Government Leadership

Regional Energy Transition Accelerator (RETA)

Nelson, Marlborough, Tasman – Summary Report

November 2023

EECA
TE TARI TIAKI PŪNGAO
ENERGY EFFICIENCY & CONSERVATION AUTHORITY

1 Foreword

Moving our industrial sector off fossil fuels and onto clean energy requires good information, collaboration, and a well-connected energy system.

This Nelson, Marlborough, Tasman RETA report provides businesses and renewable energy suppliers with the information they need to make investment decisions – taking into account the region's specific needs, opportunities and barriers.

The report is part of EECA's Regional Energy Transition Accelerator (RETA) programme which aims to create a regional pathway through the energy transition. RETA work builds on the site-specific decarbonisation pathways that EECA's Energy Transition Accelerator (ETA) programme developed for organisations across the region and asks what is needed to coordinate and fast track the region to clean and clever energy.

The report highlights the vital role played by demand reduction and the need to support the region through upstream infrastructure investments. The analysis shows that the region will be able to quickly reduce emissions by focusing on a few key projects and making proactive infrastructure investment decisions ahead of known future need.

Many regional businesses are already undertaking low emissions projects or have a pathway mapped out with EECA. But there is potential to support smaller businesses in the region further.

Insights in the report illustrate that biomass could have a significant role in the region. Pathway analysis suggests that the available residues will be more than enough to supply new process heat demands that come from industry switching to renewable biomass energy. There is also the potential for Nelson, Marlborough, Tasman to support nearby regions with biomass.

Working together is essential if we are to accelerate the uptake of renewable energy. We are proud to have worked collaboratively to develop this report with the Nelson Regional Development Agency, Marlborough District Council's Economic Development Unit, local EDBs such as Nelson Electricity, Network Tasman, and Marlborough Lines, Transpower, regional forestry companies, wood processors, electricity generators and retailers, and medium to large industrial energy users.

We look forward to providing continued support to the region as it continues its journey.

Nicki Sutherland
Group Manager Business, EECA

Photo: Lake Grassmere, Marlborough, New Zealand. Credit – Dominion Salt

"The region will be able to quickly reduce emissions by focusing on a few key projects."

Nicki Sutherland , Group Manager Business, 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 Nelson, Marlborough, and Tasman region
- Nelson Regional Development Agency & Economic Development Unit at the Marlborough District Council
- Local electricity distribution businesses (EDB) Nelson Electricity, Network Tasman and Marlborough Lines
- 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:

- **Lumen** – process heat demand-side assessment
- **Ahikā and Margules Groome** – biomass availability analysis
- **Ergo Consultants** – electricity network analysis
- **EnergyLink** – electricity price forecast
- **Wayne Manor Advisory** – report collation, publication and modelling assistance

The Nelson, Marlborough, Tasman region is the focus for New Zealand's sixth Regional Energy Transition Accelerator (RETA).

Nelson, Marlborough, Tasman – New Zealand

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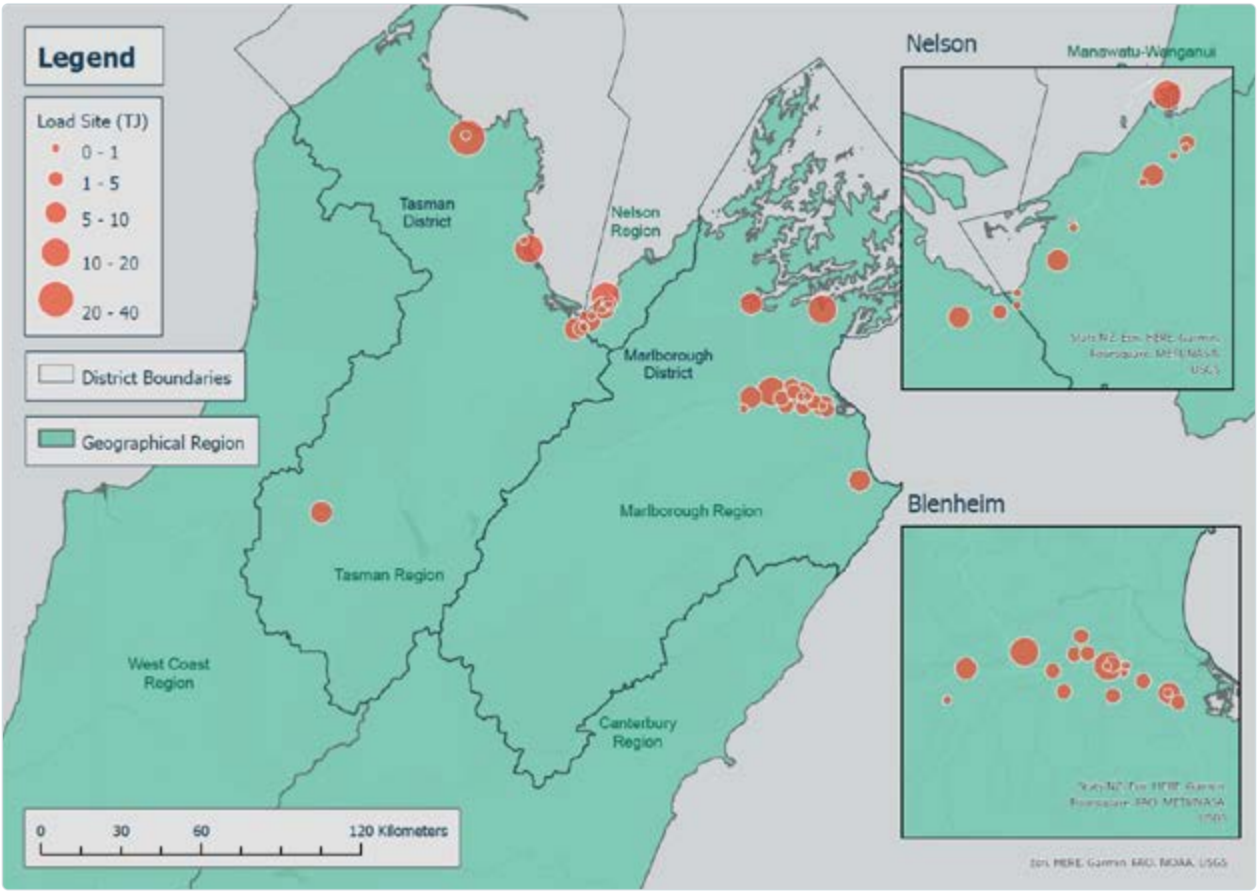
J.S Ewers, Nelson, New Zealand

4 Nelson, Marlborough, Tasman overview

This region covers the Nelson City, Marlborough, and Tasman districts (Figure 1). For the purposes of this report, we refer to this region as 'NMT'.

Figure 1 – Map of area covered by the Nelson, Marlborough, Tasman RETA.



The NMT RETA brings together information about process heat decarbonisation plans from EECA's Energy Transitional Accelerators (ETAs) with individual organisations and data from the Regional Heat Demand Database (RHDD) completed by local electricity distribution businesses, Transpower and EECA. While ETAs focus on the decarbonisation pathways and plans of individual organisations, the RETA expands this focus to consider barriers and opportunities for regional supply-side infrastructure (e.g. networks and regional resources) to better support decarbonisation decisions.

This report is the culmination of the RETA planning phase in the region and aims to:

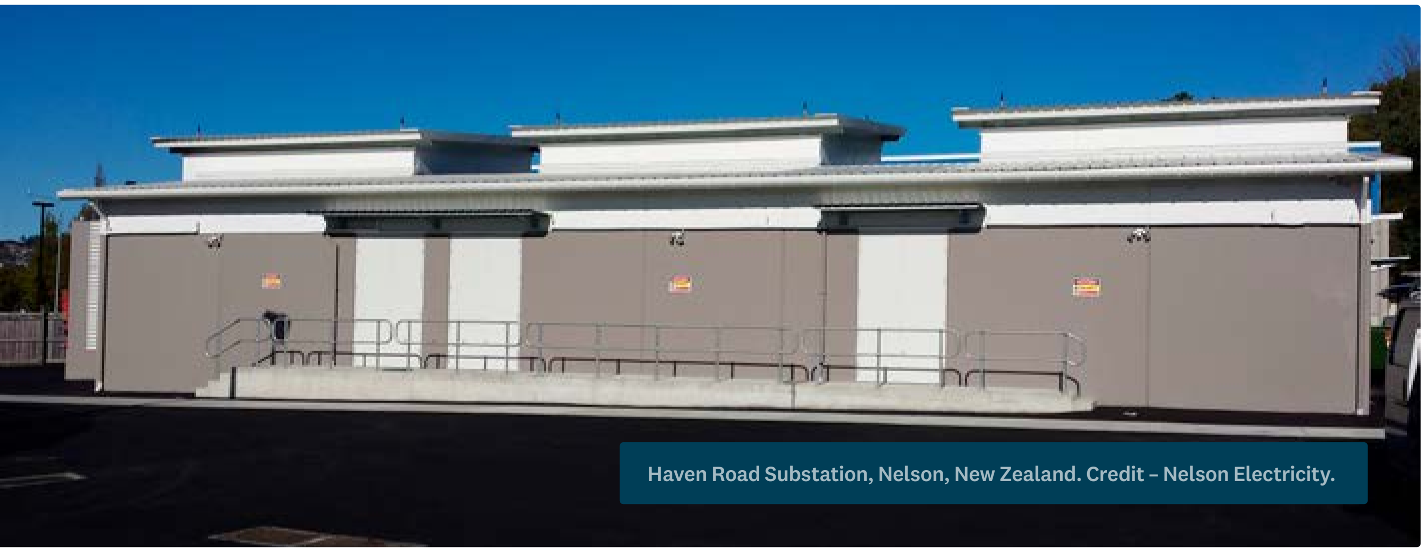
- Provide process heat users with coordinated information specific to the region to help them with making more informed decisions on fuel choice and timing.
- Improve fuel supplier confidence to invest in supply side infrastructure.
- Surface issues, opportunities, and recommendations.

The next phase of a RETA focuses on implementing recommendations from phase 1 that remove barriers or accelerate opportunities for decarbonisation of process heat.

The 38 sites covered span the dairy, meat, industrial and commercial[1] sectors. These sites either have fossil-fuelled process heat equipment larger than 500kW (i.e. process heat equipment details have been captured in the Regional Heat Demand Database) or are sites for which EECA (Energy Efficiency and Conservation Authority) has detailed information about their decarbonisation pathway[2]. Together, these sites collectively consume 998TJ of process heat energy, primarily in the form of coal, and currently produce 88kt pa of carbon dioxide equivalent (CO_2e) emissions.

Table 1 – Summary of NMT RETA sites fossil fuel process heat demands and emissions

Sector	Sites	Thermal capacity (MW)	Thermal fuel consumption (GWh/yr)	Process heat demand today (TJ/yr)	Process heat annual emissions (kt CO_2e/yr)
Dairy	2	12	79	283	26
Meat	6	22	46	167	12
Industrial	17	60	124	445	44
Commercial	13	24	28	102	5
Total	**38**	**118**	**277**	**998**	**88**



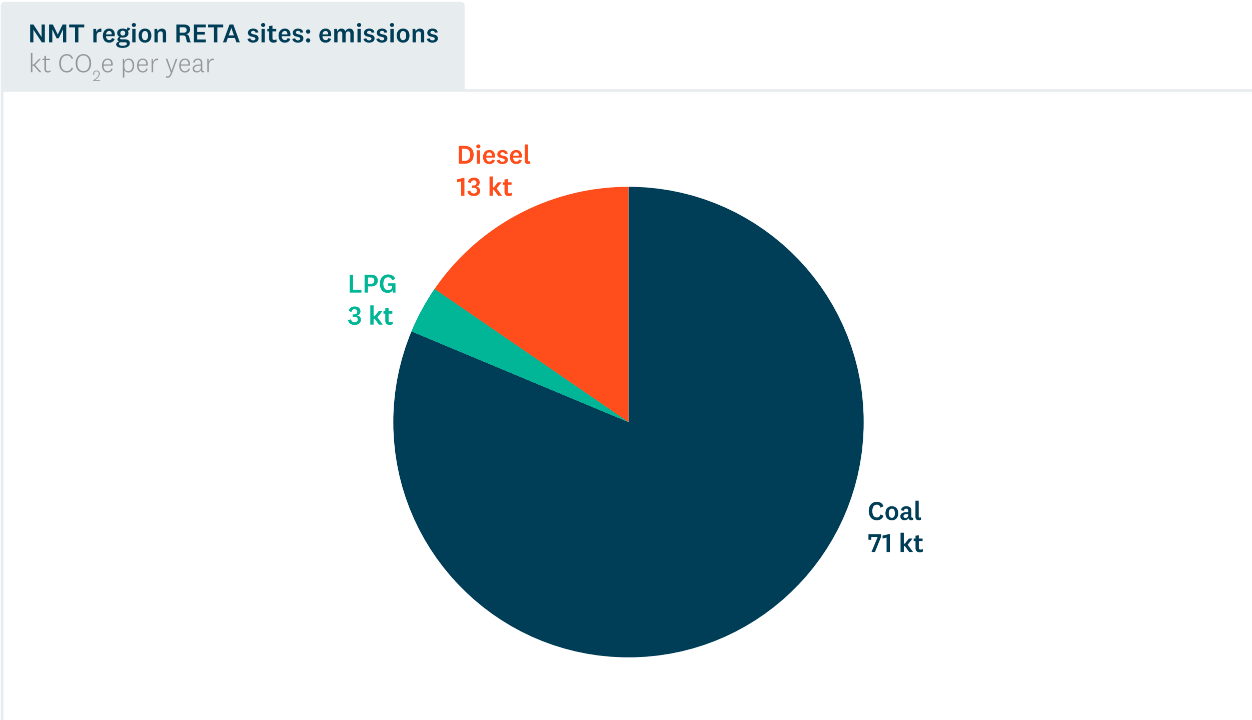
Haven Road Substation, Nelson, New Zealand. Credit – Nelson Electricity.

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

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

The majority of NMT RETA process heat emissions come from coal (Figure 2).

Figure 2 – 2020 annual emissions by process heat fuel in NMT RETA. Source: EECA



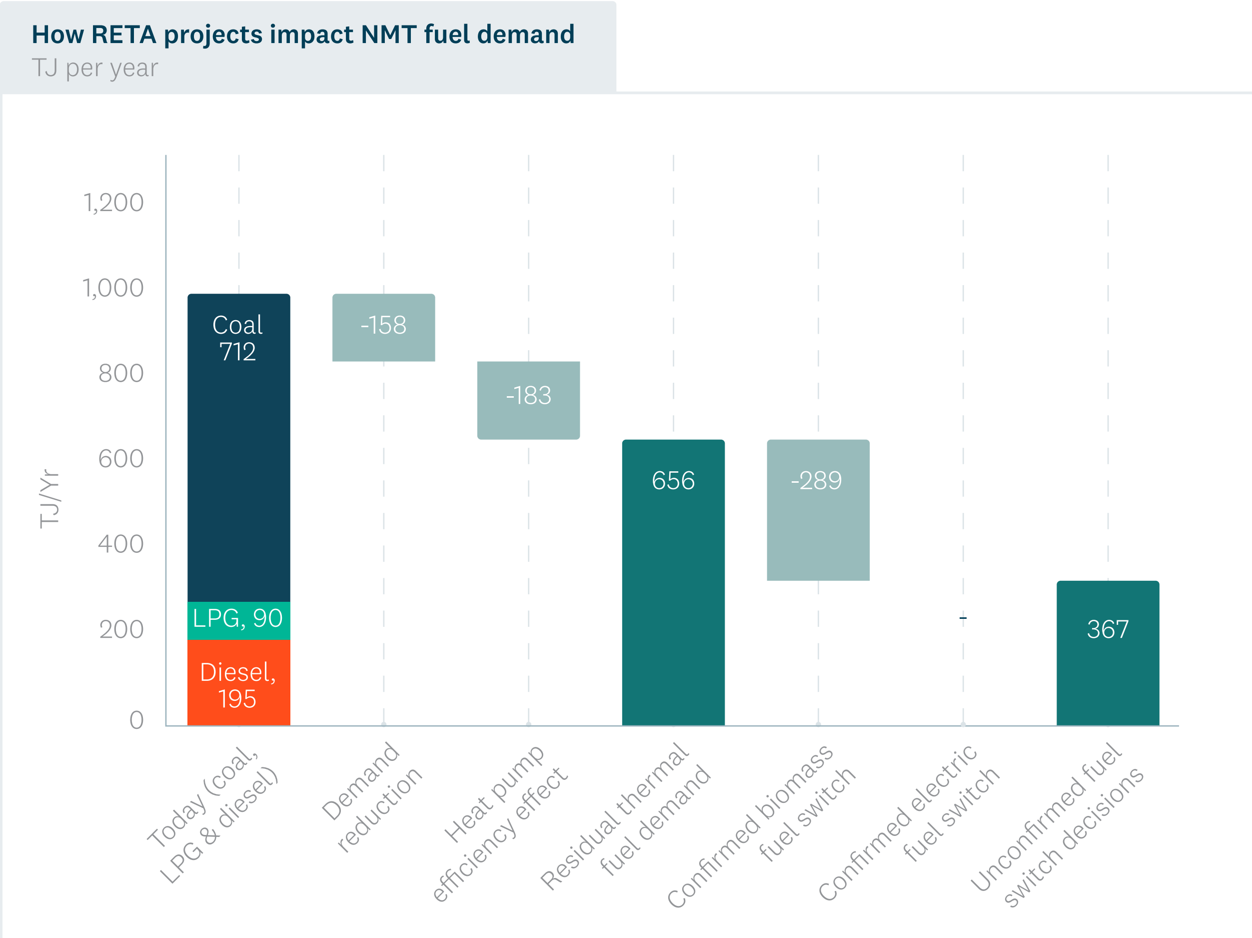
The objective of the NMT RETA is to eliminate as much of these process heat emissions as possible. It does this by supporting organisations in their consideration of:

- Demand reduction (for example reducing heat demand through process optimisation).
- Thermal efficiency (for example installation of highly efficient heat pumps).
- Switching away from fossil-based fuels to a low-emissions source such as biomass and/or electricity.

J.S Ewers, Nelson, New Zealand.

Figure 3 illustrates the potential impact of RETA sites on regional fuel demand, both as a result of decisions where investment is already confirmed, and decisions yet to be made.

Figure 3 – Potential impact of fuel switching on fossil fuel usage, 2023-2037. Source: EECA



As explored below, this RETA looks at a number of pathways by which the 367TJ of unconfirmed fuel switching decisions could occur. Both biomass and electricity are considered as potential fuel sources. EECA's assessments of biomass and electricity focus on the key issues that are common to all RETA process heat sites contemplating fuel switching decisions. This includes the availability and cost of the resources that underpin each fuel option, as well as the sufficiency of the networks required to ensure that the fuel can be delivered to the process heat users' sites. This assessment is unique to the NMT region. The availability and cost of supply resources and connection can then be used to simulate RETA sites' collective decisions about fuel switching under different sets of assumptions. This provides valuable information to individual process heat decision makers, infrastructure providers, resource owners, investors, and policy makers.

4.1 RETA site summary

As outlined above, there are 38 sites considered in this study. Across these sites, there are 76 individual projects spanning the three categories discussed above – demand reduction, heat pumps and fuel switching.

Table 2 shows the current status of the NMT RETA process heat projects. Some have been confirmed by the process heat organisation (i.e. the organisation has committed to the investment and funding allocated) but are not yet completed. Over 90% of the 76 projects are unconfirmed, in that the process heat organisation is yet to commit to the final investment.

Table 2 – Number of projects in NMT RETA: Confirmed vs Unconfirmed. Source: Lumen, EECA.

Status	Demand reduction	Heat pump efficiency	Fuel switching	Total
Confirmed	1	1	4	6
Unconfirmed	32	21	17	70
Total	**33**	**22**	**21**	**76**

Demand reduction and thermal efficiency are key parts of the RETA process and, in most cases, enable (and helps optimise) the fuel switching decision. This RETA report has a greater level of focus on the fuel switching decision, due to the higher capital and fuel intensity of this decision.

Below we show the expected remaining fuel demands from each site in the NMT RETA, after any demand reduction projects and/or heat pump projects are accounted for. We present biomass demands both in TJs and green tonnes (55% moisture content) and report the peak demand from the boiler should it convert to electricity.

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Table 3 – Summary of NMT RETA sites with fuel switching requirements. Green shading indicates confirmed projects; orange highlighting indicates the preferred fuel option according to a commercial decision making criteria explained below.

Site name	Industry	Project status	Bioenergy required TJ ('000t)/yr	Electricity peak demand (MW)
Talleys Blenheim	**Pet Food & Rendering**	**Confirmed**	**48.85 (6.8)**	**N/A**
South Pine (Nelson) Ltd	**Sawmill**	**Confirmed**	**8.06 (1.12)**	**N/A**
Parklands School	**Education**	**Confirmed**	**0.17 (0.02)**	**N/A**
J S Ewers Appleby	**Horticulture**	**Confirmed**	**225.36 (31.37)**	**N/A**
Talleys Motueka	Pet Food & Rendering	Unconfirmed	41.44 (5.77)	**4.47**
Dominion Salt Lake Grassmere	Other Manufacturing	Unconfirmed	**23.01 (3.20)**	2.77
Sealord Nelson	Pet Food & Rendering	Unconfirmed	35.9 (5.00)	**4.38**
Sanford Havelock	Pet Food & Rendering	Unconfirmed	**27.27 (3.80)**	2.55
McCashins Brewery	Brewery	Unconfirmed	**17.54 (2.44)**	2.37
Fonterra Takaka	Dairy Processing	Unconfirmed	134.86 (18.77)	**5.25**
Shonrei Products	High Temperature Manufacturing	Unconfirmed	**11.38 (1.58)**	3.17
Fulton Hogan Renwick	High Temperature Manufacturing	Unconfirmed	**8.54 (1.19)**	4.95
Indevin Ltd	Winery	Unconfirmed	**7.58 (1.06)**	1.09
Delegat Marlborough	Winery	Unconfirmed	**5.16 (0.72)**	1.73
Pernod Richard	Winery	Unconfirmed	**5.03 (0.70)**	2.73
Nelson Hospital	Hospitals (with Surgery)	Unconfirmed	**0.00 (0.00)**	2.20
Villa Maria Estate Ltd Blenheim	Winery	Unconfirmed	**1.99 (0.28)**	1.27
WineWorks Marlborough	Winery	Unconfirmed	1.03 (0.14)	**0.09**
Kim Crawford Winery	Winery	Unconfirmed	**0.63 (0.09)**	0.86
Ariki New Zealand Ltd	High Temperature Manufacturing	Unconfirmed	**0.53 (0.07)**	0.15
Waihopai River Vineyard	Winery	Unconfirmed	**0.16 (0.02)**	0.22

Four sites have already confirmed their fuel of choice (shaded in blue), representing a demand for 282TJ (39,310t[3]) of biomass.

[3] Wet tonnes (55% moisture content) and assuming a boiler efficiency of 80% (compared to coal at 78%).

5 Simulated decarbonisation pathways

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

Rather than attempt to include all these factors, we present a range of different potential NMT-specific pathways reflecting different decision-making criteria that process heat users (who have not confirmed their fuel choice) will use.

Two pathways present 'bookends' that focus exclusively on one of the two fuel options (biomass or electricity). Two others use a global standard marginal abatement cost, or MAC, to quantify the cost to the organisation of decarbonising their process heat. This is expressed in dollars per tonne of CO_2e reduced by the investment and allows us to determine the timing of the investment as being the earliest point when a decarbonisation decision saves the process heat user money over the lifetime of the investment – the point in time that the MAC of the project is exceeded by the expected future carbon price.

Haven Road substation, Nelson, New Zealand. Credit – Nelson Electricity.

The pathways were then developed as follows:

Pathway name	Description
Biomass Centric	All unconfirmed site fuel switching decisions proceed with biomass at the timing indicated in the organisation's ETA pathway. If not indicated, timing is set at 2036.
Electricity Centric	All unconfirmed fuel switching decisions with electricity as the sole fuel at the timing indicated in the organisation's ETA pathway. If not indicated, timing is set at 2036.
BAU Combined	All unconfirmed fuel switching decisions (i.e. biomass or electricity) are determined by the lowest MAC value for each project; timing of commissioning as indicated in the organisation's ETA pathway. If not indicated, timing is set at 2036.
Linear	Each site switches to the fuel with the lowest MAC value for that site; projects ordered and timed to achieve a relatively constant annual level of emissions reduction and growth in electricity/biomass consumption (within reason)[4].
MAC Optimal	Each site 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 10-year rolling average of the Climate Change Commission's future carbon prices in their Demonstration Path.

For all pathways, the following constraints were applied to the methodology:

- Boiler conversions involving facilities owned by the Ministry of Education, Ministry of Health or the Department of Corrections are all assumed to occur by the end of 2025.
- All RETA decarbonisation projects are executed by 2037 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[5]. This means that any projects that are still not 'economic' using our MAC criteria by 2036, are assumed to be executed in 2036.

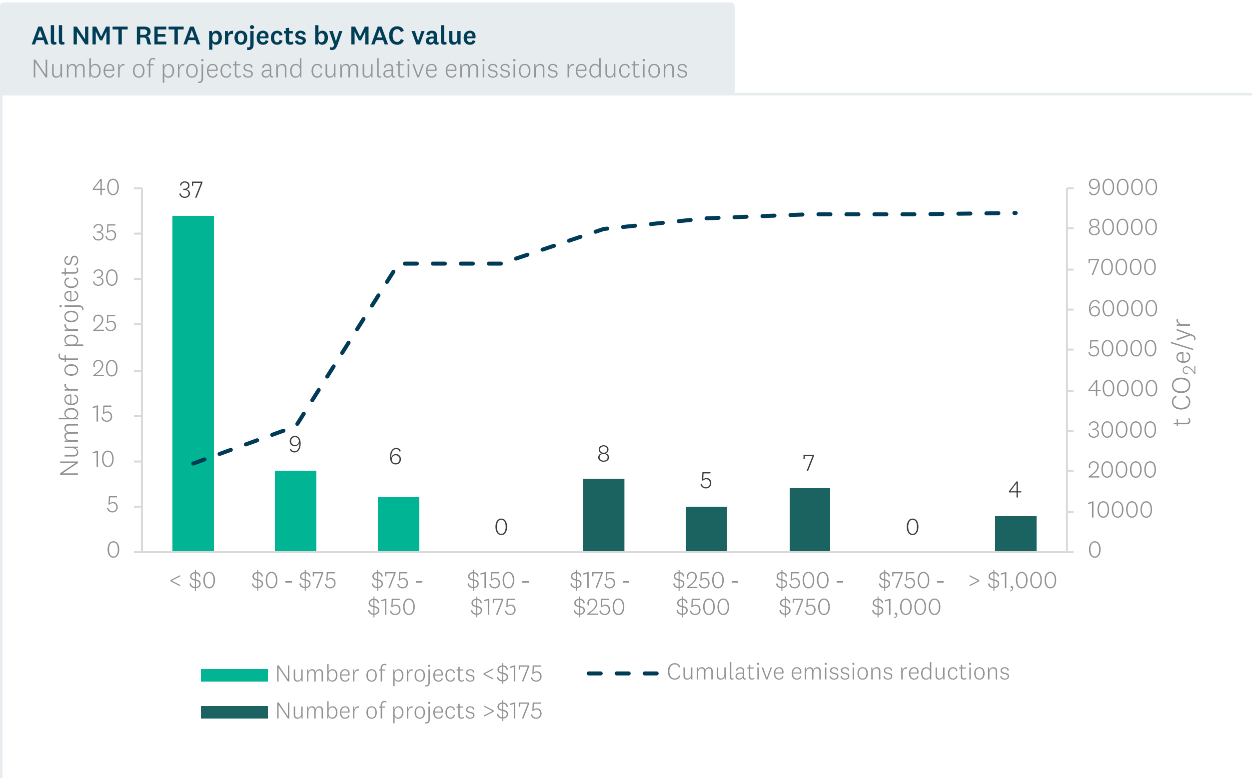
4 There could be a range of ways this could be observed. We suggest it could be thought of as organisations desiring to take a MAC Optimal approach, but being slowed by capital constraints, the effect of uncertainty, a more gradual emergence of biomass resources, and/or the realities of constraints on Transpower and EDBs ability to deliver network upgrades as a result of regulatory requirements, construction capacity etc.

5 See https://environment.govt.nz/acts-and-regulations/national-policy-statements/national-policy-statement-for-greenhouse-gas-emissions-from-industrial-process-heat/. The new National Environmental Standard which supports the NPS also places increased restrictions on process heat boilers burning fossil fuels other than coal. We assume that all RETA process heat fossil fuels will convert to a low emissions equivalent by 2037.

5.1 At expected carbon prices, 85% of emissions reductions are economic by 2037[6]

Using the biomass and electricity costs presented in Section 6 and Section 7, Figure 4 summarises the resulting MACs associated with each decision, and the emissions reduced by these projects.

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



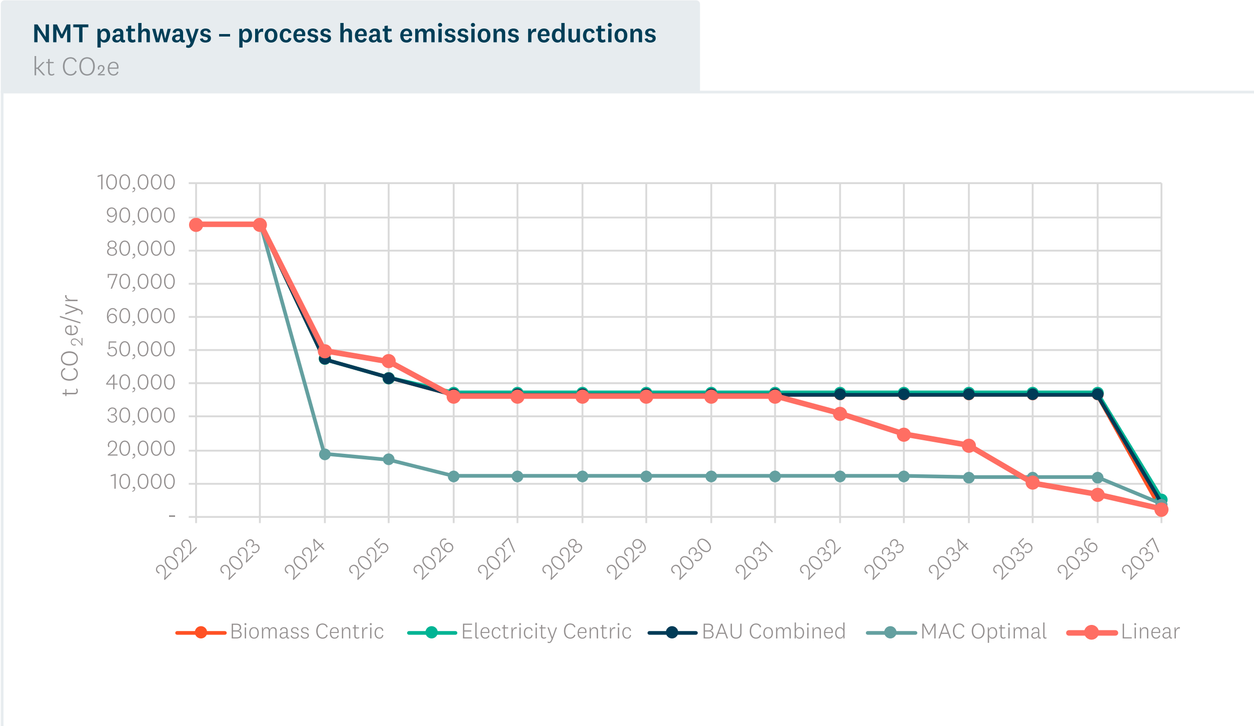
Out of 84kt of process heat emissions covered in the NMT RETA, 71kt (85%) have marginal abatement costs (MACs) less than $150/t$CO_2$e. Based on an expectation the carbon prices will follow the Climate Change Commission's Demonstration Pathway, these emissions reduction projects would be economic prior to 2037. Without any carbon price, 37 of these projects would be economic.

Compared to a scenario where each of these projects was executed based on the organisations' current plans (a BAU pathway), executing these projects using a commercial MAC decision-making criteria (MAC Optimal) would accelerate decarbonisation, and reduce the release of long-lived emission by 342kt over the 15-year period of the RETA analysis (Figure 5[7]).

6 By 'economic', we mean that at a 6% discount rate these projects would reduce costs for the firms involved over a 20-year period (i.e. the Net Present Value would be greater than zero, at the assumed trajectory of carbon prices).

7 Note that the Electricity Centric and Biomass Centric pathways are obscured in the chart by the BAU Combined pathway.

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



The MAC Optimal pathway proceeds faster, with most emissions reductions achieved by 2028. However, this pace is likely to be constrained by practical matters such as:

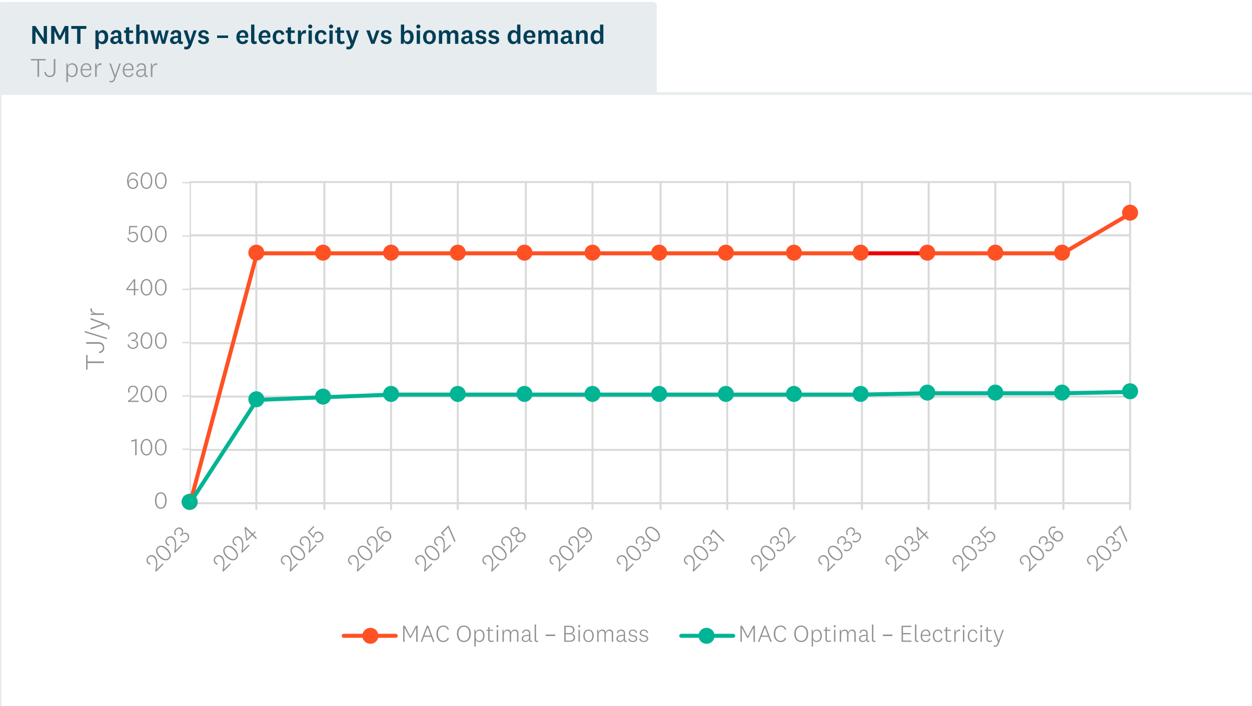
- The ability of process heat users to secure funding and commit to these investments in this timeframe.
- The ability of infrastructure providers to deliver the necessary network upgrades.
- The ability of forest owners and bioenergy aggregators to make sufficient resource available.


Alliance Group, Nelson, New Zealand.

5.1.1 Pathway implications for electricity and biomass demands

The MAC Optimal pathway sees fuel decisions that result in 28% of the energy needs in 2037 supplied by electricity, and 72% supplied by biomass (Figure 6). We expand further on these outcomes in the sections below.

Figure 6 – Electricity and biomass demand in MAC Optimal pathway. Source: EECA



Before doing so, it is important to recognise the significant impact that demand reduction and heat pump efficiency projects have on the overall picture of NMT process heat decarbonisation. As shown in Figure 3, investment in demand reduction and heat pumps meets 34% of today's NMT energy demands[8] from process heat users, which in turn reduces the necessary fuel switching infrastructure required: thermal capacity required from new biomass and electric boilers would be reduced by 35MW if these projects were completed. We estimate that demand reduction and heat pumps would avoid investment of $35M to $53M in electricity and biomass infrastructure[9].

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

[9] On the assumption that 1MW of electrode boilers, and associated network connections, or 1MW of biomass boilers, cost on average between $1M-$1.5M.

Fringed Hill, Nelson, New Zealand. Credit – Nelson Electricity.

6 Biomass – resources and costs

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). Suppliers and consumers of biomass for bioenergy need to be confident they understand any wider implications of their choices. No formal guidelines or standards exist in New Zealand at this point, and EECA recommends one is developed for the New Zealand context, drawing on international standards and experience.

A good sense of the total availability of harvestable wood in the NMT region requires both a top-down and bottom-up analysis (based on interviews with major forest owners), as forest owners' actual intentions will often deviate from centralised forecasts due to changes in log prices and other dynamic factors. The bottom-up analysis also provides an assessment of where the wood is expected to flow through the supply chain – via processors to domestic markets, or export markets, as well as volumes that are currently being utilised for bioenergy purposes. It also allows us to estimate practical levels of recovery of harvesting residues.

A top-down analysis shows that the level of harvested wood in the NMT region will vary considerably over the next 15 years (Figure 7). There will be a significant decline from around 4.3M tonnes to around 3M tonnes between now and 2034, recovering thereafter to between 3.5M and 4.0M tonnes.

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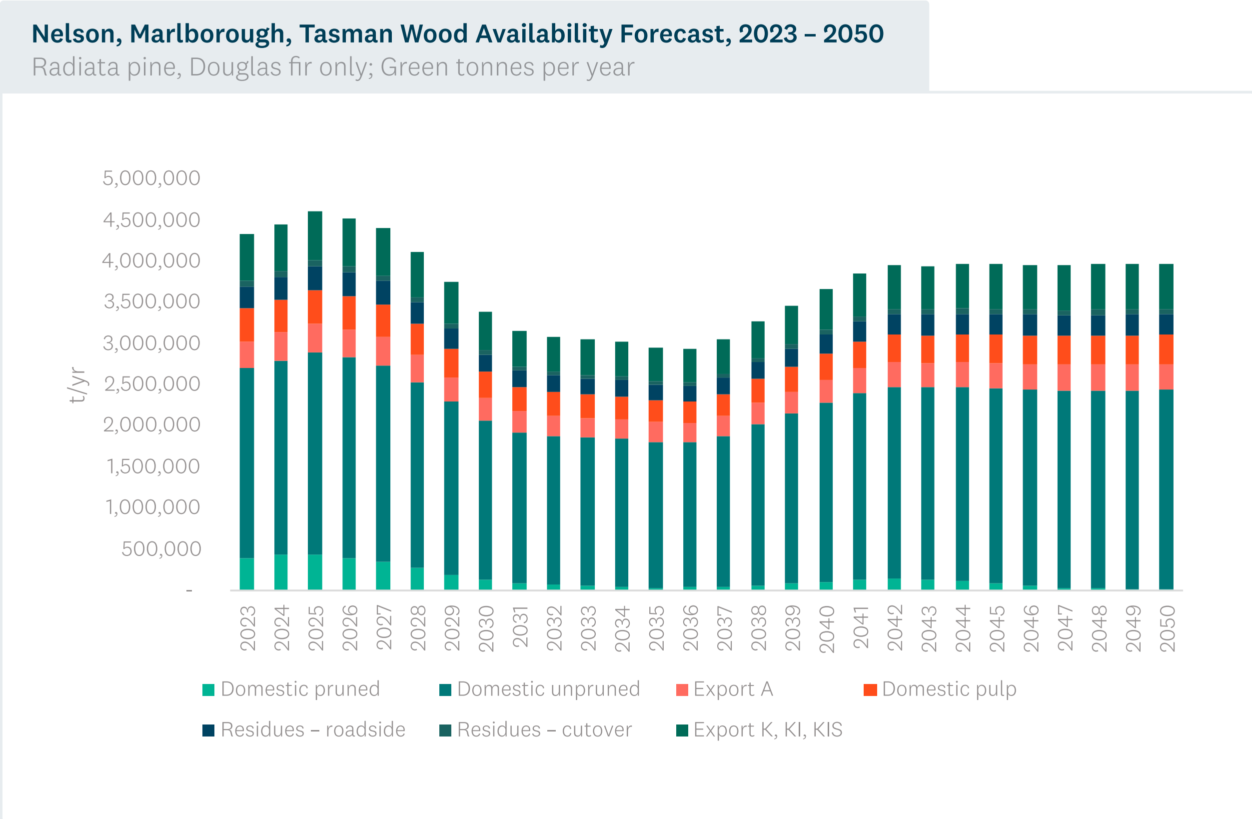
Figure 7 – Wood resource availability in the Nelson, Marlborough, Tasman region, 2023-2050. Source: Ahikā, Margules Groome

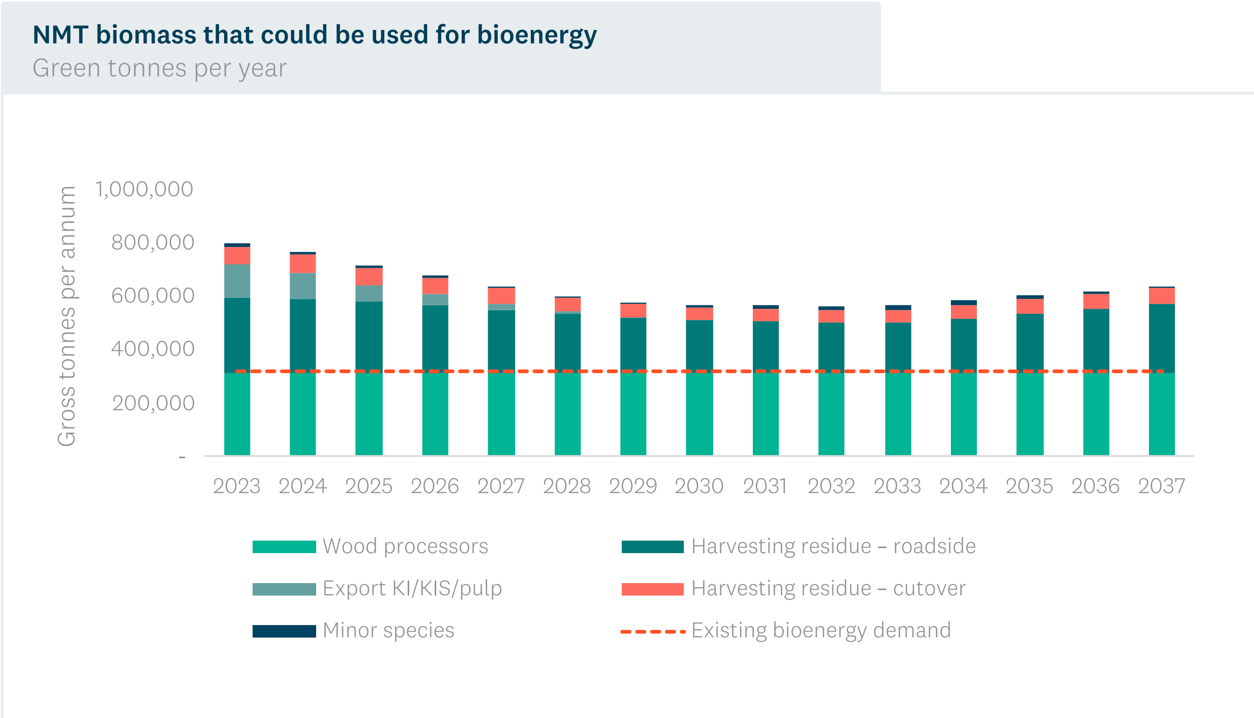


A more comprehensive view of resource availability, that combines the top-down and bottom-up analyses, reveals the potential volumes that could be available for bioenergy. This analysis:

- Includes minor species (e.g. cypress and eucalyptus) that isn't accounted for in Figure 7.
- Removes volumes that are currently contracted to domestic markets, including the use of domestic pulp for MDF production.
- Takes a more realistic approach to estimating the potential harvesting residues (roadside and cutover) than the theoretical potential used in Figure 7.
- Considers the potential volumes arising as residues from processing sawlogs for the domestic market.
- Overlays the existing demand for bioenergy, that already draws on these resources.

The resulting potential volume for bioenergy is shown in Figure 8.

Figure 8 – Assessment of available NMT woody biomass that could be used for bioenergy. Source: Ahikā, Margules Groome



The overall analysis of the NMT region is summarised in Figure 9. Wood flows that could – in part or in full – be diverted to new bioenergy demand from process heat are shown in green.

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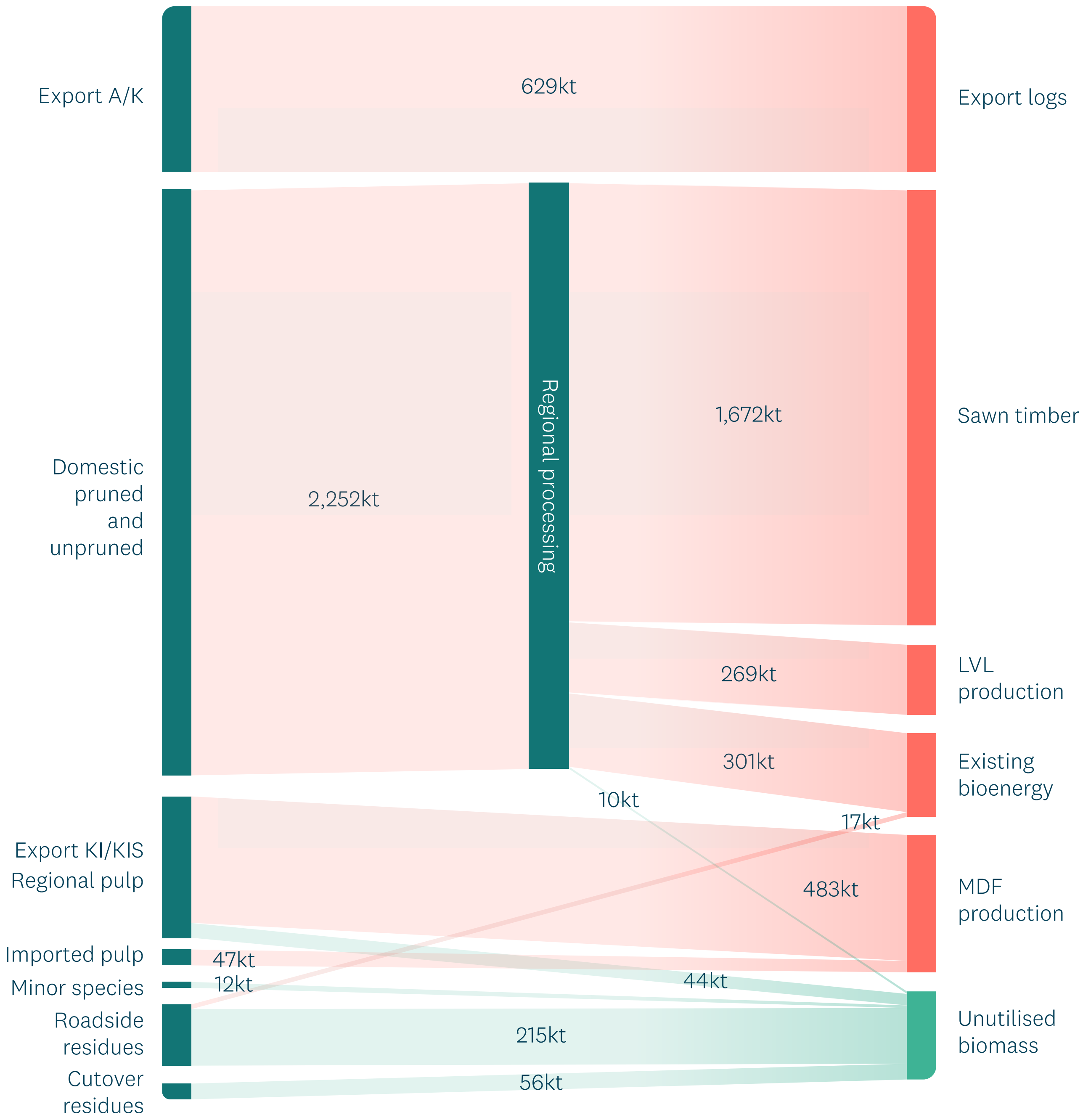
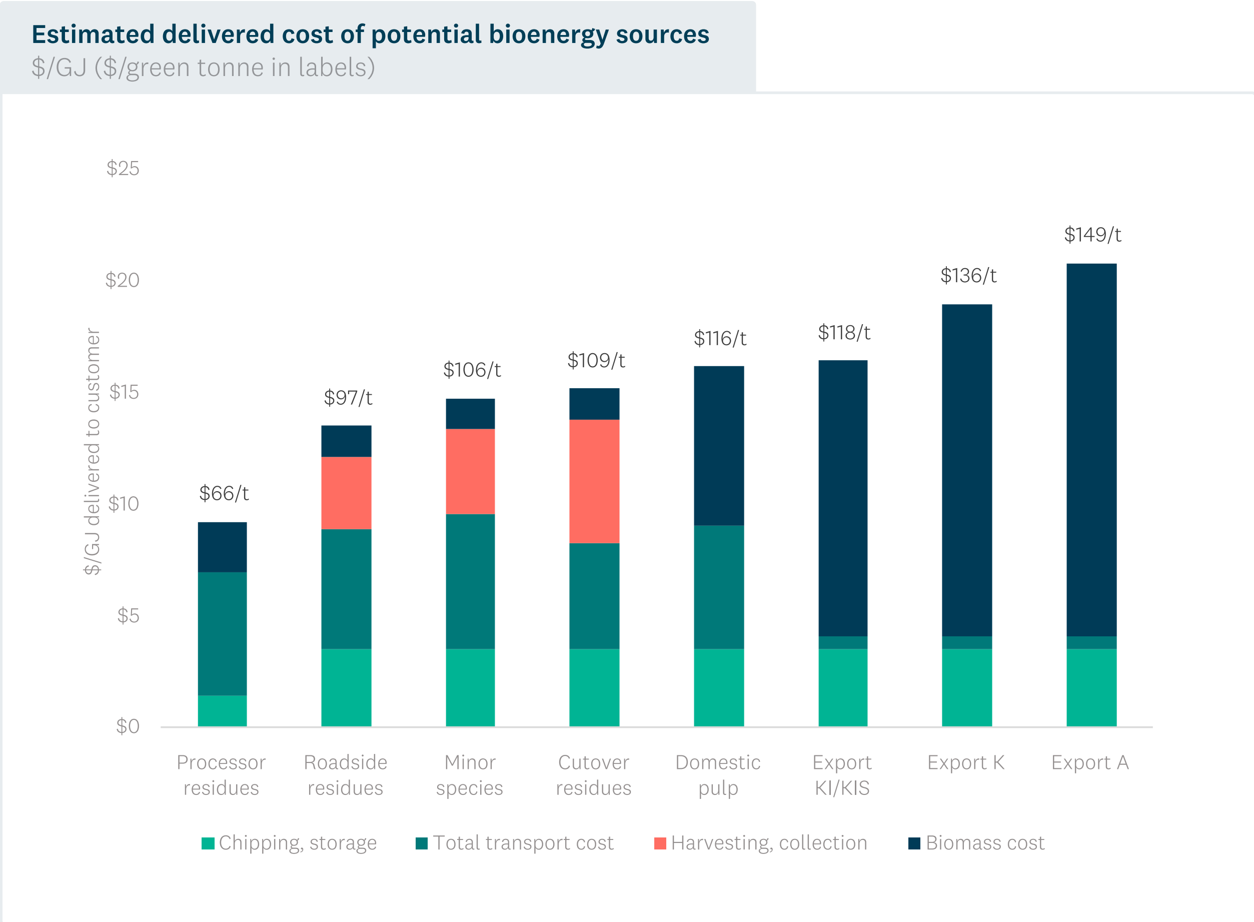
Figure 9 – Average wood flows over 15 years in NMT region. Source: Ahikā, Margules Groome



Overall, EECA estimates that, on average over the next 15 years, **approximately 337,000t per year (2,420TJ) of NMT woody biomass is currently unutilised and could be recovered for new boiler demands without disrupting low grade export markets or existing bioenergy consumers.** However, this average disguises the significant variance in the annual availability described above.

The costs of accessing this biomass, and delivering it to the process heat user's site, is presented in Figure 10.

Figure 10 – Estimated delivered cost of potential NMT bioenergy sources, average value 2023-2037. Source: Ahikā, Margules Groome



We retain export grade A logs in the analysis to represent 'scarcity values' if our scenario analysis below should indicate that other more plausible and sustainable sources of bioenergy are insufficient. We do not believe these are sustainable or practical sources of bioenergy.

Our expectation is that available biomass will be processed into products that suit the size of the NMT process heat user. In our modelling, we assume that for small process heat users, the available volumes in Figure 8 can be processed into pellets and delivered for $28/GJ ($478 per tonne of pellets). For large users, the biomass will be processed into dried woodchip and delivered for $25/GJ ($310 per tonne of woodchip).

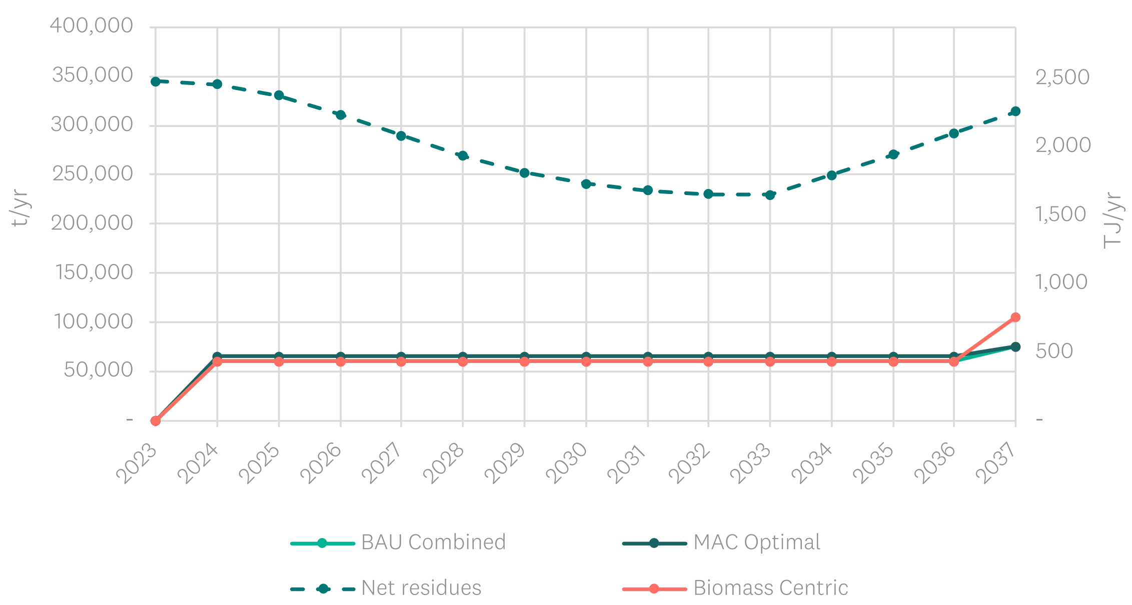
6.1 Impact of pathways on biomass demand

Our pathway analysis below shows the growth in biomass demand (in both tonnes and TJ per year) arising from each of the pathways (Figure 11). The different pathways are broadly similar for most of the period considered in our analysis, except for 2037, where the Biomass Centric pathway picks up greater demand, as a result of the pathway assumptions.

The pathways also show that the availability of harvesting and processing residues is expected to be more than sufficient for the demand arising from any pathway. In fact, it highlights that there may be potential for the NMT region to export biomass to neighbouring regions, depending on transport costs. This will be considered in a future RETA report for the South Island as a whole.

Figure 11 – Growth in biomass demand from NMT pathways. Source: EECA

NMT region pathways – biomass and available residues
Green tonnes & TJ



Based on the biomass cost figures provided above, our analysis suggests that, over the next 15 years, the MAC Optimal process heat market demand for these residues could be around $90M (on a cost basis[10]).

The degree to which these resources are used is a commercial decision, which would include a comparison with alternatives in terms of cost, feasibility, and desirability. Depending on the process heat users' preference of fuel type some types of resources may not be suitable. In some situations, higher cost pellets may be required, which in turn require higher-grade raw material.

[10] Cost of 6,600TJ of biomass collected and delivered to a hub for $14/GJ (wet wood), not including costs associated with processing into dried wood chips or secondary transport from the hub to each process heat user.

7 Electricity – network capacity and costs

The availability of electricity to meet the demand from process heat users is largely determined at a national 'wholesale' level. Supply is delivered to an individual RETA site through electricity networks – a transmission network owned by Transpower, and a distribution network, owned by electricity distribution businesses (EDBs), that connects individual consumers to the boundary of Transpower's grid (known as grid exit points, or GXPs). There are three EDBs serving the NMT region – Network Tasman, Nelson Electricity and Marlborough Lines.

The price paid for electricity by a process heat user is made up of two main components[11]:

- A price for 'retail electricity' – the wholesale cost of electricity generation plus costs associated with electricity retailing.
- A price for access to the transmission and distribution networks.

As shown in Figure 12, the forecast price of **retail electricity** (excluding network charges) is expected to increase (in real terms) from 12c/kWh in 2027 to 13c/kWh in 2037 under a 'central' scenario. However, different scenarios could see real retail prices higher or lower than that level by 2037.

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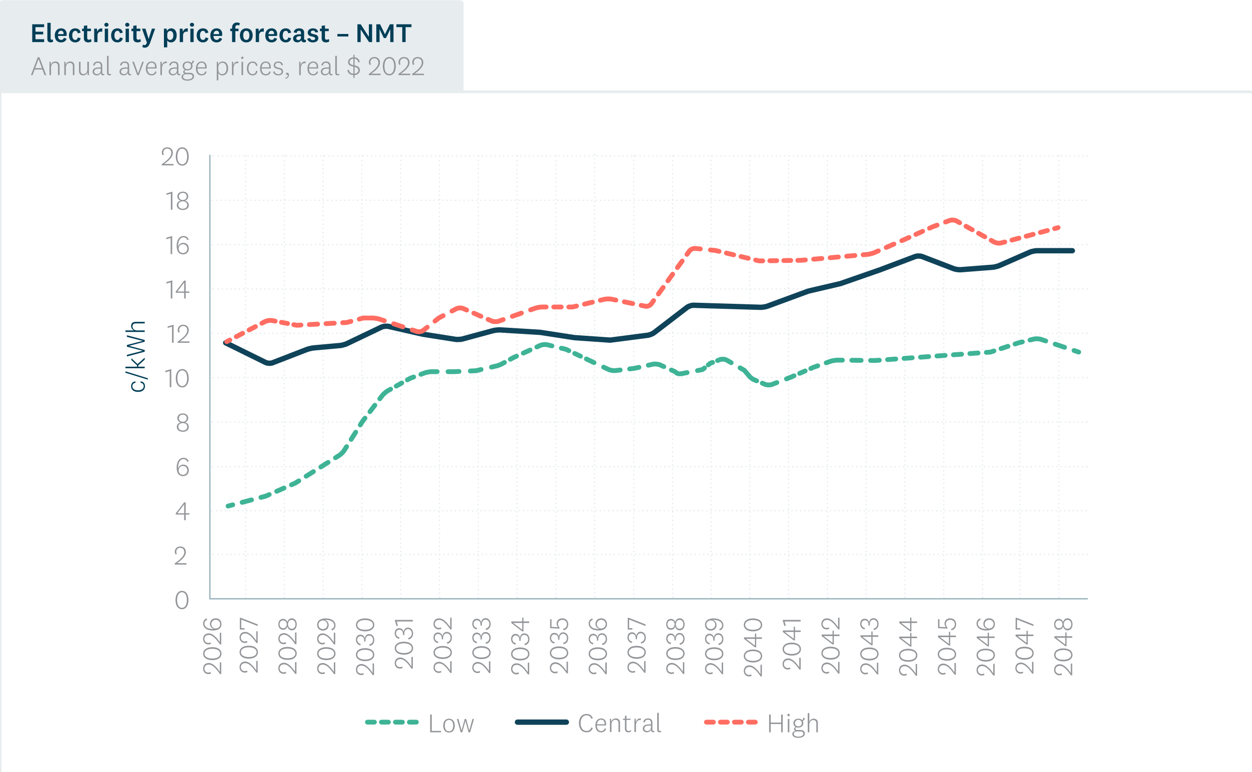
[11] Other smaller components include metering and regulatory levies.

Figure 12 – Forecast of real annual average electricity price for large commercial and industrial demand in the NMT region. Source: EnergyLink



Beyond 2037, this forecast sees more significant increases in electricity prices. However, it is difficult to predict pricing beyond the end of the RETA 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 business cases consider a range of scenarios.

EDBs charge electricity consumers for the use of the *existing* distribution network. In addition, where the connection of new electric boilers requires EDBs to invest in distribution network upgrades, the cost of these can be paid through a mix of ongoing network charges, and an up-front 'capital contribution'. Each EDB maintains policies that govern the degree of capital contribution, and process heat users should discuss these with their respective EDBs.

Furthermore, process heat users who connect new electric boilers directly to Transpower's grid will face equivalent transmission charges, as determined under the Transmission Pricing Methodology (TPM). Process heat users who connect to the EDBs networks will also face a share of these transmission costs, as determined by the EDBs pricing methodologies.

An approximation of the potential charges faced by process heat users who electrify is presented in Table 4. These are based on each of the EDB's announced prices for the year 2023/24.

Table 4 – Estimated and normalised network charges for NMT's large industrial process heat consumers, by EDB; $ per MVA per year.

EDB	Distribution charge	Transmission charge	Total network charge
Nelson Electricity	$55,000	$23,000	$78,000
Network Tasman	$69,000	$41,000	$110,000
Marlborough Lines	$115,000	$30,000	$145,000

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[12] and process heat. The timing of demand growth (that drives this investment) is uncertain, which results in a challenging decision-making environment for network companies. As we recommend below, it is important that process heat users considering electrification keep EDBs abreast of their intentions.

The primary considerations for a process heat user considering electrification are:

- The current 'spare capacity' (or headroom) and security of supply levels in Transpower and the EDBs' networks to supply electricity-based process heat conversions.
- The cost of any upgrades required to accommodate the demand of a process heat user, considering seasonality and the user's ability to be flexible with consumption, as well as any other consumers looking to increase electricity demand on that part of the network.
- The timeframe for any network upgrades (e.g. procurement of equipment, requirements for consultation, easements and regulatory approval).
- The price paid for electricity to an electricity retailer (or direct to the wholesale market, for large sites), and any other charges paid by electricity consumers (e.g. use-of-network charges paid to EDBs and Transpower).
- The level of connection 'security' required by the site, including its ability to tolerate any rarely occurring interruptions to supply, and/or the process heat user's ability to shift its demand through time in response to a signal from the network or the market. This flexibility could reduce the cost of connection, and the supply costs of electricity.

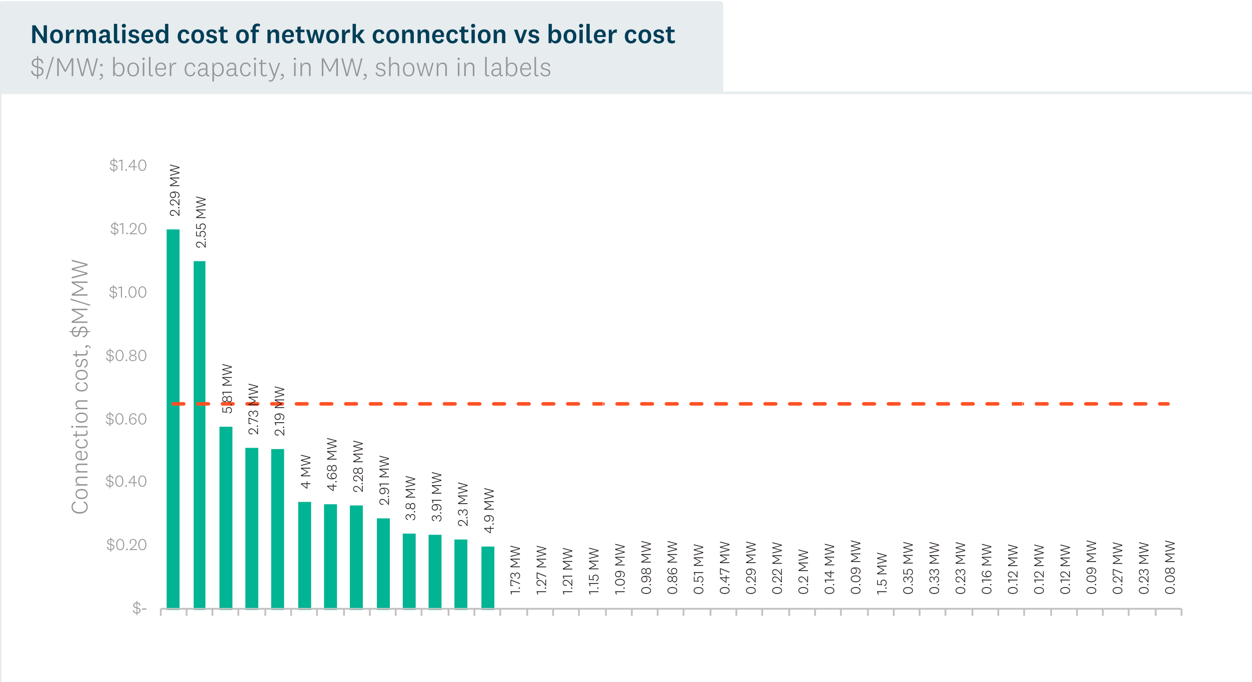
For most sites considering electrification, the 'as designed' electrical system can likely connect the site with minor distribution level changes and without the need for substantial infrastructure upgrades. Most of these minor upgrades would have connection costs under $1M (and many under $200,000, excluding the cost of a distribution transformer and associated equipment) and experience connection lead times of less than 12 months.

More substantial upgrades to the distribution network are required for three of the 38 sites, with commensurately higher costs (mostly between $0.7M and $3.4M) and longer lead times (12-24 months).

[12] While this RETA analysis only examines demand from process heat electrification, and public EV charging facilities where this information is available to EECA, this broader context of potentially rapid growth in demand is important to understanding the challenges associated with accommodating new load.

The costs of connection can be a significant part of the overall capital cost associated with electrifying process heat demand. Figure 13 shows each site's connection costs expressed in per-MW terms, i.e. relative to the capacity of the proposed boiler.

Figure 13 – Normalised cost of network connection vs boiler cost, NMT RETA sites. Source: Ergo, EECA



The red dashed line in Figure 13 compares these per-MW costs to the estimated cost of an electrode boiler ($650,000 per MW). The figure shows not only a wide variety of relative costs of connecting electrode boilers, but that for twelve sites, the connection cost more than doubles the overall capital cost associated with electrification. We note that these costs represent the total construction costs of the expected upgrades. The degree to which process heat users need to make capital contributions to these upgrades depends on a variety of factors and needs to be discussed with the relevant EDB.

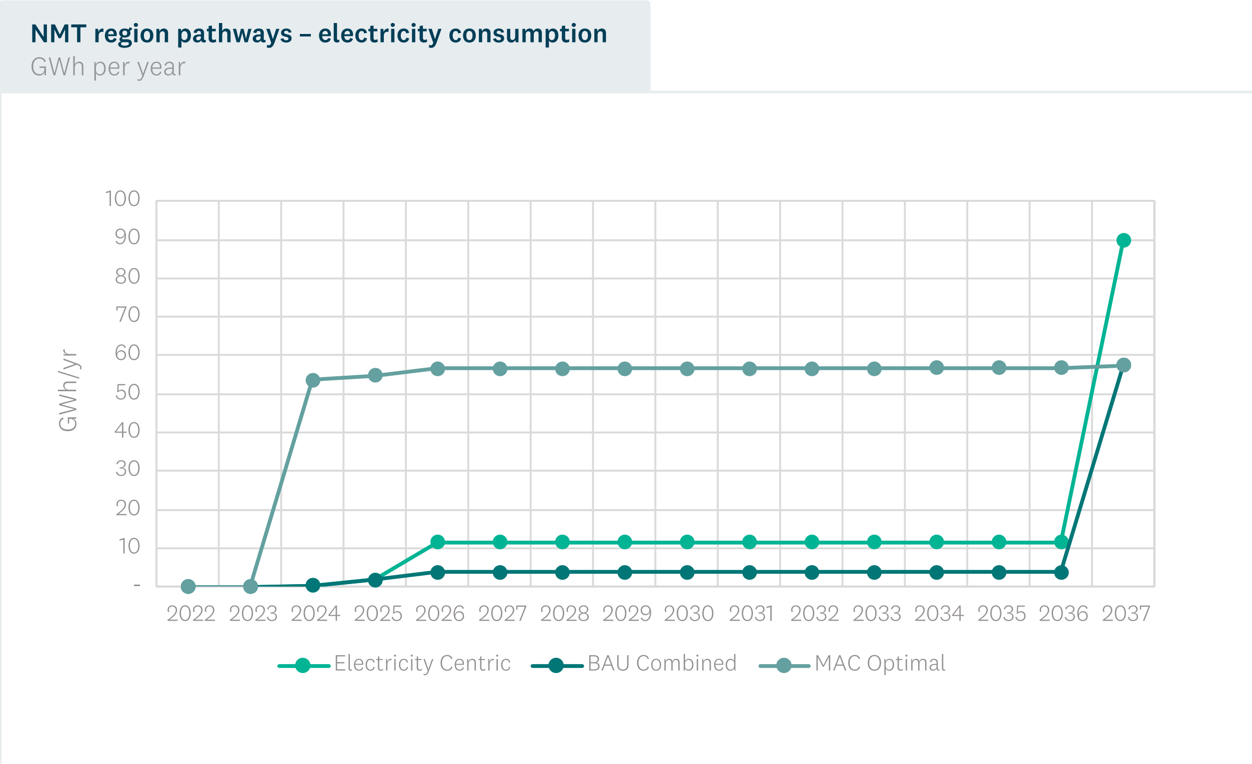
The timeframes for connection above assume these investments do not require Transpower or EDBs to obtain regulatory approval. We note that if connections also rely on wider upgrades to the network, the EDB would have to seek regulatory approval for these investments, which could also add to the timeline.

The costs provided above are indicative and appropriate for a screening analysis. They should be further refined in discussion with network owners, and the final costs in some situations will depend on the collective decisions of a number of RETA sites who require access to similar parts of the network.

7.1 Impact of pathways on electricity demand

Figure 14 shows the pace of growth in electricity consumption under the different pathways.

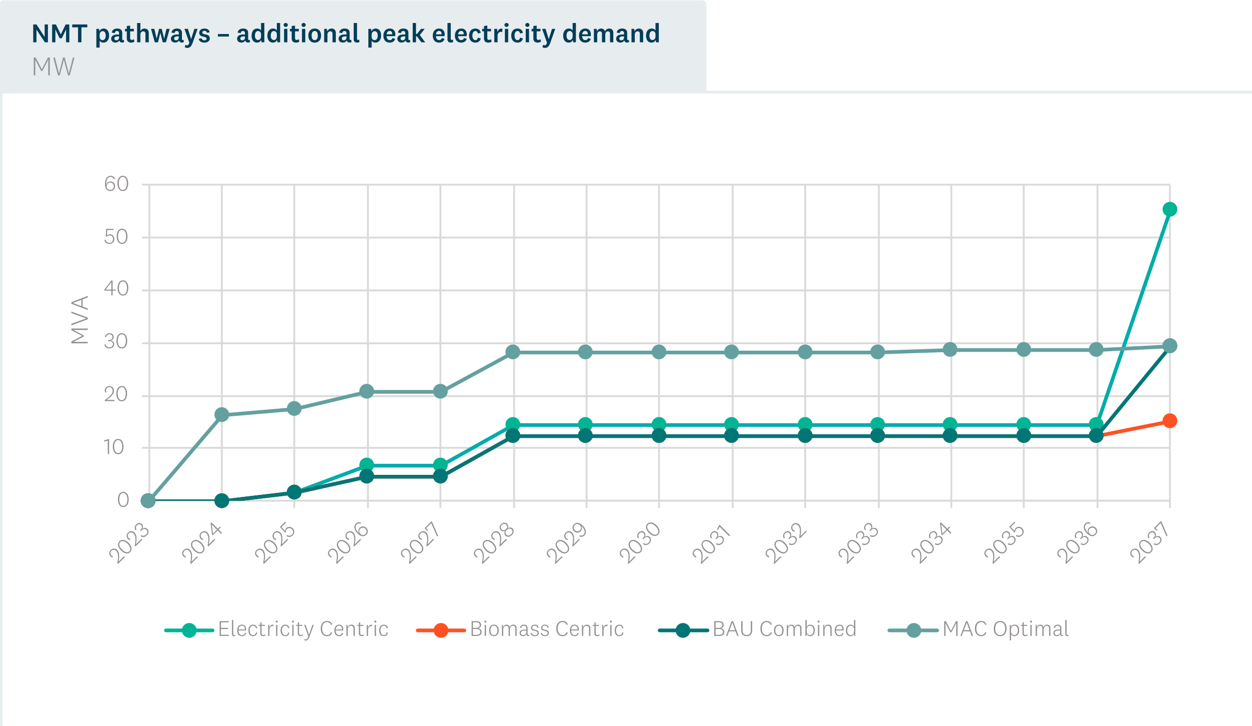
Figure 14 – Growth in NMT electricity consumption from fuel switching pathways. Source: EECA



In all pathways, electricity consumption in NMT would grow by around 5% and7% between now and 2037. In the MAC Optimal pathway, most of this growth would be observed in the next two years.

EDBs' investments will be driven more by increases in peak demand than by growth in consumption over the year. Figure 15 shows how the different pathways affect peak demand across the three networks.

Figure 15 – Potential NMT peak electricity demand growth under different pathways.



The electricity demand from new electrode boilers and heat pumps ranges between 12MW and 28MW[13] between now and 2036, with a further material increase in 2037 in the Electricity Centric pathway.

Table 5 shows how process heat connections potentially affect each EDB's network investment between now and 2037. Note that these costs are only the upgrades required to accommodate each process heat user in isolation of demand growth from other process heat users, or wider growth from transport electrification or 'normal' growth. They do not include a share of the cost of any investments deeper in the network that might be triggered by this collective growth picture.

Table 5 – New connections (MW) and customer-driven connection costs under Electricity Centric and MAC Optimal pathways

EDB	Electricity Centric pathway		MAC Optimal pathway	
	Connection capacity (MW)	Connection cost ($M)	Connection capacity (MW)	Connection cost ($M)
Nelson Electricity	7.4	$1.0	5.2	$0.5
Network Tasman	17.3	$3.5	15.0	$3.2
Marlborough Lines	30.7	$4.5	9.2	$0.1
Total	**55.4 (+25%)**	**$9.1**	**29.3 (+13%)**	**$3.7**

[13] Between 5% and 12% of the three EDBs combined peak demand today.

Table 5 shows that, understandably, Network Tasman will experience the largest increase in process heat-related electricity demand in the MAC Optimal pathway results. Between $4M and $9M will be spent connecting new process heat plant to the local networks, depending on the pathway.

Note that the network upgrade costs presented in Table 5 may not necessarily reflect the connection costs paid by RETA organisations, as they may be shared between the EDB and the new process heat user. The degree of sharing ('capital contributions') depends on the policies of individual EDBs.

7.2 Opportunity to reduce electricity-related costs through flexibility

There is a potentially significant opportunity for process heat users considering electrification to reduce the costs of connection, and the total costs of purchasing electricity, by enabling flexibility in their consumption. This could take the form of being able to shift demand by a relatively small number of hours; allowing for a very small probability of interruption to their electricity supply; or maintaining a standby supply of fuel to be used in prolonged period of high electricity prices. The lowest cost way for flexibility to be enabled is for it to be designed into the electrification investment. Several service providers provide this expertise.

Azwood, Nelson, New Zealand.

8 Recommendations

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:

- **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.**
- **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.**
- **Analysis is required to determine the impact of recovering harvesting residues on soil quality, carbon sequestration, the risk of forest fires and what actions may be required to offset this.**
- **Mechanisms should be investigated and established to help suppliers and consumers 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.**
- **Wood processors are encouraged to explore the production of pellets locally, based on the likely demand provided in this report.**

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

- **EDBs should proactively engage on process heat initiatives to understand their 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) – at an early stage – are aware of information relevant to their planning.**
- **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.

- **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).**
- **EDBs and process heat users should engage early to allow the EDB to develop options for how the process heat user's new demand can be accommodated, what the capital contributions and associated network charges are for the process heat user, and any role for flexibility in the process heat user's demand. Orion's CPD (Control Period Demand) charge is an example of a network charge that rewards process heat users for enabling and using flexibility in their demand. Understanding the overall picture of capital upgrades and network charges allows both EDBs and process heat user to find the overall best investment option.**
- **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 expand future iterations of regional analyses to include transport as a decarbonising decision that will compete for electrical network capacity and biomass.**
- **EECA believes there is merit in obtaining a greater level of transparency of where fossil fuelled plant is being used to offset CPD charges, to help highlight where greater use of peak demand charges may be leading to unintended consequences, counter to decarbonisation imperatives. Monitoring changes in the use of diesel generators could be achieved through a stricter consenting regime via the regional council, or as part of EDB disclosures.**

Recommendations to assist process heat users with their decarbonisation decisions:

- **Ministries (such as Ministry for the Environment) need to work with reputable organisations to develop scenario-based carbon price forecasts that decarbonising organisations can incorporate into their business cases.**

November 2023

Government Leadership

Regional Energy Transition Accelerator (RETA)

Nelson, Marlborough, Tasman – Summary Report

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