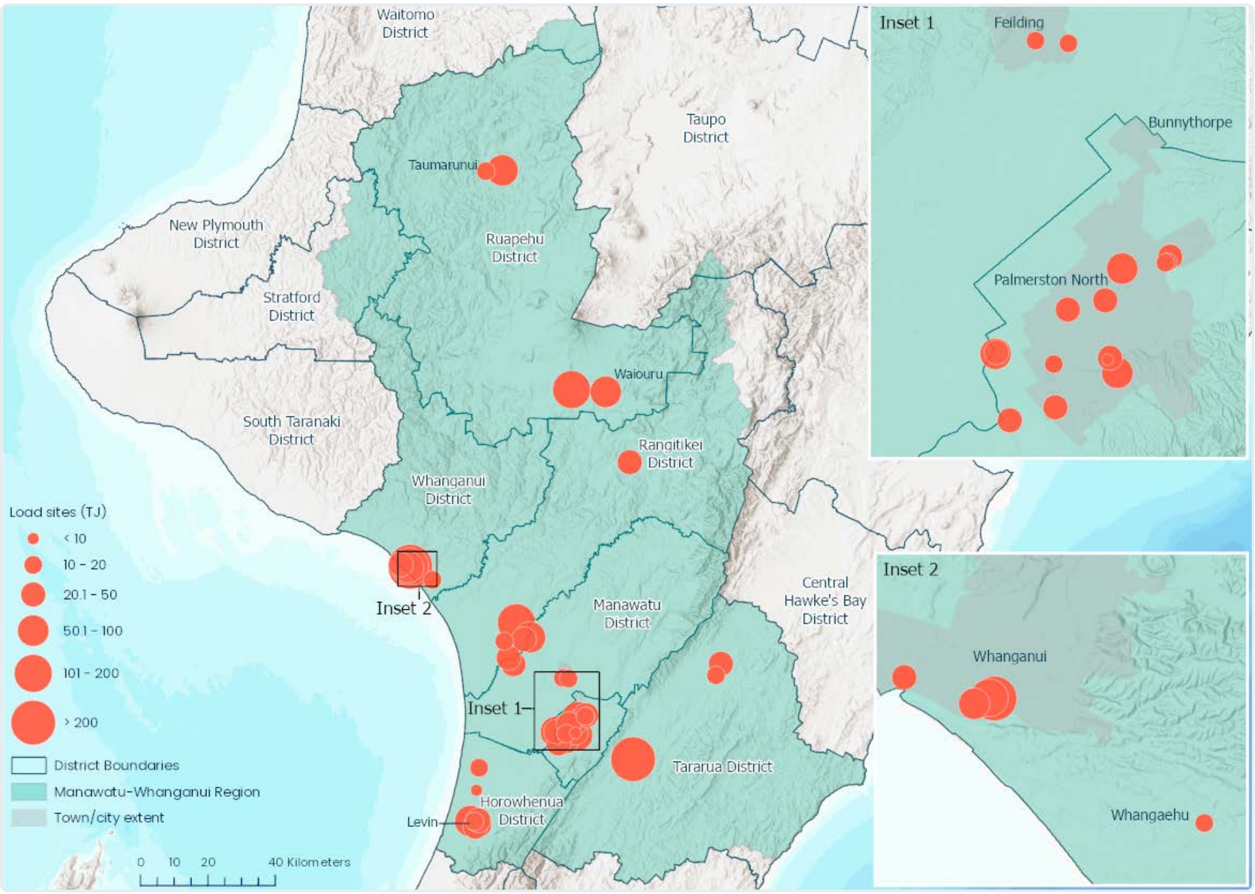
Further, this report is based on what is known at the time of writing. We acknowledge that the nature of energy supply and demand is changing faster than at any time in history, both domestically and globally. Future iterations of RETA analyses could consider current and likely future demands from other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

Photo credit: Whanganui & Partners

6 Manawatū–Whanganui process heat — the opportunity

Figure 14 illustrates the region considered in this report, with the process heat sites located and sized according to their annual energy requirements.

Figure 14 – Process heat demand sites in the Manawatū–Whanganui region.



6.1 Manawatū–Whanganui regional emissions

Statistics New Zealand's regional greenhouse gas inventory presents emissions for the whole Manawatū–Whanganui region. Figure 15 shows that the agricultural sector has the highest emissions in the region (expressed in carbon dioxide equivalent, or 'CO_2e'), followed by energy. Agriculture accounts for 74% (3,996kt) of total emissions in the region. Emissions from the energy sector make up 1,144kt (22%) of emissions out of the region's total emissions of 5,369kt.

Figure 15 – 2022 Emissions inventory for the Manawatū–Whanganui region. Source: Stats NZ. Note: 'IPPU' is industrial process and product use.

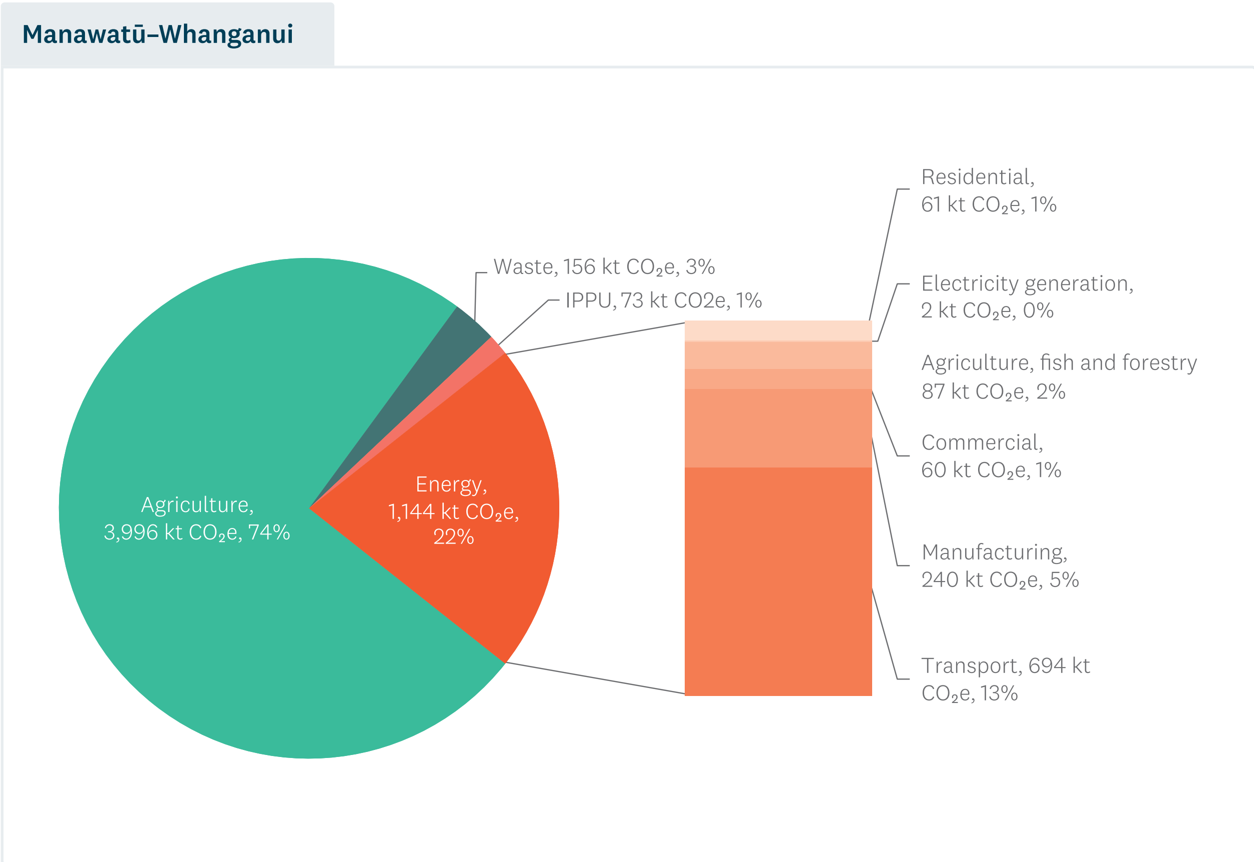


Figure 15 breaks energy emissions down into sector sources. Electricity generation, transport and residential emissions are outside the focus of the RETA study, and we expect that most energy emissions from the agriculture sector relate to off-road vehicle use or diesel generators. We conclude that the majority of the remaining energy emissions — 300kt from the commercial and manufacturing sectors — would be 'process heat' (including space heating).

The Manawatū–Whanganui RETA analysis covers a total of 42 process heat sites spanning industrial (including meat, dairy, food and beverage, and wood processors) and commercial use (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. hospitals) where EECA had information from various programmes (e.g. EECA's Regional Heat Demand Database (RHDD)).[6] Table 3 shows that the industrial sector, particularly dairy and meat, dominates fuel use and emissions, and that the fossil fuel consumption of the six dairy sector sites in the region is equal to the total fossil fuel consumption of all the other industrial sites in the region combined.

[6] See https://www.eeca.govt.nz/insights/eeca-insights/regional-heat-demand-database.

Table 3 – Summary of thermal fuel consumption and emissions from Manawatū-Whanganui process heat sites, 2022.

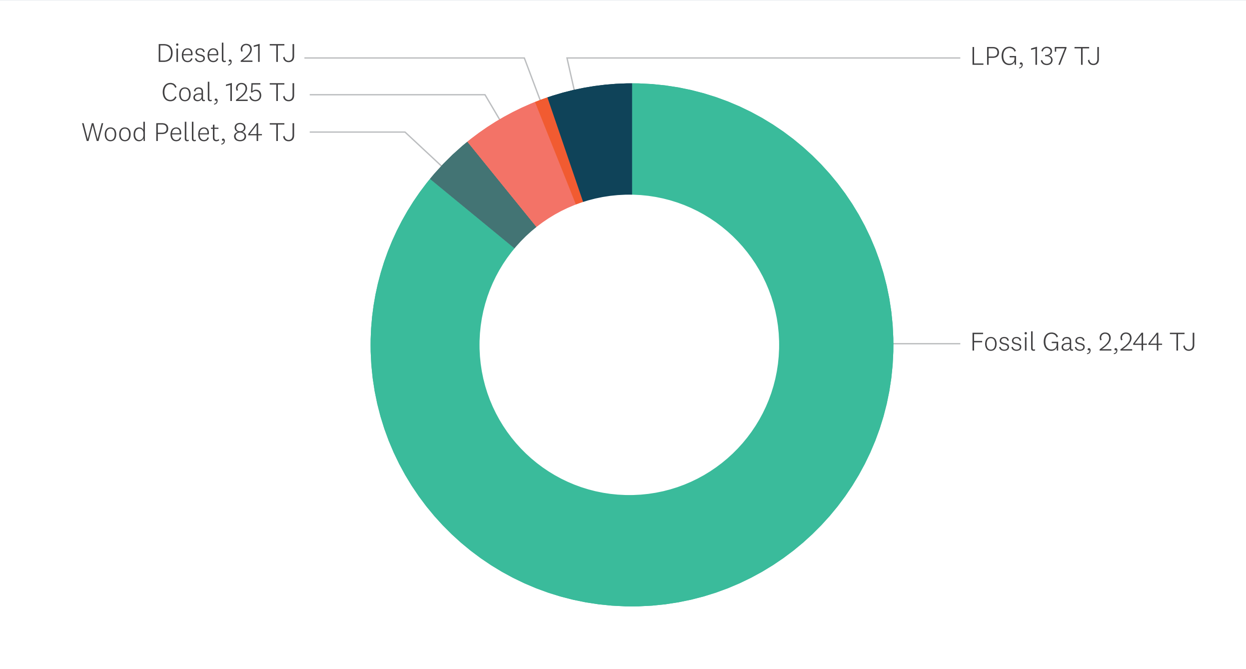
Sector	Sites	Thermal capacity (MW)	Thermal fuel consumption (GWh/yr)	Thermal fuel demand (TJ/yr)	Thermal fuel emissions (kt CO_2e/yr)
Dairy	6	117	313	1126	60
Meat	14	56	146	527	28
All other industrial	13	78	154	555	28
Commercial	9	65	112	403	25
Total	**42**	**316**	**725**	**2611**	**142**

Overall, the Manawatū-Whanganui region RETA sites in aggregate account for 142kt of process heat greenhouse gas emissions, around 47% of the 300kt of commercial and manufacturing energy emissions shown in Figure 15. 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, and this may contribute to the difference in annual emissions estimates.

We now consider the source of process heat emissions by fuel. As shown in Figure 16, current process heat requirements are predominantly met by 2,244 TJ/yr of fossil gas, followed by LPG (137/yr), and coal (125 TJ/yr). Wood pellet and diesel consumption are relatively small (84 and 21 TJ/yr respectively).

Figure 16 – Annual process heat fuel consumption, 2022.

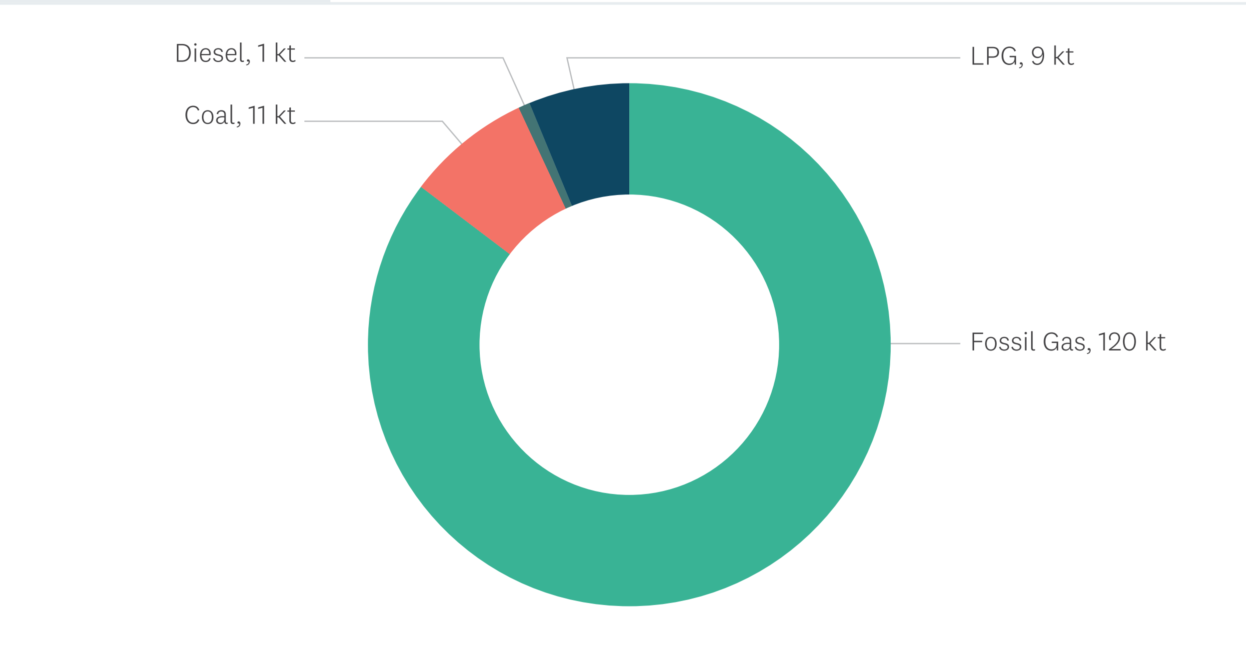
Manawatū–Whanganui



Consequently, most Manawatū – Whanganui RETA emissions come from fossil gas (85%), followed by coal (8%). This is shown in Figure 17.

Figure 17 – Annual emissions by process heat fuel, 2022.
Note: Emissions factors used are as follows (tCO_2e per GJ of fuel): fossil gas – 0.054; coal – 0.093; LPG – 0.059; diesel – 0.07

Manawatū–Whanganui



6.2 Characteristics of RETA sites covered in this study

Across the 42 sites considered in this study, 95 projects[7] have been identified across the three categories discussed in Appendix A — demand reduction, and two broad types of fuel-switching: the use of heat pumps for heat demand less than 100°C,[8] and the use of biomass or electrode boilers for heat requirements greater than 100°C.

Table 4 shows the different stages of the process heat projects considered in the RETA analysis, as at the 2022 base year. As shown, one demand reduction project, one heat pump projects and five fuel-switching projects have been confirmed (i.e. the organisation has committed to the investment and funding is allocated). However, the majority of the possible projects identified are unconfirmed – i.e. yet to commit to the final investment.

Table 4 – Number of projects in the Manawatū-Whanganui region RETA by category.

Status	Demand reduction	Heat pump	Fuel switching	Total
Confirmed	1	1	5	7
Unconfirmed	34	16	38	88
Total	**35**	**17**	**43**	**95**

6.3 Implications for local energy resources

All fuel-switching pathways (presented in Section 7) assume that the 42 Manawatū-Whanganui sites, representing 2,611 TJ per year of fossil fuelled energy consumption for process heat in 2022, will have executed demand reduction projects and switched to low emissions fuel before 2050. 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.

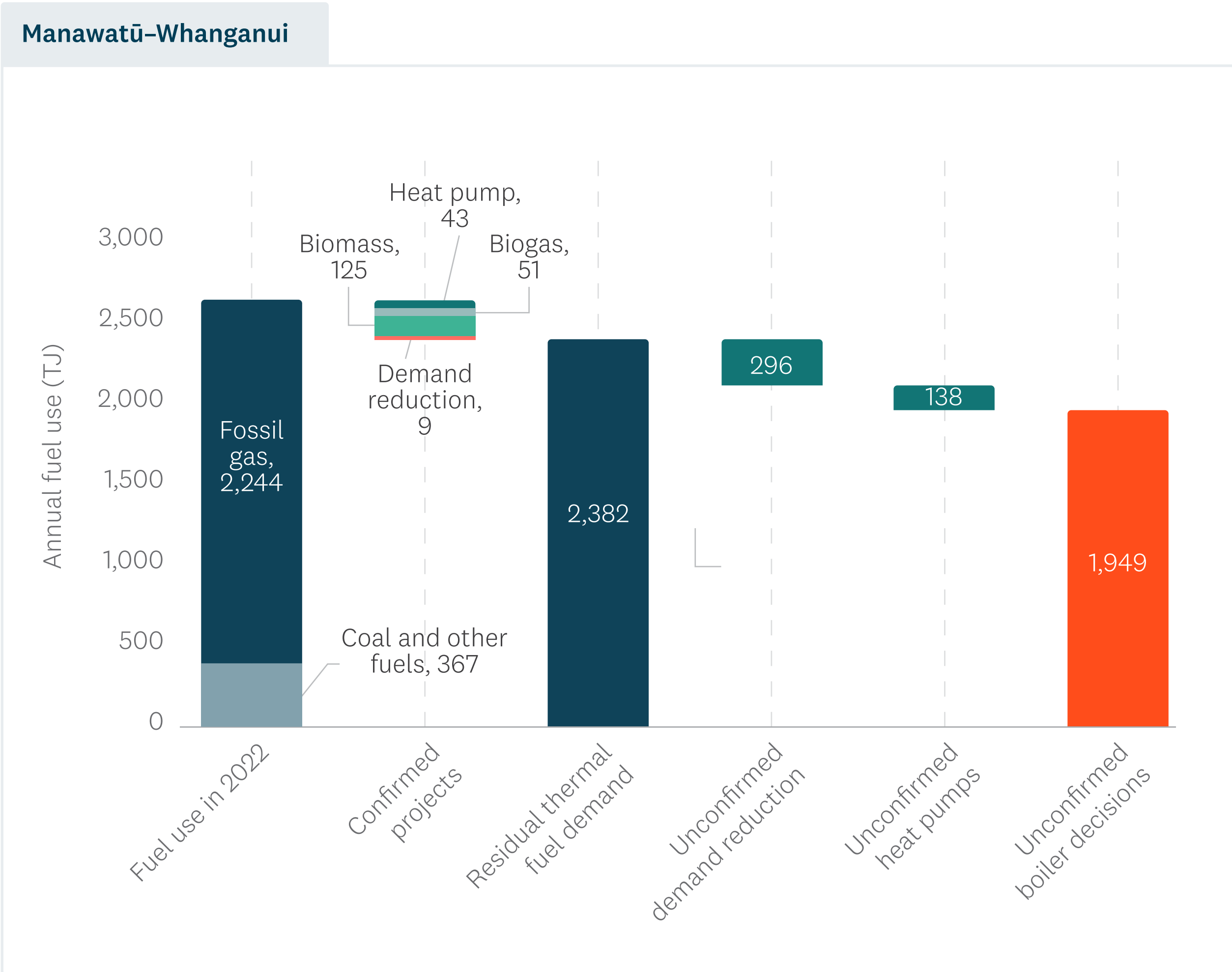
As outlined above, demand reduction and heat pumps are key parts of the RETA analysis and, in most cases enable (and help optimise) the decision to use biomass or electrode boilers for high temperature needs. This RETA report has a greater level of focus on the boiler decision, due to the higher capital 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. These investments will replace current fossil fuel usage and reduce the amount of low-emissions fuel required for any remaining fuel-switching decision.

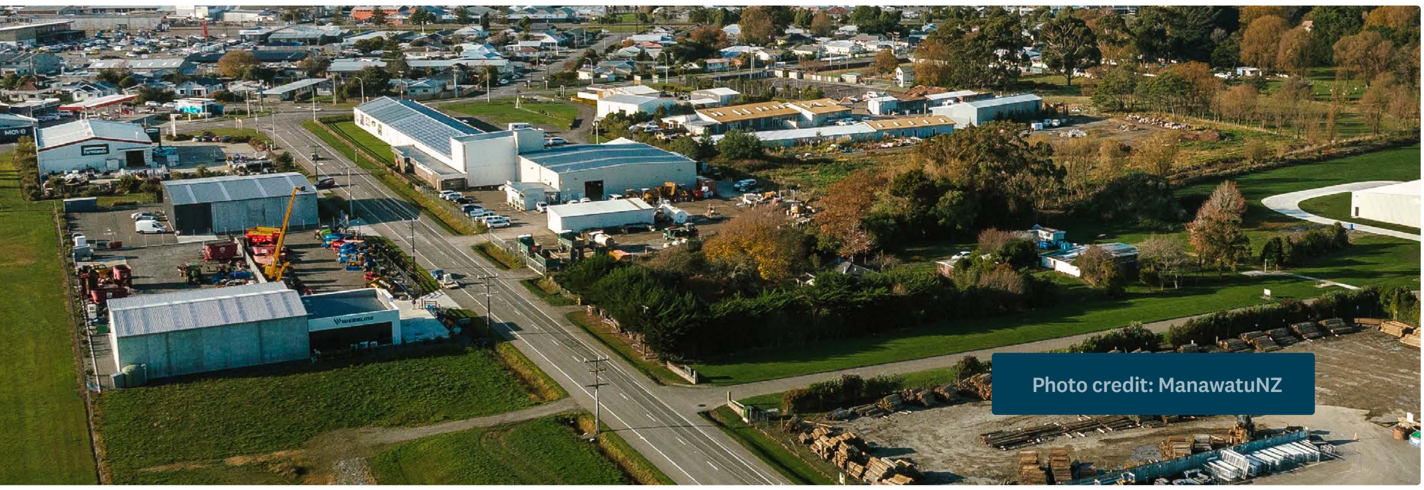
7 This is the number of projects once the optimal fuel switch decision has been determined for a given site (i.e. this reflects the number of projects in the MAC Optimal pathway). The total number of potential projects assessed across all of the sites, including all fuel switch options, was 130.

8 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. In both cases, the use of heat pumps is categorised as a 'heat pump fuel switch'.

These components are presented in Figure 18, to provide a picture of how fossil fuel use may change over the period of the RETA study.

Figure 18 – Potential impact of demand reduction and fuel-switching on Manawatū–Whanganui region fossil fuel usage.





As 1,949 TJ 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 171MW across the region's electricity network, if all sites reached their maximum outputs at the same time. Although this is considered unlikely, this instantaneous demand would increase the maximum demand in the region by 51%.[9] These electrification decisions would also increase the region's annual consumption of electricity by 421GWh, an increase of approximately 26% of today's gross electricity consumption in the Manawatū–Whanganui region.[10]
- If all unconfirmed boiler fuel-switching decisions choose biomass, this could result in an increase of 274kt of biomass demand (1,971 TJ) per year (see Section 8.6). Assuming sufficient resources were available, this is nearly a ten-fold increase in biomass demand for bioenergy compared to today, given our estimate of 29kt of biomass currently being used for heat within the Manawatū–Whanganui region.
- These two scenarios 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 identified in Manawatū–Whanganui, after any demand reduction projects and/or heat pump projects are accounted for. We present biomass demands in TJs and report the peak demand from electrification projects, should they electrify. Confirmed projects are shaded in blue. For unconfirmed projects, the fuel choice that has the lowest MAC value (see Section 7.1) is shown in bold and highlighted green. Empty cells mean that the fuel choice is not applicable to that site.

The table shows that biomass is the preferred fuel switching option for most of the sites. The reasons for this are explained in the next chapter.

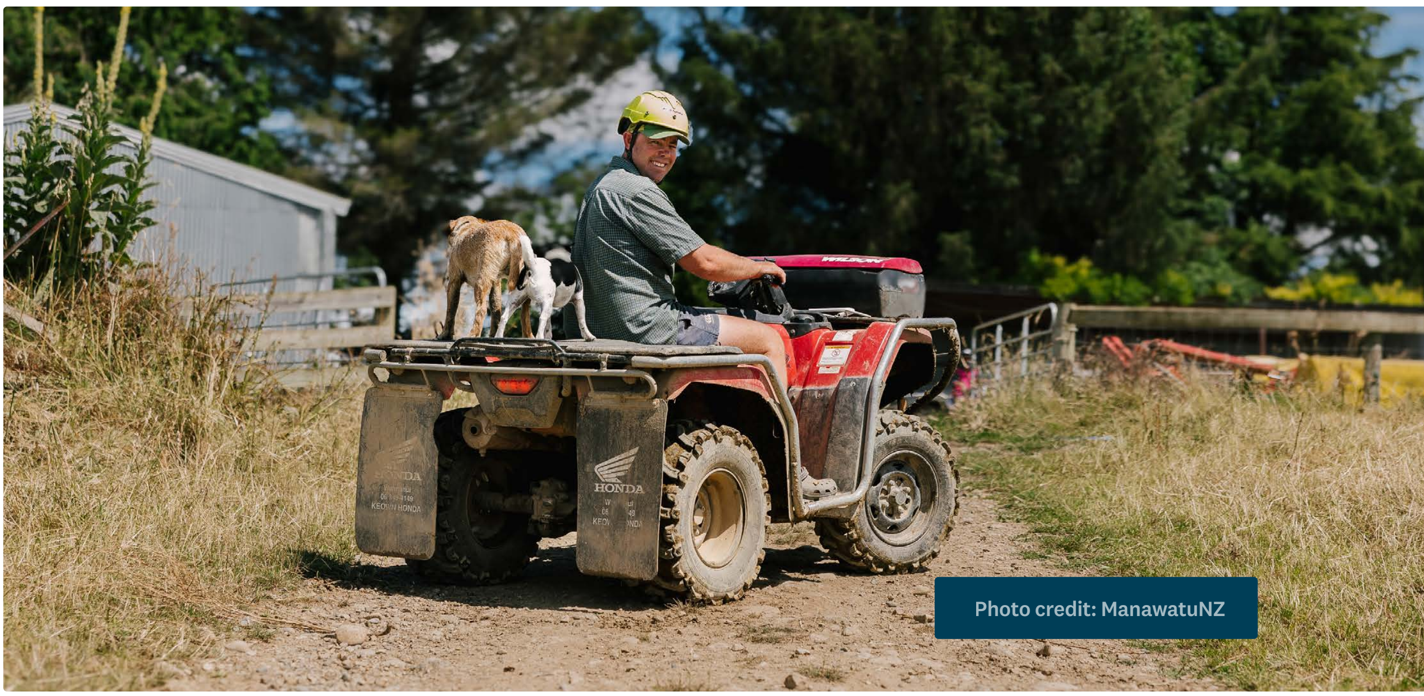


Photo credit: ManawatuNZ

9 Transpower reports that the 2022 regional peak demand was 337MW.

10 Manawatū–Whanganui regional electricity consumption is around 1,600GWh per year (source: emi.ea.govt.nz).

Table 5 – Summary of potential fuel-switching requirements for Manawatū–Whanganui region RETA sites.

Site name	Industry	Project status	Bioenergy Required (TJ/yr)	Electricity peak demand, MVA
Alliance Group Dannevirke	Industrial	Confirmed		**0.35**
Alliance Group Levin	Industrial	Confirmed	**51**	
Fonterra Brands Palmerston North	Industrial	Confirmed		**0.21**
Hautapu Pine Products Taihape	Industrial	Confirmed	**31**	
NZ Defence Force Waiouru Millitary Camp	Commercial	Confirmed	**91**	
AFFCO Castlecliff	Industrial	Unconfirmed	**17**	2.59
AFFCO Imlay	Industrial	Unconfirmed	**82**	7.09
AFFCO Manawatū	Industrial	Unconfirmed	**11**	1.26
AgResearch Grasslands Research Centre	Industrial	Unconfirmed	**8**	0.44
Alsco Palmerston North	Industrial	Unconfirmed	**27**	2.67
ANZCO Foods Manawatū	Industrial	Unconfirmed	**14**	1.56
ANZCO Foods Rangitīkei	Industrial	Unconfirmed	**18**	1.61
Farmland Foods Bulls	Industrial	Unconfirmed	**13**	0.72
Fonterra Longburn	Industrial	Unconfirmed	**25**	1.8
Fonterra Pahiatua	Industrial	Unconfirmed	**576**	38
Fonterra R&D Centre	Industrial	Unconfirmed	**35**	3.96
Godfrey Hirst Dannevirke	Industrial	Unconfirmed	**8**	2.38
Goodman Fielder Ernest Adams	Industrial	Unconfirmed	**21**	1.7
Goodman Fielder Longburn	Industrial	Unconfirmed	**44**	3.25
Higgins Palmerston North Asphalt Plant	Industrial	Unconfirmed	**14**	10.7
Kakariki Proteins	Industrial	Unconfirmed	**35**	2.5
King Country Pet Food Taumarunui	Industrial	Unconfirmed	**76**	7.04
Malteurop Marton	Industrial	Unconfirmed	**101**	14.4
Mitchpine Levin	Industrial	Unconfirmed	**9**	0.49
Moana New Zealand	Industrial	Unconfirmed	10	**0.51**
Nestle Purina Petcare Marton	Industrial	Unconfirmed	**35**	2.4

Site name	Industry	Project status	Bioenergy Required (TJ/yr)	Electricity peak demand, MVA
NZ Pharmaceuticals	Industrial	Unconfirmed	**25**	3.75
Oji Fibre Solutions Central	Industrial	Unconfirmed	**29**	3.75
Open Country Dairy Whanganui	Industrial	Unconfirmed	**294**	28.43
Ovation NZ Feilding	Industrial	Unconfirmed	**15**	0.2
RJs Confectionery Levin	Industrial	Unconfirmed	**10**	1.08
Tasman Tanning Castlecliff	Industrial	Unconfirmed	**21**	1.79
Turk's Poultry	Industrial	Unconfirmed	**13**	2.31
Winstone Pulp International (site closed in 2024)	Industrial	Unconfirmed		**1.19**
Department of Corrections Whanganui Prison	Commercial	Unconfirmed	**16**	3.31
Horowhenua District Council Levin Aquatic Centre	Commercial	Unconfirmed	**26**	3.87
Massey University Palmerston North Campus	Commercial	Unconfirmed	**15**	5.7
Health NZ Horowhenua Health Centre	Commercial	Unconfirmed	**34**	1.5
Health NZ Palmerston North Hospital	Commercial	Unconfirmed	**84**	3.49
Health NZ Taumarunui Hospital	Commercial	Unconfirmed	**16**	0.9
NZ Defence Force Linton	Commercial	Unconfirmed	**40**	0.55
NZ Defence Force Ōhakea Air Base	Commercial	Unconfirmed	**33**	1.14

Gaseous biofuels, derived from organic waste materials from households, industry and/or agricultural sources, landfills and wastewater treatment plants, are an alternative, renewable supply of gaseous fuel that can be produced on an individual site or added to the existing gas network as a replacement for fossil gas. Most biogas currently produced is associated with wastewater treatment or landfills, and is commonly used for electricity generation. There are some locations where biogas is being used for process heat, for example at Nelson Hospital and at the Turners and Growers Reporoa site. However for the purposes of this analysis there is insufficient information about the potential volume and cost of biogas available in the region, therefore it has not been considered as an alternative fuel in this report's modelling. We note that the Bioenergy Association is working with EECA and other industry stakeholders to identify opportunities to esatablish and grow the biogas market in New Zealand.

Photo credit: Whanganui & Partners

7 Manawatū–Whanganui fuel-switching pathways

As outlined above, a primary driver for the RETA analysis 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 organisations, as they only become apparent when the collective impacts of many project decisions within a region 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 Manawatū–Whanganui region. We refer to each of these scenarios as 'pathways'.

7.1 Simulating fuel-switching decisions

To explore different fuel-switching pathways for Manawatū–Whanganui, we must develop a simple, repeatable methodology to simulate the decisions of process heat users – specifically, which low-emissions fuel (electricity or biomass) they will choose to replace their existing fossil fuel, and when they would 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 by a defined date. These pathways are somewhat unrealistic, but in the absence of confirmed plans, it serves 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 fuel-switching, 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 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 the 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 (MACs). Our methodology for calculating MACs is outlined in more detail in Appendix B, but essentially, they represent the net cost to the organisation of reducing emissions – for a particular demand reduction, heat pump or fuel-switching project – expressed as cost per tonne of emissions reduced by the project. In some situations, this can be a net benefit (i.e. the MAC value will be less than $0/t$CO_2$e), if the reduction in fossil fuel procurement costs exceeds the costs of the fuel-switching project. As a result, we can compare the economics of projects across sites, and for different low emissions fuels.

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

Photo credit: Vicki Timpson The Horowhenua Company Ltd

7.1.1 Resulting MAC values for RETA projects

The range of marginal abatement costs for the 95 potential projects (confirmed and unconfirmed) identified across the 42 Manawatū–Whanganui sites considered in this study are illustrated in Figure 19. 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.

Figure 19 – Number of projects, and cumulative emissions reductions, by range of MAC value

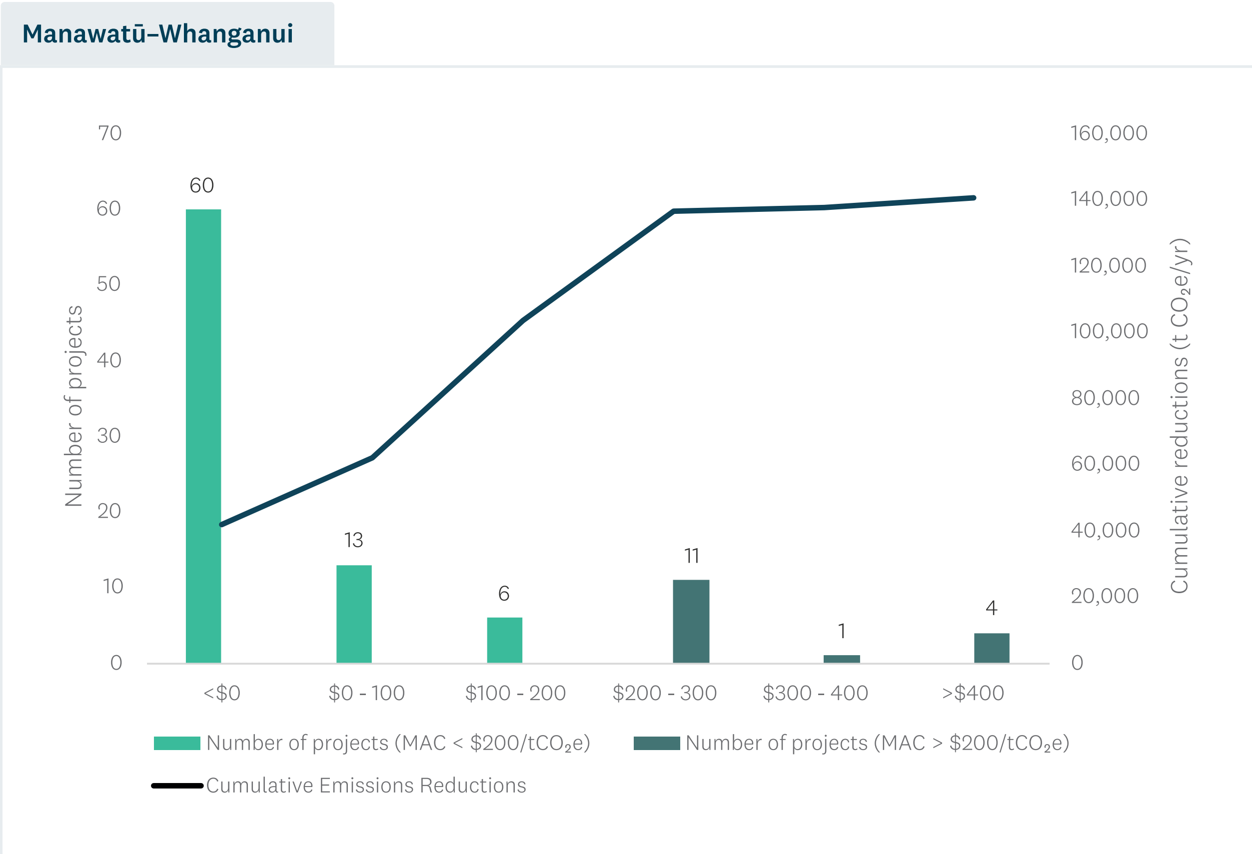


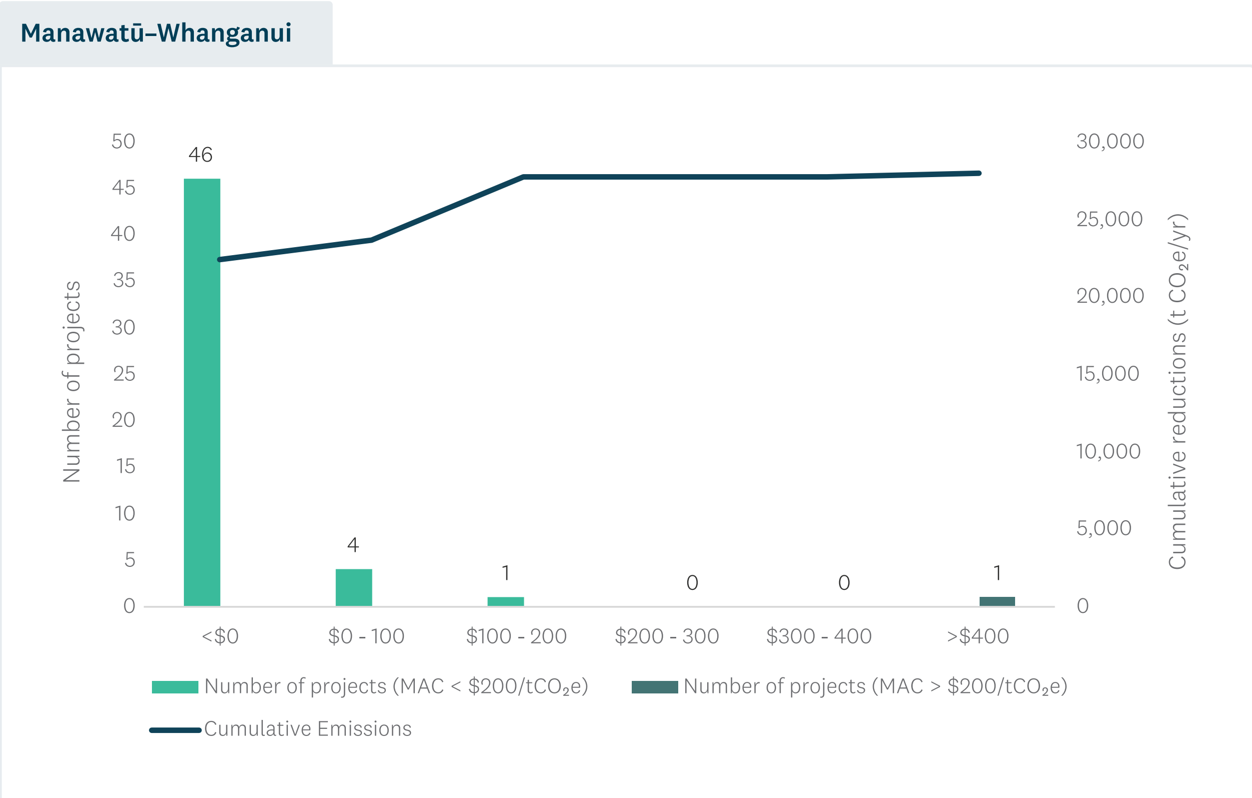
Figure 19 shows that 79 (out of a total of 95) potential Manawatū -Whanganui projects have MAC values less than \$200/tCO_2e. These projects would be economic if executed before 2033, which is when expected future carbon prices are expected to exceed \$200/tCO_2e, if they rise in line with the Treasury's shadow carbon prices.[11] The figure also shows that these 79 projects would deliver a 72% (103kt CO_2e) reduction in total process heat-related emissions across these RETA sites.

Delivering 30% of the total potential emissions reductions (42ktCO_2e), 60 projects would be economic without any carbon price.

11 These 'shadow prices' are consistent with the marginal abatement cost needed in the economy to deliver the next tonne of CO_2e 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). We use a 10-year forward average of Treasury's shadow carbon price projections.

Figure 20 shows that the vast majority of projects that have MAC values less than $200/t$CO_2$e (51 of 79 projects), delivering 28kt of emissions reductions, are demand reduction projects and heat recovery using heat pumps. This reflects the fact that demand reduction projects have low capital and operating costs, relative to the reduction in fossil fuels (and emissions) they achieve.

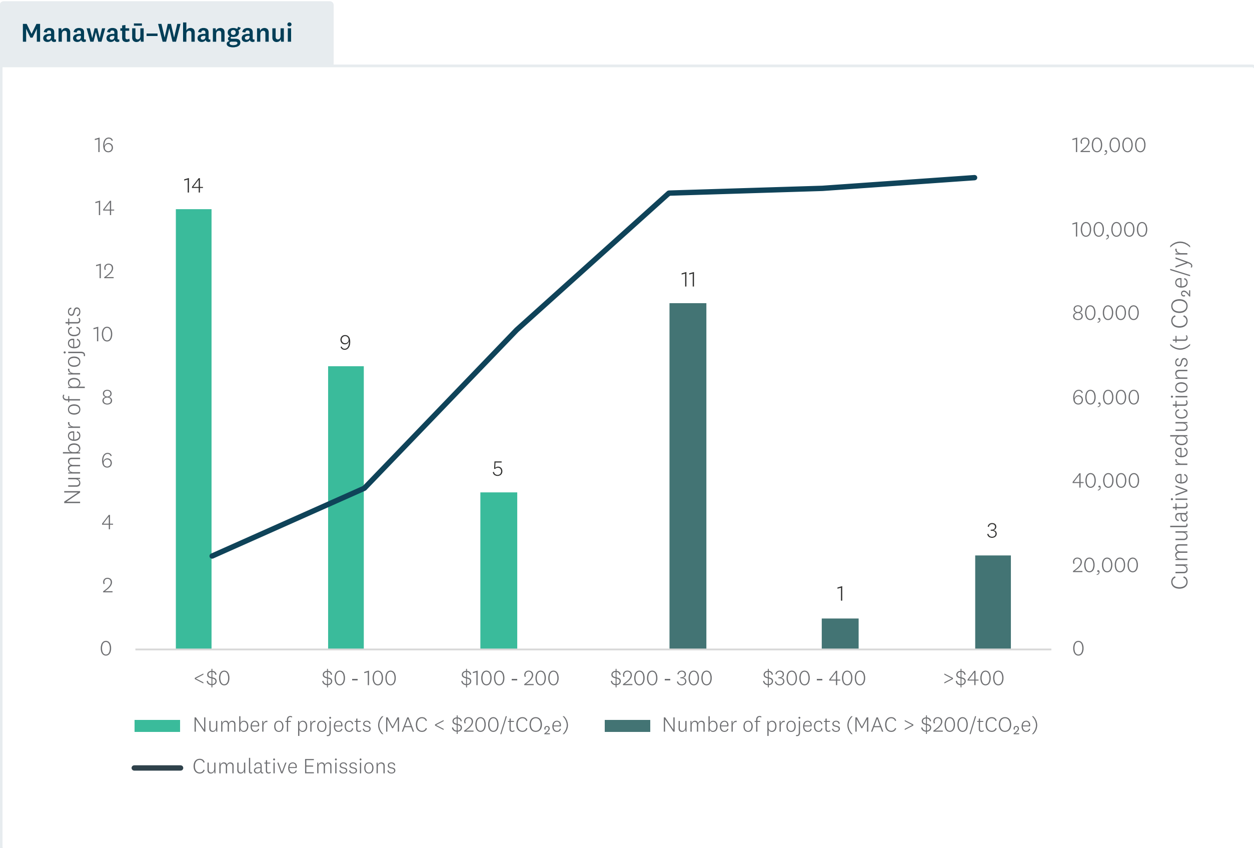
Figure 20 – Demand reduction and heat pump projects by MAC value.



In comparison, 15 of the 95 projects have MAC costs greater than $200/t$CO_2$e. These are all fuel-switch projects (Figure 21), where the MAC reflects electricity and biomass pricing and the various combinations of site-specific factors, such as the lumpy nature of potential electricity upgrade costs (described in Section 9), the operating profile over the year and the overall utilisation of the boiler capacity.

Of the 43 fuel-switching projects, 28 are economic prior to 2033, delivering 76kt of emissions reductions — 54% of the total process heat emissions (Figure 21). Five involve use of heat pumps, 22 involve fuel switch to biomass, while one involves fuel switch to electricity.

Figure 21 – Fuel-switching projects by MAC Value.



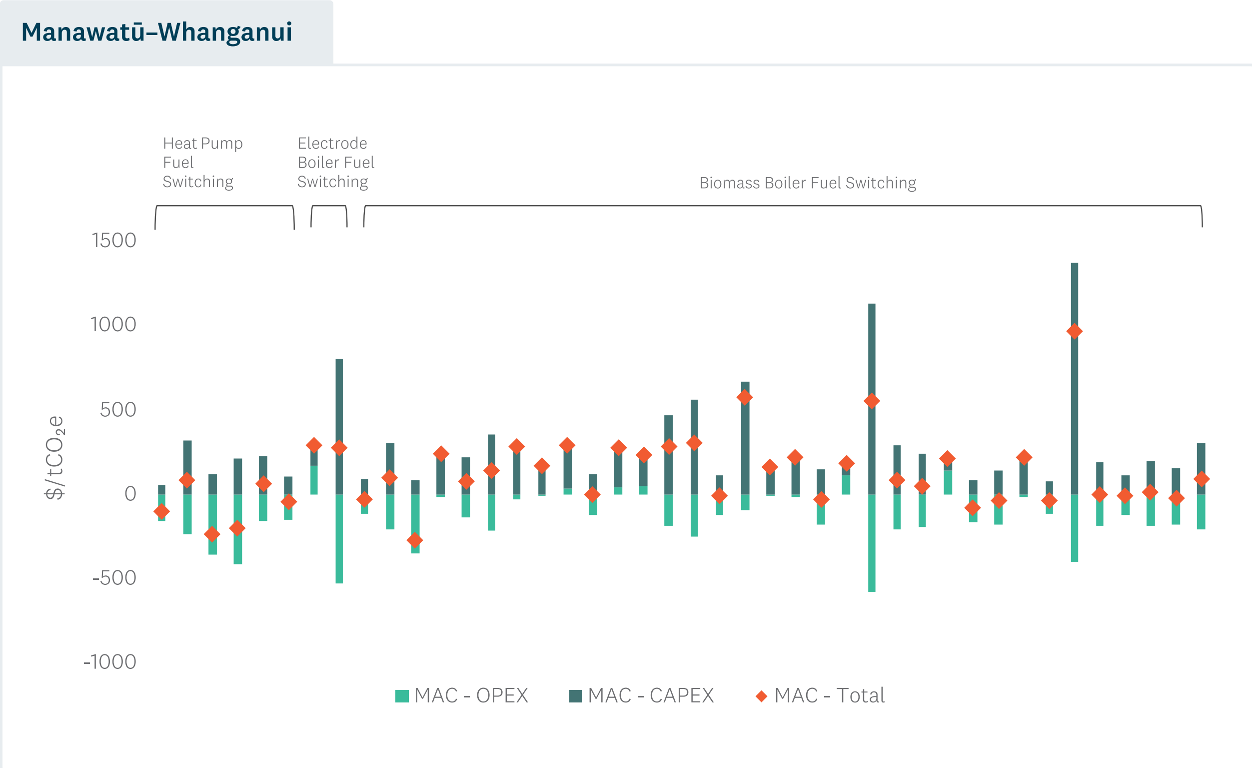
7.1.2 What drives Manawatū–Whanganui MAC values?

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 analysis: 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 mostly from piped fossil 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 Manawatū–Whanganui RETA sites, Figure 22 illustrates the MAC values for the unconfirmed fuel-switching options, across the biomass and electricity options (heat pumps and electrode boilers). The MAC value shown is split between the project's up-front capital costs (CAPEX) and operating costs or benefits (OPEX). We analysed and produced MAC values for each of the 78 fuel switch options considered across the 42 sites. This chart shows the range of costs for the full set of project options.

Figure 22 – CAPEX and OPEX MAC values for unconfirmed fuel-switching projects.



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

- The capital costs for biomass and electricity (heat pumps and electrode boilers) are reasonably similar but electricity-related projects may incur connection costs, which, depending on the level of security required, can be very high (per MW of demand).
- Retail electricity costs (including network charges) are higher (per unit of energy) than biomass.
- Both heat pumps (if they can be used) and electrode boilers are more efficient than biomass boilers, thus 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 22, 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 a number of heat pump and electrode boiler projects in Figure 22. Ordinarily, due to their very high efficiency, heat pumps are very capital efficient. However, the project with a high MAC – CAPEX value represents a situation 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 22, 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 Manawatū–Whanganui region is based on the regionally specific assumptions 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 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.

7.2 Indicative Manawatū–Whanganui pathways

Indicative pathways for fuel switching have been prepared on the following basis. Projects that are known to be committed by an organisation (e.g. funding allocated and project planned) are locked in for all pathways. Where organisations do not have a confirmed project, the following assumptions were applied.

- All low to medium temperature (<300°C) coal boiler decarbonisation projects are executed by 2036 in line with the National Policy Statement (NPS) for greenhouse gas emissions from industrial process heat that came into effect in July 2023, which prohibits greenhouse gas emissions from existing medium temperature (<300°C) coal boilers after 2036.[12]
- All other unconfirmed projects are assumed to occur 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 (illustrated in Figure 19) by 2049, are assumed to be executed in 2049.

As only two sites in Manawatū–Whanganui were using coal in 2022 and both of these sites have since switched to biomass, all of the unconfirmed fuel switch projects are therefore assumed to occur in 2049. It is acknowledged that this is an artificial scenario but in the absence of information about confirmed plans, it provides an indication of the possible total demand for each type of fuel considered.

[12] See National-Direction-for-Greenhouse-Gas-Emissions-from-Industrial-Process-Heat-Industry-Factsheet.pdf.

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, either in 2036 (for coal) or in 2049.
Electricity Centric	All unconfirmed fuel-switching decisions proceed with electricity, where possible, either in 2036 (for coal) or in 2049.
BAU Combined	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 New Zealand 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. 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.[13]
- 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.[14]

The assumptions 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 these carbon prices are not available in a format that is easily accessible for process heat users, and EECA should work with agencies to improve this.

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

14 See Table 1 in https://www.treasury.govt.nz/sites/default/files/2024-10/cbax-tool-climate-environmental-impacts-oct24.pdf

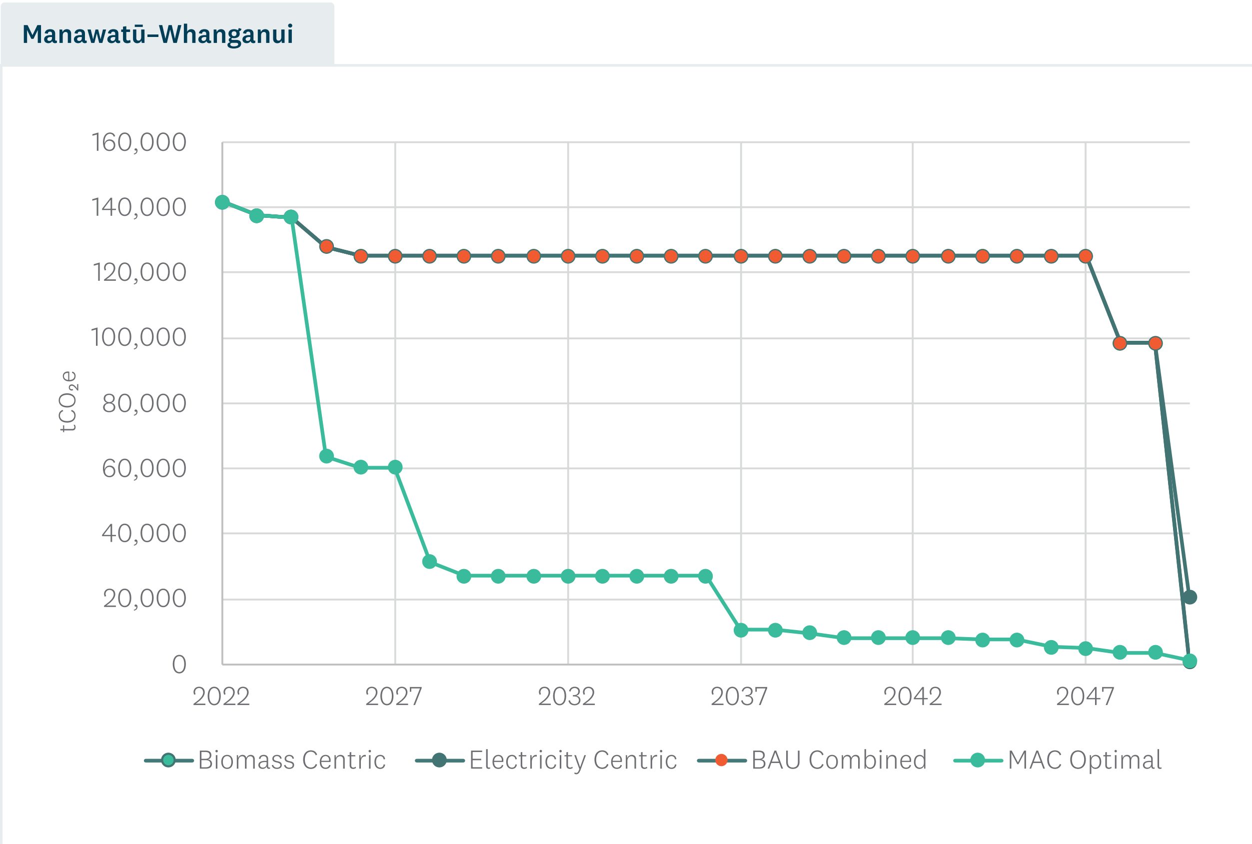
7.2.1 Pathway results

Figure 23 shows the MAC Optimal pathway delivers the largest annual emissions reductions early in the RETA period. Under the MAC Optimal pathway:

- by 2026, 81kt of annual emissions are eliminated (57% of Manawatū–Whanganui site's process heat emissions)
- by 2037, 131kt of annual emissions are eliminated (93% of Manawatū–Whanganui site's process heat emissions).

Although all pathways eliminate between 85% and 99% of the region's emissions by 2050 (given the pathway assumptions made), the cumulative difference between the MAC Optimal and the Electricity Centric pathway is around 2,569kt CO_2e across the period 2024 to 2050, while the cumulative difference between the MAC Optimal and the Biomass Centric pathway is around 2,550kt CO_2e across the same period.

Figure 23 – Emissions reduction trajectories for different pathways.



Note: the Electricity Centric and Biomass Centric pathways are obscured in the chart by the BAU Combined pathway, because the project timings and the emissions reduction are identical until 2049.

7.3 Pathway implications for fuel usage

We can now compare the trajectory of demand for biomass and electricity arising from the various Manawatū–Whanganui 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).

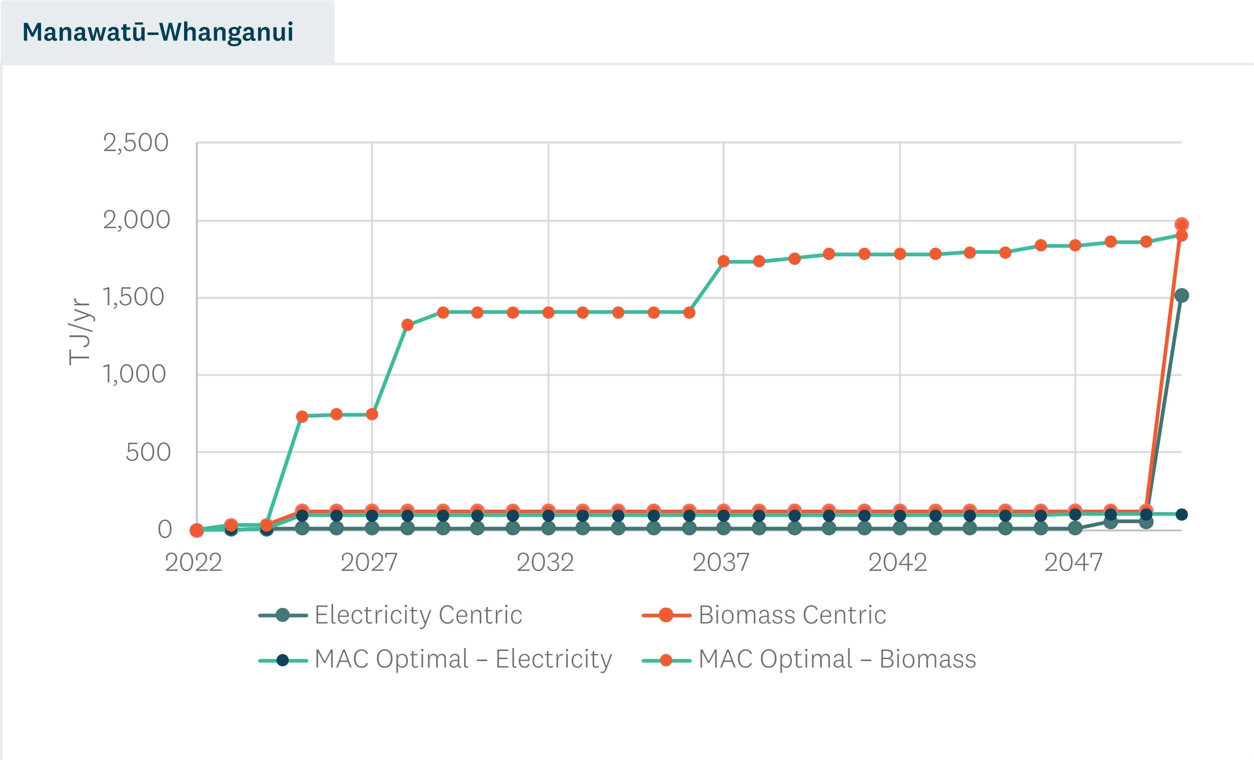
As shown in Figure 24, the increase in demand for electricity and biomass takes place earlier in the analysis period in the MAC Optimal pathway compared to the Centric pathways. However, in 2050 the Biomass Centric and Electricity Centric pathways deliver a higher demand for biomass and electricity respectively in energy terms, given the assumptions made.

More specifically:

- In the MAC Optimal pathway, **electricity demand** remains stagnant at 95 TJ/yr in 2025 until 2047 when it reaches its near peak of 103 TJ/yr and 104 TJ/yr in 2050. In the Electricity Centric pathway, electricity demand only gradually increases to around 54T J/yr in 2049, before increasing to 1,515 TJ/yr in 2050.
- **Biomass demand** in the MAC Optimal pathway increases from 734 TJ/yr in 2025 to 1,405 TJ/yr in 2029, reaching 1,906 TJ/yr in 2050. In the Biomass Centric pathway, biomass demand increases from 122 TJ/yr in 2025 but remains stagnant until 2050 when it reaches 1,971 TJ/yr.

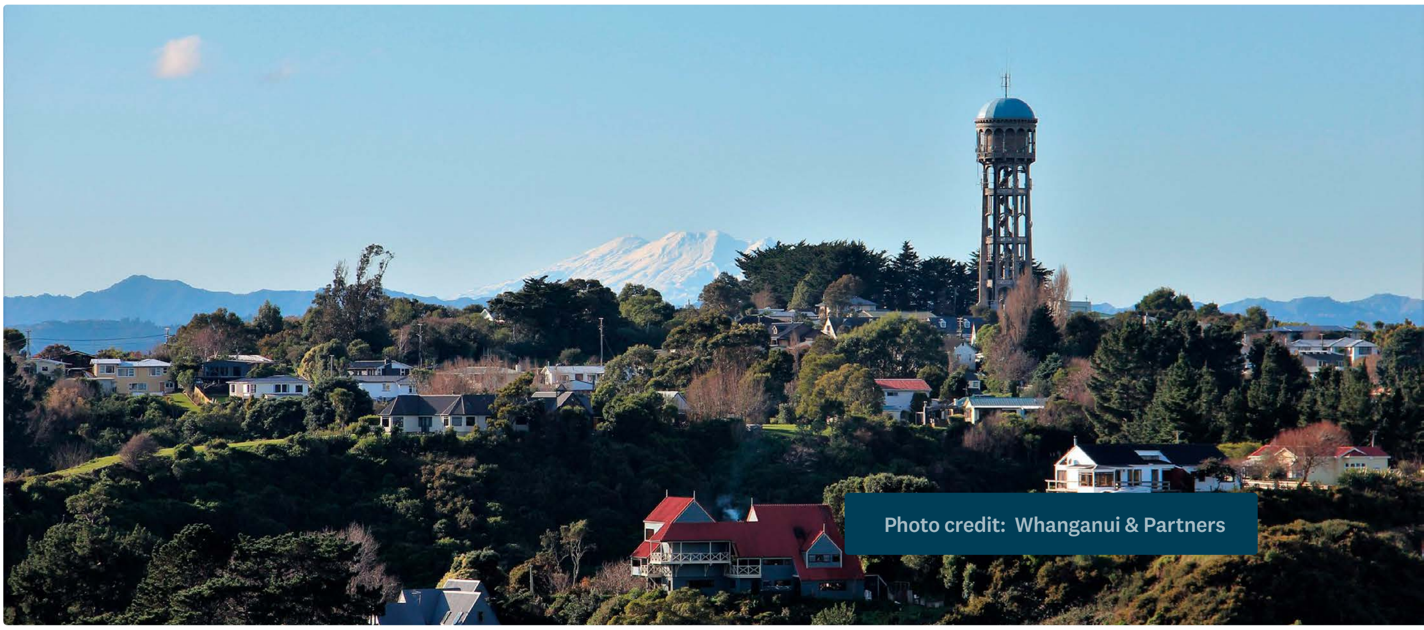
Overall, the pathways that use MACs to determine fuel-switching decisions result in around 5% of the energy needs supplied by electricity (with a consumption of 104 TJ/yr of delivered energy), and 95% of energy needs supplied by biomass (with 1,906 TJ/yr of delivered energy).

Figure 24 – Simulated demand for biomass and electricity under different pathways.



The sheer dominance of biomass reflects its lower overall cost as a fuel for large industrial projects which require high temperature boilers (over 100°C) for their process heat, so cannot switch to heat pumps alone.

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



7.3.1 Implications for electricity demand

Figure 25 shows the growth in electricity consumption in each of the pathways.

Figure 25 – Growth in electricity consumption under different pathways.

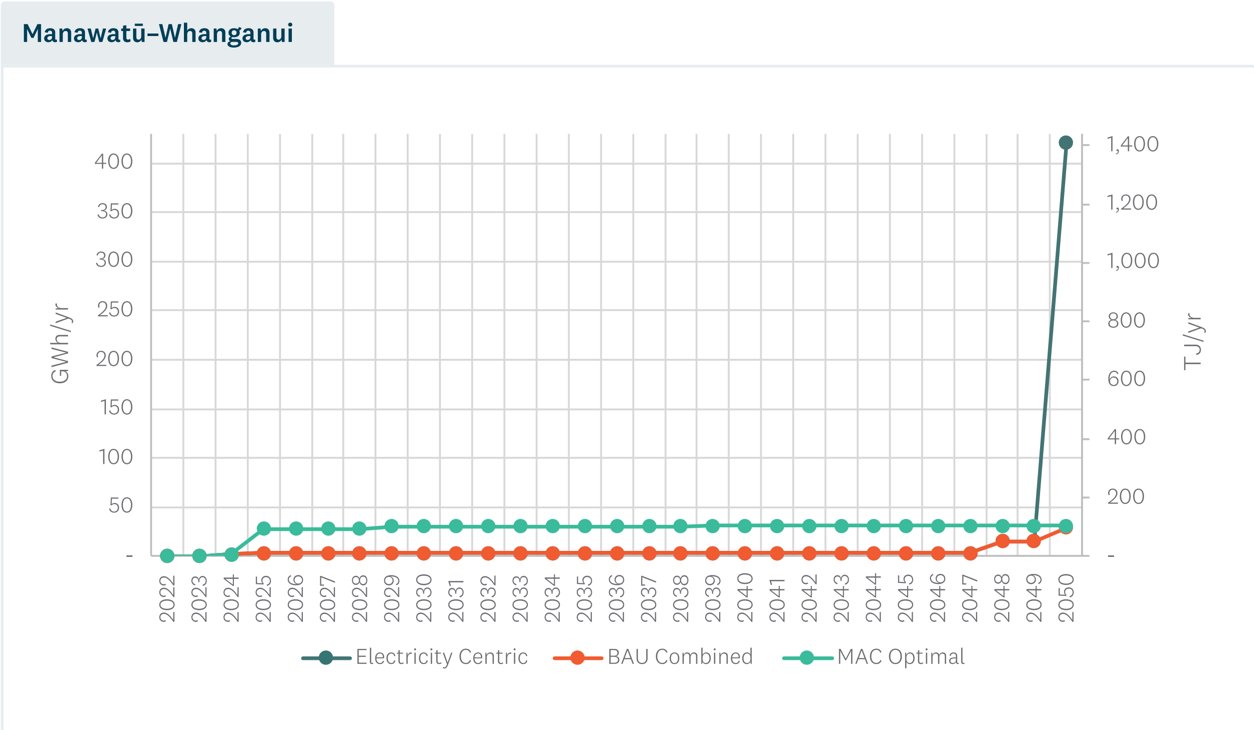
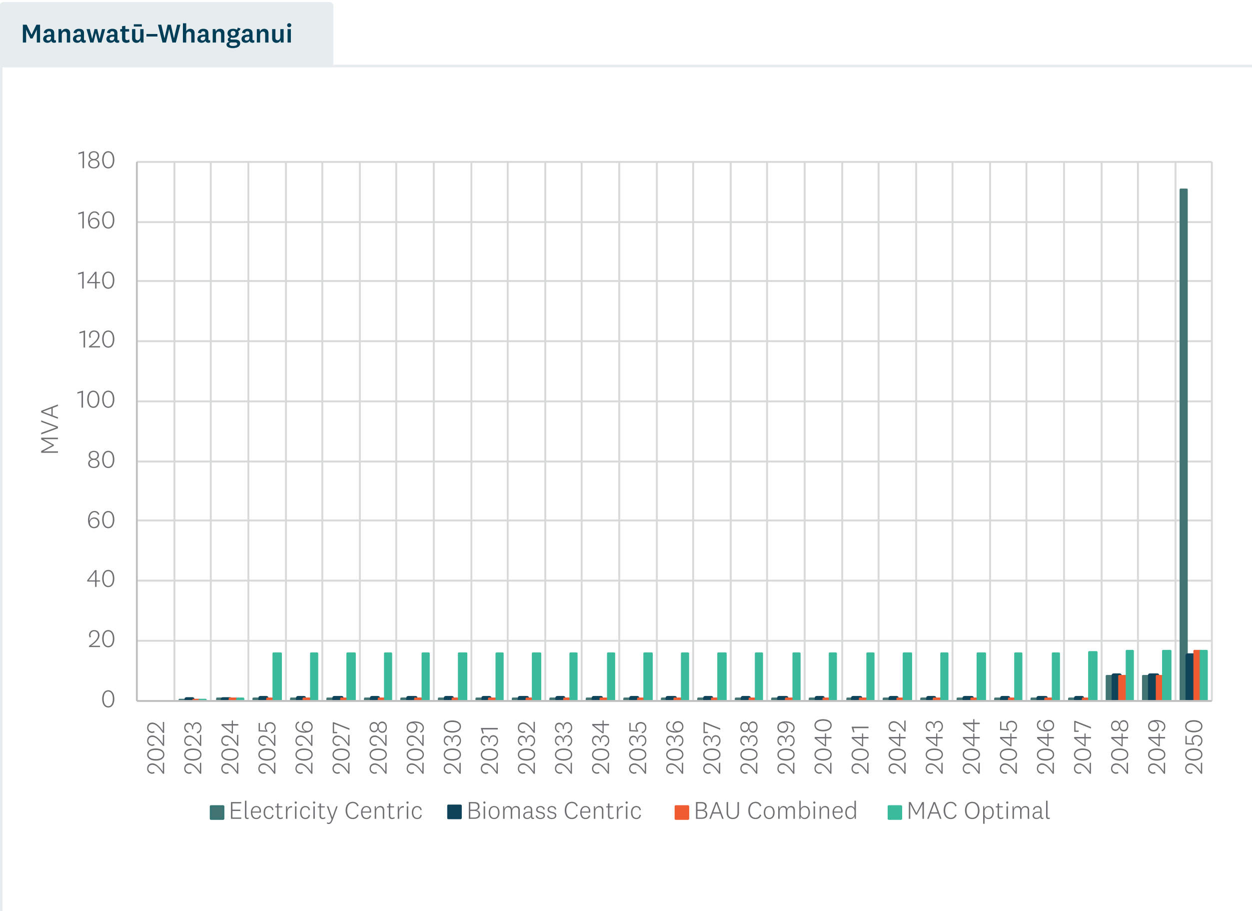


Figure 25 shows that the use of MACs to simulate decision making accelerates 26 GWh of investment in heat pumps from 2050 to 2025.

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 26 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.

Figure 26 – Potential peak electricity demand growth under different pathways.



By 2026, process heat electrification could add up to 16MVA to peak electricity demand, depending on the pathway, representing an increase of up to 5% in the local EDBs' peak. By 2050, the Electricity Centric pathway increases demand by a further 155 MVA representing a 51% increase compared to current regional peak demand. Most of 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. In the more realistic MAC Optimal pathway, peak electricity demand only reaches 17 MVA in 2050.

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 diversity amongst peak demands as discussed further in Section 9, as well as commercial incentives to shift this peak demand away from the time 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

There are four EDBs in the Manawatū–Whanganui region. The impact of the modelled electricity peak demand on each of their networks is shown in Table 6.

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

EDB	New connections — Electricity Centric pathway		New connections — MAC Optimal pathway	
	Connection capacity (MVA)	Connection cost ($)	Connection capacity (MVA)	Connection cost ($)
Electra	13	$52m	0.26	$1.3m
PowerCo	147	$279m	11.3	$29.1m
Scanpower	2.7	$3m	0.35	-
The Lines Company	8.0	$17m	0.05	-

Note: The costs of some connections are shown as zero in this column due to the way we assess network upgrade costs for very small connections (see Section 9). In reality, these very small connections may require no additional electrical infrastructure, some may need up to $300,000 of additional components, but we have insufficient information about these small sites to be definitive either way.

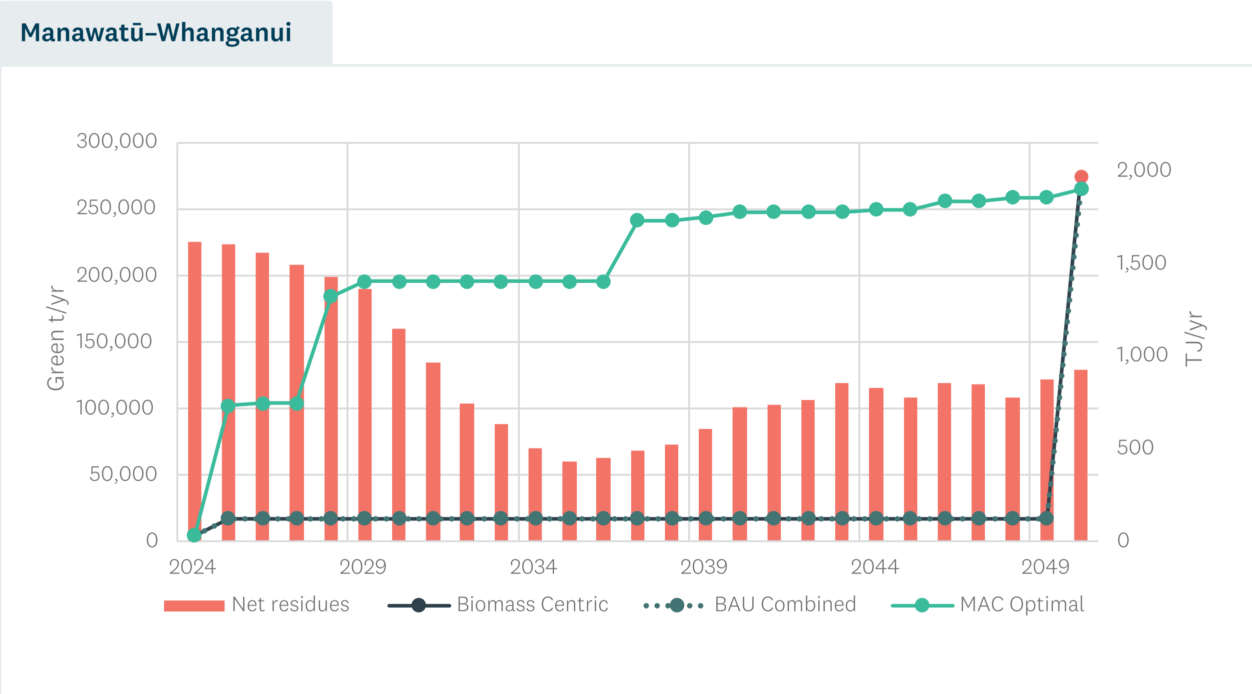
Note that the connection costs presented in Table 6 are total construction costs and may not necessarily reflect the connection costs paid by individual organisations, as costs may be shared between the relevant EDB and the new process heat user. The degree of sharing 'capital contributions' depends 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 27 shows the growth in biomass demand (in both tonnes and TJ per year) arising from each of the pathways.

As discussed previously, additional biomass demand in the MAC Optimal pathway gradually increases from 734 TJ/yr in 2025 to 1,323 TJ/yr in 2028 and 1,906 TJ/yr in 2050. In the Biomass Centric pathway, the use of biomass grows from 122 TJ/yr in 2025 to 1,971 TJ/yr in 2050.

Figure 27 – Growth in biomass demand under fuel-switching pathways, and available residues.



The modelling shows that net residues alone will not be sufficient to meet biomass demand in the MAC Optimal pathway from 2029 onwards. In the Biomass Centric and BAU Combined, supply of net residues will be short of biomass demand from 2049. To fill the gaps, pulp/export KIS grades will need to be used. However, wood availability may differ from the forecast in the chart. Discussions with forestry industry stakeholders as part of this RETA programme indicate that the peak volumes of harvesting modelled for years 2024 and 2025 are not being realised. Therefore, actual harvest volumes – and corresponding harvest residue volumes — are expected to be lower in the near term, allowing for additional volumes being available to fill some of the troughs in the mid-2030s.

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:

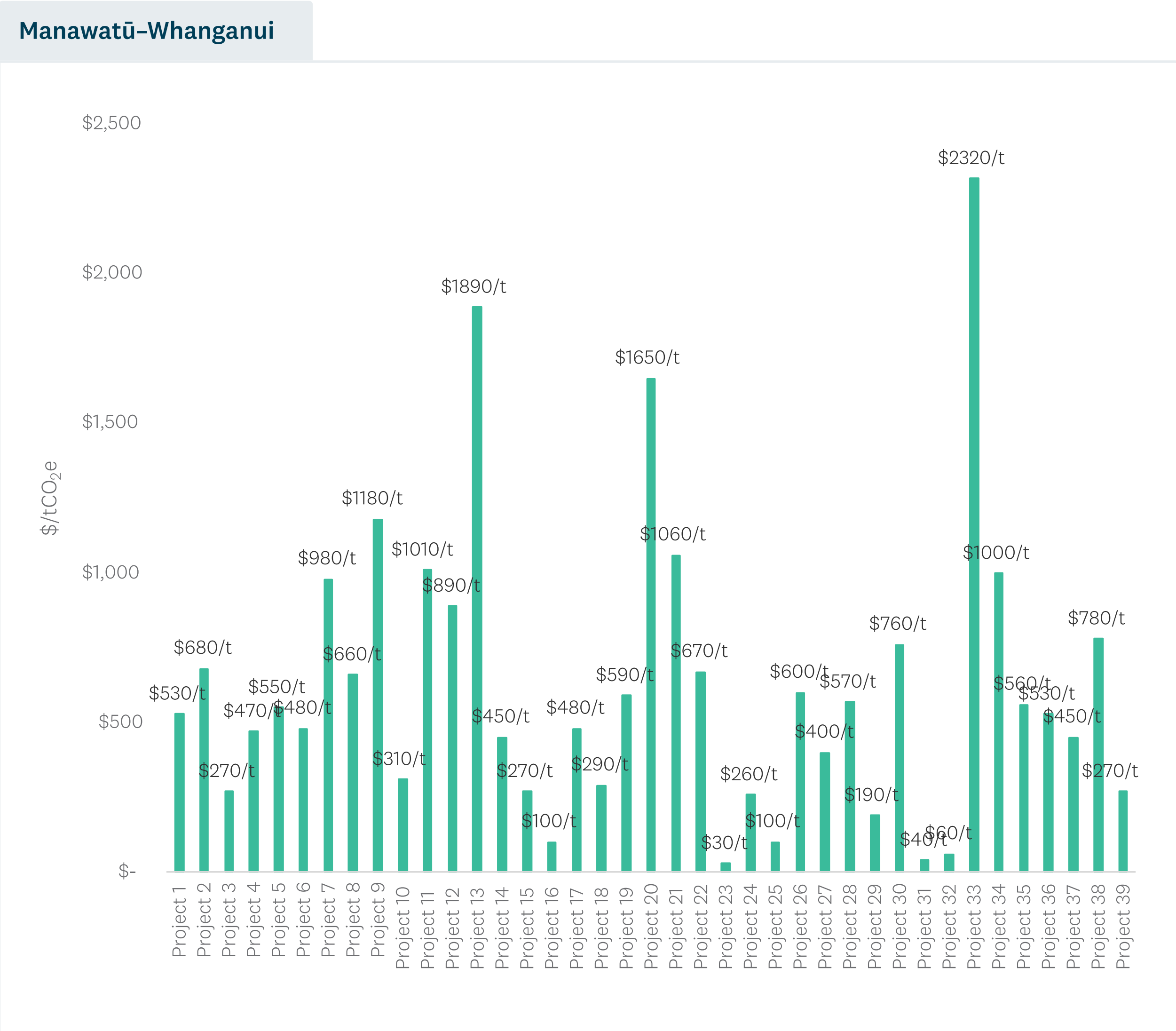
- The uncertainty in the underlying variable fuel costs (fossil gas, electricity and biomass). Electricity has a combination of fixed (per-year use-of-network charges) and variable costs.
- The uncertainty regarding the magnitude of up-front upgrade costs required to connect an individual RETA site to 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 had more than one low-emissions fuel to choose from.

Thirty-nine boiler fuel-switch projects had a choice between biomass and electricity for their fuel-switching decision. Figure 28 shows that for 33 of these projects, the difference in the MAC is typically greater than $200/tCO$_2$e.

Photo credit: Whanganui & Partners

Figure 28 – Difference between electricity and biomass MAC values for sites where both fuel options are feasible.



It would take a considerable change in underlying costs to change the optimal fuel decisions for these projects.

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 a '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).
- We also present an analysis which explores the changes required in fuel costs (electricity, biomass and fossil gas) to significantly accelerate emissions reductions.

The following sections discuss these sensitivity analyses.

7.4.1 Lower and higher electricity prices

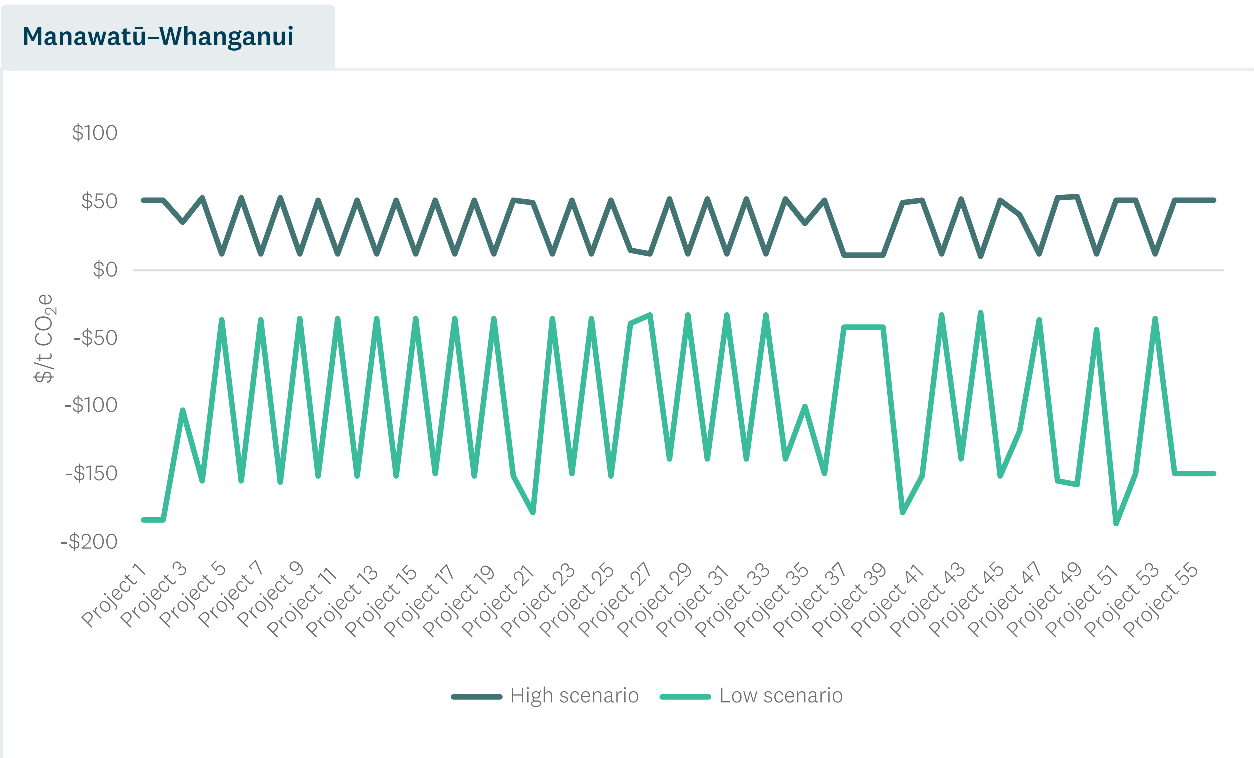
As discussed in Section 13.1.2.1, there are a range of factors that could lead to electricity prices that are materially different to the 'central' scenario used for the analysis in this chapter. We have presented a 'high' and 'low' price scenario. They reflect the following price paths:

- The base (central) scenario assumes 9.9c/kWh in 2026, rising to 13c/kWh by 2048 (a 16% increase compared to the price in 2026).[15]
- The low scenario assumes an average price of 8.9c/kWh in 2026, rising to 12c/kWh by 2048 (a 35% increase compared to the price in 2026).[16]
- The high scenario assumes 10.4c/kWh in 2026, rising to 14.1c/kWh by 2048 (an 19% increase compared to the price in 2026).

Using the 'high' scenario in the MAC calculations led to increases of \$12-41/tCO_2e for half of all projects, and \$50/tCO_2e or more for the remaining 28 projects, as shown in Figure 29.

Using the 'low' scenario in the MAC calculations led to decreases of \$31-43/tCO_2e for 33 projects, and over \$50/tCO_2e for the remaining 23 projects. However, even though the 'low' scenario reduced the MAC values for electricity fuel switch projects (thereby reducing the gap between biomass and electricity) for all unconfirmed projects, it did not cause a change in the fuel choice from biomass to electricity.

Figure 29 – Impact of electricity low and high price scenarios on MAC values for unconfirmed electricity fuel switch projects.



15 For years up to 2026, we smooth prices between today's level and EnergyLink's forecast in 2026.

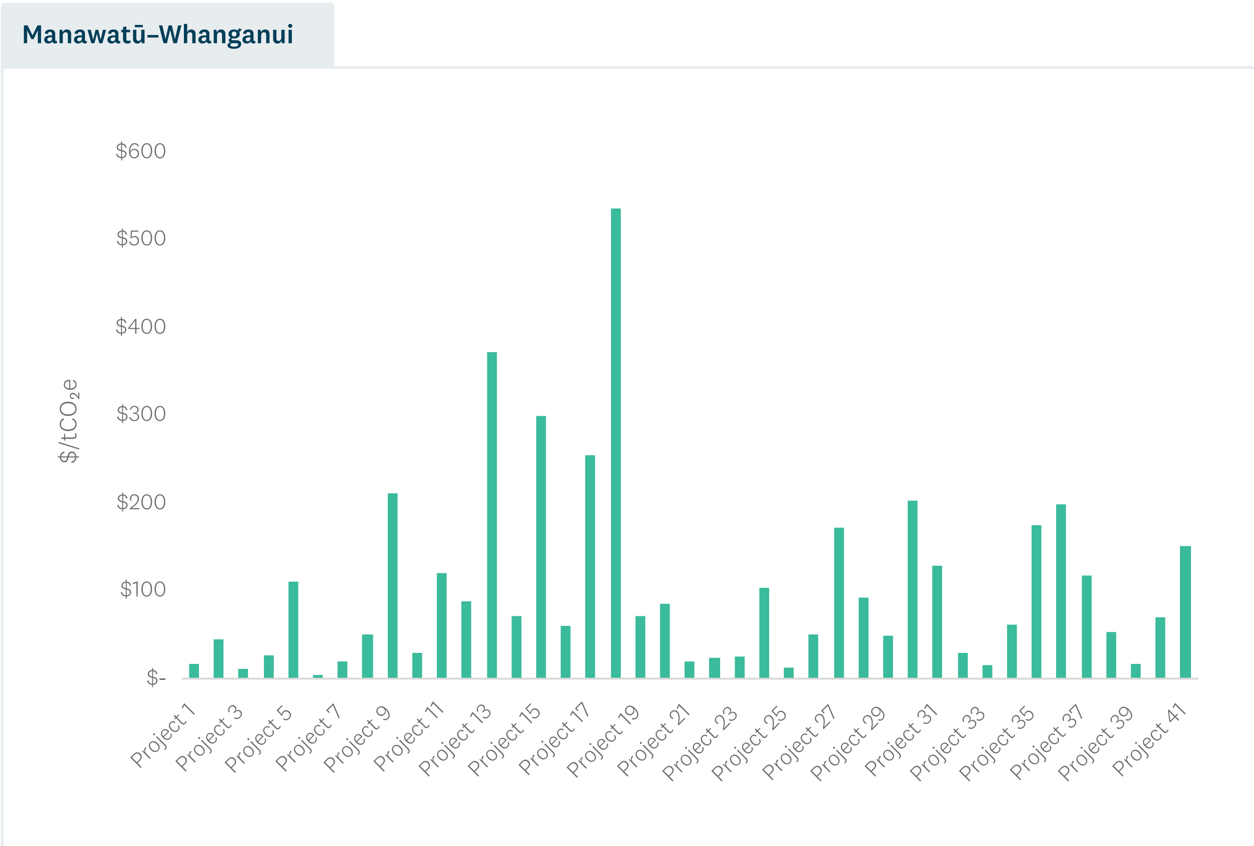
16 These figures are annual averages: typically, commercial and industrial retail prices vary across the year (reflecting the underlying supply and demand for electricity). As a result, some sectors, such as dairy, will effectively pay a lower price than this, as their demand is weighted towards periods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

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

For the projects that require 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 30 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). Although the impact on the electrification MAC can be significant, this is not enough to offset the large difference between electrification and biomass MACs, mainly attributable to significant connection costs for electrification.

Figure 30 – Impact of a 50% increase in network upgrade costs required to accommodate fuel switch to electricity.



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), and a 'very-low' carbon price path based on the second Emissions Reduction Plan.[17]

The different carbon price scenarios don't necessarily need to reflect what carbon prices will be; these scenarios test what process heat investors may believe about future carbon prices when making their investment commitment decisions.

Figure 31 – Comparing effect of carbon prices on MAC-based decision-making criteria.

[17] ENZ results model published at https://consult.environment.govt.nz/climate/second-emissions-reduction-plan/

Figure 31 shows that using a 10Y forward average *central* (the base case) rather than a *current* ETS price accelerates some emissions reductions: on a cumulative basis over the analysis period, the current ETS price scenario delivers 277kt more CO_2e emissions than the base case. Similarly, we find that, compared to the base case of carbon prices, a MAC Optimal pathway using *low* 10Y forward average carbon prices delivers 397kt more emissions by 2050 on a cumulative basis and the ***very low* path delivers 1,211kt more emissions by 2050, on a cumulative basis**. By contrast, a MAC Optimal pathway using *high* 10Y forward average carbon prices delivers 211kt fewer cumulative emissions by 2050.

7.4.4 Changes in fuel prices accelerate emissions reductions

For this sensitivity, we progressively reduced input costs to see at what point that significant acceleration of emissions reductions occurred.[18]

Electricity 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 (Figure 32). Neither a 20% nor a 60% reduction in retail electricity prices causes significant reductions in emissions. Both the 20% and 60% reductions in retail electricity prices accelerated one project, and the 60% reduction caused two projects to switch from biomass to electricity. However, because grid electricity is not zero emissions, the net effect is that emissions increase with the change to electricity: the 60% reduction in electricity prices results in fewer emissions reductions compared to the 20% scenario (2.5kt CO_2e vs 6.3kt CO_2e of emissions reductions on a cumulative basis). This is not distinguishable on Figure 32.

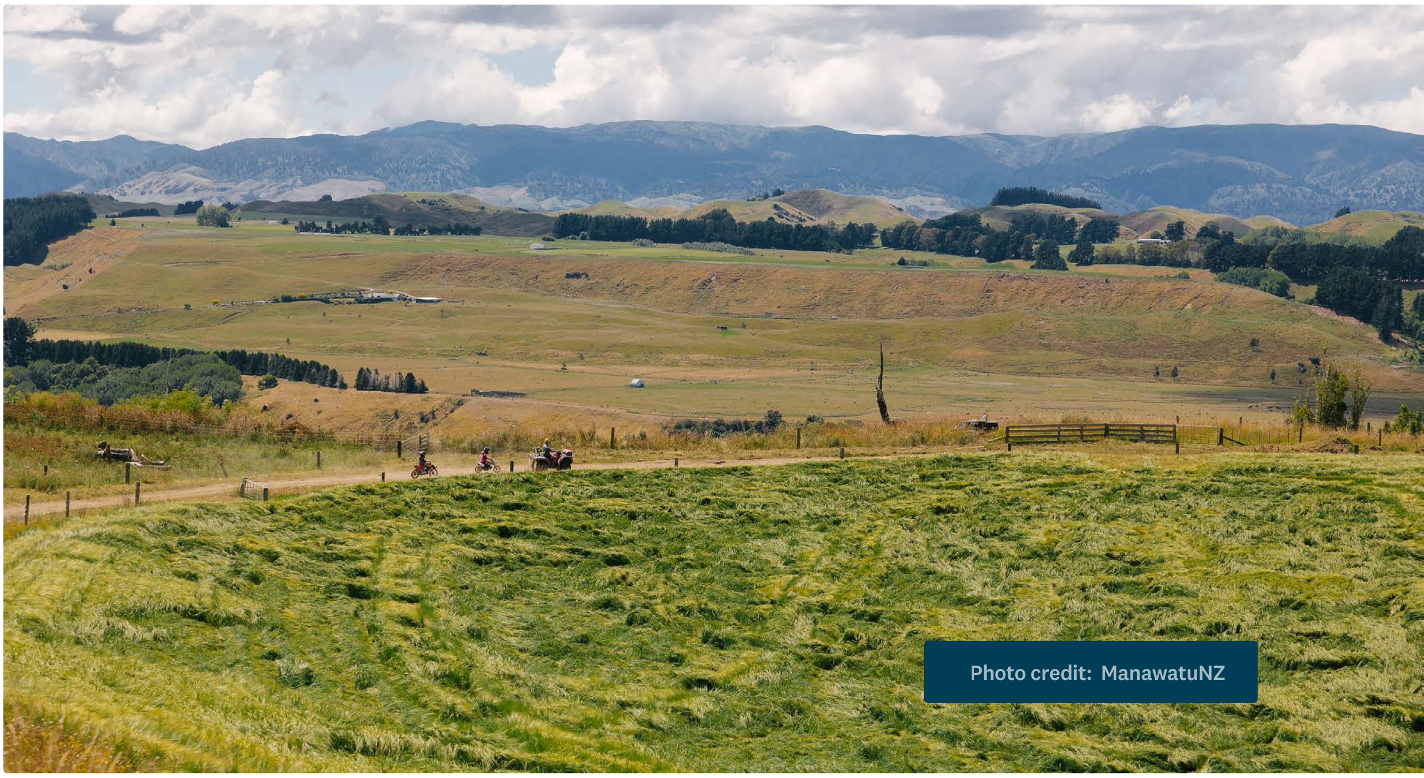
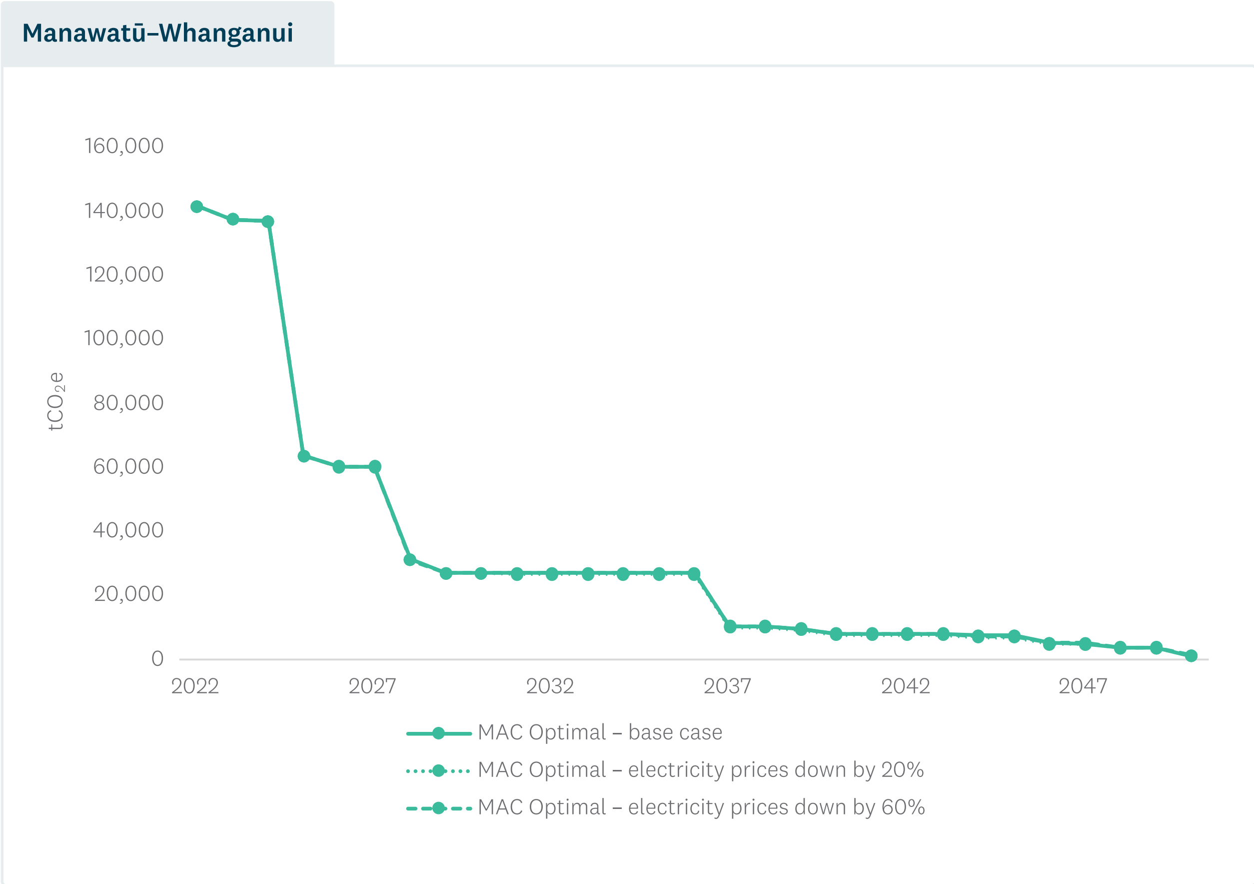


Photo credit: ManawatuNZ

[18] 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.

Figure 32 – Impact on emissions reductions of a 20% and a 60% reduction in retail electricity prices.



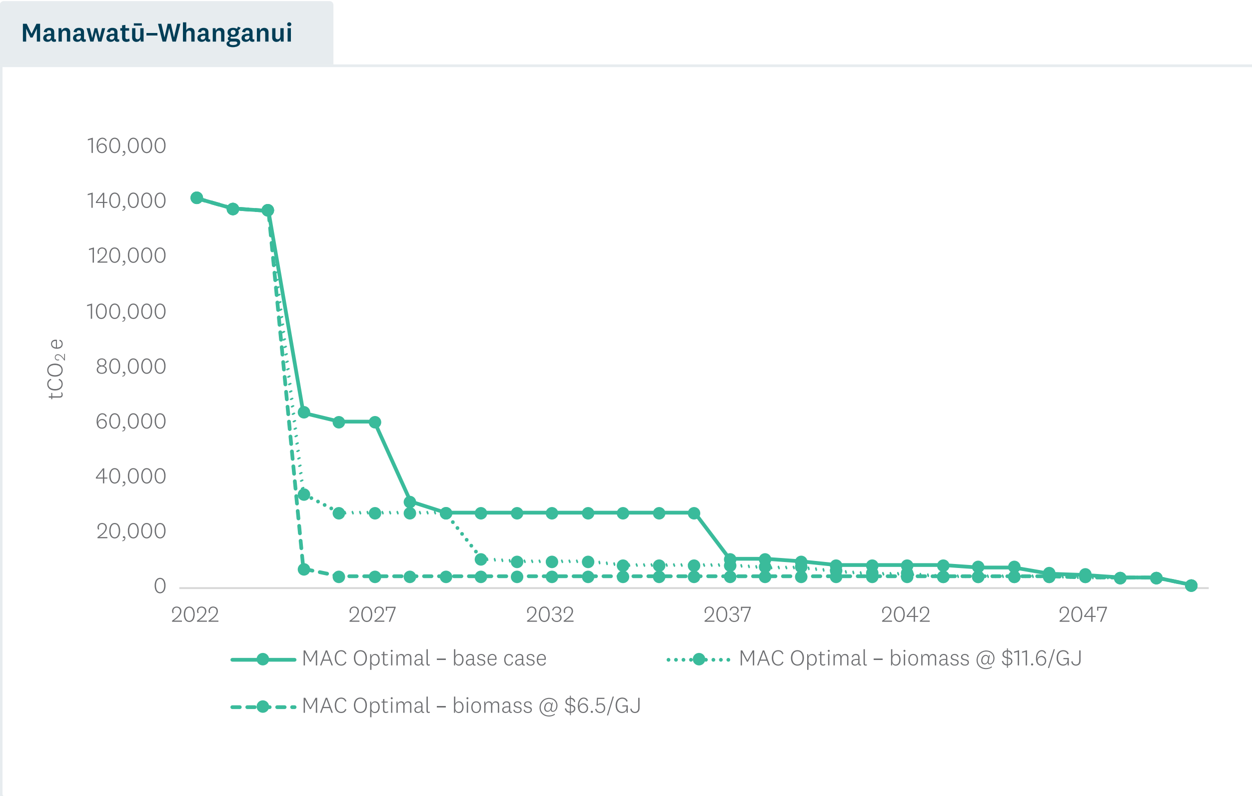
Biomass fibre cost

The base-case assumptions in our modelling assumed that biomass could be supplied to a hub for $12.9/GJ ($92.6/ green tonne). This price is akin to a wholesale price for biomass, as the biomass supplier would then transform this biomass into a final product (dried woodchip, pellets or hog) and apply a margin.[19]

Given the dominance of biomass in the base case MAC Optimal pathway, a lower price is unlikely to change many fuel-switching decisions. A 10% reduction in the wholesale biomass fibre price to $11.6/GJ ($83.3/t) caused one project to switch from electricity to biomass, and accelerated four projects, delivering an additional 254kt of CO_2e emissions reductions by 2050 on a cumulative basis. A significant 50% reduction in the biomass fibre price (to $6.45/GJ or $41.7/t) changed two projects from electricity to biomass and also accelerated four projects, delivering an additional cumulative emissions reduction of 423kt CO_2e by 2050.

[19] Total biomass delivered costs to the end users are assumed to be $19.2/GJ, $20.2/GJ and $22.9/GJ for hog fuel, woodchip and pellet respectively. These costs include biomass processing costs, an assumed $3/GJ margin that would be added at the hub, and secondary transport costs from the hub to the end user.

Figure 33 – Impact on emissions reductions of a 20% and a 50% reduction in biomass fibre price.



For the Manawatū–Whanganui region, this analysis suggests that finding ways to lower the cost of biomass fibre would be a fruitful avenue for accelerating emissions reductions. However, as a consequence, demand for biomass would exceed available residues much earlier than in the base case, thus accelerating the need to find alternative sources — whether export diversion or importing residues from other regions.

Fossil gas prices

In this section we test the sensitivity of emissions reductions to the price of fossil gas. All fossil gas prices are shown in real $2022.

Box 1 – Assumptions on future fossil gas prices.

Gas prices (expressed in $/GJ) belie the reality that 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.[1] 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 explore 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:

- exploration for, and extraction of, new resources (known as '2C' resources)[2]
- development of a domestic biogas supply
- production of hydrogen, and/or
- importing LNG.

Almost any combination of these future supplies would have significant implications for the price of gas (or its substitutes). It is difficult to forecast prices in this context, as any combination of these scenarios could have could have markedly different price impacts. 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 ex carbon) by 2035.[3]

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/dmsdocument/27344-energy-in-new-zealand-2023-pdf

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

For commercial users, the base fossil gas prices assumed in the analysis is the average of the four quarters June 2023 to March 2024 of MBIE's retail prices for commercial users. This is $25.66/GJ or $0.09/kWh.

For industrial users, the MBIE average of retail prices is $10.39/GJ or $0.037/kWh. However, within this industrial category, we expect there are two broad sets of customers around the North Island — those who also use gas as a feedstock, and those who don't. For our analysis, we have assumed that the fossil 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 (**i.e. all industrial users in Manawatū–Whanganui**), 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 prices include an NZ ETS component. Our analysis uses the fossil gas price excluding NZ ETS.

Publicly available scenarios of future gas prices suggest real price escalators (annual growth rate) could be between 1.5%[20] and 6%[21] per year. In our base case, a mid-point of 3% is assumed, with the other values being tested for sensitivity.[22]

We also test for sensitivity the case where the fossil gas price reaches $45/GJ ($0.16/kWh) by 2035, excluding ETS (to test the imported LNG scenario, described in Box 1). This implies the following annual escalators: 6% for commercial users and 10% for RETA industrial users.

Photo credit: ManawatuNZ

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

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

22 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).

Figure 34 – Impact on emissions reductions of different gas prices.

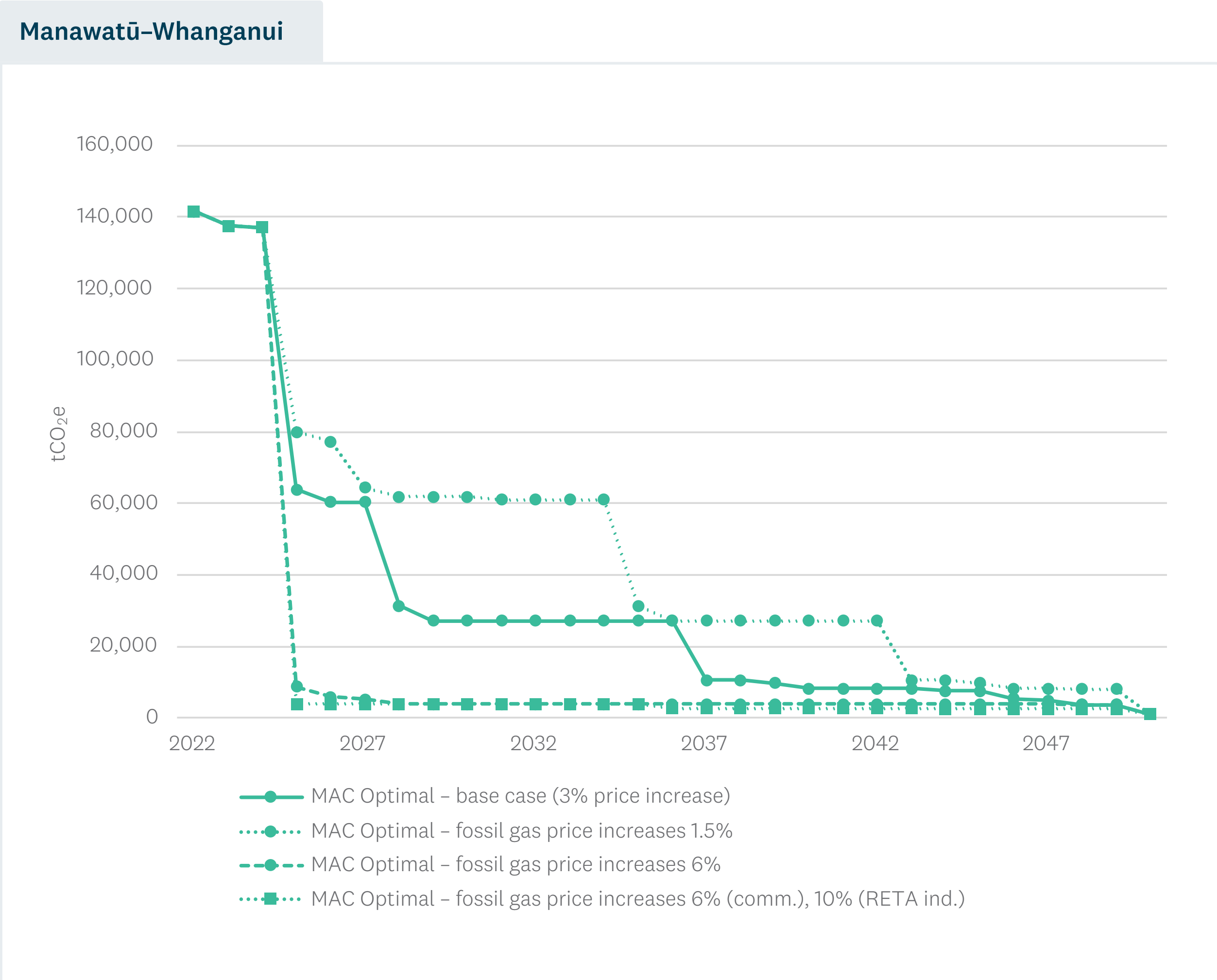


Figure 34 shows that:

- Halving the fossil gas price escalator to 1.5% resulted in 11 fuel-switching decisions being deferred (relative to the base case), resulting in 406kt of additional emissions on a cumulative basis through to 2050.
- By contrast, increasing the escalator to 6% accelerated four projects, reducing CO_2e emissions by 425kt by 2050 on a cumulative basis. As outlined above in the biomass sensitivity, this would also accelerate the need for alternative biomass sources.
- Finally, an increase in the wholesale fossil gas price to $45/GJ by 2035 (excl. NZ ETS) accelerated four projects. Overall, this reduced CO_2e emissions by 451kt by 2050, on a cumulative basis. Higher gas prices can result in a change between the low-emissions fuel options due to the different balances of CAPEX and OPEX for electricity and biomass: higher gas prices result in the OPEX savings from decarbonisation to increase; at some point this may result in the higher efficiency and lower CAPEX nature of electricity outweighing its higher variable cost, compared to biomass.

8 Bioenergy in the Manawatū–Whanganui region

8.1 Approach to bioenergy assessment

This section considers the availability and potential cost of wood resources in the Manawatū–Whanganui region as a potential source of bioenergy for process heat fuel-switching. Although there are other sources of biomass (e.g. landfills), the focus is on major sources that could collectively provide the demand should all sites with unconfirmed fuel switch projects elect to switch to biomass for process heat.

Factors that need to be considered when determining the sustainability of biomass from forestry are outlined. 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.
- Apply expert judgement 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 Manawatū–Whanganui 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 alternatives.

Only biomass sources within the Manawatū–Whanganui region are considered. More generally, neighbouring regions could also use biomass from the forests that are included in the Manawatū–Whanganui regional 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). 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:

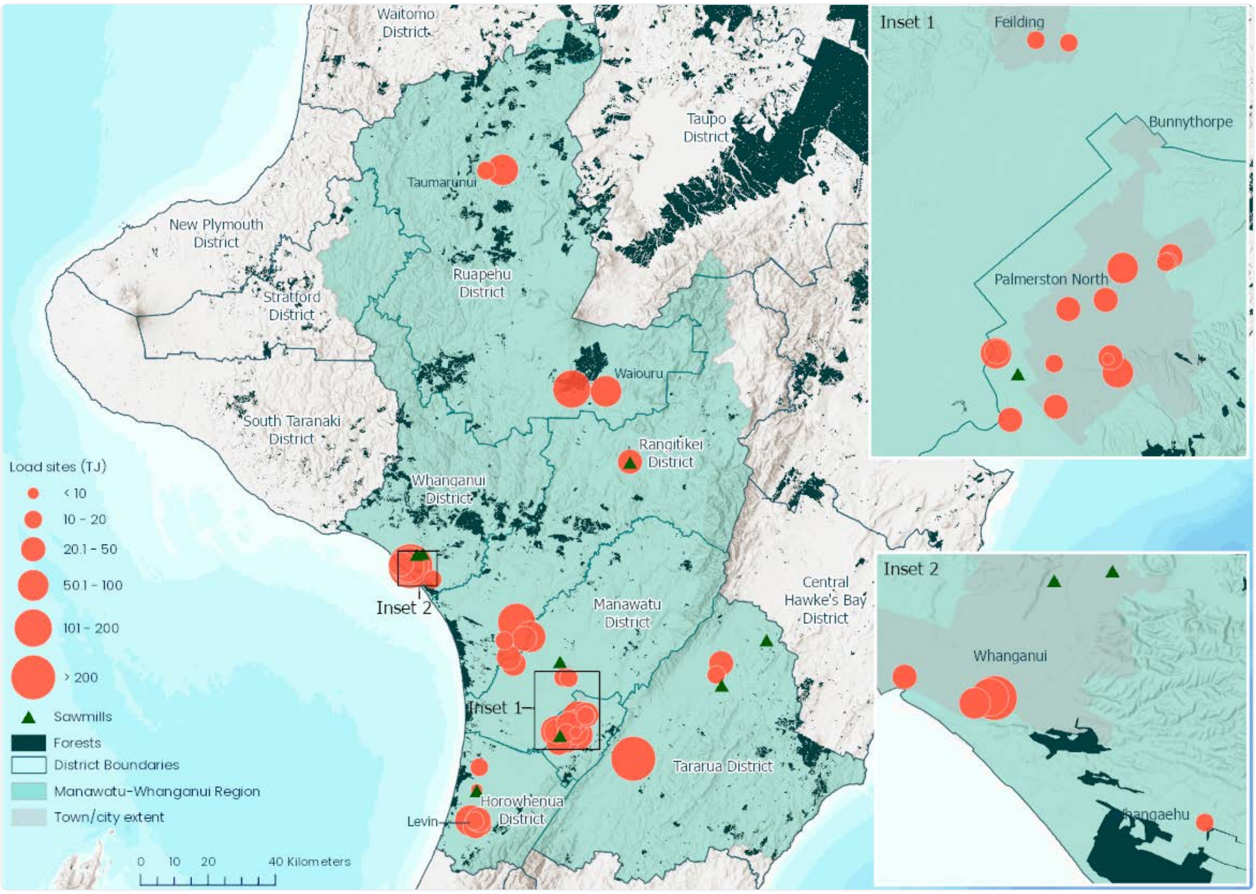
- The Roundtable for Sustainable Biomass, Biofuels, and Biomaterials (RSB), which states that no roundwood should be used for bioenergy.
- The International Sustainability and Carbon Certification scheme (ISCC) discusses deforestation.
- The European Union Renewable Energy Directive II (RED II), which 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 Manawatū–Whanganui regional wood industry overview

Figure 35 – Map of Manawatū–Whanganui forest resources and wood processors.



The Manawatū–Whanganui region has approximately 82,862 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 approximately 55% of the planted forests (45,890ha). These owners tend to have long-term forest management contracts and aim to harvest at sustained levels. Unlike other regions, a large portion of the region's forestry estate is owned by small foresters — approximately 45% (36,972ha), with only a few of them engaged in long-term contracts.

8.3.2 Wood processors

Log and timber processors in Manawatū–Whanganui processed approximately 965kt of logs in mixed grades (pruned, unpruned and pulp logs) in 2024, 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, bark, woodchip, shavings, post peelings and other residues (described in Appendix D).

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, and
- 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.

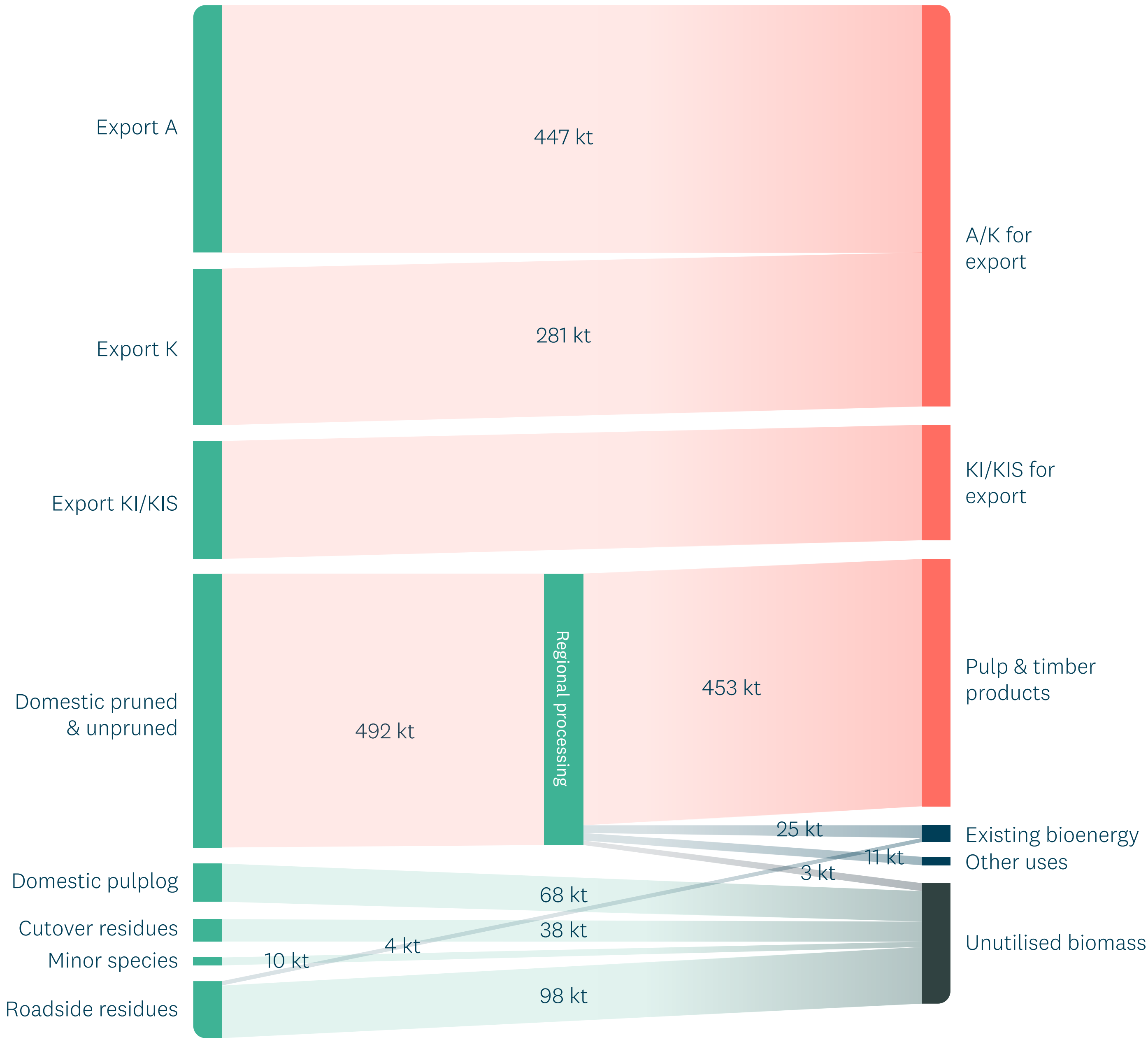
The outcome of this section is summarised in Figure 36. Wood flows that could be utilised for new bioenergy demand from process heat are shown in green.

We 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 and because it is a reasonable period over which process heat users would want to enter into supply contracts, if they were making the decision in the next few years.

Figure 40 illustrates this changing availability in more detail, and over a longer period.

Photo credit: Hautapu Pine

Figure 36 – Wood flows in the Manawatū–Whanganui region, 2024-2038 average. Source: Whirika and Margules Groome.



A top-down analysis suggests that an average of around **1,645kt (11,815 TJ) per year of wood will be harvested in the Manawatū–Whanganui region over the next 15 years**. A more comprehensive view of resource availability, that combines the top-down and bottom-up analyses reveals:

- On average, **140kt of harvest residues can be economically recovered**. Around 4kt (26 TJ) per year of roadside residues is currently being recovered and is used for bioenergy. The remaining available harvest residues (136kt or 978 TJ) are not currently utilised and **could be available for new bioenergy demand**.
- Interviews with sawmills suggested that around **82kt (588 TJ) per year of processing residues** are produced. Out of this, 44kt (319 TJ) per year is woodchip sold to Oji (Kinleith), and 25kt (180 TJ) per year is already used for bioenergy (mainly sawdust and shavings). Around 11kt (80 TJ) per annum are used for animal bedding or landscaping. The remainder 3kt (20 TJ) of processor residues is currently unutilised.
- On average through to 2038, **K log resources are 281kt (2,016 TJ) per year, the KI/KIS log resource is 208kt (1,493 TJ) per year, and the total pulp resource is 68t (488 TJ) per year**.

Overall, EECA estimates that, on average over the next 15 years, approximately 217kt per year (1,557 TJ per year) of woody biomass (forest and processor residues, and pulp) 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 following analysis.

8.4.1 Forecast of wood availability

'Wood Availability Forecasts' (WAFs) are produced on a periodic basis by MPI, with the most recent forecasts shown for the period 2021 to 2055.

In Figure 37 total volumes are broken down into log grades using national exotic forest description (NEFD) data and the log-grade split for forest owners in the region as provided for the WAF. This has been compared with log-grade data provided by forest owners to ensure the two sources are aligned and reflect the region's market.

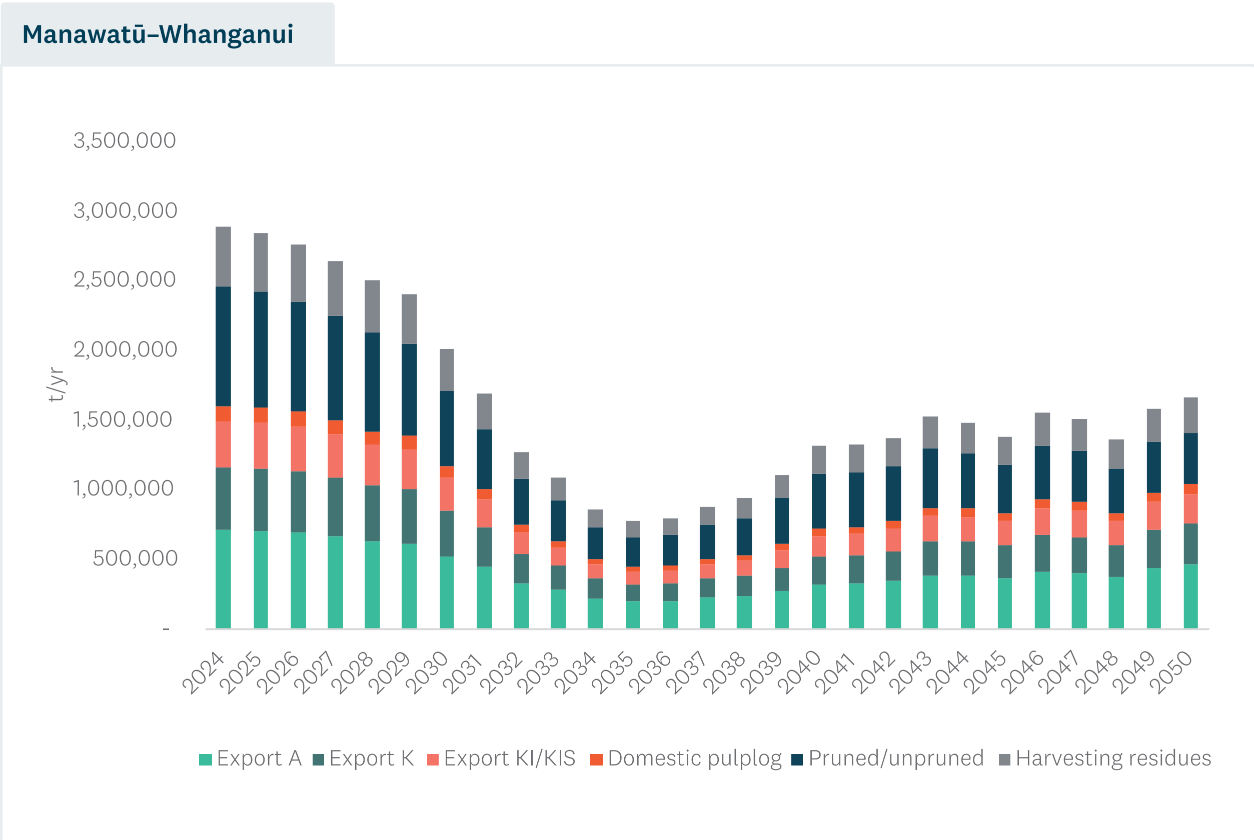
Key log grades are:

- A, K, KI and KIS grades logs — exported primarily to Asia. Export grade volumes are sent to Wellington Port.
- Pruned, Unpruned, and Pulp log grades - go to domestic markets including wood processors and firewood. Domestic grades are utilised in Manawatū–Whanganui by local processors.

For this RETA analysis, we also quantify harvesting residues, a by-product of harvesting and a primary source for bioenergy and firewood. These residues are commonly referred to as 'billet' wood; here it is split into 'roadside' (skid site, roadside and easily accessible residues) and 'cutover' (residues from stems and branches left in the forest and not as easy to access). Residue volumes are determined as a portion of total recoverable volume based on the average of estimates from harvesting studies by Hall (1994), Robertson and Manley (2006) and Visser (2010). The costs of recovering residues are discussed further below.

Note that Figure 37 shows the total volumes, whereas Figure 40 and subsequent analysis will only consider the economically recoverable volumes.

Figure 37 – Forecast of Manawatū–Whanganui Wood Availability, 2024-2050. Source: Margules Groome, Whirika.



As can be seen from Figure 37, there is some annual variation in total available wood resource, with a significant decline through the 2030s. 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. For example, large forest owners are more likely to maintain harvesting at a steady rate to keep harvesting contractors working and fulfil their supply contracts to sawmills. Small forest owners are more likely to accelerate or delay harvesting to maximise revenue when market pricing for different wood grades is favourable but may be restricted by harvesting contractor availability. Such factors are not easily modelled particularly as prevailing market conditions will change in unpredictable ways. 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.

Large-scale owners hold 55% of the modelled resource in Manawatū–Whanganui, and small-scale owners hold the remainder. A key issue 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.

The wood availability forecast is exactly that - a forecast which may differ to what will occur in reality. Discussions with forestry industry stakeholders as part of this RETA programme indicate that the peak volumes of harvesting shown in Figure 37 in the near years (2024 and 2025) are not being realised. Therefore actual harvest volumes are expected to be lower in the near term, allowing for additional volumes being available to fill some of the troughs in the mid-2030s.

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

Ten 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 that have been reported as readily available in Manawatū–Whanganui. Definitions of the different types of residues can be found in Appendix D.

Table 7 – Products readily available for bioenergy from processors in Manawatū–Whanganui.

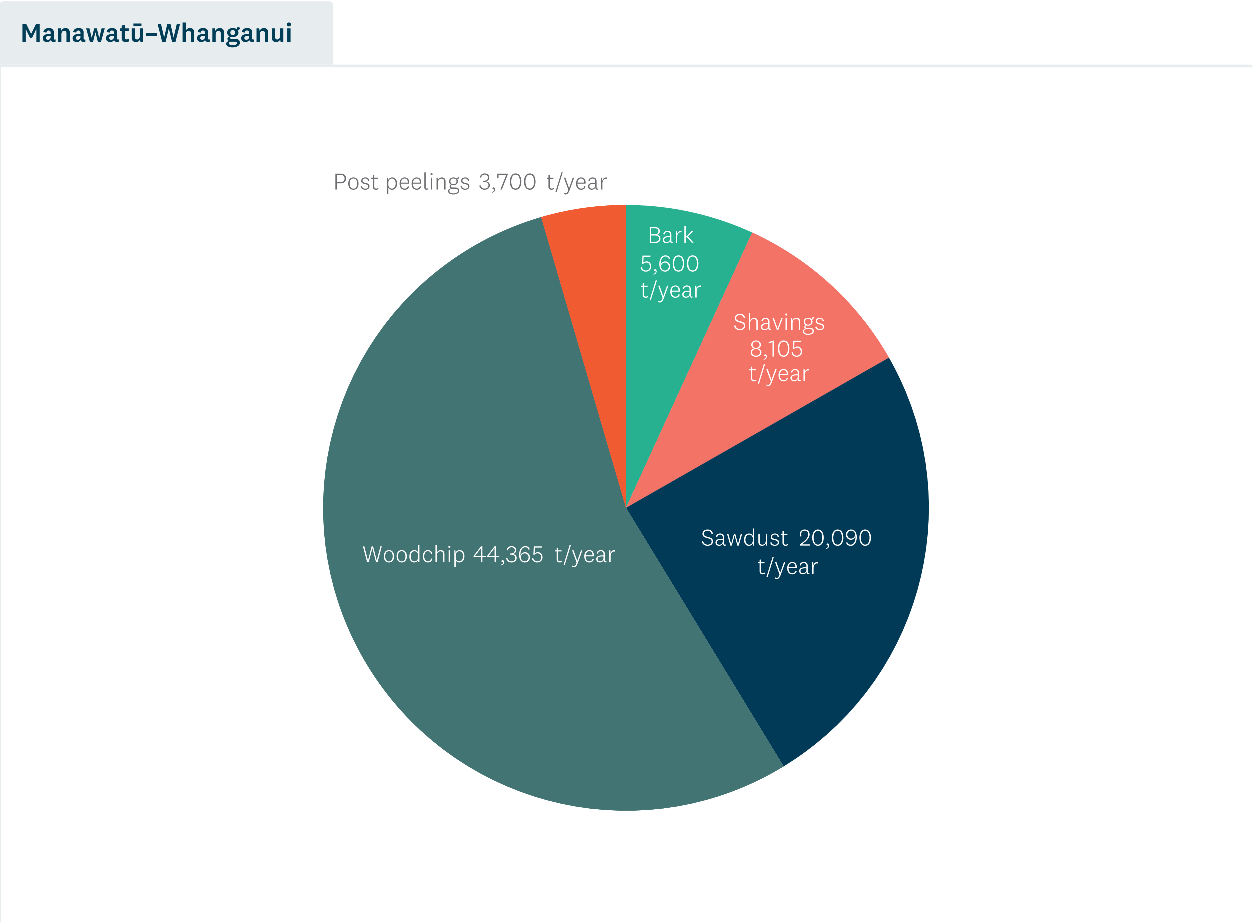
	Sawdust	Woodchip	Shavings	Bark	Post peelings
Creighton ITM					
Crosscut Timbers	x				
Eastown Timber	x		x		
Hautapu Pine					x
Kiwi Lumber	x	x	x	x	
Kiwi Pallets	x				
Lumber Process	x	x			
Mitch Pine	x	x	x		
MacBlack Timber	x				
Ruahine Timber	x		x		x

The interviews conducted suggest that there are, on average, 82kt per year of processing residues created in Manawatū–Whanganui, the majority of which is woodchip (Figure 38). 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.

These processing residues are currently being used as follows:

- Most of Manawatū–Whanganui woodchip is sold to Oji Kinleith plant (43kt pa)
- Overall, each year, 25kt of processor residues are already being utilised by Manawatū–Whanganui processors for their own bioenergy needs.
- Another 11kt of processor residues are utilised for landscaping and animal bedding.

Figure 38 – Manawatū–Whanganui processing residues, green tonnes per year (15-year average). Source: Whirika.



8.5.2 In-forest recovery of biomass

In forest residue volumes were estimated by Margules Groome. Based on forest owner surveys, Manawatū–Whanganui forest residues have been split into two categories:

- **Roadside** is described as a percentage of total recoverable volume based on the average of estimates for ground based and hauler harvesting sites for stem and branch waste from three different studies. Practically, this will include skid site, roadside and easily accessible residues.
- **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.

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. 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.

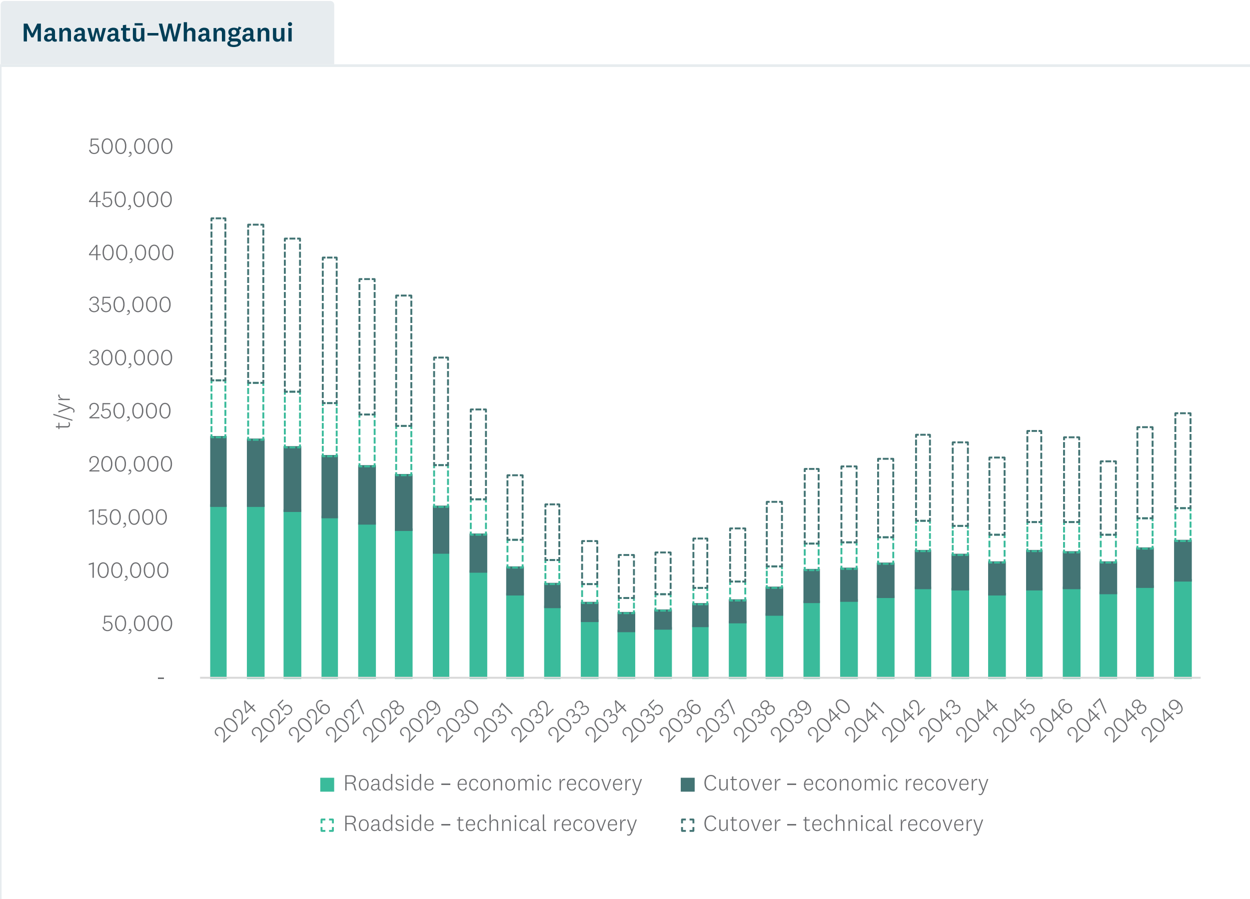
Furthermore, cutover residues provide important nutrient value for plantations, which could become increasingly important if environmental pressures against the use of synthetic fertilisers in forests increase.

For the reasons above, only a proportion of total technically available forest residues are deemed as economically recoverable. On average through to 2050, we have assumed that 75 % of the potential roadside residue, and 30% of the potential cutover residue is economically recoverable.

Figure 39 compares the technical and economic potential of harvest residues. The analysis of available volumes for bioenergy includes economic recovery only.

Photo credit: Hautapu Pine

Figure 39 – Estimated in-forest residues — technical potential vs economic recovery.



On average over the next 15 years, there are 140kt per year of economically recoverable harvesting residues expected to be available.

Based on interviews with forest owners, about 4kt (26 TJ) of roadside harvesting residues are already being recovered for bioenergy. No cutover residues are being recovered currently.

8.5.3 Existing bioenergy demand

The interviews highlighted where some of the sources of potential biomass are already being used for bioenergy.

- About 31% of processing residues are being used internally by wood processors in the region as boiler fuel, totalling 25kt.
- About 4kt of roadside residues are also being used by a process heat user for internal bioenergy needs (4% of economically recoverable roadside residues).

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

Figure 40 shows our overall assessment of the forest (and forestry by-product) resources in Manawatū–Whanganui, overlaid on the existing bioenergy demand.

Figure 40 – Woody biomass availability in the Manawatū–Whanganui region. Source: Whirika and Margules Groome.

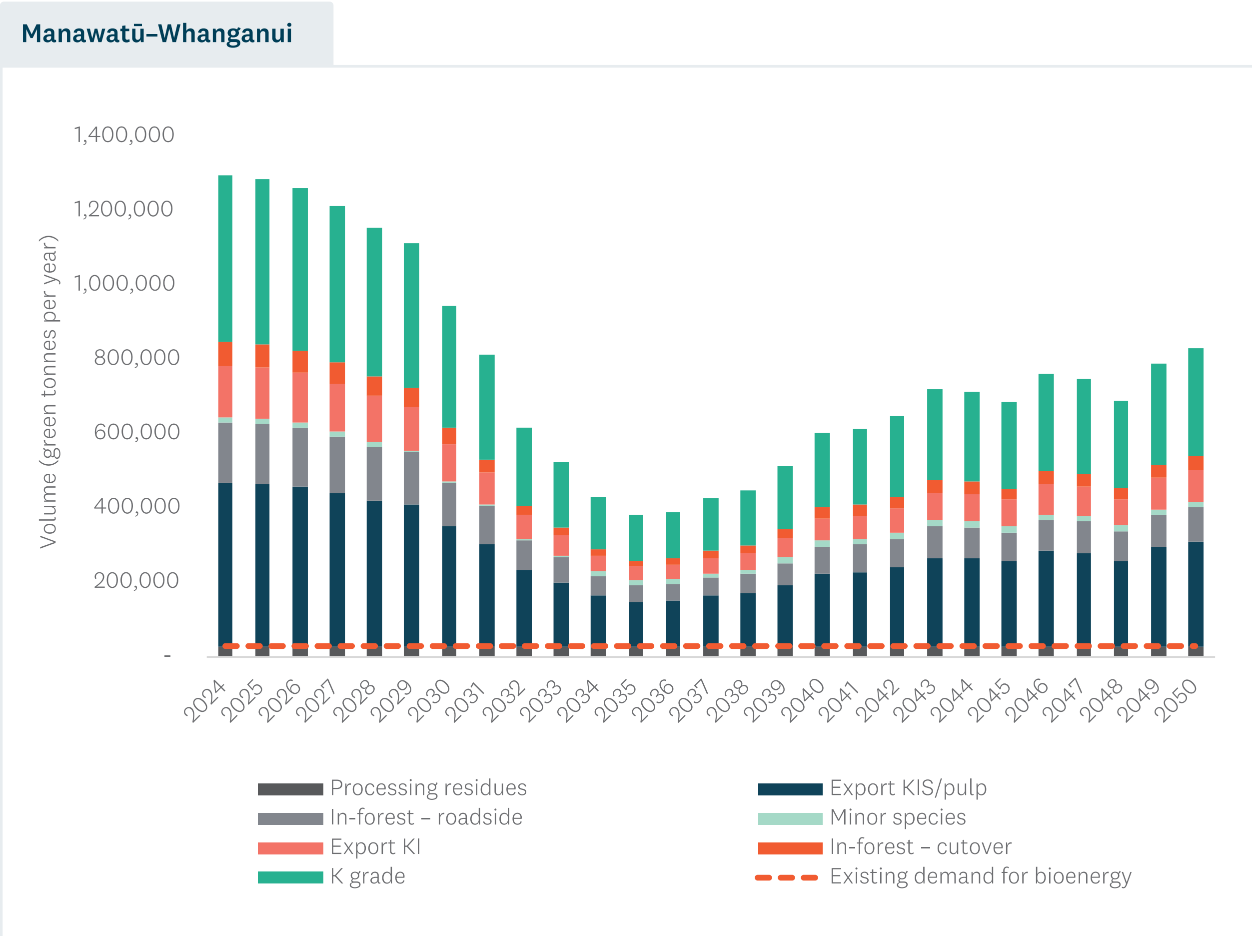


Figure 40 shows there is scope to increase the within-region use of bioenergy from the level today (29kt or 205 TJ), albeit subject to the annual variability of forest harvesting.

We note that export A-grade and K-grade timber have been excluded from the total available for bioenergy due to cost (discussed in the next section).

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

8.6 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.

8.6.1 Cost components

A key cost component is the cost of transporting the material from source to a hypothetical processing location. For the Manawatū–Whanganui Region, we have assumed that two hubs are established, in Whanganui and Palmerston North, at an average distance of 61 km from the nearest forest gate. 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 nearest 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 roadside 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 Manawatū–Whanganui is assumed to be transported to Port of Wellington 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.

8.6.1.1 Estimated costs of bioenergy

Table 8 and Figure 41 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, so this will need more detailed consideration by process heat users contemplating conversion to biomass.

Table 8 – Sources and costs of biomass resources in the Manawatū–Whanganui region (rounded to nearest $). Source: Margules Groome (2024).

Bioenergy source	Cost of biomass source ($/t)	Harvesting and collection ($/t)	Chipping and storage ($/t)	Transport to biomass hub ($/t)[23]	Total cost delivered to hub ($/t)	Total cost delivered to hub ($/GJ)[24]
Processor residues	$39	--	$10	$25	**$74**	**$10**
Harvesting residues – roadside	$10	$26	$25	$32	**$93**	**$13**
Minor species	$10	$31	$25	$28	**$94**	**$13**
Harvesting residues – cutover	$10	$44	$25	$31	**$109**	**$15**
Export KIS/ pulp	$84	--	$25	-$25	**$84**	**$12**
Export KI	$91	--	$25	-$25	**$91**	**$13**
Export grade K logs	$112	--	$25	-$25	**$112**	**$16**
Export grade A logs	$125	--	$25	-$25	**$125**	**$17**

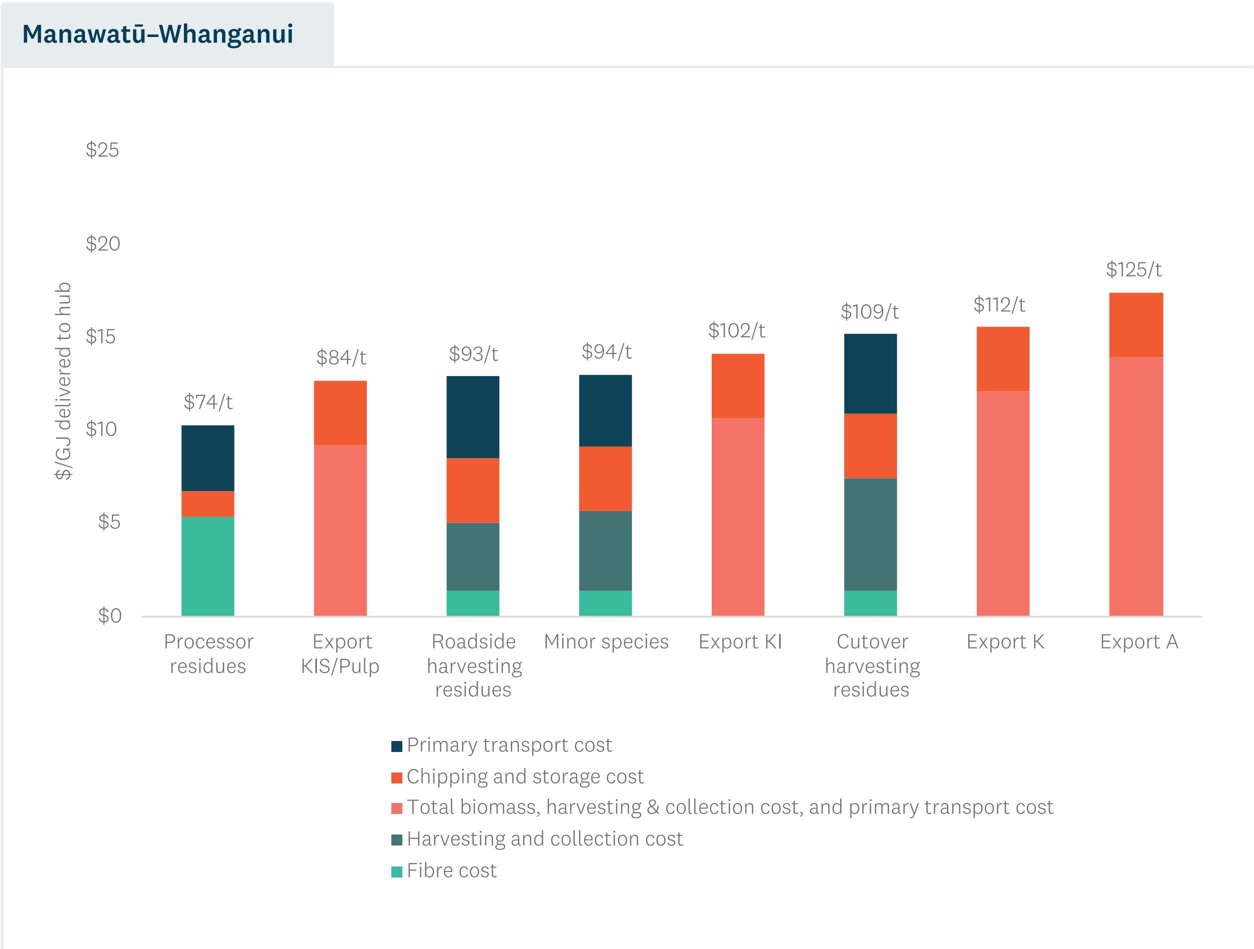
The figures in the far-right column of Table 8 only include the average cost of primary transport from the forests to the closest of the two hubs (Whanganui and Palmerston North) assumed to be 61 km from the forest gate.[25]

23 The negative values reflect cartage adjustments for export grades: the cost of transporting to the biomass hub (primary transport cost) is determined by subtracting from the at-wharf-gate export price the difference in transportation cost for delivery to the closest log export port and to the hypothetical biomass hub location. To determine the primary transport cost for pulp, excess pulp is treated as KIS export pulp logs.

24 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).

25 'Secondary' transport from the hub to the process heat user are used in the MAC calculations, assuming $2.21/GJ over 56km from the hub.

Figure 41 – Estimated delivered cost of potential bioenergy sources ($/GJ and $/green tonne). Source: Margules Groome (2024).



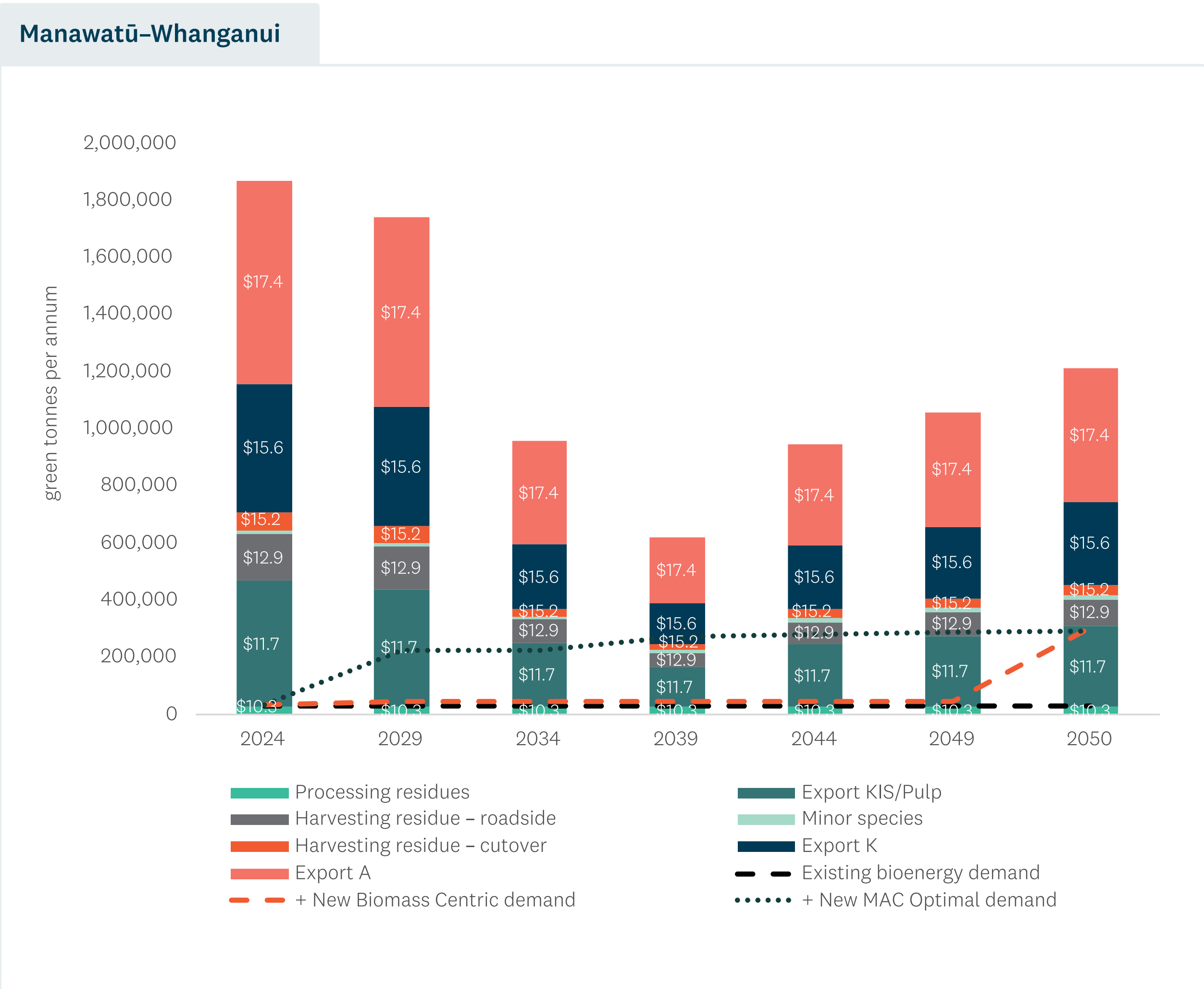
8.6.2 Supply curves

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 8.4.

Figure 42 provides a summary of available biomass volumes and the total delivered cost to the hub 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 demand for biomass would, by 2049 (in the MAC Optimal pathway) or by 2050 (in the Biomass Centric pathway), would exhaust KIS/pulp volumes and would likely require roadside residues. On this basis, we assume that the long-term biomass price (delivered at hub) in the Manawatū-Whanganui region is set by the price of roadside residues, i.e. $12.9/GJ.

Figure 42 – Biomass supply curves through to 2050, five-year average volumes Source: Margules Groome (2024).



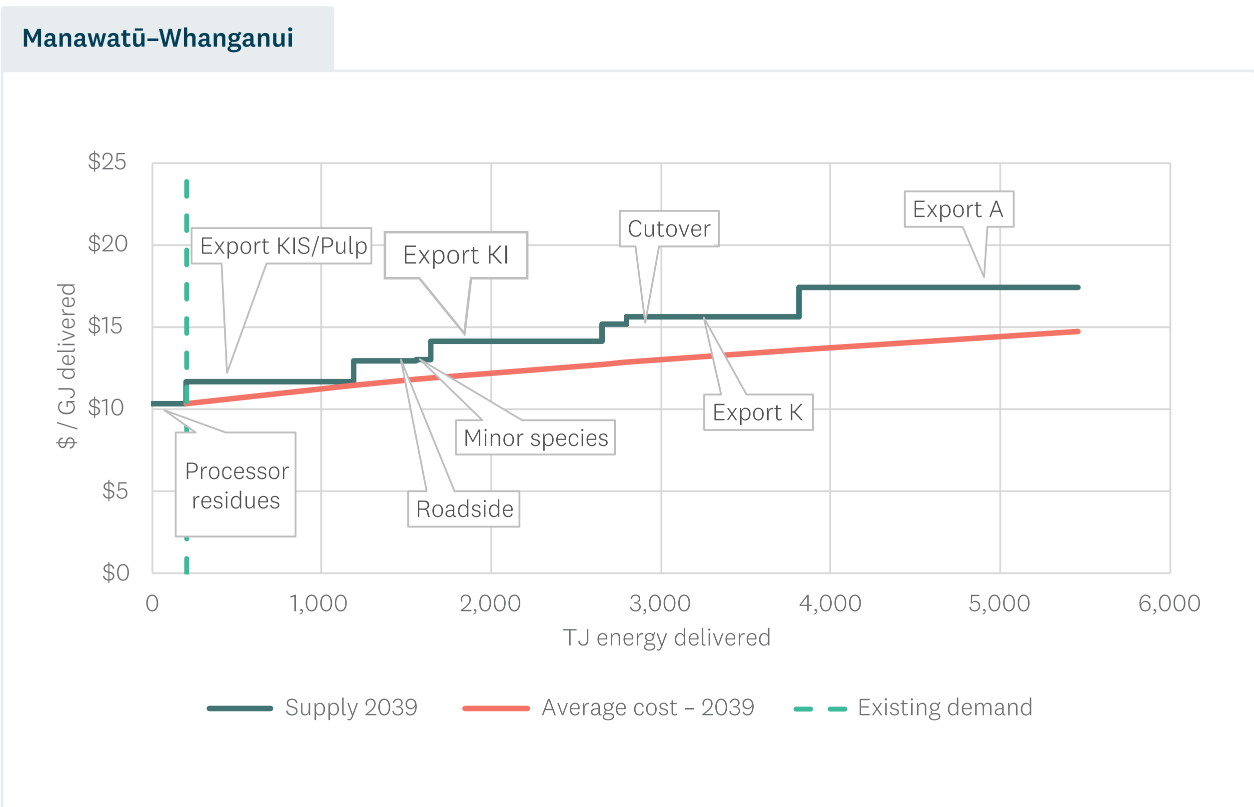
As an example, Figure 43 shows the biomass supply curve and average prices in 2039.

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 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 43 – Biomass supply curve, 2039.



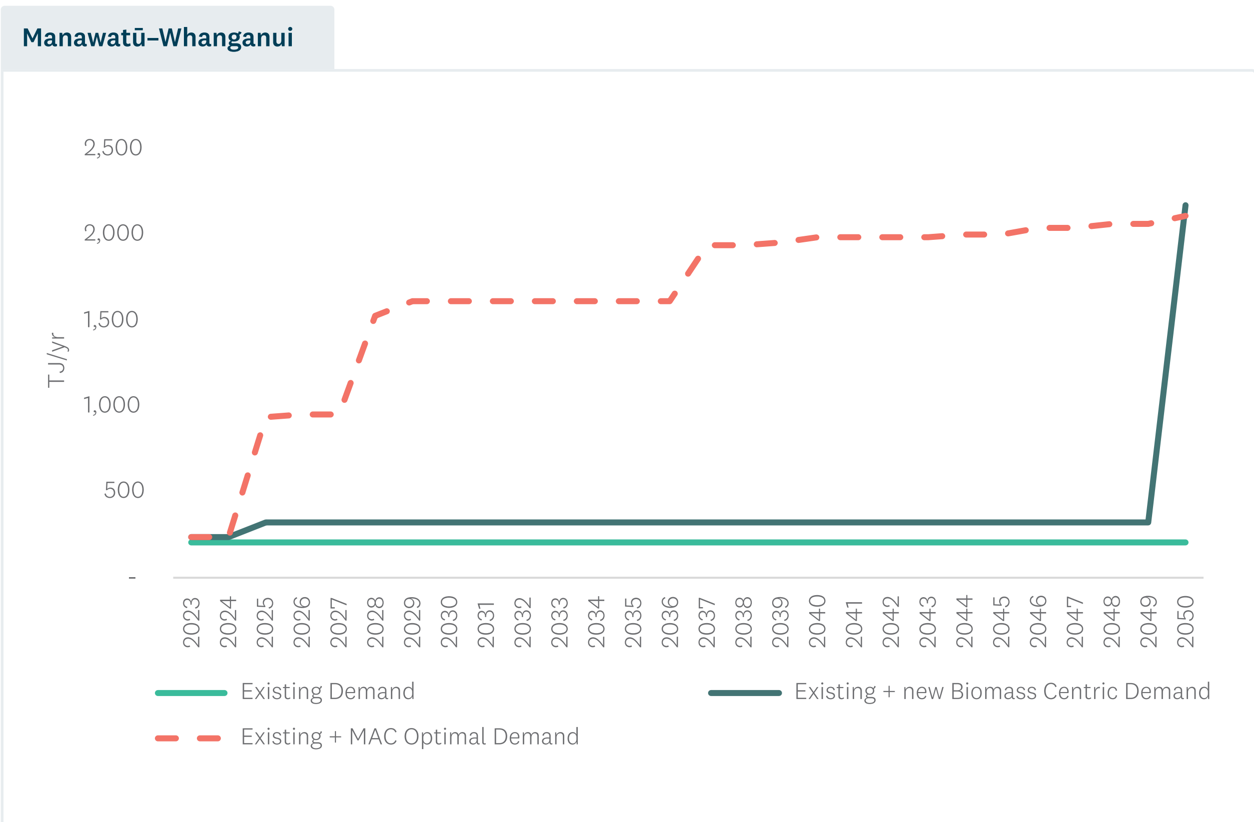
8.6.3 Scenarios of biomass costs to process heat users

With a nascent bioenergy market, there is no price history to draw on 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 (364kt per year) and assumes that 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 analysis (excluding confirmed electricity fuel switches), 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 44 – Existing and potential process heat biomass demand to 2050.



In Figure 45, we overlay the various increments in Manawatū–Whanganui demand on six supply curve periods.

Figure 45 – Biomass supply and demand in 2029, 2034, 2039, 2044, 2047 and 2050 under MAC Optimal Pathway. Source: Margules Groome, EECA.

Manawatū–Whanganui

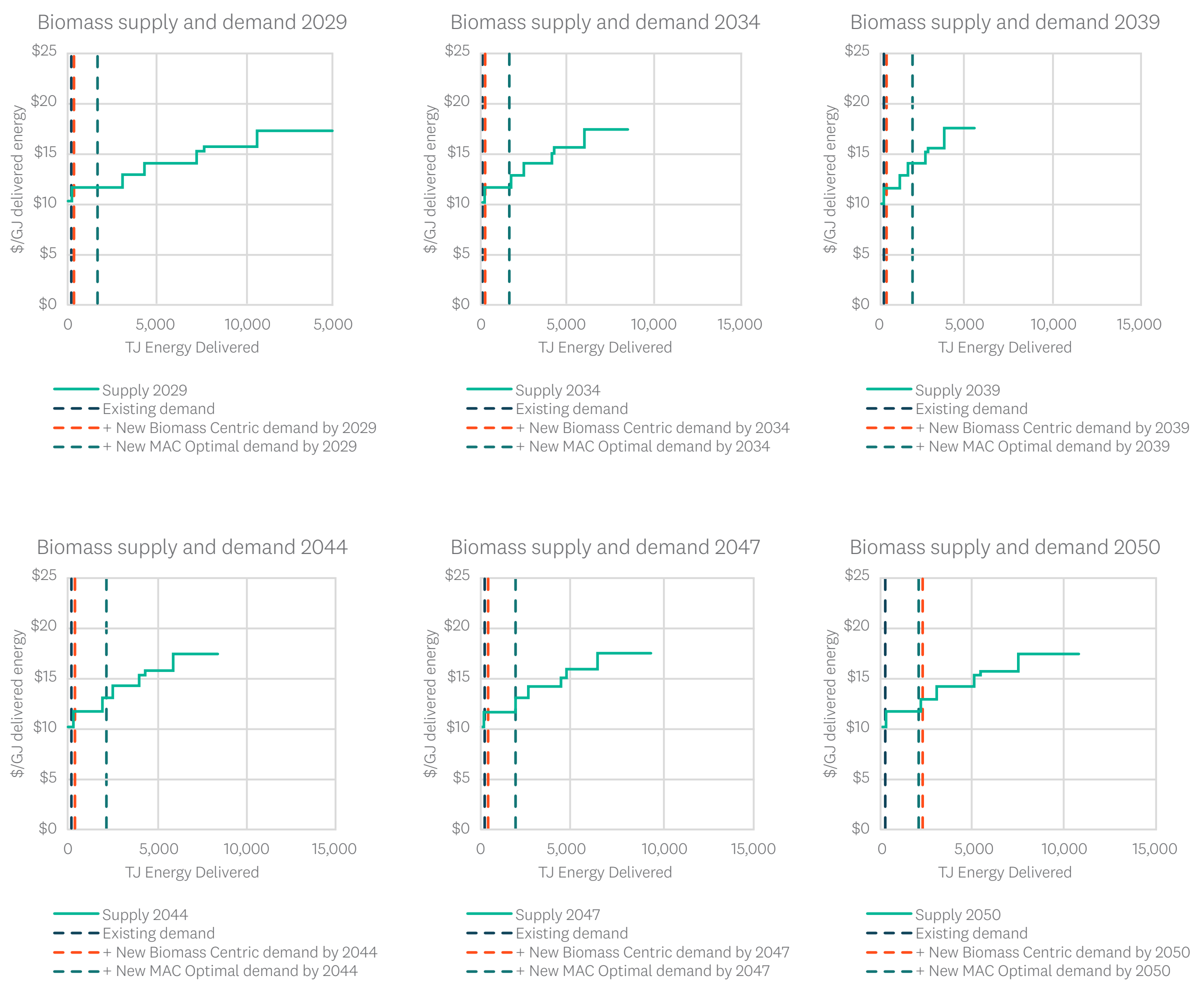


Figure 44 shows that demand for biomass, over and above current use for bioenergy, starts to increase from 2024, when the MAC Optimal pathway (240 TJ pa, including existing demand) is 15% higher than existing demand.

By 2029, the MAC optimal pathway (1,600 TJ pa, including existing demand) is eight times higher than existing demand. This also holds for 2034 (5,000 TJ pa, including existing demand), as illustrated in Figure 45. In 2029, the MAC Optimal pathway uses all processing residues, and 48% of KIS/pulp grades. By 2034, all processing residues are used as well as 88% of KIS/pulp grade logs.

The figure shows that:

- In 2039, demand in the MAC Optimal pathway (1,960 TJ pa, including existing demand) is ten times higher than existing demand, using all processing residues, all KIS/pulp grades, all minor species, all forest residues, and 31% of KI-grade logs.
- In 2044 demand in the MAC Optimal pathway (2,000 TJ pa, including existing demand) is ten times higher than existing demand, using all processing residues, all KIS/pulp grades, and 43% of roadside residues. In 2050, demand in the MAC Optimal pathway (2,100 TJ pa, including existing demand) is ten times higher than existing demand, using all processing residues and 94% of KIS/pulp grades.
- In 2050, demand in the Biomass Centric pathway increases from 330 to 2,200 TJ per year (including existing demand), using all processing residues and 98% of KIS/pulp grades.

Given that 2050 demand will require almost all of the KIS/pulp resource, and therefore potentially tap into roadside residues, and that a significant share of roadside residues will be required in 2044, we assume that the long-term equilibrium biomass price (the base price assumed over the analysis period) is determined by roadside residues, i.e. $12.9/GJ at the biomass hub.


Photo credit: Hautapu Pine

9 Manawatū–Whanganui electricity supply and infrastructure

This section considers the impact of the electrification of process heat on the Manawatū–Whanganui 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 RETA site through electricity networks – a transmission ‘state highway’ grid owned by Transpower, and a distribution ‘local roads’ network, owned by Electricity Distribution Businesses (EDBs). The distribution grid connects individual consumers to the boundary of Transpower's grid. The points on the grid where EDBs networks (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 compete to provide 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).

The well-established national wholesale electricity market is designed to ensure that electricity supply and demand matches at every point in time (at a price). The associated transmission of electricity to achieve this instantaneous matching can be a challenge, especially if increases in electricity demand are beyond the existing capability of the local distribution network, and/or the existing capacity of Transpower’s high-voltage transmission network.

Electrification of process heat will lead to (potentially significant) increases in demand on local electricity networks. As EDBs design their networks to cope with the highest level of instantaneous electricity demand – known as ‘peak demand’, any increase in peak demand will need to be planned for by the EDBs or managed through market mechanisms (e.g. the market is designed to incentivise owners of generation to invest in new power stations when demand increases).

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 charges?
- 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?
- 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.

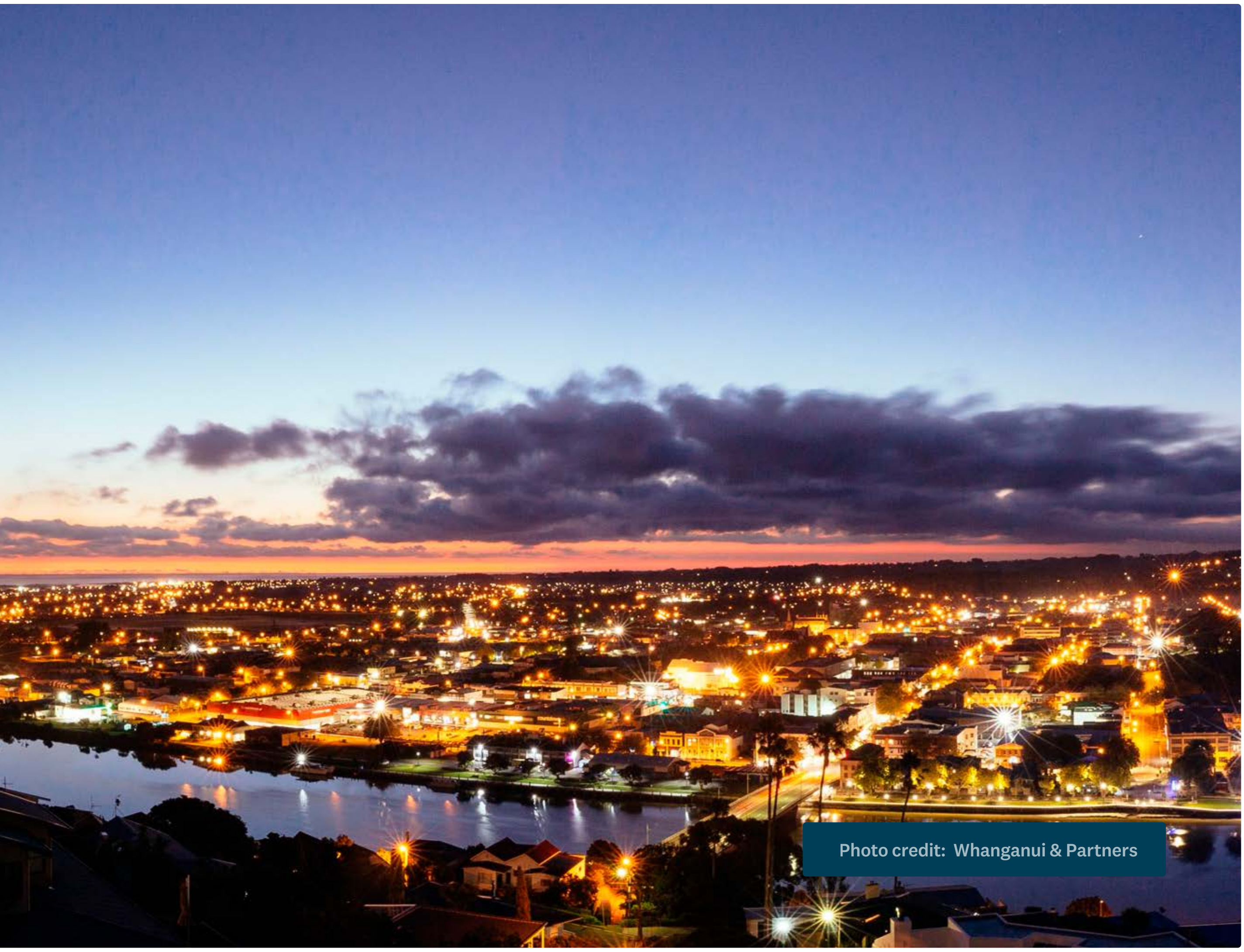


Photo credit: Whanganui & Partners

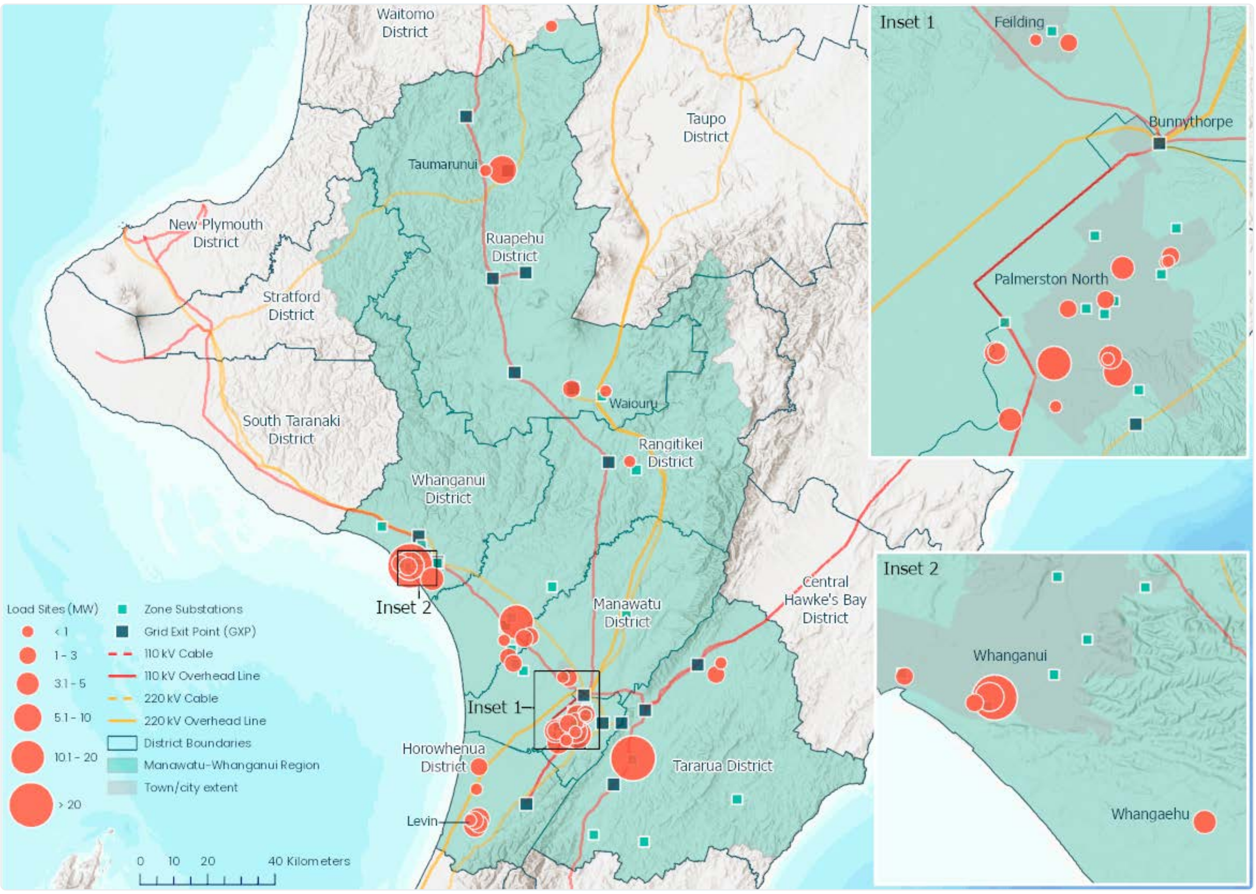
9.1 Overview of the Manawatū–Whanganui electricity network

Figure 46 shows the high-voltage grid (owned by Transpower) that services the Manawatū–Whanganui region. Electricity leaves the national transmission grid via 14 GXPs and supplies the local distribution networks of four EDBs – Electra, The Lines Company, Powerco, and Scanpower. In addition, electricity also leaves the national transmission grid to directly supply industrial loads at Tangiwai GXP.[26]

Of the GXPs that supply local networks, one supplies Electra, three supply The Lines Company, eight supply Powerco, and two supply Scanpower. The Lines Company and Powerco also supply other regions including Manawatū–Whanganui, Bay of Plenty and Taranaki. Reports with analysis for those regions are available on the EECA website.

In addition to GXPs, Figure 46 shows the sub-transmission zone substations that are owned and operated by the four EDBs, alongside the 38 process heat demand sites where electrification of process heat could be considered.

Figure 46 – Map of the Manawatū–Whanganui transmission grid, location, and process heat demand sites.



[26] The industrial user connected to Tangiwai GXP is currently shut down; information on this GXP is included in this report for other parties that may wish to utilise this connection.

The transmission grid in Manawatū–Whanganui region supplies Palmerston North city along with a number of smaller towns (Whanganui, Linton, Dannevirke, Levin, Foxton, Shannon, Pahiatua, Eketāhuna, Alfredtown, Pongaroa, Bulls, Marton, Ohakune, Taihape and Waiouru). It also supports heavy industry and ski field operations and includes a mix of embedded generation across the region.

- Electra is supplied via Mangahao GXP. Electra supplies the towns of Levin, Shannon and Foxton, and provides connection of the embedded Mangahao generation. There are a mixture of agriculture and horticulture loads along with some residential and commercial, with typical morning and evening peaks.
- The Lines Company 'Southern Network' is supplied via Ongarue, National Park and Ohakune GXPs. The Lines Company supplies the towns of Ohakune, Taumarunui and other small towns and villages, as well as the surrounding rural areas. The load is influenced by the winter ski-season tourist peak at both Whakapapa and Tūroa ski fields. There is also a mix of rural agricultural and residential loads, with typical daily morning and even peaks, increasing in the winter months. There is also embedded generation located at Ongarue.
- Powerco's 'Whanganui' network is supplied via Brunswick and Whanganui GXPs, the 'Rangatikei' network is supplied via Ohakune, Mataroa and Marton GXPs, the 'Manawatū' network is supplied via Bunnythorpe and Linton GXPs and the 'Tararua' network is supplied via Mangamaire GXP. Powerco supplies Palmerston North city along with a number of small townships as well as agriculture, forestry, dairy, primary and downstream processing, and fishing. Powerco also supplies a mix of other industrial, commercial and residential loads, which are predominantly winter peaking, with typical morning and evening peaks. Mercury's Tararua wind farm is also connected to Powerco's distribution network at both Bunnythorpe and Linton.
- Scanpower is supplied via Dannevirke and Woodville GXPs and includes the townships of Dannevirke and Woodville and the surrounding rural areas. There is a significant amount of agricultural (beef and sheep farming), along with some industrial, commercial and residential loads which are winter peaking, with typical daily morning and evening peaks
- Tangiwai GXP provides direct connection from the National Grid for two customers via two separate supplies — one at 55 kV, which supplies Kiwirail, and another at 11 kV, which supplies Winstone Pulp International.

The Manawatū–Whanganui region consumed 1,610GWh of electricity in 2023.[27] The maximum instantaneous ('peak') demand for the region was 337MW.[28]

Generation capacity in the region comprises of approximately 934MW including:

- Hydro — Mangahao (30MW), Makauiti (1.6MW), Kuratau (6MW), Wairere Falls (4.6MW), Rangipo (120MW), and Tokaanu (240MW)
- Wind — Tararua North (34MW), Tararua South (34MW), Turitea (221MW), Tararua Stage 3 (93MW), Te Rere Hau (49MW) and Te Apiti (90MW)
- Manawatū–Whanganui also has embedded solar PV generation (~10 MW).[29]

27 See emi.ea.govt.nz and EDB 2024 information disclosure reports.

28 Manawatū–Whanganui taken as the simple summation of individual EDB disclosed peaks.

29 emi.ea.govt.nz installed distributed generation report

Together, the local grid connection generation (wind and hydro) alongside the other local embedded[30] generation (wind, hydro and solar) produce around 1,180 GWh[31] per year, which is close to the region's annual energy consumption.

With the growing shift toward electrification of process heat and transportation, demand for electricity in the region is expected to increase. Transpower's 2023 Transmission Planning Report[32] forecasts Manawatū–Whanganui's regional demand will grow by an average 3% per year for the next 15 years, which is higher than the national average growth rate of 2% per year for the same period.

With the increase in demand, and additional renewable generation being proposed to be connected in the region, Transpower has identified some potential adverse impacts on the transmission system. As such Transpower has several replacement and refurbishment projects planned for the Manawatū–Whanganui region over the next 15 years to enable identified system issues to be resolved, some of which are covered in more detail in Table 11 in Section 9.3.3.

Photo credit: ManawatuNZ

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

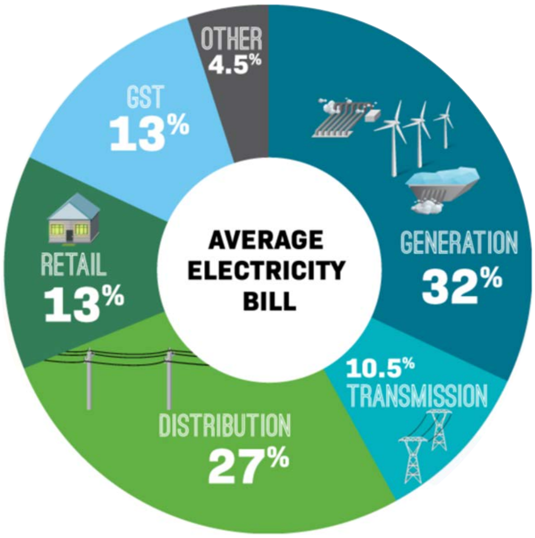
31 emi.ea.govt.nz generation trends and EDB 2024 information disclosure documentation.

32 Table 13-1: Forecast prudent annual peak demand (MW) at Manawatū - Whanganu grid exit points to 2038, 2023 Transmission Planning Report.

9.2 Retail electricity prices in Manawatū–Whanganui

Retail electricity prices, that would be faced by most of the sites, reflect the average wholesale cost of electricity plus the network charges levied by the EDBs 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 47 – Components of the bill for a residential consumer. Source: Electricity Authority.



While all of the components in Figure 47 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 provides an indication of the cost of electricity in the Manawatū–Whanganui region relative to other parts of the country, and the role that the major components in Figure 47 play.

Figure 48 – Quarterly domestic electricity prices in NZ, including GST, August 2024. Source: MBIE.

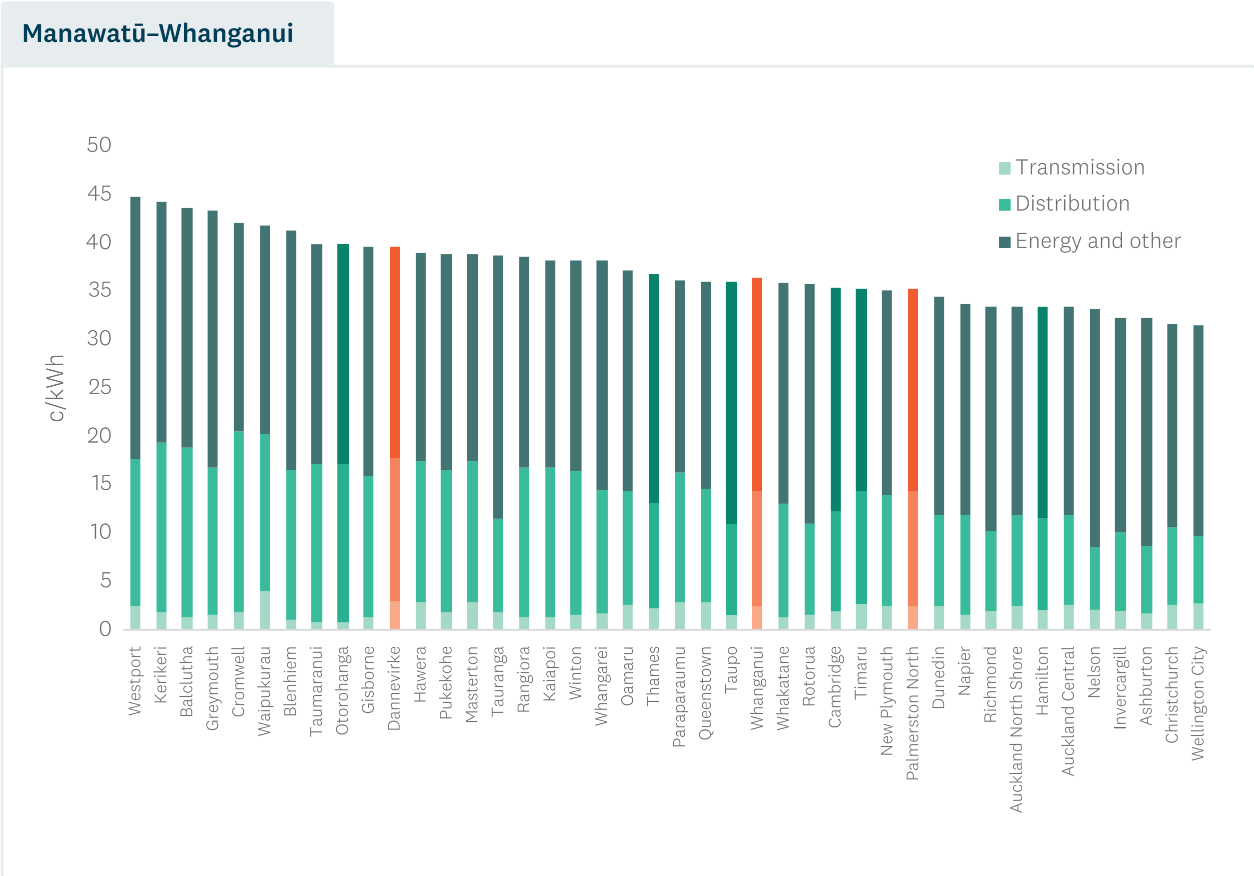


Figure 48 shows that the Manawatū–Whanganui region has a spectrum of residential prices, ranging from lower-range costs (Palmerston North) to median costs (Whanganui) and higher costs (Dannevirke).[33] These differences are likely driven by the different population densities across the three centres illustrated, electricity loss factors, 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 EDBs to obtain tailored estimates relevant to their project.

[33] Note that 'energy and other' in the chart relates to the generation, retail, and other components of Figure 47. 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.

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 for the period 2026-2050. 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, EnergyLink's low-price scenario is no longer considered representative 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).[34]

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 Manawatū–Whanganui region, but do not include distribution network losses to the customer's premises.

As part of their pricing methodology, EDBs 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 Manawatū–Whanganui, the distribution losses for sites connecting at or below 11kV are around 1.07 for Electra, 1.04 for Powerco, 1.08 for The Lines Company, and 1.07 for Scanpower.[35]

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

34 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.

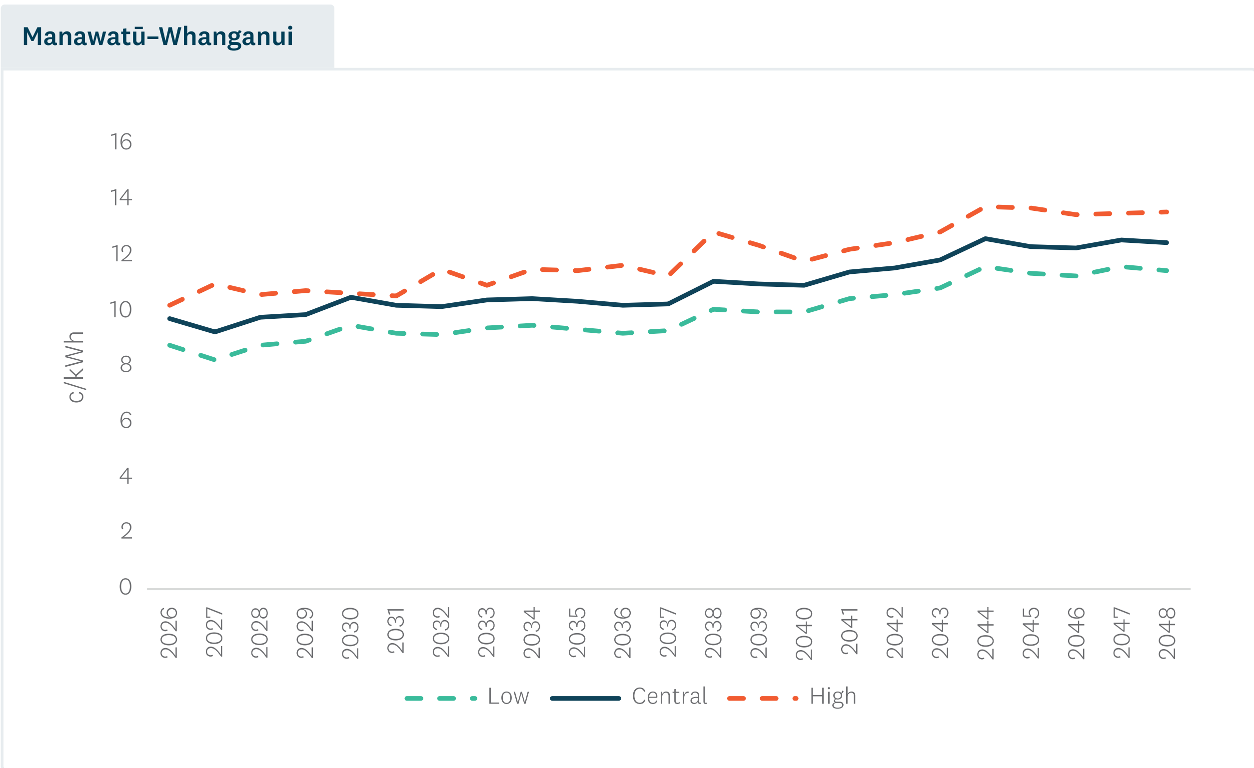
35 EDBs publish network loss factors for different parts of the network, usually as part of their pricing schedule. An individual customer can find their loss factor by entering their ICP number (found on a recent power bill) in https://www.ea.govt.nz/consumers/your-power-data-in-your-hands/my-meter/. 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 to2048. Three retail price scenarios have been developed, 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.

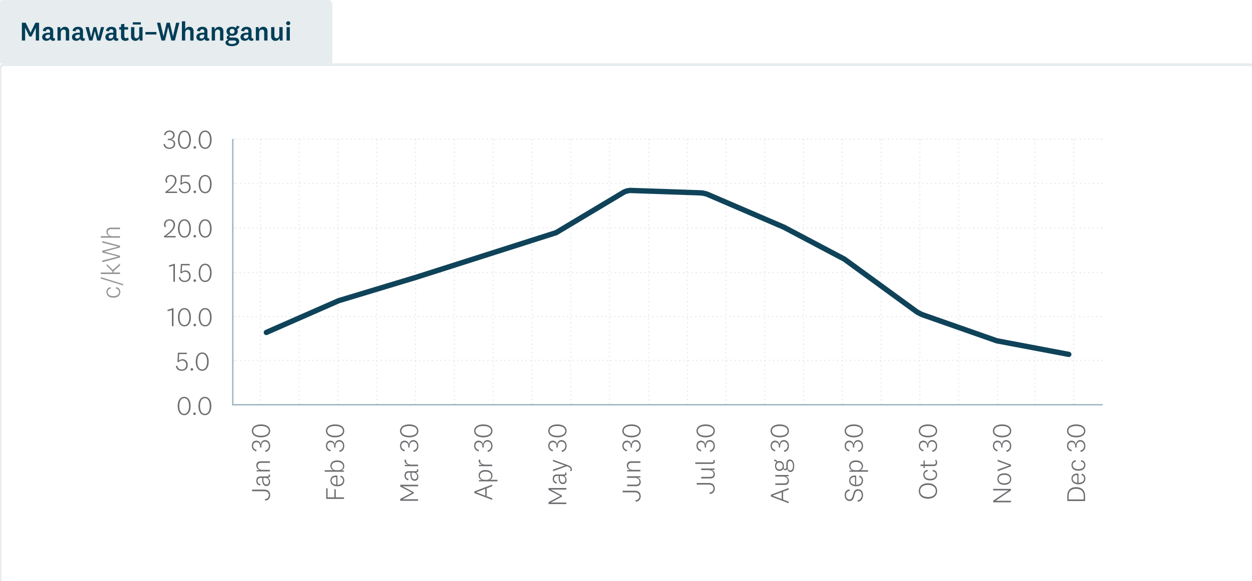
For the central scenario, real electricity prices for the Manawatū–Whanganui region increase by 16% between 2026 and 2040. Beyond 2040, the forecast sees more significant increases in electricity prices. However, it is difficult to predict pricing beyond this period. Some New Zealand market analyses 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.

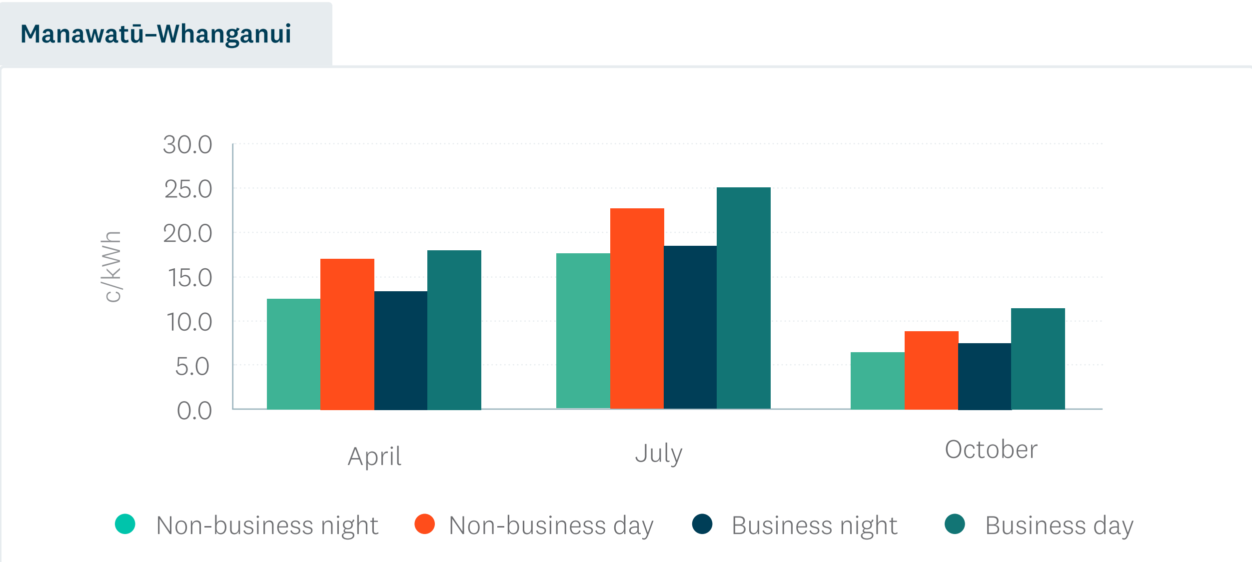
Figure 49 – Forecast of real annual average electricity prices ($2022) for large commercial and industrial demand in the Manawatū–Whanganui region Source: EnergyLink.



As outlined earlier, the price forecasts are provided at a finer resolution than the annual average series in Figure 49. Figure 50 zooms in on 2030, showing (a) the variation over the year in the two scenarios, and (b) the variation between day type, and time of day.

Figure 50 – 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 agriculture, 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 above. 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 the EDB the customer is located in. 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 a Transpower GXPs. These charges are in addition to the generation and retail ('energy') component[36] of a customer's tariff. 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,[37] while the way they charge customers (generally referred to as 'distribution pricing')[38] 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'.[39]

Most businesses considering electrification of process heat would likely fall into a 'large commercial and industrial' or medium voltage (11kV) category of charging. The five main factors used by these EDBs for pricing in these categories are:

i. Fixed daily charges
ii. Demand charges (related to either the 'anytime maximum demand' reached by the site over a year, or the 'coincident peak demand' occurring during times when the whole network experiences its highest demand, usually measured in kW or MW)
iii. Capacity charges (related to the full capacity of the connection provided by the EDB, measured in kVA or MVA)
iv. Time of use charges, based on kWh consumption during certain, pre-determined times of the day
v. Power factor charges (based on the power factor of the site measured in kVAr), reflecting the need for the network to provide voltage support.[40]

These network charges — for both distribution and transmission (refer to Section 9.2.5) — are summarised in Table 9 below. The charges in the table do not reflect the exact pricing structures each EDB uses — we have approximated the effect of different variables to simplify the charges for the purposes of summarising into a single price ($/MVA per year).[41]

36 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.

37 This excludes consumer-owned EDBs whose revenue is not regulated by the Commerce Commission.

38 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/

39 The 2024-25 pricing schedules and methodologies for the four EDBs can be found on the websites of Electra, Powerco, The Lines Company, and Scanpower.

40 In Table 10, we did not include power factor charges, on the assumption that most of the electrical loads considered in this report would relate to electrode boilers which are understood to be close to unity power factor.

41 Based on the EDBs' disclosure prices published April 2024 pricing year.

Table 9 – Estimated and normalised network charges for large industrial process heat consumers by EDB for April 2024-March 2025 pricing year; $/MVA per year.

EDB	Distribution charge	Transmission charge	Total charge
Powerco	$72,000	$48,000	$120,000
Electra	$121,000	$1,000	$122,000
The Lines Company	$146,000	$62,000	$208,000
Scanpower	$180,000	$38,000	$218,000

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.

The estimated network charges in Table 9 are for the April 2024 to March 2025 pricing year. On 20th November 2024, the Commerce Commission announced its final revenue limits and quality standards for Transpower and revenue and quality regulated EDBs for 2025 to 2030.[42] As a result, the Commerce Commission decision have estimated a transmission charge increase of 16% in years one and two, and 5% for years three to five, and a distribution charge increase of 24% for year one (on average) with lower business specific increases for years two to five. When calculating MAC values, we have included these increases in the modelling of future EDB charges.

While we provide these indicative levels of charges for process heat users, it is important that each business considering electrification of process heat engages with their EDB to discuss the exact pricing that would apply to them.

42 In the electricity industry, this period is often referred to as the Default Price Path 4 ('DPP4'), for EDBs, and Regulatory Control Period 4 ('RCP4') for Transpower.

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 EDBs (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[43] (assuming that it is EDBs that constructs the new assets rather than a third party). EDBs may elect to calculate an up-front capital contribution that is only a portion of the total cost of the required upgrades. In some situations, EDBs 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 varies between EDBs and is outlined in their 'capital contribution' policies. It is important that process heat users contemplating electrification meet with EDBs to discuss how this will work in their situation. For the pathway modelling outlined in Section 7.2, we assume that EDBs contributes 50% of the capital costs associated with distribution network upgrades required to connect process heat users, while we also test sensitivities where end users pay 50% more or less than this amount (i.e. equivalent to a 25% or 75% capital contribution, or a 50% capital contribution with an overall 50% increase or decrease in the cost of connection).

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 EDBs. As noted previously approximate transmission charges for each of the Manawatū–Whanganui EDBs are included in Table 9.

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).

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.

[43] Electricity Network Association information on EDB connection pricing. Also note that the Electricity Authority is considering new requirements on the way that EDBs calculate capital contributions.

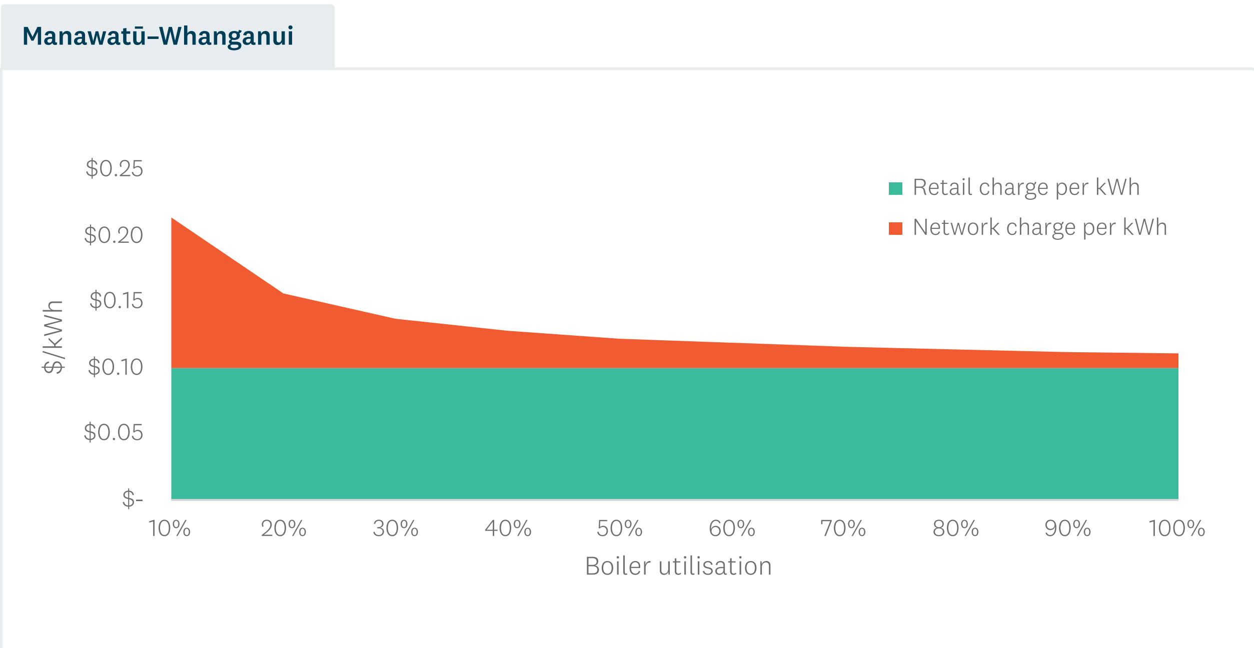
9.2.6 Pricing summary

In summary, process heat users considering electrification in the Manawatū–Whanganui region would face two charges for electricity consumption:

- A retail tariff (including wholesale market and retail costs) which would **average around 10.7c/kWh over the 20-year project life**, including losses of between 4-8% across 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, and are specific to the part of the network the process heat user is in. We have approximated the published charges of the region's EDBs on a common per-MW (installed capacity) basis, suggesting the combined distribution and transmission charge **could (on average) be between $120,000/MW and $218,000/MW per year** (based on the prices published in the April 2024 pricing year), depending on the EDB. However, we strongly recommend process heat users engage with the relevant EDB 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 electrification project is installed) – e.g. anytime peak demand (kW). 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).

Figure 51 – Illustrative example of how overall cost of electricity varies with heat plant utilisation. (Assumes retail charge $0.10/kWh fixed over a year and network charge of $100,000/MW).



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 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.

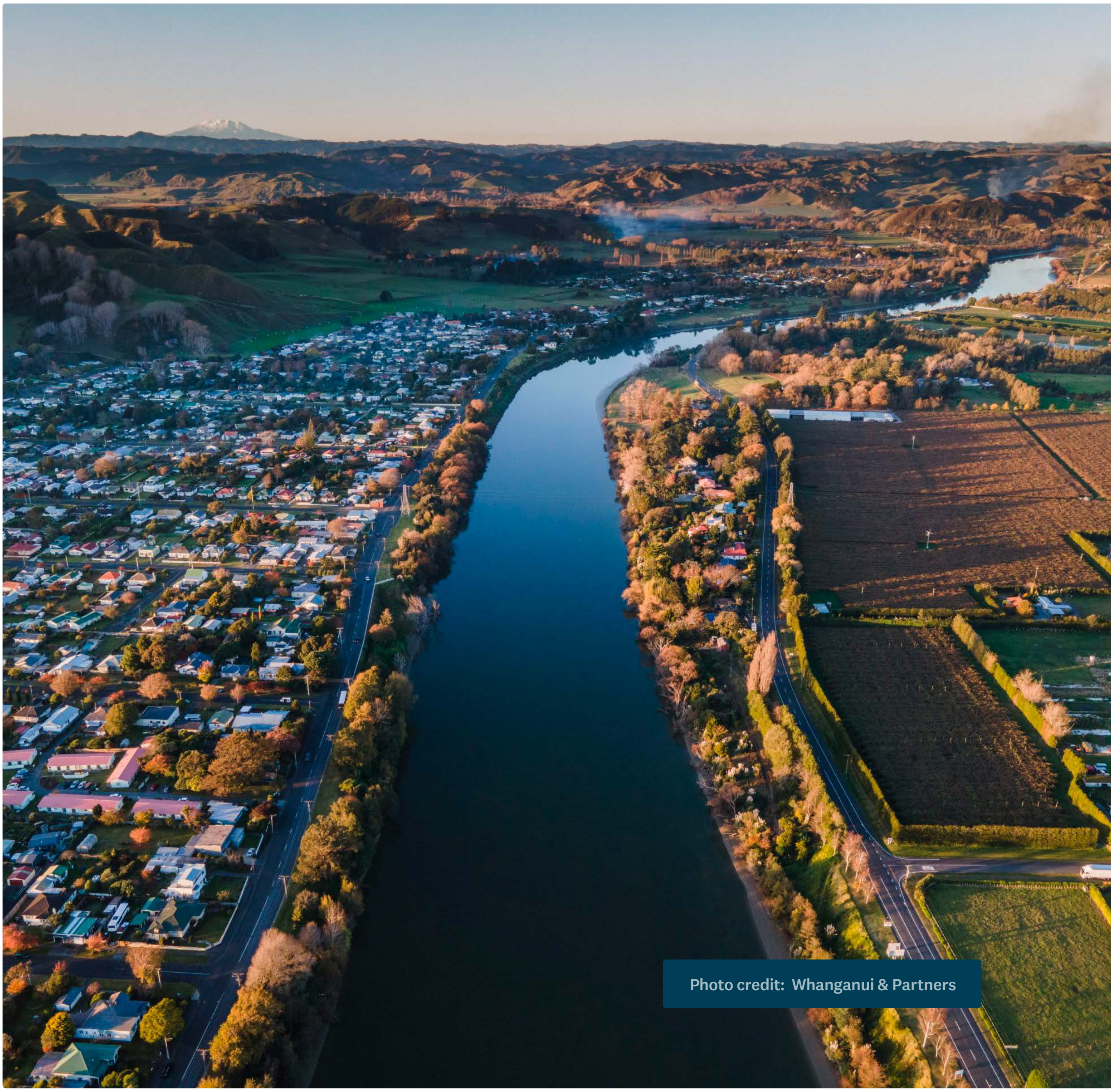


Photo credit: Whanganui & Partners

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 each identified process heat demand site, given the current capacity of the Manawatū–Whanganui 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 their EDB 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.[44]

These opportunities are not included in our assessment of connection costs, and process heat users should engage with their EDB 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).

According to EDB disclosure information, maximum demand for each network is:

- Electra (42MW)
- Powerco – Western (272MW)
- The Lines Company (24MW)
- Scanpower (20MW).

If all four EDBs reached their individual peak demands at the same time, the regional peak would be 358MW; however, the 2023 regional prudent peak demand was 337MW indicating that there is some degree of regional diversity.

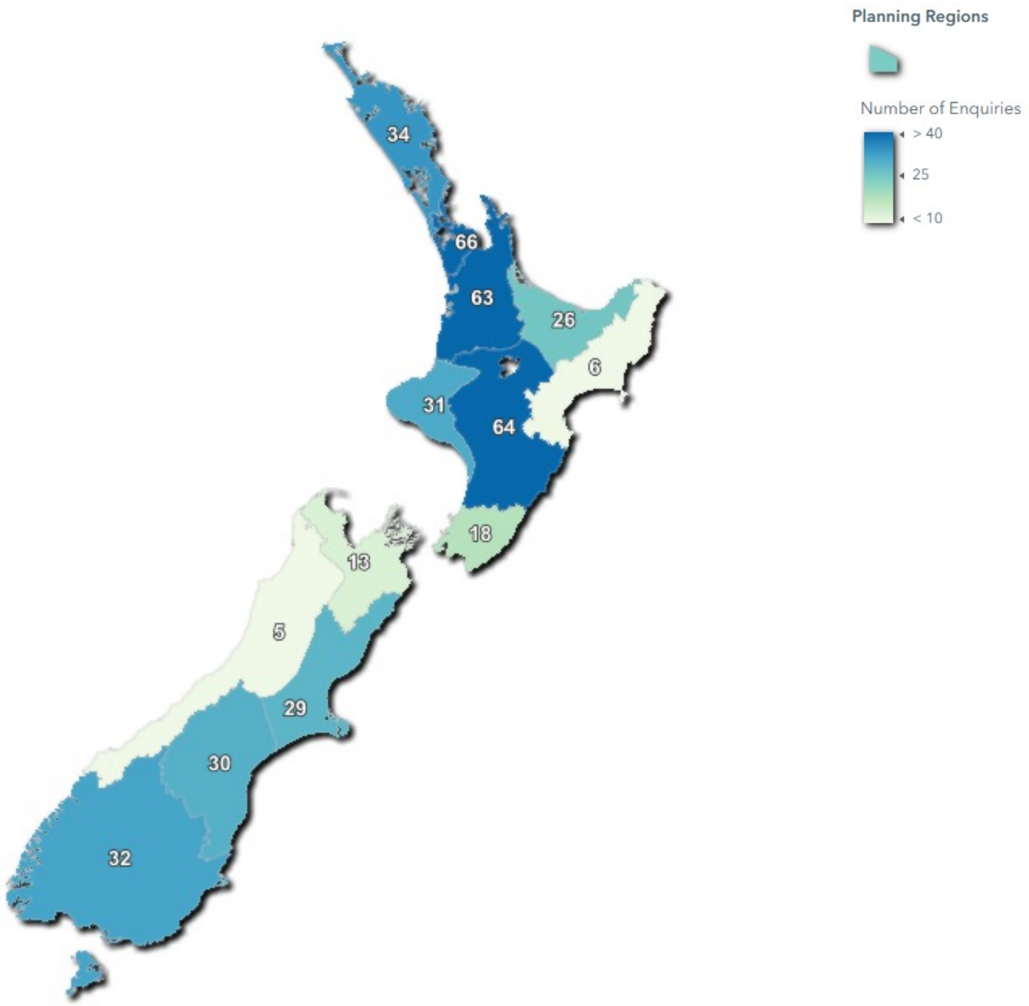
If all Manawatū–Whanganui process heat demand projects electrified, Powerco would increase its maximum demand by 54%, compared to The Lines Company (47%), Electra (34%) and Scanpower (18%). Should the increase in all the EDBs' peak demand occur at the same time, this would represent a regional increase of 170MW, i.e. 50% 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 in this report 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. At the same time, 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.

[44] 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.

To illustrate this, Figure 52 shows the number of enquiries Transpower alone is facing in each of its planning regions. As at April 2025, of the 417 enquiries they face nationally, 51% have need dates prior to 2025. Transpower reports that of the 99 enquiries in the Manawatū/Whanganui region,[45] 11 are for demand-side needs including network upgrades and EDB/Transpower demand connections. The remainder are for supply-side needs including grid-connected generation (70), EDB connected generation (13) as well as grid connected energy storage (1), asset transfers (1) and non-connection requirements (3).

Figure 52 – Number of grid connection enquiries per region, April 2025. 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.

45 As defined by Transpower as Central North Island, including areas that are part of the RETA defined 'Manawatū–Whanganui' region.

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.

Each EDB will have developed peak demand forecasts over the next 10+ years that account for projected growth. 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 Manawatū–Whanganui 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. That is, 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.
- **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.

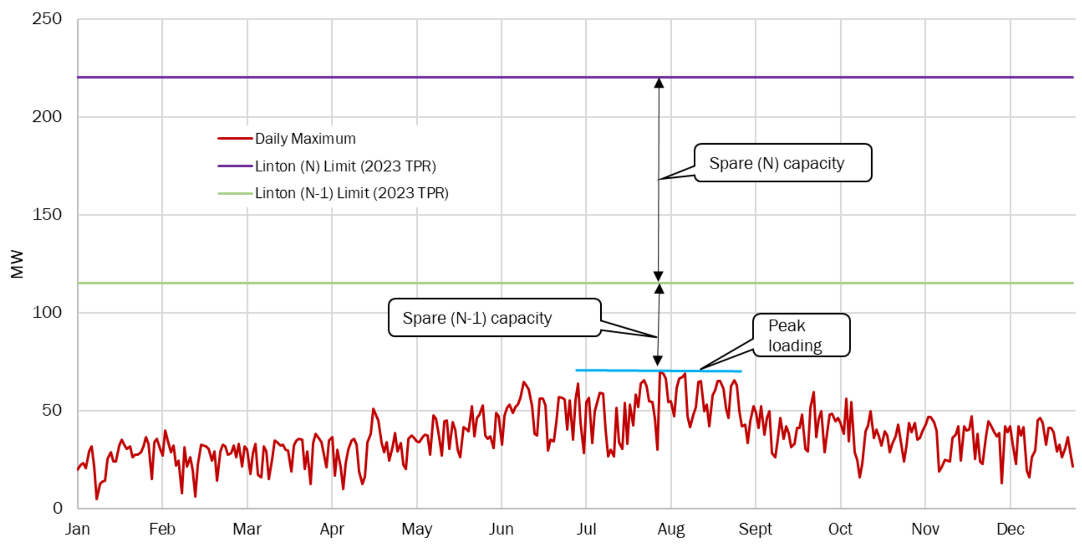
N-1 is generally provided through building redundancy into network assets, relative to the expected (peak) demand. It is the standard that applies on the 'interconnected' parts of Transpower's high-voltage transmission grid, due to the scale of bulk power flows affecting a large part of the population.

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 53 illustrates the difference between the available capacity for N and N-1 security for Linton grid exit point which supplies five zone substations in Powerco's Manawatū–Whanganui network.

Figure 53 – Illustration of spare N and N-1 security capacity at Linton GXP. Source: Ergo.

Manawatū–Whanganui



If a customer agrees with the EDB to utilise N security capacity, 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.[46]

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).

[46] 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 RETA sites will increase the electricity demand at 10 of the 14 regional GXPs, shown on Figure 54. This has implications for both regional and GXP demand.

Regional considerations

As previously noted, Transpower's load forecast for the Manawatū–Whanganui over the next 15 years is higher than the expected national average of 2.0% per year. However, as noted by Transpower,[47] there has been investigations and proposals for solar generation and battery energy storage systems (BESS), as well as some interest in wind generation opportunities in the region. To supply the forecast demand, and to facilitate the connection of new generation and/or BESS 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.

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 demand switching within EDBs, 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 the EDBs and other stakeholders to operationally manage the existing grid asset capability within the Manawatū–Whanganui region.

The inherent assumptions in our analysis for the Manawatū–Whanganui region are:

- Transpower's investment programme will address the Manawatū–Whanganui thermal stability issues noted over the next 15 years.[48]
- There is always sufficient local grid connected and embedded generation to provide voltage support and energy within the region.
- The transmission lines connecting the region to the national grid have sufficient capacity, at all times, to import into the region as necessary and/or export any excess generation produced.

47 Transpower 2023 Transmission Planning Report Section 9.8

48 2023 Transmission Planning Report: section 9.3.2.

GXP, Sub-transmission substation level connection considerations

The available spare capacity for different security levels (N and N-1), at each of the Manawatū–Whanganui GXPs is shown in Figure 54. For the avoidance of doubt, Figure 54 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).

Figure 54 – Spare capacity at Transpower's Manawatū–Whanganui's GXPs. Source: Ergo.

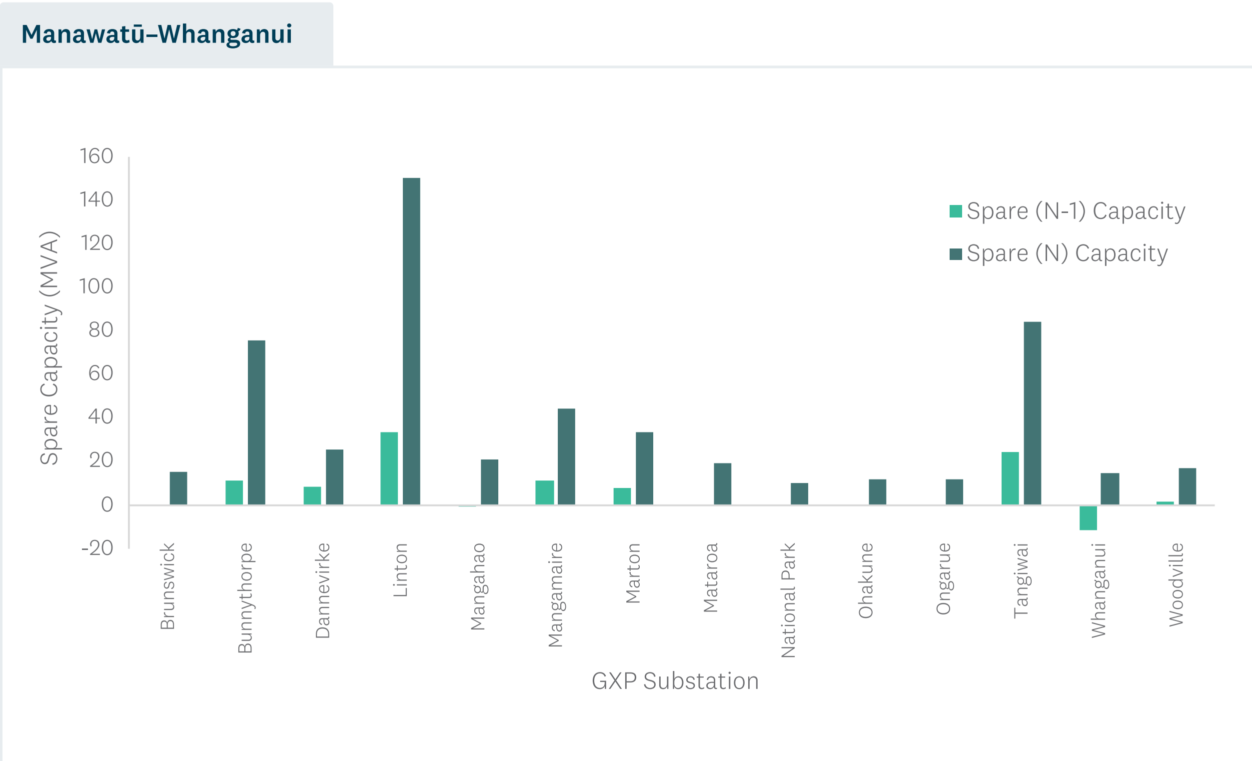


Figure 54 infers that based on the 2023 forecast demands for the region,[49] there are modest levels of spare N-1 capacity at Bunnythorpe, Dannevirke, Linton, Mangamaire and Tangiwai. Based on the 2023 forecast demands for the region, there is little or no spare N-1 capacity at Mangahao and Woodville, but there is spare N capacity at each of these locations. Brunswick, Mataroa, National Park, Ohakune and Ongarue have no spare N-1 capacity as they are all supplied by a single transformer, therefore can only operate at N. A negative value for spare N-1 capacity is shown for Whanganui. This doesn't necessarily mean that this site is exceeding N-1 today. Rather, it reflects the fact that Transpower's *prudent* peak demand forecast exceeds the N-1 capacity of the GXP — that is, the GXP will effectively be experiencing N security if that level of demand is reached.

[49] From demand forecasts included in Transpower's 2023 TPR, and the 2024 EDB AMPs.

As previously noted, Manawatū–Whanganui 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 influences spare capacity:

- **Bunnythorpe GXP** — Local generation includes Tararua Wind 'North' (34MW), which connects within Powerco's network, thereby supporting demand in the local area.
- **Linton GXP** — Local generation includes Tararua Wind 'South' (34MW), which connects within Powerco's network, thereby supporting demand in the local area. In addition, Turitea Wind (221MW) connects directly to Transpower's 220kV Linton substation.
- **Mangahao GXP** — Local generation includes Mangahao hydroelectric (38MW), which connects within Electra's network and when generating provides N-1 security for demand in the local area.
- **Ongarue GXP** — Local generation include Mokauiti hydroelectric (1.6MW), Kuratau hydroelectric (6MW), and Wairere Falls hydroelectric (4.6MW), all of which are connected within The Lines Company network and support demand in the local area.
- **Rangipo GIP** — Local generation includes Rangipo hydroelectric which connects directly to the National Grid via a dedicated grid injection point.
- **Tararua GIP** — Local generation includes Tararua Wind Stage 3 (93MW) and Te Rere Hau wind generation (49MW) connecting directly to the National Grid via a dedicated grid injection point.
- **Tokaanu GXP** — Local generation includes Tokaanu hydroelectric (240MW) which connects at Transpower's 220kV Tokaanu substation.
- **Woodville GXP** — Local generation includes Te Apiti wind generation (90MW) which connects at Transpower's 110kV Woodville substation.

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.

We would note that the spare capacities shown in Figure 54 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 the relevant EDB.

For those sites with limited spare capacity left, we comment below on any planned transmission upgrades specifically mentioned in the Transpower 2023 Transmission Planning Report (TPR). These are summarised in Table 10.

Table 10 – Manawatū–Whanganui GXPs – spare capacity and currently planned grid upgrades.

GXP	EDB	RETA sites analysed	Spare N-1 GXP capacity	Planned Transpower GXP upgrade
Brunswick 33kV	Powerco	• AFFCO Castlecliff	None	None. The 220/33kV transformer is due for risk-based condition replacement (2023-2026). A failure of the single transformer is managed by transferring load to the Whanganui GXP by switching in Powerco's network. Transpower and Powerco are investigating installation of a second 220/33kV transformer at Brunswick. (See Section 12.5.1 of 2023 TPR).
Bunnythorpe	Powerco	• Alsco Palmerston North • Kakariki Proteins • AFFCO Manawatū • NZDF Ōhakea Air Base • Moana NZ • Fonterra Brands Palmerston North • Ovation Feilding	12MVA	None. Peak load forecast was expected to exceed N-1 capacity of supply transformers from Winter 2023 without any contribution from the Tararua North wind generation. Transpower manages the expected overload operationally, vis switching within Powerco's network moving demand to Linton GXP post contingency. (See Section 11.5.2 of 2023 TPR)

GXP	EDB	RETA sites analysed	Spare N-1 GXP capacity	Planned Transpower GXP upgrade
Dannevirke	Transpower	• Godfrey Hirst Dannevirke • Alliance Group Dannevirke	9MVA	None. Peak load is forecast to exceed the N-1 capacity of the transformers due to a metering limit by 2030. Transpower plans to resolve the metering limit at the GXP (estimate cost $0.1m) which will relieve the issue for the forecast period. (See Section 11.5.3 of 2023 TPR)
Linton	Powerco	• Higgins Palmerston North Asphalt Plant • Massey University Manawatū • Fonterra R&D Centre • NZ Pharmaceuticals • Health NZ Palmerston North Hospital • Goodman Fielder Longburn • Fonterra Limited Longburn • Goodman Fielder Ernest Adams • NZDF Force Linton • AgResearch Grasslands Research Centre	34MVA	None
Mangahao	Electra	• Horowhenua District Council Levin Aquatic Centre • Oji Fibre Solutions Packaging NZ Central • Turk's Poultry • Health NZ Horowhenua Health Centre • RJs Confectionery Levin • Mitchpine Levin	None	None. Peak load exceeds the N-1 capacity of the supply transformers when Mangahao power station is not generating. With Mangahao generating, the supply transformer overload and low voltage issues are managed operationally.

GXP	EDB	RETA sites analysed	Spare N-1 GXP capacity	Planned Transpower GXP upgrade
				The supply transformers are due for risk-based condition replacement (2026-2028) and at the time of replacement, the required transformer sizing will be investigated by Transpower and Electra. (see Section 11.5.5 of 2023 TPR)
Mangamaire	Powerco	• Fonterra Pahiatua	12MVA	None
Marton	Powerco	• Malteurop Marton • Nestle Purina Petcare Marton • ANZCO Foods Rangitīkei • ANZCO Foods Manawatū • Farmland Food Bulls	8MVA	Peak load was forecast to exceed N-1 supply capacity from Winter 2023, with the N supply capacity forecast to be exceeded when Powerco shift load from Bunnythorpe to Marton (2025). The proposed Marton 33kV ODID conversion project and protection upgrade will remove the transformers protection constraint. Transpower and Powerco have discussed the options to manage low voltage and supply capacity issues. (See Section 11.5.7 of 2023 TPR)
Ongarue	The Lines Company	• King Country Pet Food Taumarunui • Health NZ Taumarunui Hospital	None	None. Peak load is forecast to exceed the capacity of the supply transformers from Winter 2030. The supply transformer is due for condition-based replacement toward the end of the forecast period. (See Section 11.5.11 of 2023 TPR)

GXP	EDB	RETA sites analysed	Spare N-1 GXP capacity	Planned Transpower GXP upgrade
Whanganui	Powerco	• Open Country Dairy Whanganui • AFFCO Imlay • Department of Corrections Whanganui Prison • Tasman Tanning Castlecliff	-11MVA	Demand already exceeds the N-1 limit of the GXP. Powerco manages this by using switching within the sub transmission network to shift load onto Brunswick GXP as required. Transpower is planning to replace the smaller of the two transformers at Whanganui (2027) and is investigating replacing the other transformer at the same time. (See Section 12.5.12 of 2023 TPR)

Assessing the transmission grid implications of connecting identified process heat demand sites against *current* spare capacity is only part of the story.

- In some of the cases 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 RETA 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 Manawatū–Whanganui region, Ergo's analysis concluded that the electrification of 17 potential RETA projects would, by themselves, trigger the need for transmission upgrades as shown in Table 13. Section 9.5 considers whether the collective connection of a number of other sites may also lead to a need for transmission investment.[50]

[50] 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

9.3.4 Analysis of impact of individual RETA sites on EDB (distribution) 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.[51] Further, the costs presented approximate the total capital cost of constructing the connection assets and have not considered the potential for capital contributions from the EDB. It is imperative that process heat owners seek more detailed assessments from the relevant EDB (and potentially Transpower) should they wish to investigate electrification further or develop more robust budgets.

Below we present the results of Ergo's analysis of the RETA sites in three tables, 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 that connects the substation to the GXP.
- **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 the EDB 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 and are based on the assumptions set out in Appendix 13.1.6. Each individual site should be re-considered when more detail is available.

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).

[51] 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.

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.

We have also provided estimates of timing to plan, design, procure, construct and commission the connection works. Important to note is that if a distribution transformer and/or switchgear is required, the lead time is expected to be around 9-12 months.

Table 11 lists the connections that are categorised as 'minor' in nature.

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

Site	Transpower GXP	Network	Peak site demand (MW)	Total network upgrade cost ($m)	Estimated timing
Moana New Zealand	Bunnythorpe	Powerco	0.51	<$0.3	3-6 months
Fonterra Brands	Bunnythorpe	Powerco	0.21	<$0.3	3-6 months
Ovation Feilding	Bunnythorpe	Powerco	0.20	<$0.3	3-6 months
Alliance Group Dannevirke	Dannevirke	Scanpower	2.1	<$0.3	3-6 months
Goodman Fielder Ernest Adams	Linton	Powerco	1.7	$0.35	3-6 months
NZDF Linton	Linton	Powerco	0.55	<$0.3	3-6 months
AgResearch Grasslands Research Centre	Linton	Powerco	0.44	<$0.3	3-6 months
Mitchpine Levin	Mangahao	Electra	0.49	<$0.3	3-6 months
Farmland Foods Bulls	Marton	Powerco	0.72	<$0.3	3-6 months
Health NZ Taumarunui Hospital	Ongarue	The Lines Company	0.9	<$0.3	3-6 months

Table 12 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 planning, design, procurement, construction and commissioning.

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

Site	Transpower GXP	Network	Peak site demand (MW)	Total network upgrade cost ($m)	Estimated timing
Godfrey Hirst Dannevirke	Dannevirke	Transpower	2.38	$3.08	12-18 months
Higgins Palmerston North Asphalt Plant (N security)	Linton	Powerco	10.7	$4.20	12-18 months
Higgins Palmerston North Asphalt Plant (N-1 security)	Linton	Powerco	10.7	$6.70	24-36 months
Massey University Manawatū (N security)	Linton	Powerco	5.7	$2.04	12-18 months
Massey University Manawatū (N-1 security)	Linton	Powerco	5.7	$6.99	24-36 months
Fonterra R&D Centre (N security)	Linton	Powerco	3.96	$2.14	12-18 months
Fonterra R&D Centre (N-1 security)	Linton	Powerco	3.96	$7.09	24-36 months
NZ Pharmaceuticals (N security)	Linton	Powerco	3.75	$7.44	24-36 months
NZ Pharmaceuticals (N-1 security)	Linton	Powerco	3.75	$12.84	24-36 months
Health NZ Palmerston North Hospital (N security) – short term	Linton	Powerco	3.49	$2.80	3-6 months
Health NZ Palmerston North Hospital (N security)	Linton	Powerco	3.49	$6.10	24-36 months
Health NZ Palmerston North Hospital (N-1 security)	Linton	Powerco	3.49	$21.30	24-36 months
Goodman Fielder Longburn (N security)	Linton	Powerco	3.25	$2.08	12-18 months
Goodman Fielder Longburn (N-1 security)	Linton	Powerco	3.25	$4.58	24-36 months

Site	Transpower GXP	Network	Peak site demand (MW)	Total network upgrade cost ($m)	Estimated timing
Fonterra Longburn (N security)	Linton	Powerco	1.80	$2.08	12-18 months
Fonterra Longburn (N-1 security)	Linton	Powerco	1.80	$4.58	24-36 months
Nestle Purina Petcare Marton (N security)	Marton	Powerco	2.40	$10.46	24-36 months
Nestle Purina Petcare Marton (N-1 security)	Marton	Powerco	2.40	$19.31	24-36 months
ANZCO Foods Rangitīkei (N security)	Marton	Powerco	1.61	<$0.3	3-6 months
ANZCO Foods Rangitīkei (N-1 security)	Marton	Powerco	1.61	$1.41	24-36 months
ANZCO Foods Manawatū (N security)	Marton	Powerco	1.56	<$0.3	6-12 months
ANZCO Foods Manawatū (N-1 security)	Marton	Powerco	1.56	$1.55	24-36 months

Table 13 shows the 17 connections that are categorised as 'major'. These connections are significant, in terms of cost, complexity and the estimated time to complete. At two of the sites we propose staging the upgrades due to the size of the electrical load required. As mentioned in section 9.3.3, there is little or no N-1 capacity remaining at Brunswick, Bunnythorpe, Mangahao, Mangamarie, Marton, Ongarue and Whanganui GXPs. For sites to increase their N-1 capacities at each GXP, the total cost of this investment has been attributed in full to each of the individual sites. In reality the transmission upgrades for each GXP are likely to support multiple process heat users, and the costs would be shared amongst the different users.

Table 13 – Connection costs and lead times for major complexity connections. Source: Ergo.

Site	Transpower GXP	Network	Peak site demand (MW)	Total network upgrade cost ($m)	Estimated timing
AFFCO Castlecliff (N security)	Brunswick 33kV	Powerco	2.59	$2.12	12-18 months
AFFCO Castlecliff (N-1 security)	Brunswick 33kV	Powerco	2.59	$11.02	36-48 months
Alsco Palmerston North (N security)	Bunnythorpe	Powerco	2.67	$0.56	12-18 months
Alsco Palmerston North (N-1 security)	Bunnythorpe	Powerco	2.67	$12.16	36-48 months
Kakariki Proteins (N security)	Bunnythorpe	Powerco	2.5	$2.58	12-18 months
Kakariki Proteins (N-1 security)	Bunnythorpe	Powerco	2.5	$17.38	36-48 months
AFFCO Manawatū (N security)	Bunnythorpe	Powerco	1.26	$1.28	12-18 months
AFFCO Manawatū (N-1 security)	Bunnythorpe	Powerco	1.26	$20.28	36-48 months
NZDF Ōhakea Air Base (N security)	Bunnythorpe	Powerco	1.14	$1.08	12-18 months
NZDF Ōhakea Air Base (N-1 security)	Bunnythorpe	Powerco	1.14	$18.53	36-48 months
Horowhenua District Council Levin Aquatic Centre (N security)	Mangahao	Electra	3.87	$2.20	12-18 months
Horowhenua District Council Levin Aquatic Centre (N-1 security)	Mangahao	Electra	3.87	$11.20	36-48 months
Oji Fibre Solutions Packaging NZ Central (N security)	Mangahao	Electra	3.75	$0.58	12-18 months
Oji Fibre Solutions Packaging NZ Central (N-1 security)	Mangahao	Electra	3.75	$9.58	36-48 months
Turks Poultry (N security)	Mangahao	Electra	2.31	$0.52	12-18 months
Turks Poultry (N-1 security)	Mangahao	Electra	2.31	$9.52	36-48 months
Health NZ Horowhenua Health Centre (N security)	Mangahao	Electra	1.5	$1.12	12-18 months

Site	Transpower GXP	Network	Peak site demand (MW)	Total network upgrade cost ($m)	Estimated timing
Health NZ Horowhenua Health Centre (N-1 security)	Mangahao	Electra	1.5	$10.12	36-48 months
RJs Confectionery (N security)	Mangahao	Electra	1.08	$2.20	12-18 months
RJs Confectionery (N-1 security)	Mangahao	Electra	1.08	$11.20	36-48 months
Fonterra Pahiatua – Stage 1 (N security)	Mangamarie	Powerco	13.00	$5.78	24-36 months
Fonterra Pahiatua – Stage 2 (N security)	Mangamarie	Powerco	25.00	$44.90	36-48 months
Fonterra Pahiatua – Total (N security)	Mangamarie	Powerco	38.00	$50.68	
Fonterra Pahiatua – Stage 1 (N-1 security)	Mangamarie	Powerco	13.00	$8.88	24-36 months
Fonterra Pahiatua – Stage 2 (N-1 security)	Mangamarie	Powerco	25.00	$65.15	36-48 months
Fonterra Pahiatua – Total (N-1 security)	Mangamarie	Powerco	38.00	$74.03	
Malteurop Marton (N security)	Marton	Powerco	14.40	$13.25	24-36 months
Malteurop Marton (N-1 security)	Marton	Powerco	14.40	$33.90	36-48 months
King Country Pet Food Taumarunui (N security)	Ongarue	The Lines Company	7.04	$2.75	24-36 months
King Country Pet Food Taumarunui (N-1 security)	Ongarue	The Lines Company	7.04	$20.43	36-48 months
Open Country Dairy Whanganui - Stage 1 (N security)	Whanganui	Powerco	6.0	$0.96	12-18 months
Open Country Dairy Whanganui - Stage 2 (N security)	Whanganui	Powerco	9.0	$10.50	24-36 months
Open Country Dairy Whanganui - Stage 3 (N security)	Whanganui	Powerco	13.43	$20.50	36-48 months
Open Country Dairy Whanganui - Total (N security)	Whanganui	Powerco	28.43	$31.96	

Site	Transpower GXP	Network	Peak site demand (MW)	Total network upgrade cost ($m)	Estimated timing
Open Country Dairy Whanganui - Stage 1 (N-1 security)	Whanganui	Powerco	6.0	$16.12	36-48 months
Open Country Dairy Whanganui - Stage 2 (N-1 security)	Whanganui	Powerco	9.0	$16.90	24-36 months
Open Country Dairy Whanganui - Stage 3 (N-1 security)	Whanganui	Powerco	13.43	$10.50	24-36 months
Open Country Dairy Whanganui - Total (N-1 security)	Whanganui	Powerco	28.43	$43.52	
AFFCO Imlay (N security)	Whanganui	Powerco	3.31	$10.49	24-36 months
AFFCO Imlay (N-1 security)	Whanganui	Powerco	3.31	$29.70	36-48 months
Department of Corrections Whanganui Prison (N security)	Whanganui	Powerco	7.09	$6.80	12-18 months
Department of Corrections Whanganui Prison (N-1 security)	Whanganui	Powerco	7.09	$19.88	36-48 months
Tasman Tanning Castlecliff (N security)	Whanganui	Powerco	1.79	$0.50	12-18 months
Tasman Tanning Castlecliff (N-1 security)	Whanganui	Powerco	1.79	$15.66	36-48 months

Case Study — Open Country Dairy Whanganui

Open Country Dairy Whanganui is presently supplied by Powerco's Beach Road zone substation, which in turn is supplied from Whanganui GXP (see Section 9.3.3). The zone substation has 6MVA of spare N-1 capacity, and 7MVA of N capacity. Whanganui GXP already exceeds its N-1 capacity and has 15MVA of spare N capacity. The costs noted in the table show each stage separately as well as a 'total' site in which the costs are cumulative, as each latter stage is dependent on the prior stages being completed. Due to the size of the load, analysis focussed on a staged approach.

- **Stage 1 (6MVA).** The first stage adds an additional 6MVA onto the existing load. Beach Road zone substation has sufficient N and N-1 capacity to handle this increase. Whanganui GXP has adequate N capacity for this demand, but insufficient N-1 capacity. Considering the final demand at site, it is expected that a 33kV rated feeder would be installed to supply the site, thereby removing any requirement to upgrade the supply transformers at Beach Road zone substation in future stages. Due to the urban/industrial topography of the area, it is expected this feeder would be underground and would be approximately 0.3km long. For Stage 1, the feeder would be operated at 11kV supplied by the Beach Road 11kV switchboard.

  Brunswick GXP has an outdoor to indoor conversion (ODID) planned for 2025-2028. Once the Brunswick ODID is complete, the single circuit to Whanganui GXP and switchable circuit to Brunswick GXP would provide acceptable 'N-1 switched' security for the sub transmission circuits.

  For Whanganui GXP to provide adequate N-1 capacity the supply transformers at the GXP would need to be replace/upgraded, which would be required for the demand requirements of Stage 3. If Whanganui is to provide N security to the demand, a special protection scheme may be implemented to avoid overloading the remaining transformer in the event of a single transformer outage.
- **Stage 2 (9MVA).** The second stage adds an additional 9 MVA, bringing the total load proposed to 15 MVA. For an N-1 supply, an additional sub transmission circuit from the GXP to the zone substation or load site would be required. It is expected that this sub transmission circuit would be underground due to space constraints (existing overhead lines) along the route, and the route would include a river crossing, therefore requiring an additional 1km of cabling, utlising one of the existing bridges to cross the river. The sub transmission cables would be ~10km long.

  For this Stage Open Country Dairy Limited Whanganui would take supply at 33kV. As such for an N-1 security sub transmission supply Powerco may establish a 33kV switchboard at the Open Country Dairy site, with the new sub transmission circuit terminating at the new 33kV switchboard. The feeder installed in Stage 1 would then be re-terminated at both the Load Site side and the Beach Road side at 33 kV, forming a 33 kV ring network with the Load Site and Beach Road off the GXP. For an (N) security supply, the 33 kV feeder installed in Stage 1 would be re-terminated to supply the site at 33 kV.

  For either security supply, the existing sub transmission circuit to Beach Road would need to be replaced/upgraded. This would involve undergrounding the existing overhead lines, involving ~10 km of undergrounding and a bridge crossing. Assuming the upgrades at Whanganui GXP mentioned Stage 1 were carried out, no further upgrades at the GXP are expected for this stage.

- **Stage 3 (13MVA).** The third stage adds an additional 13MVA, increasing the total proposed demand to 28MVA. At this stage, for either an N or N-1 supply, an additional sub transmission circuit from the GXP to the site would be required, similar to the circuit installed in Stage 2.

  Whanganui GXP does not have adequate N or N-1 capacity to supply the total demand. For an N-1 supply, assuming that the transformer replacements at the GXP were carried out for the N-1 supply in Stage 1, no further upgrades at the GXP are expected. However, for an N security supply the existing supply transformers may need to be upgraded/replaced.

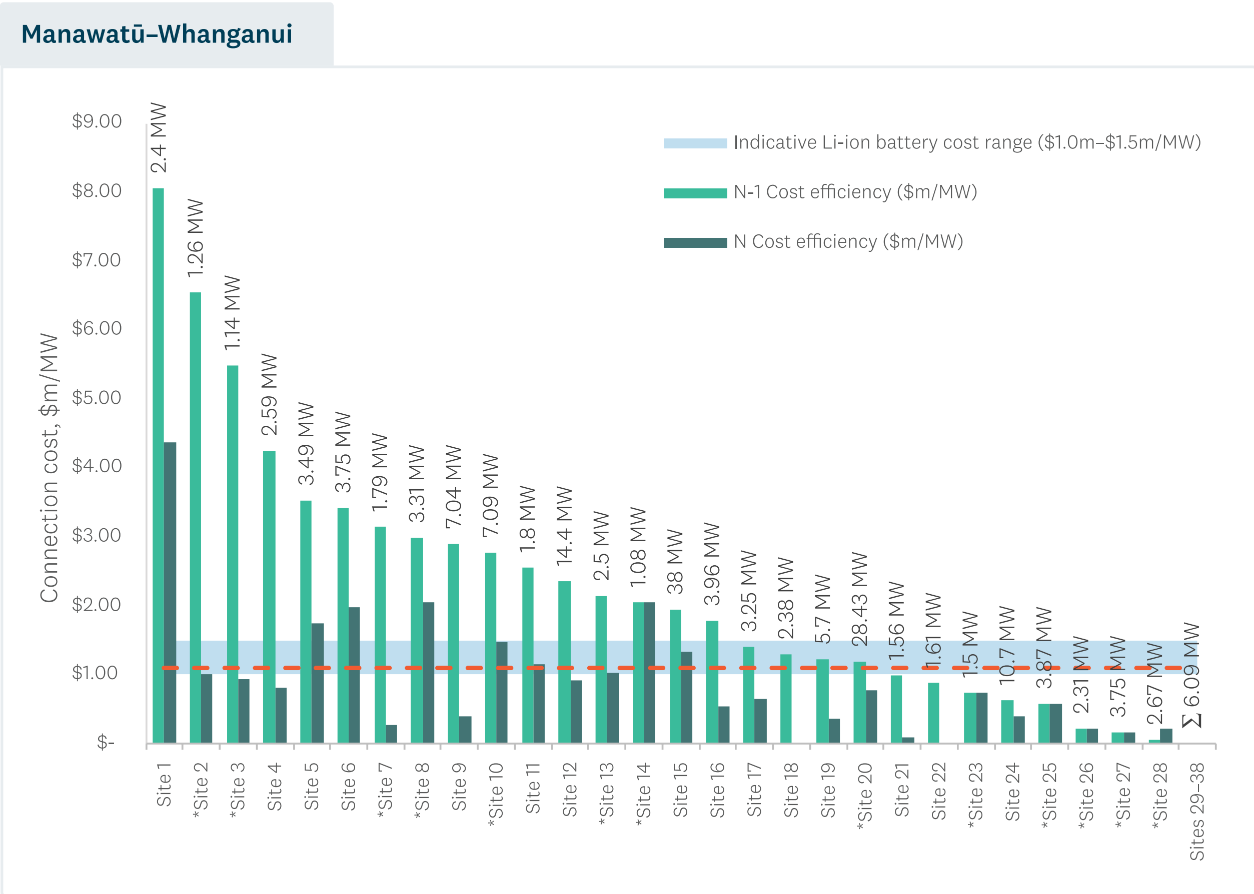
The complexity of the Open Country Dairy Limited Whanganui site — and the other 16 major connections - and the likely impact on both the distribution and transmission networks, underscores the importance of early and regular communication between process heat users, distributors and Transpower. EDBs 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.

Photo credit: Transpower

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 55 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 55 – Normalised cost of network connection vs boiler cost. Source: Ergo, EECA. Note: boiler capacity in MW shown in labels. Sites with an asterisk may trigger additional upgrades depending on the security level required (described in Section 9).



Sites marked with an asterisk (*) are projects whose N-1 option would by themselves trigger a transmission upgrade (as discussed in 9.3.3), but given multiple sites are proposing to connect to the same GXP(s), the direct transmission costs have been excluded from the chart on the expectation that any GXP transmission upgrade costs would be shared among all the sites connecting to that GXP. In addition, 10 sites (Sites 29-38), totalling ~6MW, have little or no connection costs (<$0.3m) associated with electrification.

The red dashed line in Figure 55 compares the cost per-MW to the estimated cost of an electrode boiler ($1.1m per MW).[52] The blue shaded area indicates the estimated cost range for a 1MW lithium-ion battery. Figure 55 shows not only a wide variety of relative costs of connecting electrode boilers, but that for 20 cases, the (N-1) connection cost more than doubles the overall capital cost associated with electrification and are within (or exceed) the indicative cost range for a battery energy storage solution (BESS).

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

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 is 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 generally 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).

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 relatively short peak period that coincides with the relevant network daily peaks. In these situations, the use of a BESS could not only reduce network connection costs but also provide an opportunity for the site to offer (and contract) the operation of the BESS as a network peak management service to the relevant EDB (or Transpower), such that the need for transmission or distribution investment is deferred.

While the estimates of connection costs provided here are of an accuracy commensurate with this screening analysis, it does demonstrate how connection costs, and how these are shared between users, the EDB and potentially, Transpower, 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: Whanganui & Partners

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.[53] 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.[54]
- **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.[55]
- **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 the relevant EDB'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.[56]

53 Flexibility 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 here 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

54 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 10.7c/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 year.

55 The EDBs published tariffs include capacity based daily fixed charges, congestion period demand charges and time of use charges. It is challenging to make a definitive assessment of how much of these charges could be avoided by deploying flexibility. Our analysis conservatively assumes only 50% of the overall charges could be avoided.

56 Our analysis of each of these sites suggests the average construction cost of these investments was $2,332,000/MW. However, we also assumed that the capital contribution by the process heat user would be 50%. In addition, should a process heat site be able to reduce the capacity of its connection through providing flexibility in its demand, further savings in the distribution and transmission capacity charges may be achievable.

By enabling flexibility in their process heat demands, Manawatū–Whanganui process heat users could reduce their electricity procurement costs by up to $111,000 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, and also any network charges from the relevant EDB that relate to the size of the connection.

Figure 56 – Estimates of the value of flexibility in process heat demand.
Note: The error bars indicate the 10th and 90th percentile values calculated across different projects.

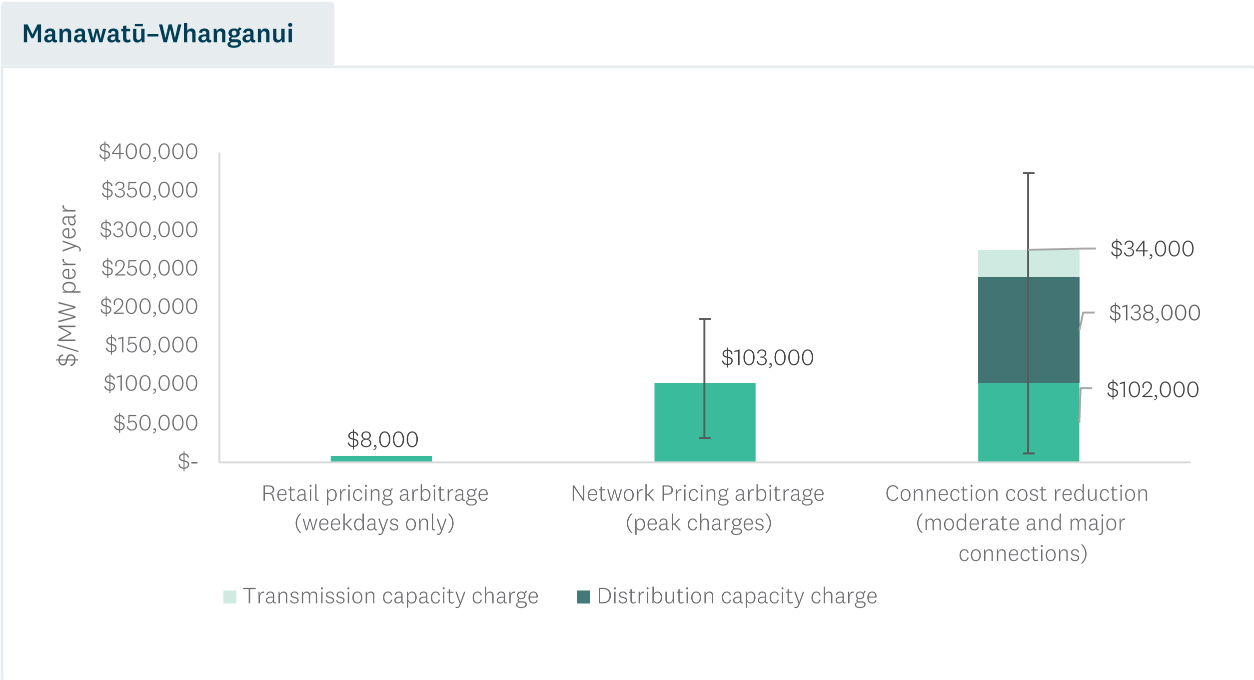


Figure 56 uses plausible estimates from the Manawatū–Whanganui RETA analysis of what this flexibility could be worth to a process heat user, per MW of demand that can be shifted into an off-peak period. We note that, in reality, the estimate for reducing connection costs may vary significantly, as the 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. The error bars in Figure 12 indicate the 10th and 90th percentile values calculated across the different projects. However, depending on which network they are connected to, a process heat user that has sufficient flexibility in their underlying process could obtain between $39,000 and $193,000[57] per year for every MW of flexibility routinely applied to avoid peak retail and distribution network charges, and additionally up to $274,000 (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.

57 $8,000 per year of retail charge savings in addition to $31,000 - $185,000 per year (corresponding to the 10th and 90th percentile) of network charge savings.

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 and thus, 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, each site 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 site operational requirements, which may see each site:

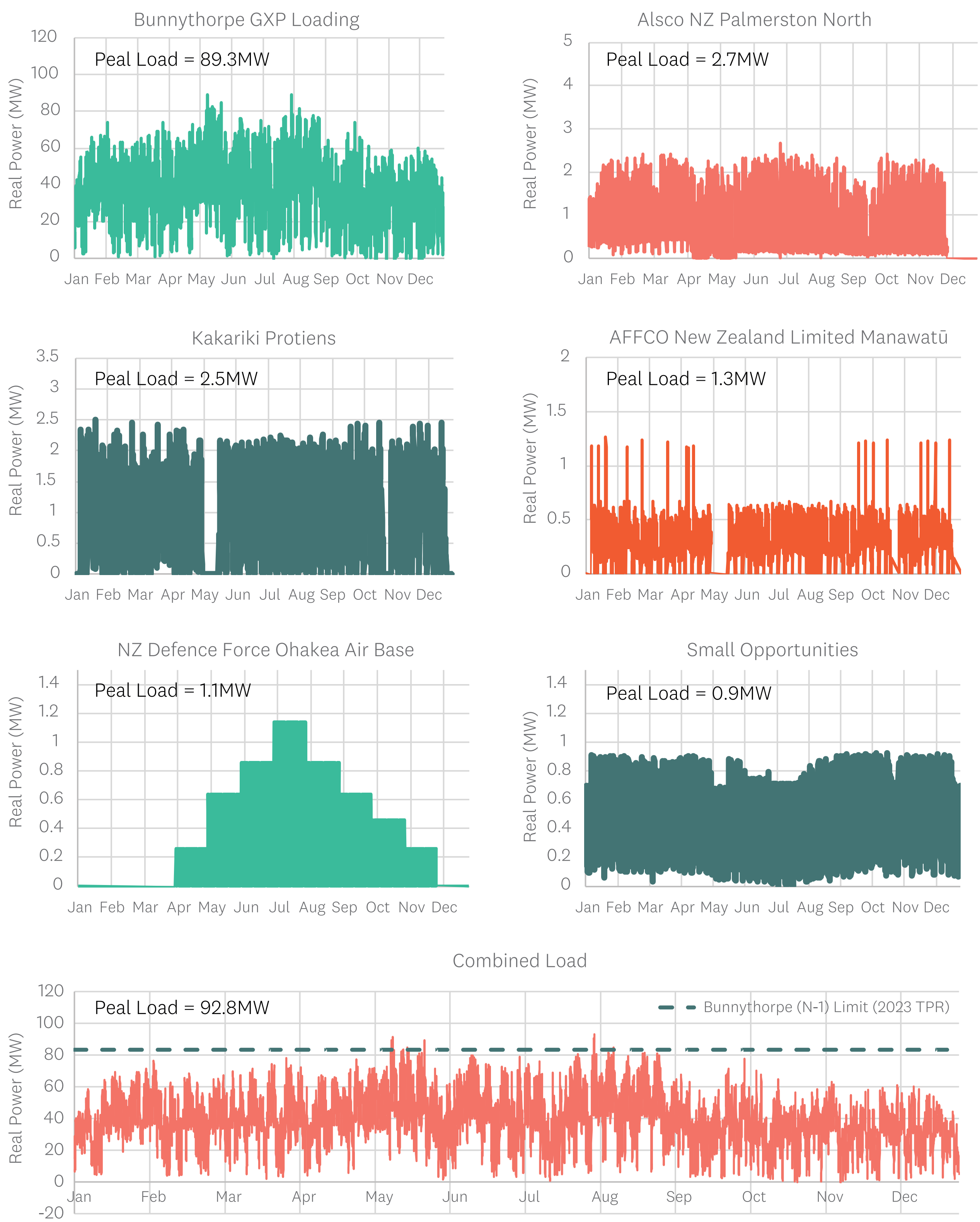
- Reach its peak demand at a different time to the other sites, and/or
- Reach its peak demand at a different time to existing network demand.

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 Manawatū–Whanganui 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 sites been electrified.

Figure 57 illustrates this approach for the Bunnythorpe GXP. The top-left chart shows the half hourly demand at Bunnythorpe over the 2023 year. Below that, we show the simulated half-hourly demand profile of each site, should they choose to electrify their process heat, and the resulting combined load at Bunnythorpe. 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. A more robust analysis would require consideration of future changes to half-hourly demand at Bunnythorpe transmission substation, including underlying growth from sources other than RETA sites.

Figure 57 – Simulation of potential impact on Bunnythorpe GXP demand if all RETA sites electrify.

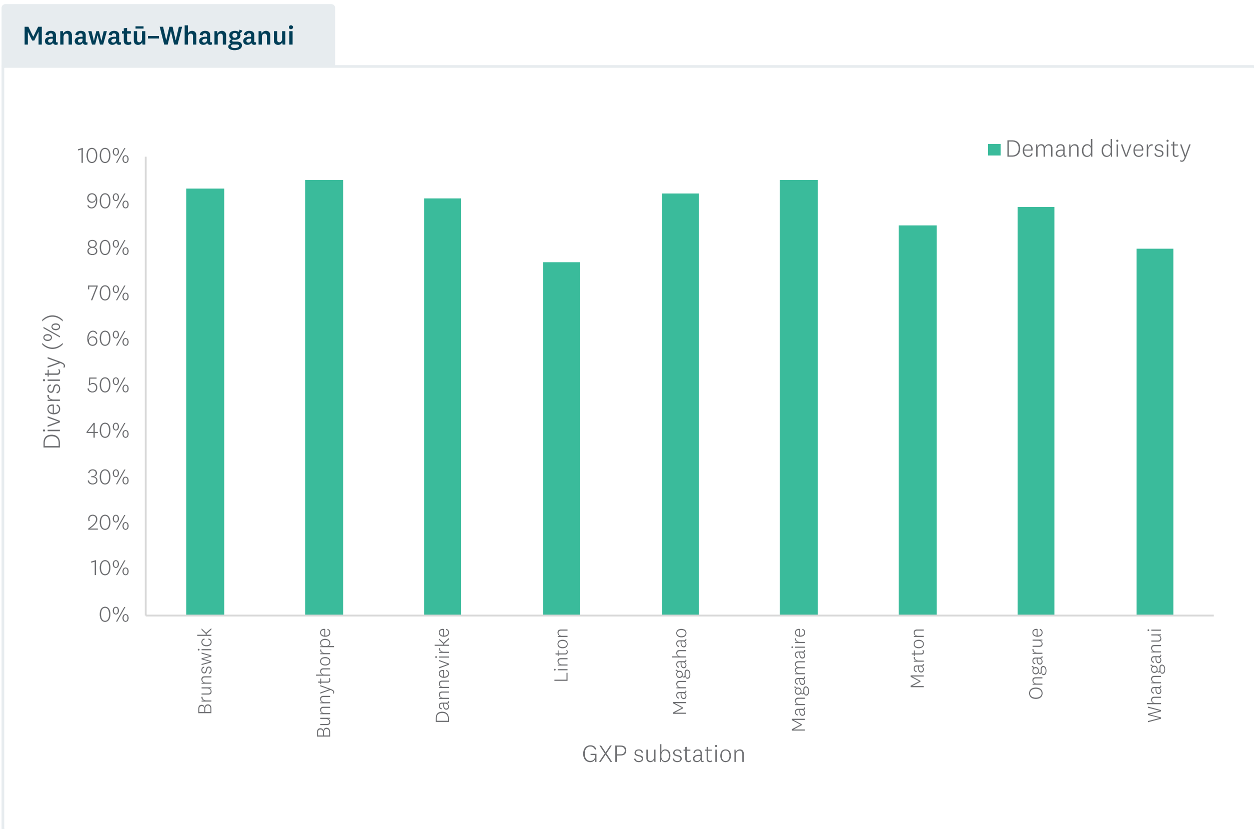


Importantly, the resulting peak GXP demand observed is 92.8MW, which is lower than the peak of 97.8MW implied by the simple addition of all individual site peaks (8.5MW) to the 2023 Bunnythorpe peak demand (89.3MW). The effect of demand diversity amongst the different Bunnythorpe sites is that the combined peak is 95% of what a simple addition would have suggested. We refer to this as a diversity 'factor'.

Bunnythorpe peak load already exceeds the N-1 capacity on some days during winter. Taking this approach shows that the combined demand from all individual sites would cause the Bunnythorpe assets to exceed their N-1 rating in an increased number of instances over the year, but within parameters that Powerco can continue to manage operationally including load transfer within the distribution network. This relatively low risk of interruption may be more acceptable to connecting customers, the EDBs and Transpower than investing in additional capacity.

Ergo repeated this analysis across the nine GXPs that have sites connected. The resulting demand diversity factors are shown in Figure 58.

Figure 58 – Demand diversity factors for Manawatū–Whanganui 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 59 shows the amount of spare capacity at each GXP under two scenarios:

- The 'Electricity Centric' pathway, where all unconfirmed Manawatū–Whanganui RETA 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.

Figure 59 – Spare capacity and potential peak demands at each GXP. Source: Ergo.

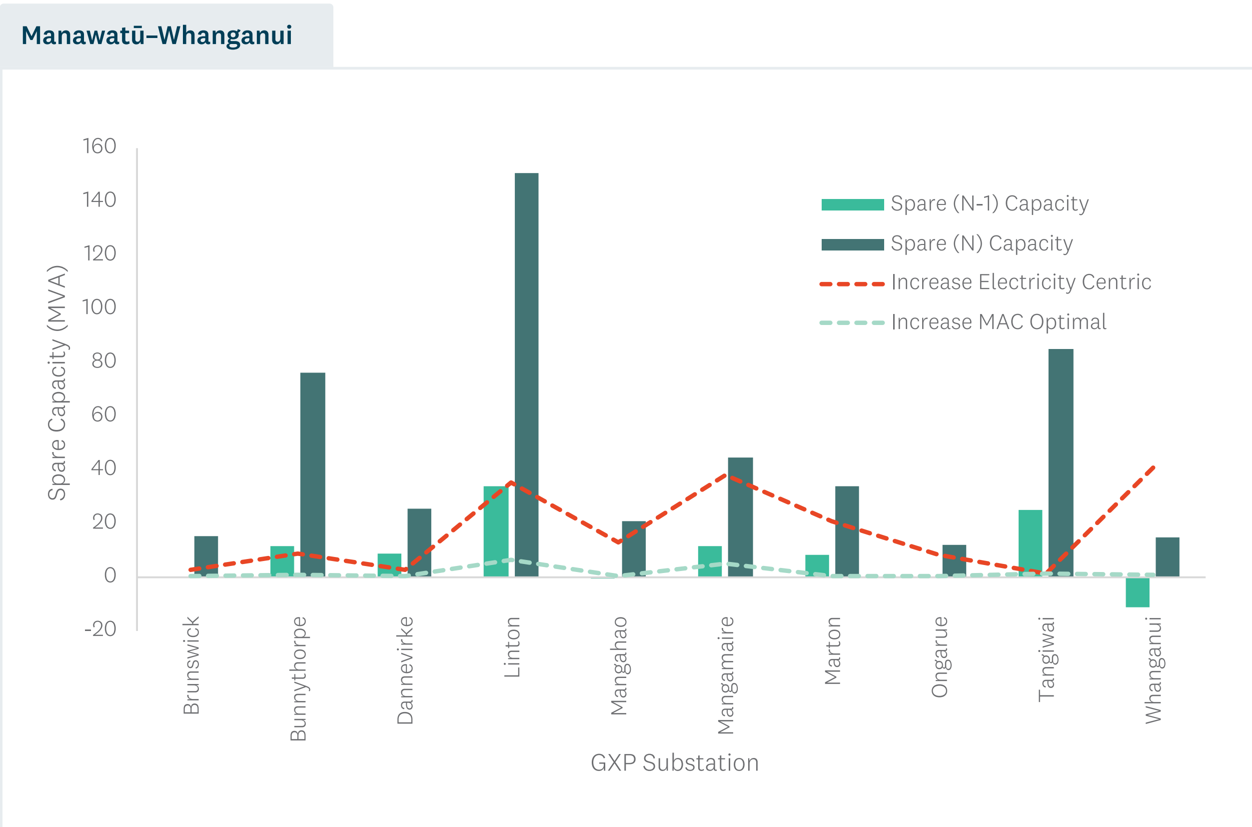


Table 14 – Potential increase in peak demand for different pathways.

GXP	Peak demand increase (MVA) – Electricity Centric pathway	Peak demand increase (MVA) – MAC Optimal pathway
Brunswick	2.6	0.3
Bunnythorpe	8.5	0.7
Dannevirke	2.7	0.4
Linton	35.4	6.4
Mangahao	13.0	0.3
Mangamaire	38.0	4.7
Marton	20.7	0.4
Ongarue	7.9	0.1
Tangiwai[58]	1.2	1.2
Whanganui	40.6	1.0

On this analysis:

- In the Electricity Centric scenario, Bunnythorpe, Dannevirke and Tangiwai have sufficient N-1 capacity to accommodate the potential demand. Comparatively, Linton, Mangahao, Mangamaire, and Marton have insufficient spare N-1 capacity, and Brunswick and Ongarue have no N-1 spare capacity as they operate at N. Therefore, any potential demand would use up a portion of the spare N capacity. Whanganui has no N-1 spare capacity, and insufficient N spare capacity.
- However, in the MAC Optimal scenario, there is very little increase in electricity demand, which is primarily attributed to fuel-switching to heat pumps for low temperature process heat requirements. As such, Bunnythorpe, Dannevirke, Linton, Mangamaire, Marton and Tangiwai have sufficient N-1 spare capacity to accommodate the potential increase from RETA demand. Whanganui already exceeds the N-1 capacity, so even a small increase from RETA demand will exacerbate the issue. The potential increase in demand under the MAC Optimal scenario for Brunswick, Mangahao, Ongarue and Whanganui 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 sites may trigger or accelerate some of the potential upgrades noted in Table 11 above, including any which are noted as 'customer driven investments'.

58 The sole industrial user connected to Tangiwai GXP is currently shut down; information is included in this report for other parties that may wish to utilise this connection.

Process heat users contemplating electrification at all nodes should engage early with the relevant EDB to ensure that this assessment of spare capacity aligns with their expectations. These organisations 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 the majority of the process heat decarbonisation projects were unlikely to trigger transmission upgrades that were not already planned for — the exceptions being the 17 sites with potentially major complexity connections as noted in Table 13.

In addition, some potential upgrades to distribution zone substations and sub transmission lines were identified.[59]

- **Feilding, Sanson and Ōhakea subtransmission, Bunnythorpe GXP (Powerco):** Several RETA sites are considering connecting to the Feilding, Sanson and Ōhakea substations, which share a sub-transmission network. The RETA sites are Kakariki Proteins, AFFCO Manawatū, NZDF Ōhakea Air Base, and Ovation Feilding. The sum of the peaks of these loads is 5.1 MW. The subtransmission network in the area is constrained at present, however, Powerco has several projects underway and planned which are expected to relieve these issues.
- **Kairanga, Linton GXP (Powerco):** Three RETA sites considering connecting to the zone substation are Higgins Palmerston North Asphalt Plant, Goodman Fielder Longburn and Fonterra Longburn. The sum of peaks of these loads is 15.75 MW, which the zone substation does not have (N-1) capacity for. However, the upgrades specified for the individual Load Sites are expected to be adequate for all the loads connecting, and should multiple of the loads connect, there may be an opportunity to share the costs of the upgrades.
- **Kairanga and Pascal St substransmission, Linton GXP (Powerco):** Three RETA sites considering connecting to the Kairanga zone substation are Higgins Palmerston North Asphalt Plant, Goodman Fielder Longburn and Fonterra Longburn. The RETA site considering connecting to the Pascal St zone substation is Goodman Fielder Ernest Adams. The sum of peaks of these loads is 17.45 MW, which the shared sub transmission lines do not have (N-1) capacity for. With the majority of the loads connecting to Kairanga, a second line from Linton GXP to Kairanga may be required. Due to the urban topography and growth in the area, it is expected that this would be underground cabled at an approximate length of 14 km. The route involves a river crossing, which is accounted for in costing by an extra 1 km of cabling. An indicative cost for this is $14.1m.
- **Turitea, Linton GXP (Powerco):** Five RETA sites considering connecting to the Turitea zone substation are Massey University Manawatū, Fonterra R&D Centre, NZ Pharmaceuticals, NZDF Linton, and AgResearch Grasslands Research Centre. The sum of peaks of these loads is 14.41 MW, which the zone substation does not have (N-1) capacity for. Additional to the upgrades specified for the individual Load Sites, a number of the connecting sites require installation of additional circuit breakers at the substation. While some of these may be shared feeders, it is expected that the existing 11 kV switch room will not have room for all of the proposed connecting circuit breakers. An indicative cost for a switch room/switchboard replacement to accommodate the required additional circuit breakers is $5.5m.

[59] Refer to Ergo's Manawatū–Whanganui Spare Capacity and Load Characteristics report (available on EECA's website) for further information.

- **Beach Road, Whanganui GXP (Powerco):** Three RETA sites considering connecting to the Beach Road zone substation are Open Country Dairy Whanganui, AFFCO Imlay, and Department of Corrections Whanganui Prison. The sum of peaks of these loads is 37.3 MW, which the zone substation does not have (N-1) capacity for. Given the intention for Open Country Dairy Whanganui to be fed from a 33 kV feeder, transformer upgrades at Beach Road are only expected if both AFFCO Imlay and Tasman Tanning Castlecliff connect. Transformer replacements would be expected to cost approximately $4.6m. It is expected that this cost would be shared between the two Load Sites. The sub transmission circuit upgrades specified for AFFCO Imlay and Tasman Tanning Castlecliff are considered adequate to supply both sites. Similarly, the sub transmission upgrades specified for Open Country Dairy are considered adequate for all of the connecting loads. This presents opportunities to share costs between RETA sites.

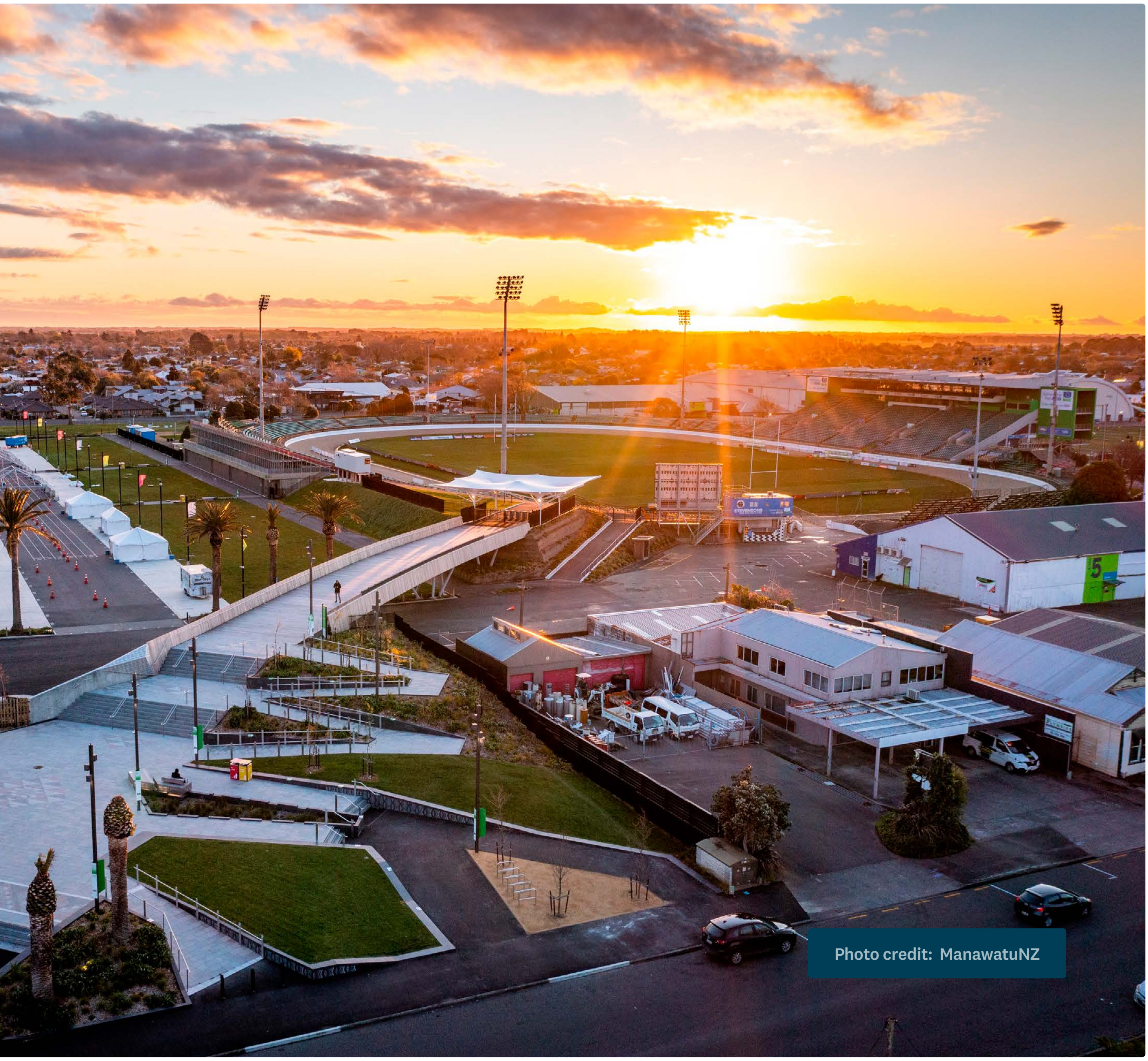


Photo credit: ManawatuNZ

10 Manawatū–Whanganui 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 Manawatū–Whanganui uses year 2022 as baseline. We note that since then, constraints in gas supply have affected prices for fossil gas, and as a result have altered fossil gas consumption patterns, making it increasingly important for organisations to understand their options for alternative fuels to ensure a secure and affordable supply.

The aim of this report 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 analysis to incorporate other sectors. The transport sector will likely 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

Our analysis suggests that up to 35 process heat users could economically switch to biomass as a fuel (including confirmed fuel-switching projects) but that the estimated volumes of unutilised harvesting and processor residues within the region will not be sufficient to meet this demand from 2029 onwards. To meet this potential demand, enhanced and cost-effective recovery from existing harvesting operations is needed otherwise more expensive local sources need to be used, or biomass will need to be imported from other regions.

There will need 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 fuel 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.
- In tandem, work should be undertaken 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[60] and greater transparency about (anonymised) prices and volumes being offered or traded. The analysis for Manawatū–Whanganui 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.

[60] 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 than biomass, 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 EDBs 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 it is unlikely that the conversion of RETA process heat to electricity will trigger significant transmission upgrades. However, there are some potential situations where EDBs will need to upgrade zone substations to accommodate some scenarios of fuel-switching. It is critical that process heat users engage with EDBs early, and often, about their plans.

10.2.1 The role we need EDBs to play

Given the pace of change, EDBs needs to 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 EDBs 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 EDBs

- **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).** EDBs 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 EDB pricing schedules. Process heat users should gain an understanding of the degree to which EDBs 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.** Transpower's web-based guide to the connection process is a good example.[61] 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 EDBs 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.**
  - 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.
  - 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.

[61] 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.

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 RETAs (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 the RETA organisations 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. Ministries such as Ministry for the Environment need 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.

It is also acknowledged that the pathways do not incorporate the potential for the growth in bioenergy and electricity for transport to compete with process heat.

Photo credit: ManawatuNZ

10.4 Summary of recommendations

In summary, our recommendations are:

- More analysis, and potentially pilots, should be conducted to understand costs, volumes, energy content (given the potential susceptibility of these residues to high moisture levels) and methods of recovering 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 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.
- EDBs should 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).
- EDBs and process heat users should engage early to allow EDBs 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 EDBs and process heat user to find the overall best investment option.
- To support this early engagement, EDBs 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 EDBs, and a network section where EDBs provides high-level options for the connection of the process heat user’s new demand. Information provided by EDBs would include the potential implications of each option for construction lead times, capital contributions, network tariffs and the use of the customer’s flexibility.
- EDBs should ensure Transpower and other stakeholders (as necessary) — at an early stage — are aware of information relevant to their planning.
- Retailers, EDBs and the Electricity Authority should assist by sharing information that helps process heat consumers model the benefits of providing flexibility.
- EDBs and retailers should ensure that the tariffs they offer process heat users are incentivising the right behaviour.
- EECA should 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 NZ ETS price assumptions for fiscal forecasting etc.

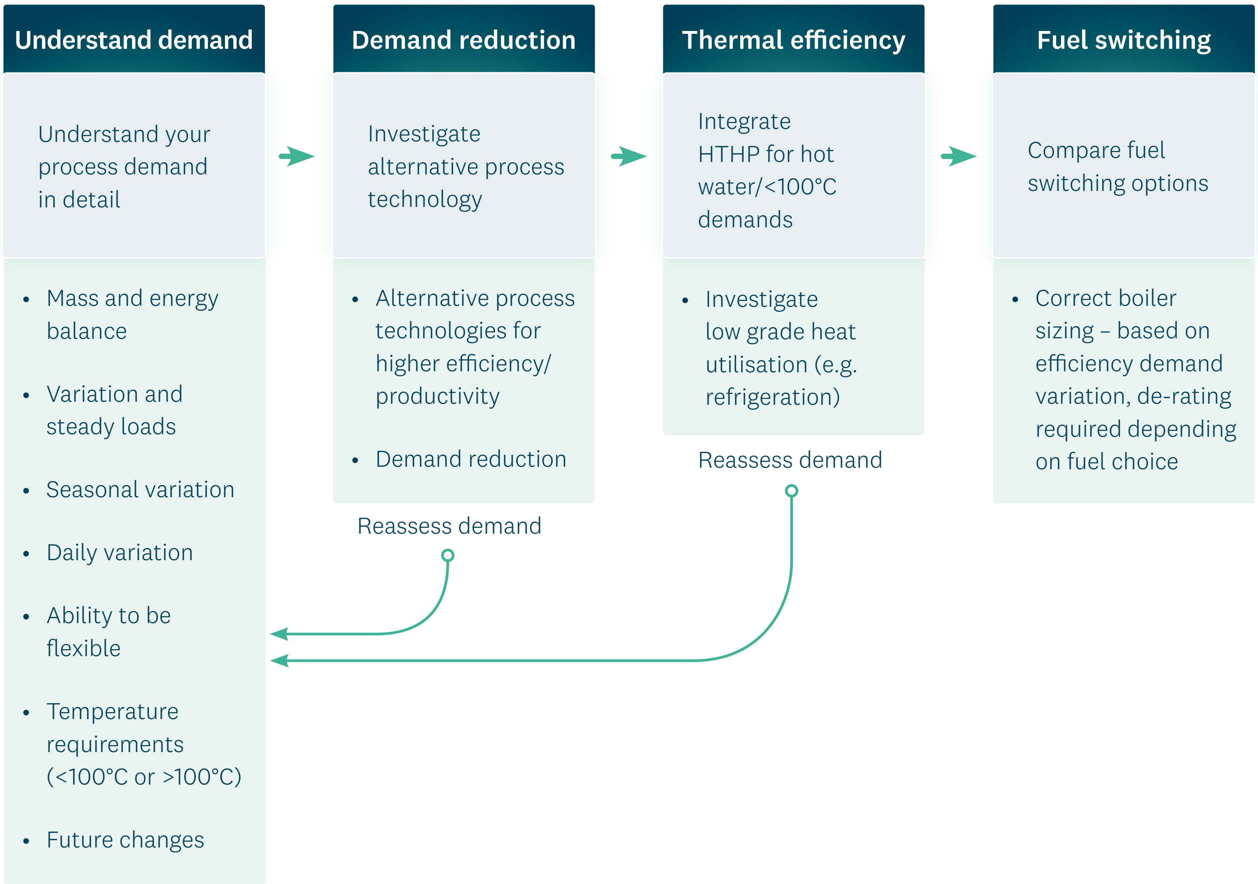
Photo credit: Whanganui & Partners

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

Figure 60 – Key steps in process heat decarbonisation projects.



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 Manawatū–Whanganui 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

Demand reduction includes projects such as 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 washdown optimisation, and pipe insulation.[62] For the dairy sector, opportunities could include 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.

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

11.1.3 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.

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).[63] 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.[64] While not yet used in New Zealand, high temperature steam heat pumps producing 150°C heat[65] 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 Manawatū–Whanganui– region (outlined in Section 7).

Heat pumps can also be integrated with heat recovery, e.g. refrigeration processes. We categorise all heat pump projects (i.e. heat pumps for waste heat recovery and standalone heat pumps) as fuel switch through electrification.

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.[66]

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.

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

64 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.

65 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/

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

Photo credit: Whanganui & Partners

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 Manawatū – Whanganui 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 Manawatū–Whanganui 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 15 is used.

Table 15 – Assumptions regarding heat pump hot water and demand reduction opportunities where ETA information unavailable. Source: DETA

Sector	Proportion of total heat demand < 100°C	Peak demand reduction (%)
Pool Heating	100%	12%
Horticulture	100%	18%
Meat processing	100%	26%
Pet food & rendering	80%	5%
Sawmill	0%	4%
Hospitals (with Surgery)	85%	14%
Hospitals (without Surgery)	100%	14%
Education	100%	11%
High Temperature Manufacturing	0%	2%
Brewery	12%	12%
Dairy Processing	9%	12%
Winery	100%	10%
Laundry	20%	5%
Commercial	100%	13%
Rest Home	100%	10%
Low Temperature Manufacturing	100%	2%

The following general rules have also been applied to each site, which reflect the decarbonisation decision making process outlined in Section 6.3:

- 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.[67]
- 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.

67 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 16 to represent the efficiency of the new process heat equipment.

Table 16 – 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 61 illustrates the NPV for three different fuel choices.

Figure 61 – Illustrative NPV for different heat technology options.

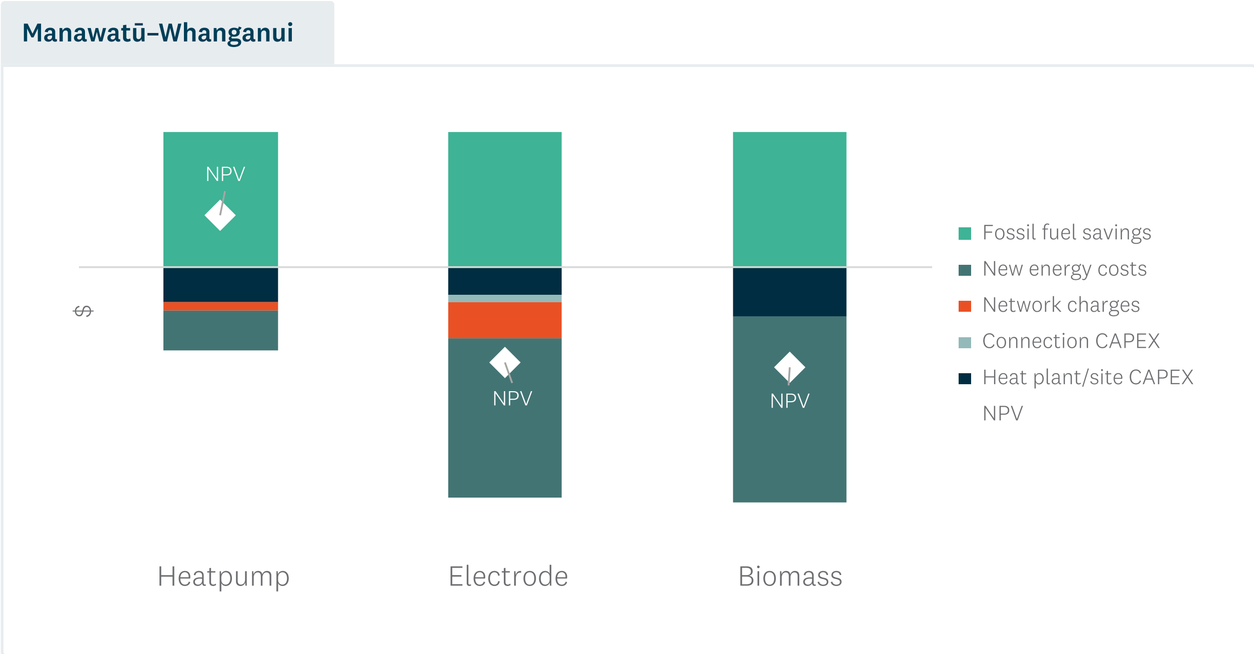


Figure 61 shows that, if the process heat site is using low temperature (<100°C) heat, a heat pump has the highest NPV. In fact, it would have a positive NPV, as the cost of the heat pump option would be more than offset by the savings in fossil fuels. This is a result of the significantly higher efficiency 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 61 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 62 illustrates the relative economics with the same parameters as Figure 61, except we have lowered the utilisation of the plant from 70% above, to 20%.

Figure 62 – Illustrative NPV for different heat technology options, low (20%) utilisation.

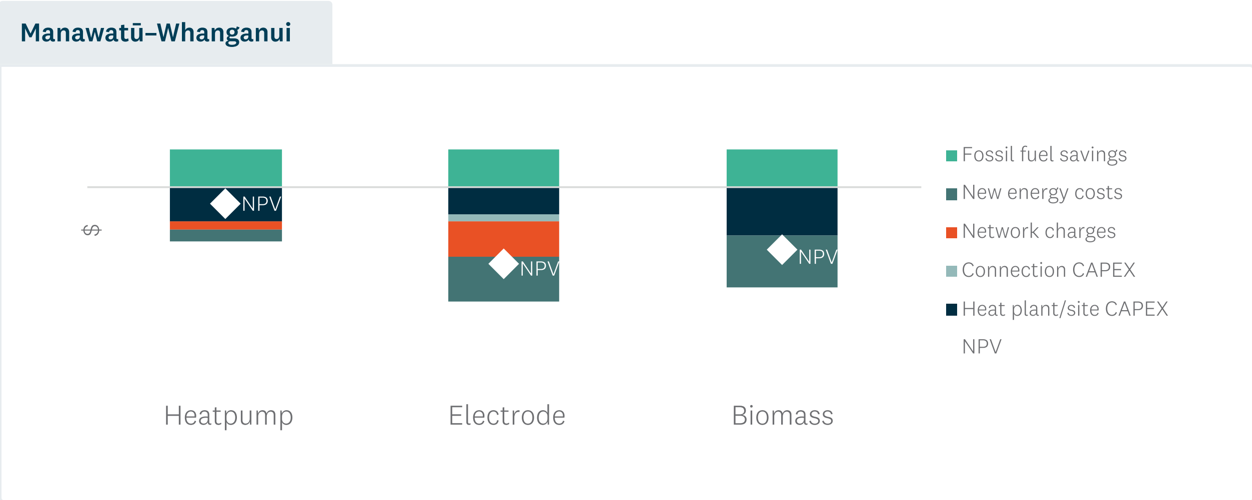


Figure 62 shows that the economics now favour biomass (if the process heat user requires heat greater than 100°C). This is because the consumption-related costs (retail electricity or biomass) have reduced, but the fixed network costs for both options remain the same. Since the biomass had lower fixed 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 61 and Figure 62) 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 61 and Figure 62 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. Many RETA businesses will be aware of the impact of the current carbon price on the price of coal -today.

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*,[68] should it continue to consume fossil fuels. 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.[69]
- 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.[70]

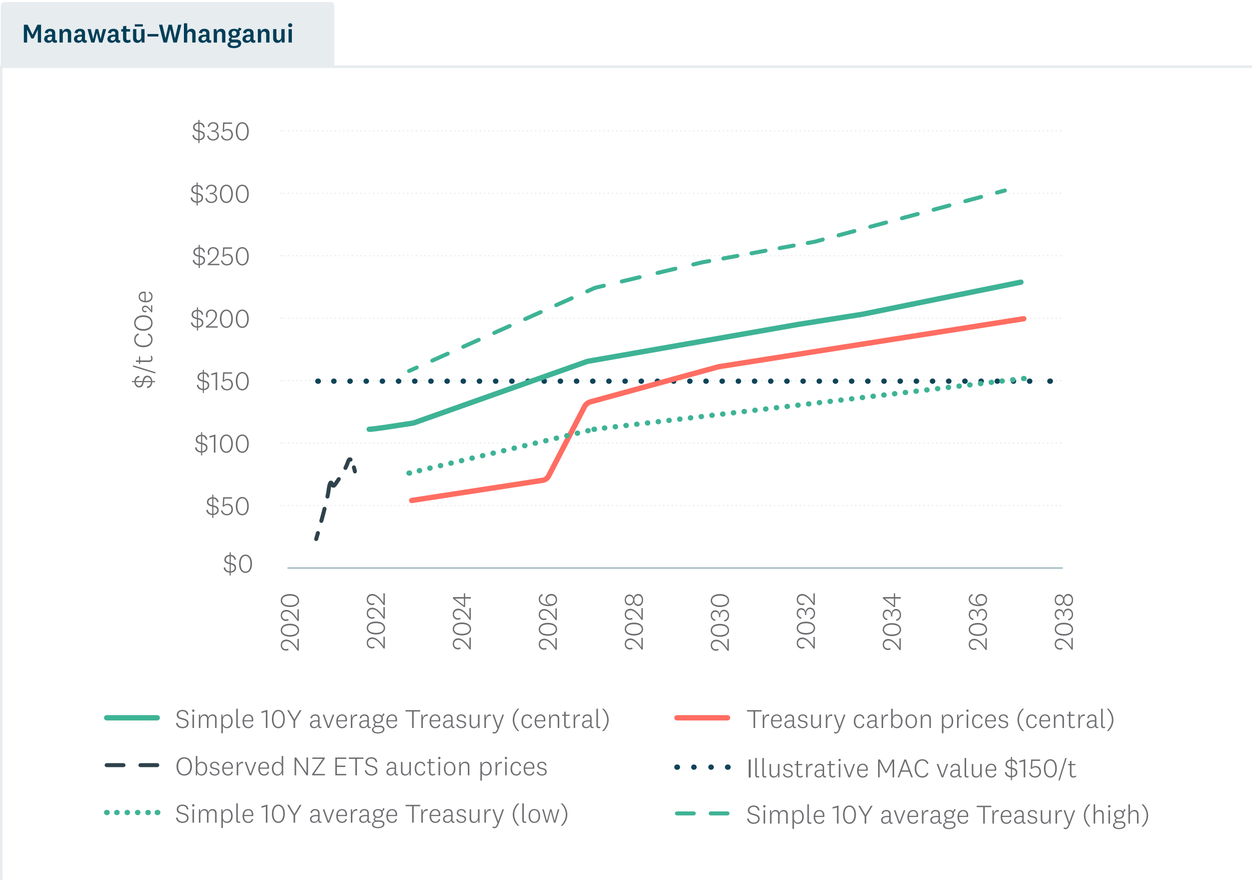
Whether or not ETS prices follow these prices depends largely on whether government policies and resulting decisions by consumers and businesses are aligned with the 'emissions budgets' recommended by the CCC.

68 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.

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

70 See Table 1 in https://www.treasury.govt.nz/sites/default/files/2024-10/cbax-tool-climate-environmental-impacts-oct24.pdf

Figure 63 – 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 63.

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.[71]

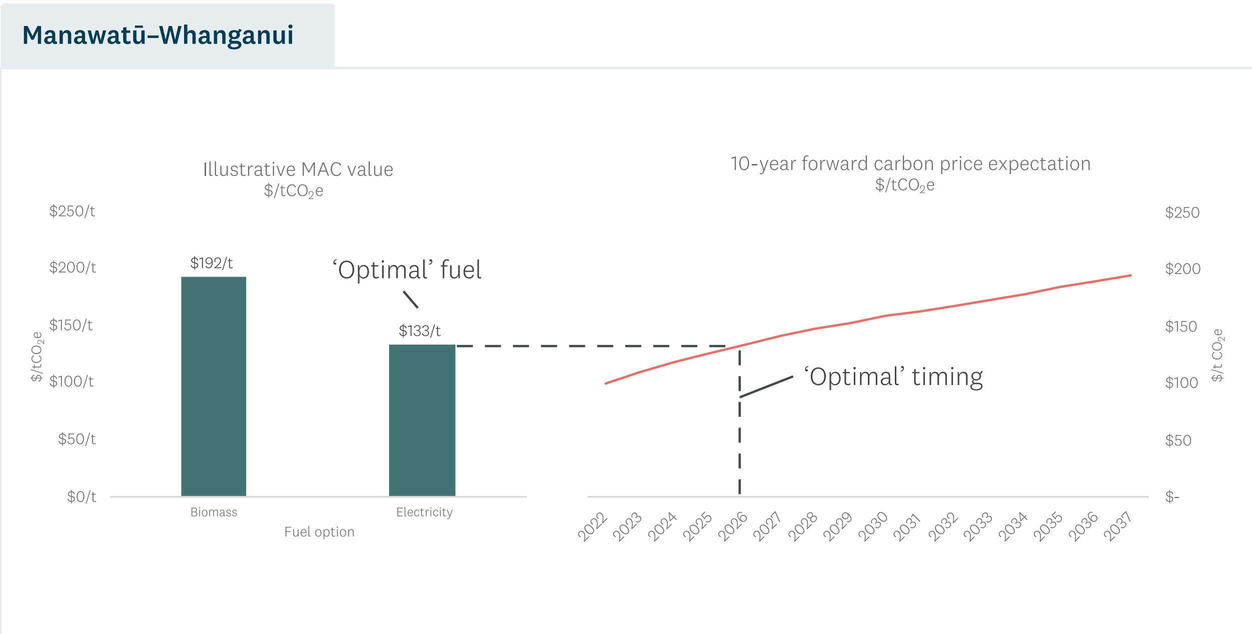
[71] Because NZUs can be purchased today and stockpiled/held for the future, these forward prices contain very limited information about future carbon prices other than the cost of carry (i.e. working capital/interest rates. If, however, the only way to meet NZU obligations in, say, 2026 was to purchase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

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 645 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.

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 63.[72]

The overall framework for how we use MAC values to create the 'MAC Optimal' pathway below is shown in Figure 64.

Figure 64 – illustration of how MACs are used to determine optimal decision making.



72 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 65, we illustrate the difference between these cost concepts using the bioenergy supply curve from Section 8.6 (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 65 – Comparison of the variable costs of biomass and electricity from a delivered heat perspective. Sources: DETA, Whirika and Margules Groome, EnergyLink, EECA.

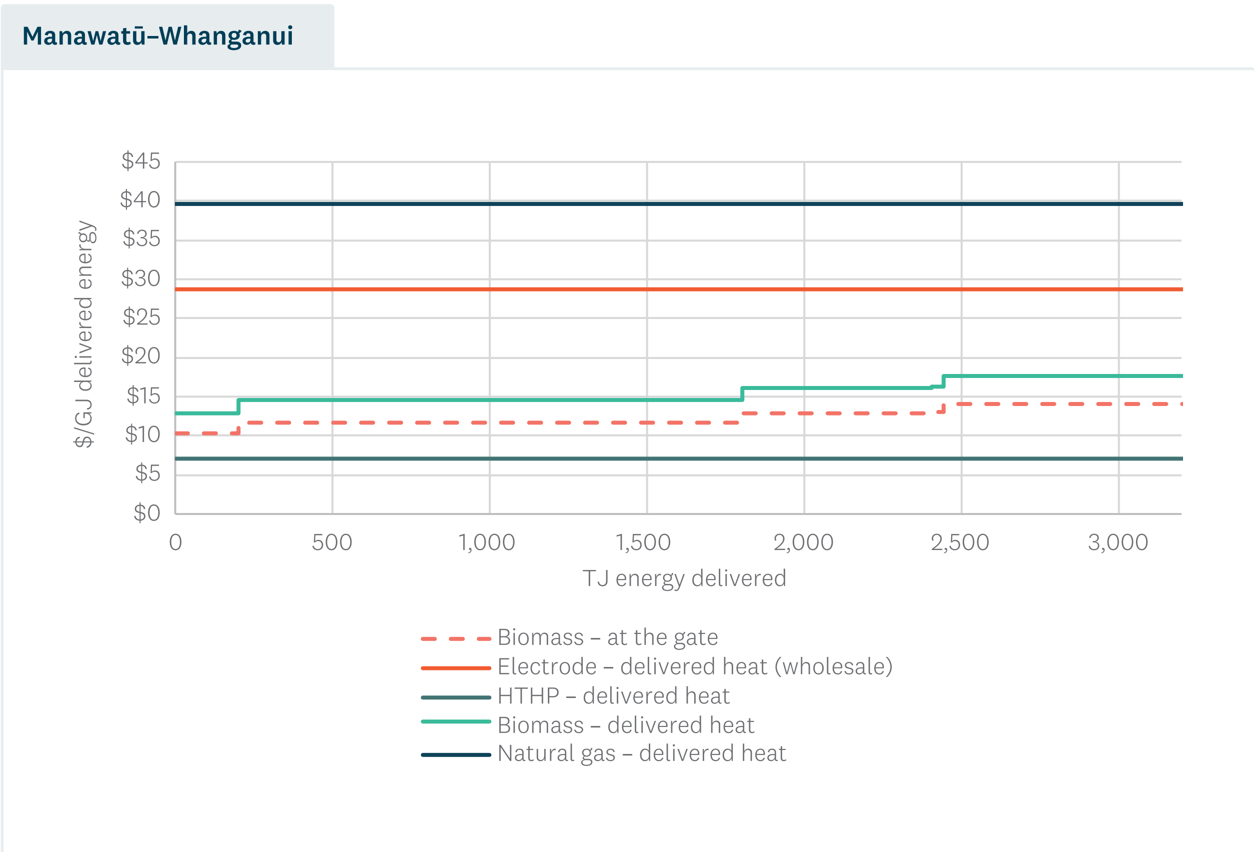


Photo credit: ManawatuNZ

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)[73] around the country where power is traded and reconciled. 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.[74]

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 13.1.2.1).

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

74 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.[75] 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[76] 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. The network component of the bill is discussed in Section 9.3.4 and 9.2.5.
- Energylink prices include the effects of high-voltage transmission losses to the nearest GXP in the Manawatū–Whanganui 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 Manawatū–Whanganui, distribution losses for sites connecting at or below 11kV are around 1.03 for Centralines, 1.08 for Firstlight Network and 1.03 for Unison Network's Manawatū–Whanganui network.[77]
- 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.[78] 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.

75 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.

76 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.

77 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.

78 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**[79] — 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 17. More detail on these assumptions is available in EnergyLink's report.[80]

Table 18 – Electricity market scenarios considered. Source: EnergyLink.

Scenario driver	Central price scenario	High price scenario
NZAS at Tīwai Pt	Remains	Remains
Demand growth[81]	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[82]	NZD75/t	NZD75/t
Generation investment behaviour[83]	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

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

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

81 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 Tīwai exit). EnergyLink's Central Estimate in 2032 looks ~3TWh lower than the CCC's 'Tīwai Stays' sensitivity.

82 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.

83 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.[84] 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,[85] but instead to apply assumptions that would deliberately lead to high and low-price outcomes. 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.[86]
- 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%.

[84] "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

[85] For example, in the Low Scenario, Tīwai is assumed to exit but other decarbonisation demand is also assumed to be muted. However, it is the Tīwai 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.

[86] 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')[87] 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'.[88]

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.[89] 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.[90]

87 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/

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

89 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.

90 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.[91] 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).[92]

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 13.3.

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').

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

92 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[93] for the 2023 year, rather than actual observed peak demand as inferred by Figure 55. 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.[94] 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.

[93] 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.

[94] 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.[95]
- 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.

95 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 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.

Of course, altering the production of process heat in order to provide flexibility services 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),[96] this can enable flexibility. 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, fossil 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 to $300,000[97] per year for every MW of demand that can be reliably moved away from the overall network peak. 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 13.2.6.

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 Manawatū–Whanganui 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.

[96] Other methods include ice slurry storage, hot oil storage, steam accumulators.

[97] 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 and consultancies** to assess the degree to which the site's response to these signals can be automated.[98]

13.2.5 The FlexForum[99]

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.[100] 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.

98 Examples of flexibility providers include Enel X and Simply Energy.

99 See https://www.araake.co.nz/projects/flexforum/

100 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 9.3.2 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[101] 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.
   - 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[102] reduce demand so that the network remains stable and thus doesn't affect other consumers connected to the network.

[101] This would have to be sufficiently reliable to give the network company the confidence to scale back its investment.

[102] 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.[103]

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 to $300,000[104] per year for every MW of demand that can be reliably moved away from the overall network peak. 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.[105] 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).

103 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.

104 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*.

105 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 Transmission Pricing Methodology (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,[106] but the beneficiaries have been established by the Authority (and allocations of charges calculated accordingly). 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 Manawatū–Whanganui 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,[107] it is too difficult to identify specific beneficiaries of each asset. 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 13.3.2 of this report.

106 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.

107 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.
- 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'[108] of the grid give EDBs some discretion to how costs will fall. 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.[109] 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.

108 Either energy usage over time, or peak demand, for example.

109 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.[110] 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 18.

Table 18 – Forecast connection charges 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 19.

Table 19 – Forecast connection charges 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

110 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 20.

Table 20 – Benefit-based investment 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[111]-4 to n-2 inclusive, in this case 2018 to 2021. 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 21.

Table 21 – Worst case benefit-based charge 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.

111 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 to 2017 inclusive. As the new electrode boiler is going to increase the consumption at the GXP by 138GWh and the 2014 to 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 22.

Table 22 – Benefit-based charges 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 charges

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 $AMDR_{baseline}$[112] is different to the one that applies for CC. However, we will assume the same allocation factor for AMD applies for the AMDRbaseline, 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 23.

Table 23 – Residual charges 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 24.

Table 24 – Residual charges 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.

112 Anytime Maximum Demand for Residual Charges baseline.

13.3.2.4 Summary of charges

Table 25 summarises the outputs of Table 18, Table 22, and Table 23 to give the forecast allocation of transmission charges to the process heat user without the proposed electrode boiler.

Table 25 – 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 26 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 26 – 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 26 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** — 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** —— 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** — 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** — 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** — produced from the offcuts of milling and is sold as firewood.
- **Dockings** — 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** — 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** — 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.

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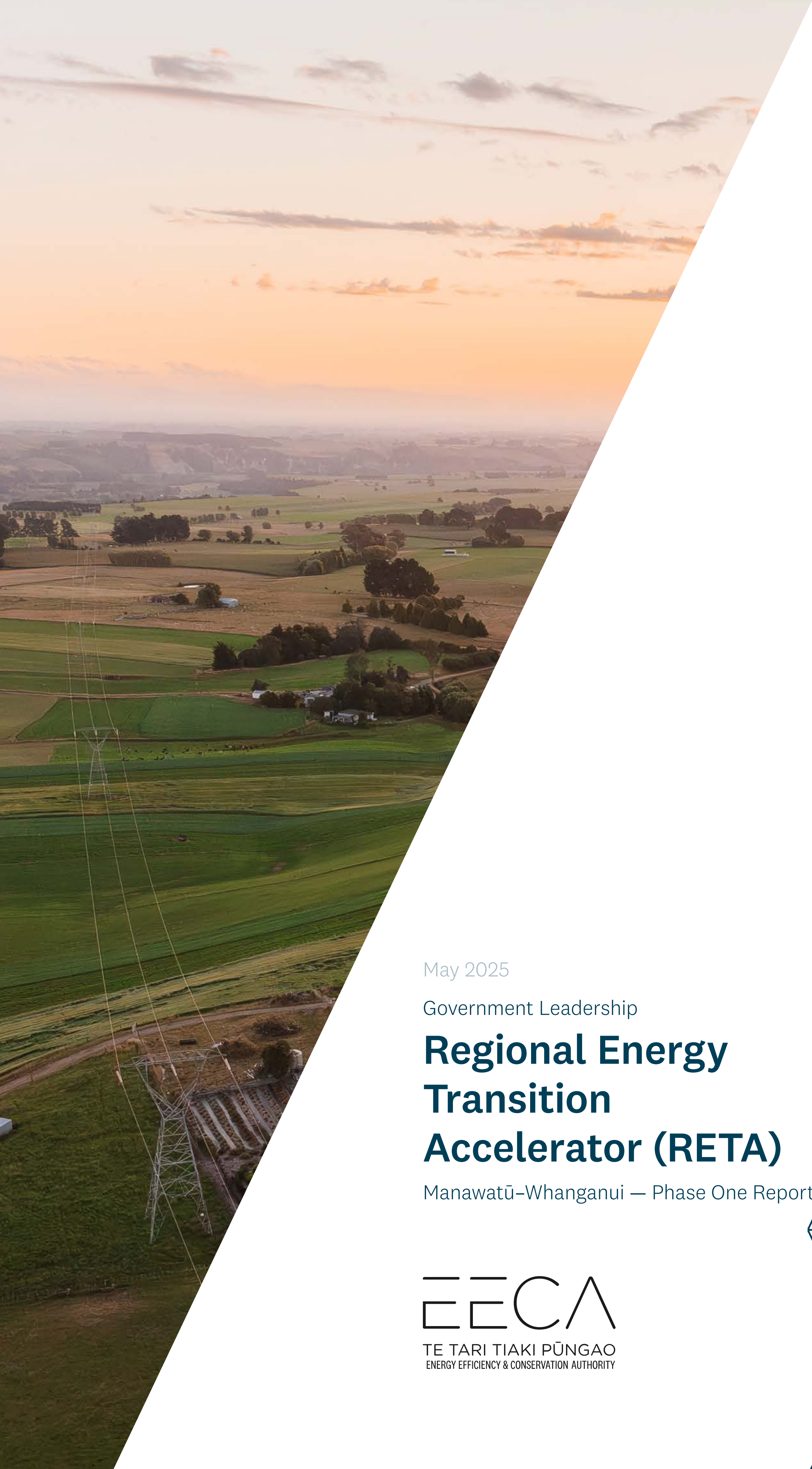

May 2025

Government Leadership

Regional Energy Transition Accelerator (RETA)

Manawatū-Whanganui — Phase One Report

TE TARI TIAKI PŪNGAO
ENERGY EFFICIENCY & CONSERVATION AUTHORITY