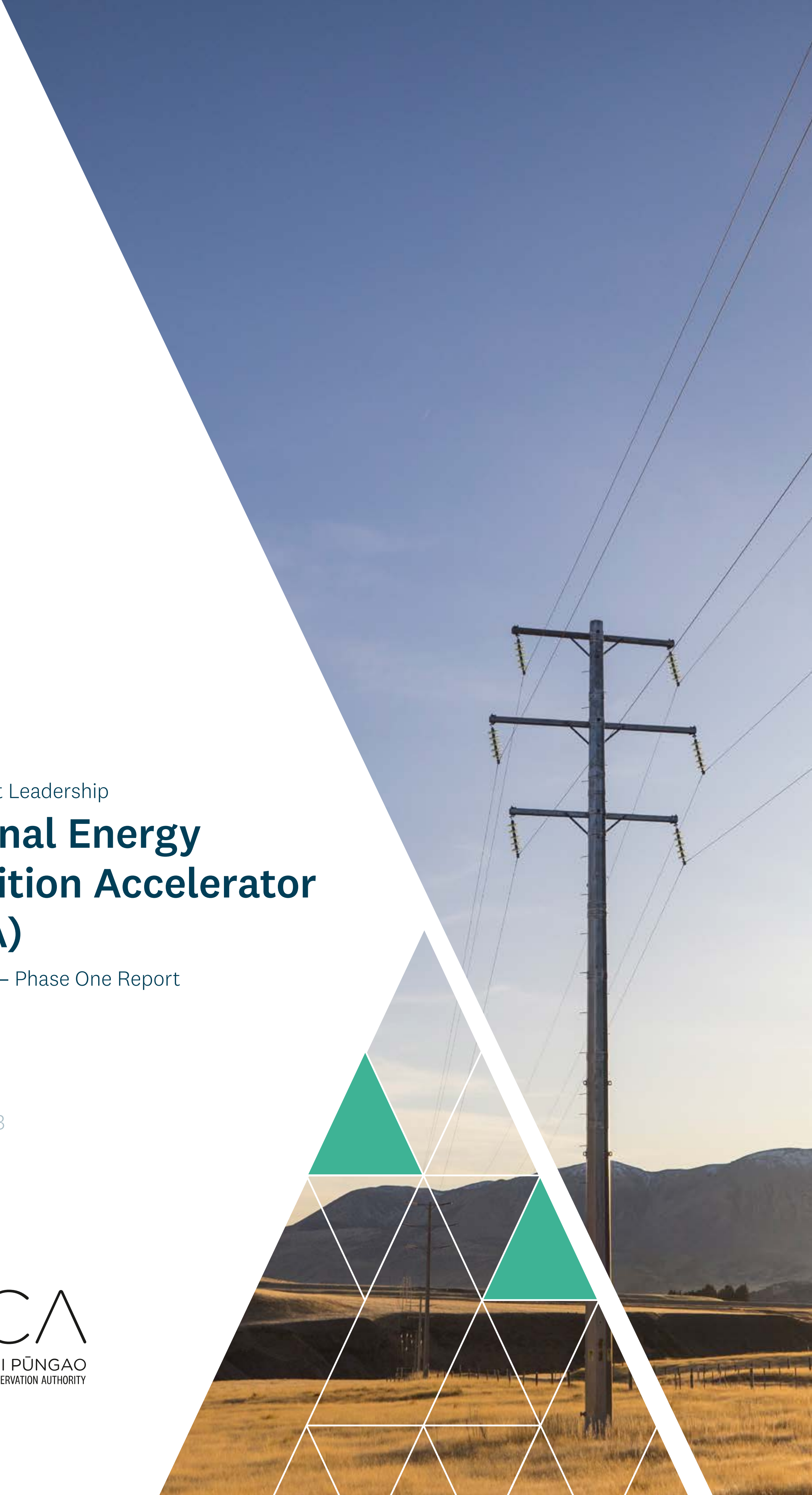
Government Leadership

Regional Energy Transition Accelerator (RETA)

West Coast – Phase One Report

August 2023



EECA

TE TARI TIAKI PŪNGAO

ENERGY EFFICIENCY & CONSERVATION AUTHORITY

1 Foreword

Taking action to tackle climate change and its effects requires us to be bold and create a sustainable energy system that will also support the prosperity and wellbeing of current and future generations.

Around a third of New Zealand's overall energy use is creating heat for processing – and 60% of this is fossil-fuelled. In the West Coast, most of these fossil-fuelled process related emissions come from coal.

EECA's West Coast Regional Energy Transition Accelerator (RETA) programme aims to develop and share a well-informed and coordinated approach to help fast-track regional decarbonisation. Our analysis has shown that by starting now, 88% of potential emissions reduction in the region will be economic by 2027.

Our RETA work leverages the site-specific decarbonisation pathways developed for organisations across the region through EECA's Energy Transition Accelerator (ETA) programme.

Understanding unique region-specific needs, opportunities and barriers is critical. Decisions about investment in infrastructure that meet future demands requires coordination that considers the impact of decisions across multiple individual sites.

This phase one West Coast RETA report provides a common set of information to all organisations considering process heat decarbonisation or who have the potential to support the transition through scaling supply of renewable energy. It shows that the collective effect of customers' fuel switching decisions will impact the investment in regional resource and infrastructure systems, including how this investment is prioritised and staged.

The report highlights the role local forestry biomass may play, with the potential for about 60% of the region's energy needs being supplied by biomass. Our analysis also shows that the biomass and electricity supply required to cover new process heat demand is already in the region.

Progress requires working together across government, council, economic development agencies, business, and community. This collaborative approach means we can accelerate efforts to reduce the region's carbon footprint and thrive in a low emissions economy.

We are proud to have worked alongside Development West Coast and several key groups including our RETA report workstream leads Transpower, Westpower, Buller Electricity, regional forestry companies and wood processors, electricity generators and retailers, and medium to large industrial energy users, to develop this West Coast RETA report.

There is significant carbon reduction potential in West Coast, and we look forward to supporting the region on its journey.

Nicki Sutherland
Group Manager Business, EECA

Photo: Porter's Pass, Canterbury, New Zealand.

> ***Our analysis has shown that by starting now, 88% of potential emissions reduction in the region will be economic by 2027.***

Nicki Sutherland , Group Manager Business, EECA

2 Acknowledgements

This Regional Energy Transition Accelerator (RETA) project undertaken by EECA and its partners 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 West Coast
- Development West Coast
- Local lines companies Westpower and Buller Electricity
- 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
- **Miles Holden** - report photographer

The West Coast region is the focus for New Zealand's third Regional Energy Transition Accelerator (RETA).

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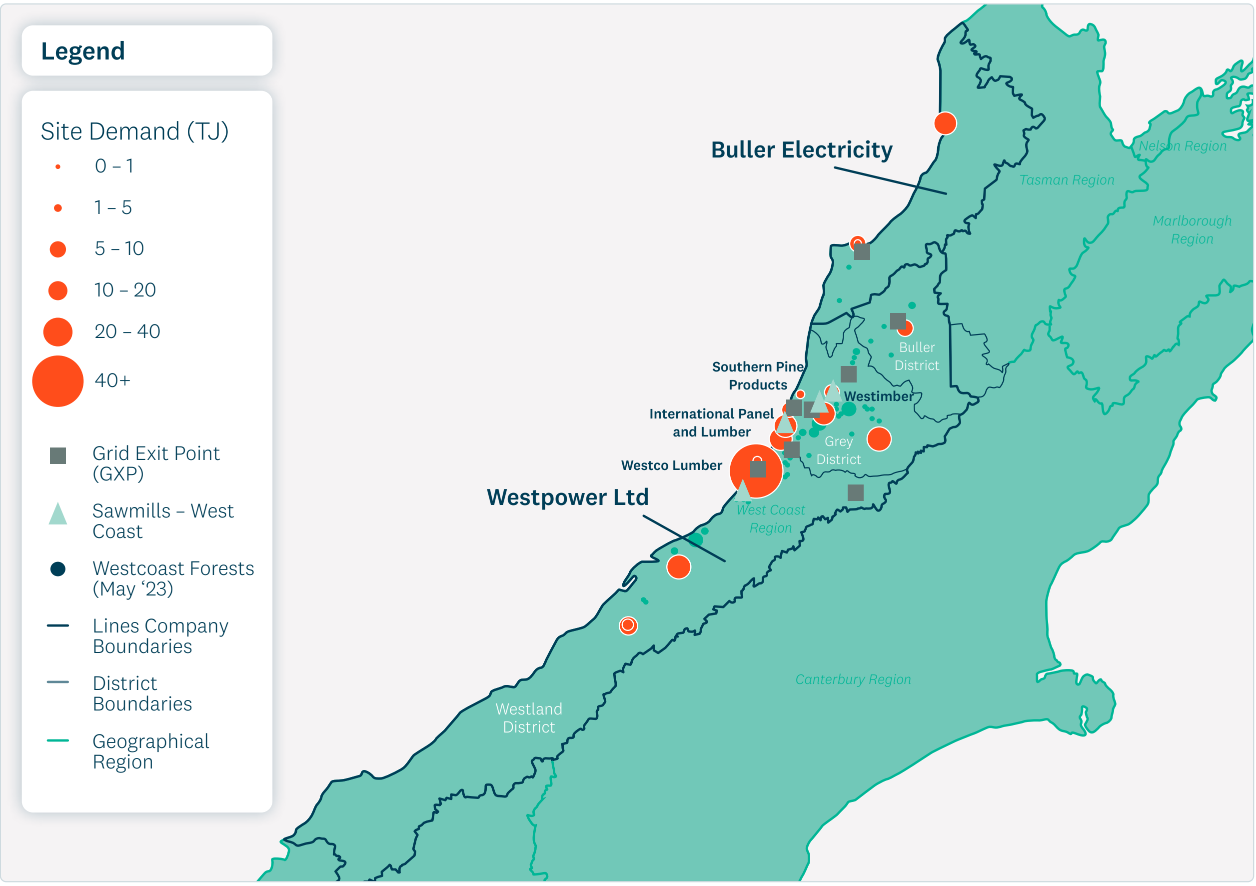
4 Executive summary

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

The West Coast region covers the Buller, Grey and Westland Districts (Figure 1).

Figure 1 – Map of area covered by the West Coast RETA



The 21 sites covered span the dairy, meat, industrial and commercial[1] sectors. These sites either have process heat equipment larger than 500kW (i.e. process heat equipment details have been captured in EECA's Regional Heat Demand Database) or are sites for which EECA has detailed information about their decarbonisation pathway[2]. **Together, these sites collectively consume 1,157TJ of process heat energy, primarily in the form of coal, and currently produce 125kt per year of carbon dioxide equivalent (CO_2e) emissions.**

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

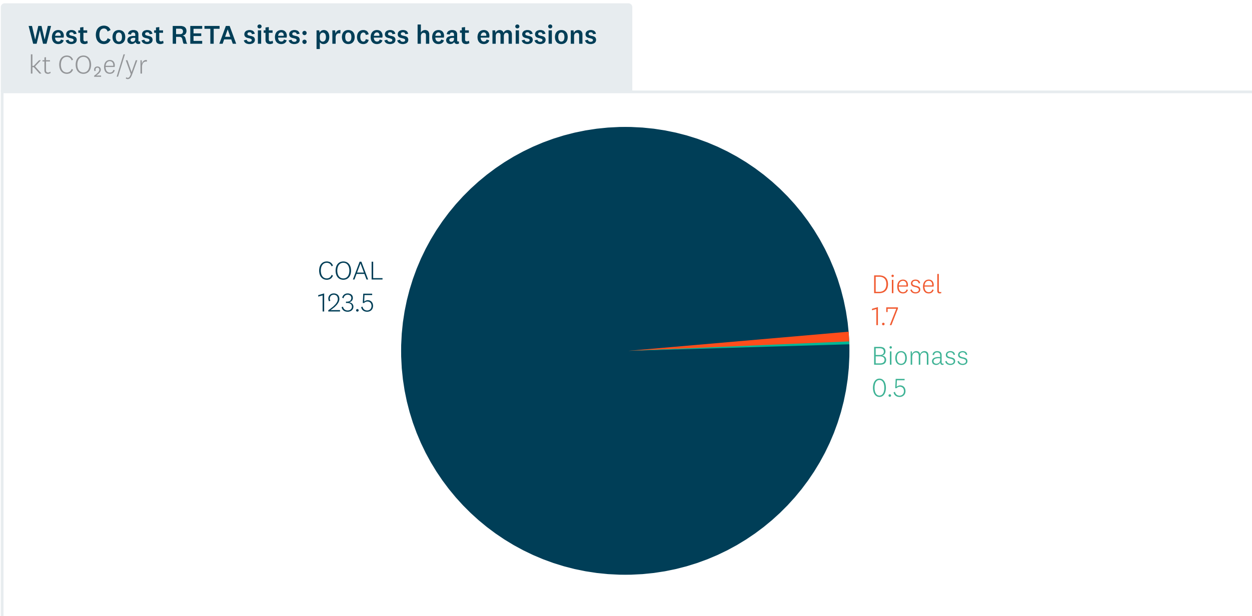
[2] That is, process heat equipment details have been captured in an ETA opportunities assessment report.

Table 1 – Summary of West Coast 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 and meat	4	65	289	1,040	114
Industrial	5	8	24	87	8
Commercial	12	9	9	32	3
Total	**21**	**81**	**322**	**1,157**	**125**

The majority of the West Coast RETA emissions come from coal (Figure 2).

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



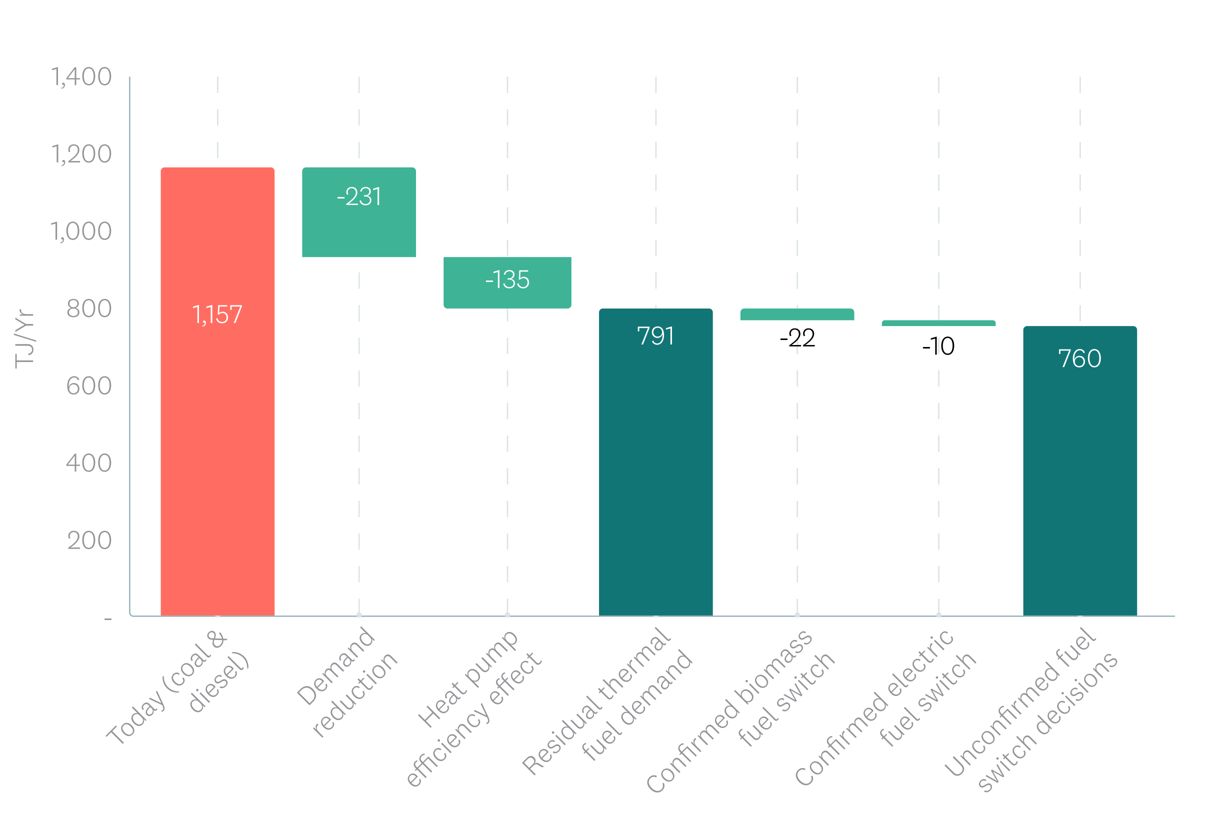
The objective of the West Coast RETA is to eliminate as much of these process heat emissions as possible. It does this by supporting organisations in their consideration of:

- 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.

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 West Coast fossil fuel usage, 2022-2037. Source: EECA[3]

Potential renewable process heat energy requirements in the West Coast
How RETA projects impact demand for fuels (TJ per annum)



This report looks at the impact of 48 emissions reduction projects across the 21 sites – covering demand reduction, heat pump efficiency, and fuel switching projects. Further, it investigates the regional availability of biomass and electricity to replace coal and diesel. Combining these two analyses – demand-side and supply-side – we can provide the indicative economics of each of the 48 process heat decarbonisation decisions.

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

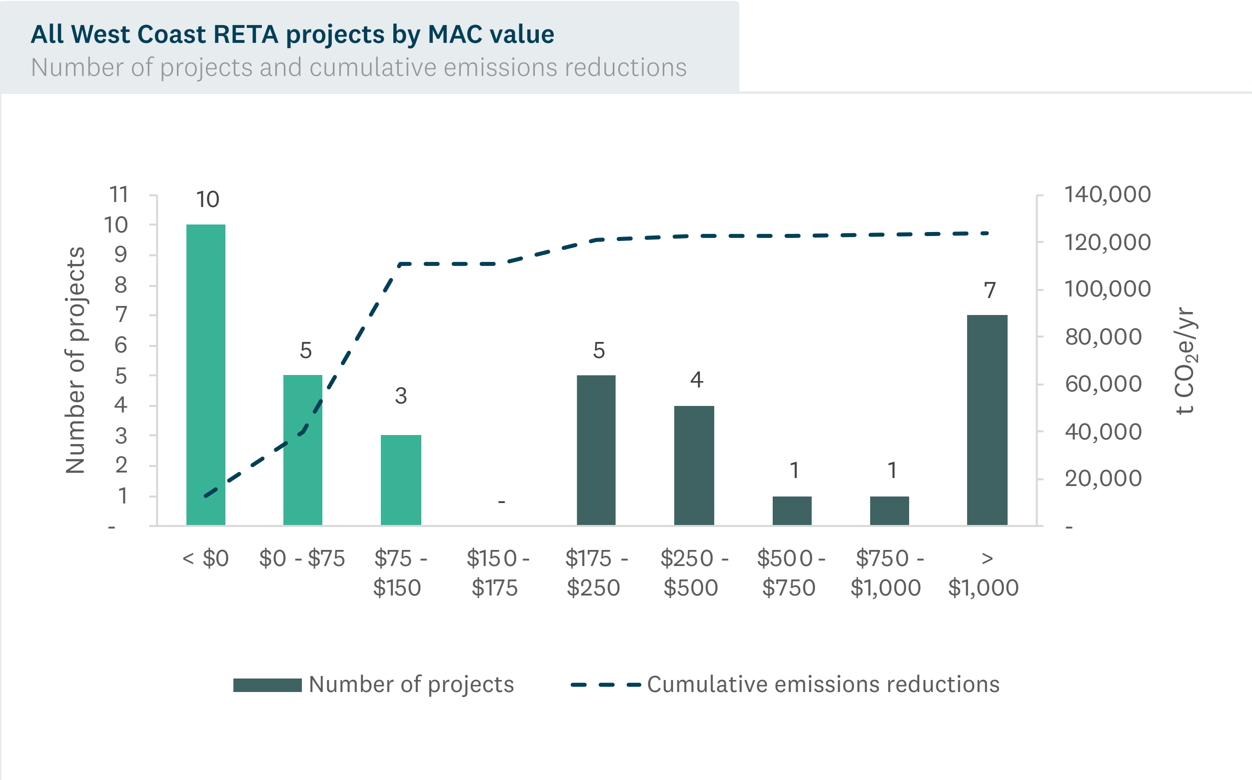
Rather than attempt to include all these factors, we use a global standard 'marginal abatement cost', or MAC, to quantify the cost to the organisation of decarbonising their process heat. This is expressed in dollars per tonne of CO_2e reduced by the investment.

[3] Of the demand reduction projects, around 33% of projects are confirmed, the remaining unconfirmed. For heat pumps, 27% are confirmed, 73% are unconfirmed.

4.1 By 2027, 88% of emissions reductions are economic[4]

Figure 4 summarises the MACs associated with each decision[5], and the emissions reduced by these projects.

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



Out of 125kt of process heat emissions covered in the West Coast RETA, 110kt (88%) have marginal abatement costs (MACs) less than $119/t CO_2e. 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 2027.

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 633kt over the 15 year period of the RETA analysis.

[4] 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).

[5] We exclude 12 of the 48 projects that have already been completed and the emissions reductions achieved.

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

We tested a range of sensitivities on this modelling – higher biomass availability, higher and lower electricity prices, and government co-funding. The underlying outcome was very similar: a significant (and sometimes greater) level of emissions reductions was economic in the very near future.

Of note, government co-funding had a relatively modest impact on the pathways, if it is assumed that business decisions reflect pure economics. However, it is acknowledged that many businesses have constraints on the amount they can borrow, irrespective of rates of return. They may also have internal competition for that available capital and need to prioritise spend, or need to align capital decisions with asset management timeframes. The presence of decarbonisation co-funding may overcome these wider constraints or cause decarbonisation projects to be prioritised, even if it has a relatively small effect on the project's economics. Government support may also enable these projects to occur more quickly than the economically rational timeframe.

4.2 What emissions reductions mean for fuel switching

From a supply-side perspective, the MAC Optimal pathway results in 42% of the process heat energy being supplied by electricity, and 58% by biomass.

While the fuel switching decision is typically the most significant in terms of energy usage and emissions reduction, it is important to recognise the impact that demand reduction and heat pump projects have on the overall picture of the West Coast process heat decarbonisation.

As shown in Figure 3 above, investment in demand reduction and heat pumps meets 30% of today's West Coast energy demands from process heat, which in turn reduces the necessary fuel switching infrastructure required. This reduced the thermal capacity required from new biomass and electric boilers by 24MW. We estimate that demand reduction and heat pumps has thus avoided investment in $24M-$36M of electricity and biomass infrastructure[6].

Ngāi Tahu Forestry, West Coast, New Zealand.

[6] This is true for both energy consumption and also the peak thermal demand required from biomass or electric boilers. On the assumption that 1MW of electrode boilers, and associated network connections, or 1MW of biomass boilers, cost on average between $1M-$1.5M.

4.2.1 Biomass

MAC Optimal biomass fuel switching projects, in aggregate, utilises almost all available[8] harvesting and processing residues by 2037 (Figure 6). As well as more easily recoverable roadside harvesting residues, this assumes a significant quantity of residues remaining in the forest (cutover) can be economically recovered.

Figure 6 – Growth in biomass demand under MAC Optimal and Biomass Centric[9] pathways. Source: EECA

Our analysis suggests that, over the next 15 years, the MAC Optimal process heat market demand for these residues exceeds $53M on a cost basis[10], including chipping, storage and transport.

[8] After deducting those being used for bioenergy today.

[9] Biomass Centric is a version of the BAU pathway where all unconfirmed fuel switching projects choose biomass.

[10] Cost of wood chip delivered to process heat user at $13.50/GJ (wet wood), per Section 7.7. Does not include costs associated with processing into e.g. wood pellets.

Should more fuel switching decisions choose biomass than what we have modelled in the MAC Optimal pathway, minor species may have to be harvested for bioenergy.

However, the analysis suggests that process heat users looking to biomass should have a reasonable degree of confidence that their needs can be met from resources within the region, and without the need to divert significant quantities from existing export markets.

4.2.2 Electricity

Nationally, 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. However, even allowing for a 10% rise in real electricity prices over that period, 42% of the energy required under the MAC Optimal pathway chooses electricity as the best fuel. Our sensitivity analysis suggests this outcome is relatively robust under different electricity price scenarios. Part of this is due to very favourable retail electricity offers in the market today, some targeted at process heat users who convert to electricity.

While the national electricity market is expected to deliver the necessary generation to meet the increased demand from process heat, the 21 sites in the RETA study rely on an extensive network of transmission and distribution infrastructure to deliver this power to their site.

The West Coast is home to two distribution network owners – Electricity Distribution Businesses (EDBs) – who maintain the myriad assets that connect consumers to Transpower's national grid. These assets are extensive: the length of the West Coast region is approximately the same as the distance from Auckland to Wellington. These EDBs also work with Transpower to ensure that the national transmission grid is sufficient to cope with increased demand. These entities are facing increased demands from the region as consumers consider the electrification of transport and process heat. In this growth context, these EDBs oversee networks that have challenging characteristics: sparse population served by long distribution lines, challenging weather and a relatively low population that must fund the maintenance and upgrade of the network.

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 (around 60% of current West Coast electricity demand if all process heat electrified). Instead, it's the impact on the network's peak demand that arises from electrification of boilers.

Figure 7 – Potential increase in West Coast peak electricity demand under MAC Optimal and Electricity Centric[11] pathways. Source: EECA

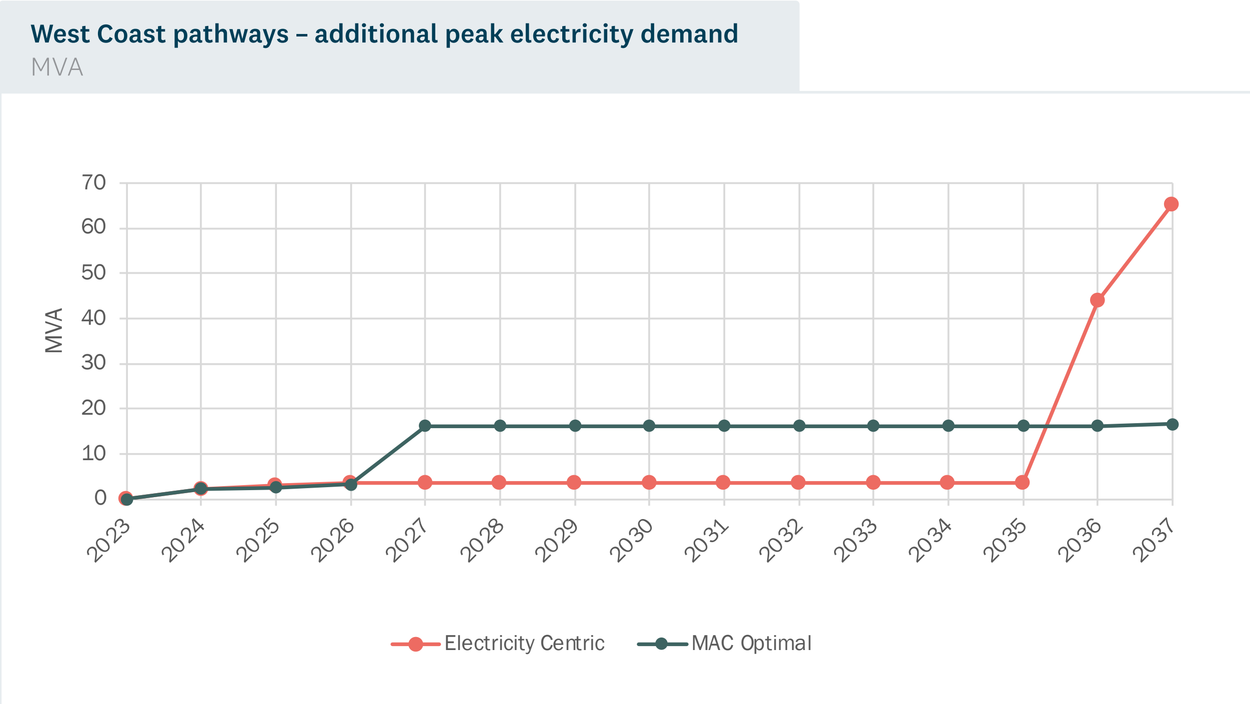


Figure 7 shows that, should all process heat users on the West Coast convert to electrode boilers (the 'Electricity Centric' pathway), the increase in demands on the two West Coast EDBs could be significant by 2037[12]. However, if the decision making follows the commercial guidelines in our MAC Optimal pathway, the network requirements are likely to be much lower. Table 2 breaks this down by EDB.

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

EDB	Electricity Centric pathway		MAC Optimal pathway	
	Connection capacity (MW)	Connection cost ($M)	Connection capacity (MW)	Connection cost ($M)
Westpower	62	$33.8	16	$1.6
Buller Electricity	3	$0.5	0.6	$-[13]
Total	65	$34.3	16.6	1.6

[11] Electricity Centric is a version of the BAU pathway where all unconfirmed fuel switching projects choose electricity.

[12] This chart shows the cumulative increase in peak demand assuming all electrode boilers peak at the same time. Section 8 discusses a more realistic view which takes into account the natural diversity between process heat users in terms of when each is likely to peak. This results in a slightly lower peak demand requirement from the networks.

[13] The process heat users requiring 0.6MW from Buller Electricity's network are individually very small and hence only require distribution transformers. The cost of these assets is included in the capital costs of the electrode boiler itself. In some situations these costs are met by the distributor.

Westpower is likely to experience the most significant relative increase in network demand as a result of process heat electrification, primarily because its network hosts Westland Milk Products. Using Table 2's figures as an upper bound[14], the electrification of the West Coast RETA sites in Westpower's network could increase its total network peak demand by between 35% (MAC Optimal) and 140% (Electricity Centric). In the MAC Optimal pathway, most of this increase would – ideally, from a decarbonisation perspective – occur before 2027.

From the process heat user's perspective, this report also analyses the cost and complexity of securing sufficient local capacity to electrify their boilers. For 12 of the 14 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) and experience connection lead times of between 12-18 months. A small number require equipment that is currently subject to longer lead times.

Two sites (Westland Milk Products and Value Proteins) require more substantial upgrades, with commensurately higher costs (between $6M and $28M) and longer lead times (3-4 years).

Both the cost faced by process heat users to connect their electric boilers to the network, and the wider network upgrades that Transpower and the EDBs are contemplating, could be reduced by harnessing the potential for process heat users to be flexible about *when* they use their boilers. We highlighted above how demand reduction and heat pumps have reduced the need for thermal capacity by around 24MW. Similarly, if process heat users could shift some or all of their electricity consumption away from critical peak times on the network (usually winter mornings and evenings), or maintain an alternative supply of fuel, a greater degree of cost savings could be experienced.

While the ability to shift demand relies on having some degree of interruptibility or storage in the process, some studies have estimated sites could save between 8% and 18% of their electricity procurement costs, and between $150,000 and $300,000 per MW of electricity infrastructure costs every year.

[14] The connection capacity sought from the West Coast RETA process heat sites, shown in Table 2, does not represent the predicted increase in network peak demand arising from the connection of these sites; due to diversity in the timing of each site's peak demand, the impact on the network peak should be lower. See Section 8.4.

4.3 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:

- **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.**
- **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.**
- **Development of national guidance or standard, based 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.**
- **Given the volumes of biomass in the region, and the potential demand from process heat users, local parties (forestry owners, processors and process heat users) should form longer-term partnerships to give each other confidence to invest in bioenergy as a resource. This could be complemented by mechanisms to help suppliers and consumers to see 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.**
- **Wood processors are encouraged to explore the production of pellets locally, based on the likely demand provided in this report.**

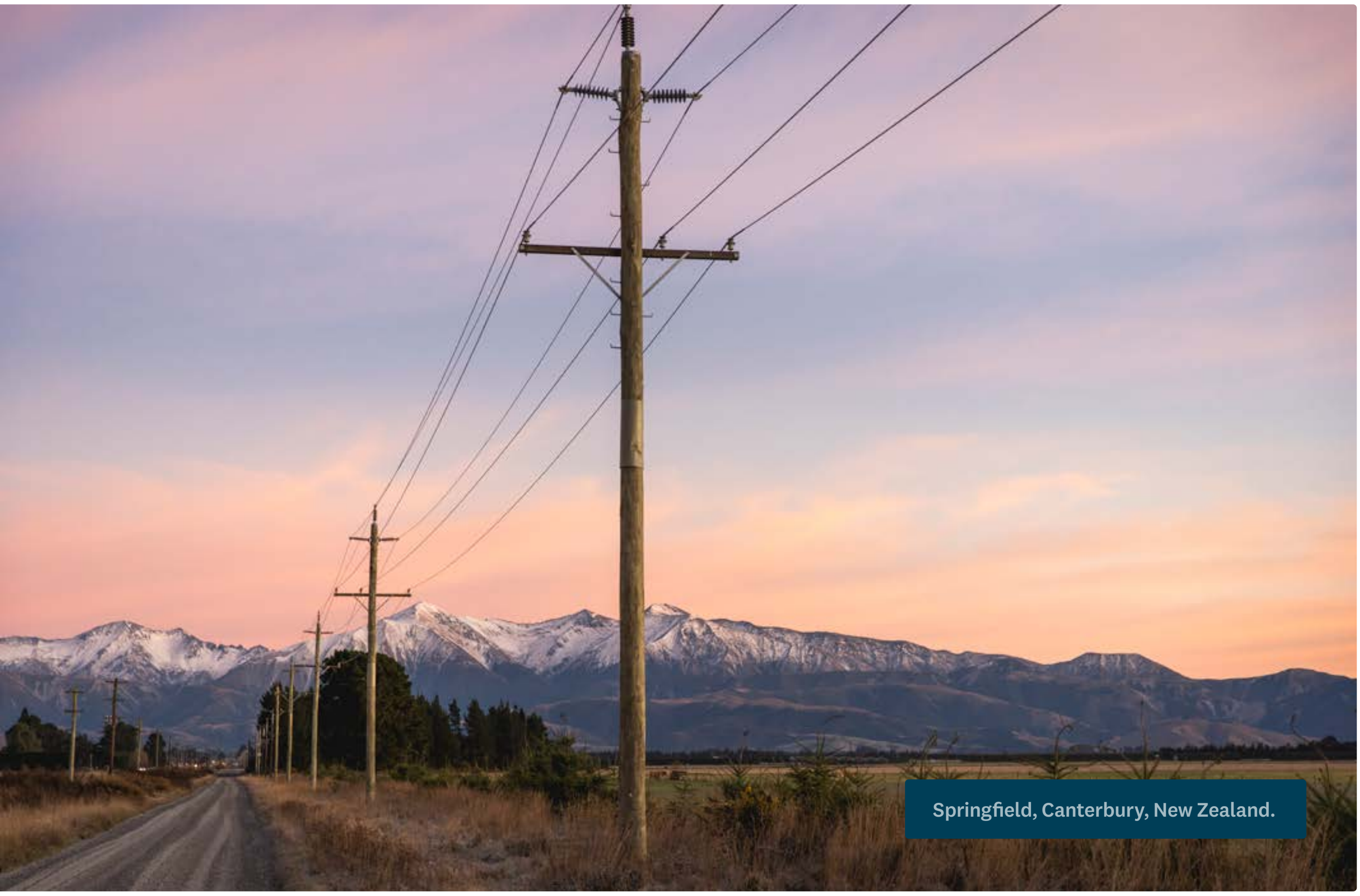
Recommendations to improve the use of electricity for decarbonisation:

- **EDBs should proactively engage with process heat users 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.**
- **More specifically, if the largest process heat users are contemplating significant electrification, EDBs, Transpower and these users need to work collaboratively to understand the implications for the grid. These implications include the network security requirements of the process heat users and the region; the potential impacts of increased peak electricity demand on the key transmission lines serving the region; and what role investment in new local generation (e.g. hydro) could play in reducing the need for costly grid upgrades.**
- **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 should share sufficient information about network demand to help process heat users determine whether they can limit the extent to which they increase peak demand on the network, and the nature of network security standards.**
- **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 process heat users to efficiently use any flexibility they have in their consumption.**

Recommendations to improve the overall decarbonisation system:

- **EECA should expand future iterations of regional analyses to include transport as a decarbonising decision that will compete for electrical network capacity and biomass.**
- **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.**
- **Process heat users should enquire about government co-funding where the economics of decarbonisation are challenging; where they are economic, EECA encourages organisations to explore the potential for self-funded acceleration.**



Springfield, Canterbury, New Zealand.

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 8 below.

Figure 8 – Overview of ETA programme. Source: EECA

EECA-led phases

1 Exploratory engagement

- Senior-level expression of interest in long-term planning & commitments
- Energy transition and climate risk assessment

2 Initial assessment

- Kick-off sprint session
- One2Five EM review
- Work with reviewer to provide energy and business data

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

Customer-led phases

3 Detailed analysis and pathway setting

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

4 Planning, implementation and review

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

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

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

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

EECA's Regional Energy Transition Accelerators (RETAs) are the projects that provide this regional perspective.

5.2 The West Coast RETA

There are two stages of a RETA project – planning and implementation. This report is the culmination of the RETA planning stage in the West Coast region. The first planning phase aims to:

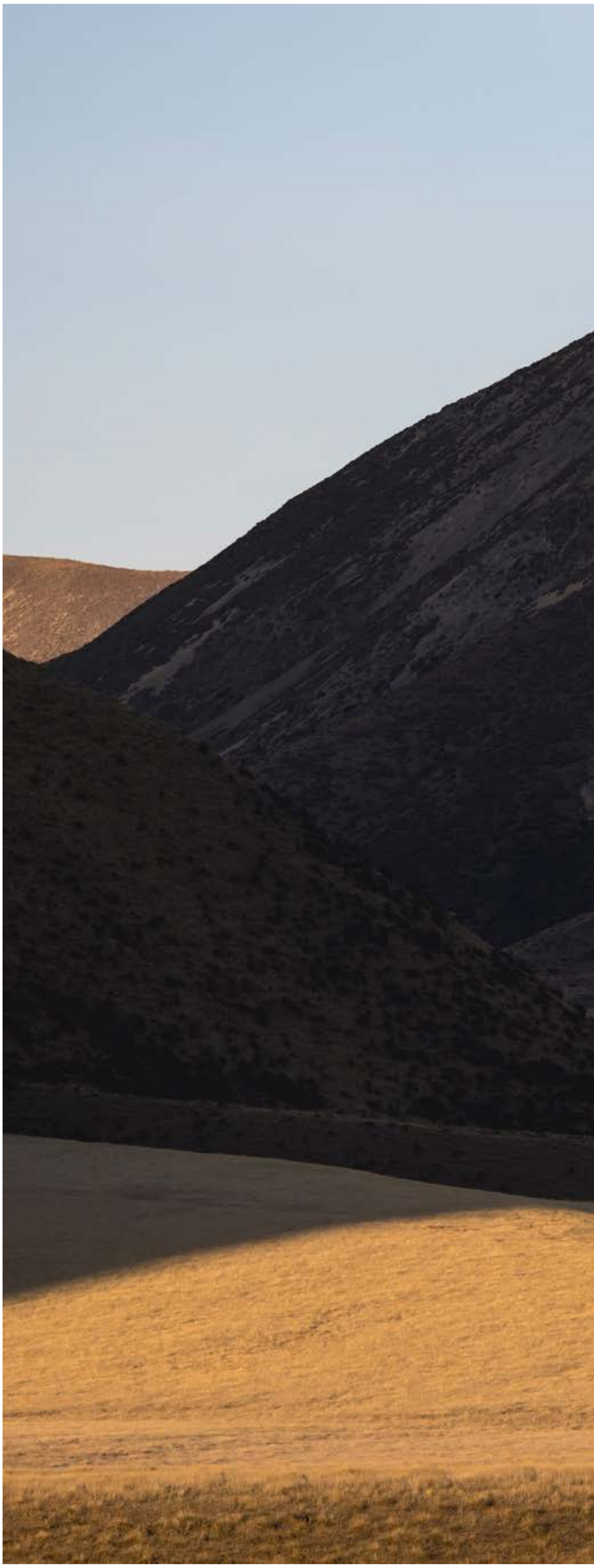
- Provide coordinated information specific to the region so that process heat users can make more informed decisions on fuel choice and timing.
- Improve fuel supplier confidence to invest in supply side infrastructure.
- Surface issues, opportunities, and recommendations.

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 (e.g. the GIDI Fund).
- Identify and commit to opportunities to fast-track process heat decarbonisation projects.

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

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



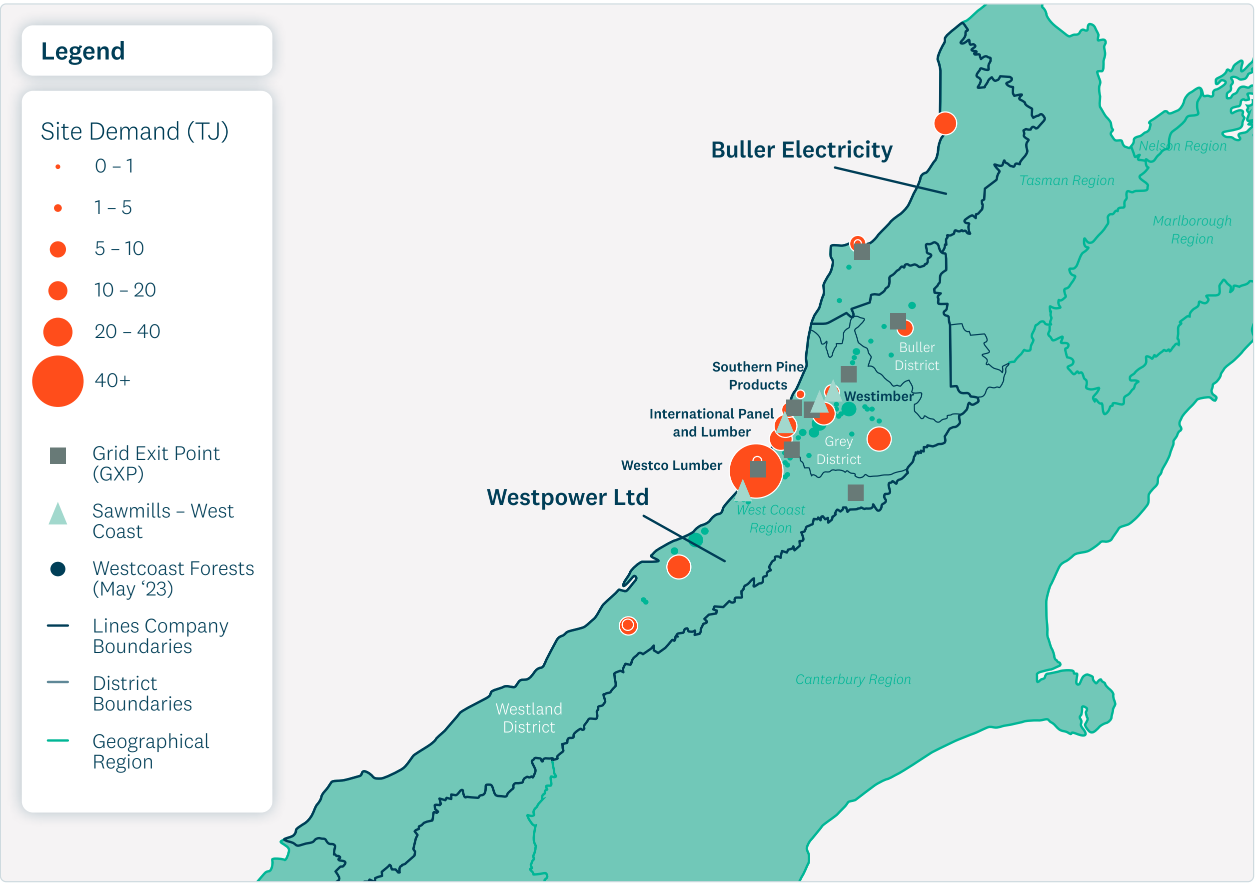
Porter's Pass, Canterbury, New Zealand.

6 West Coast process heat – the opportunity

6.1 The West Coast region

The area of study encompasses the Buller, Grey and Westland districts. Figure 9 illustrates the region considered in this report, with the process heat sites located and sized according to their annual energy requirements.

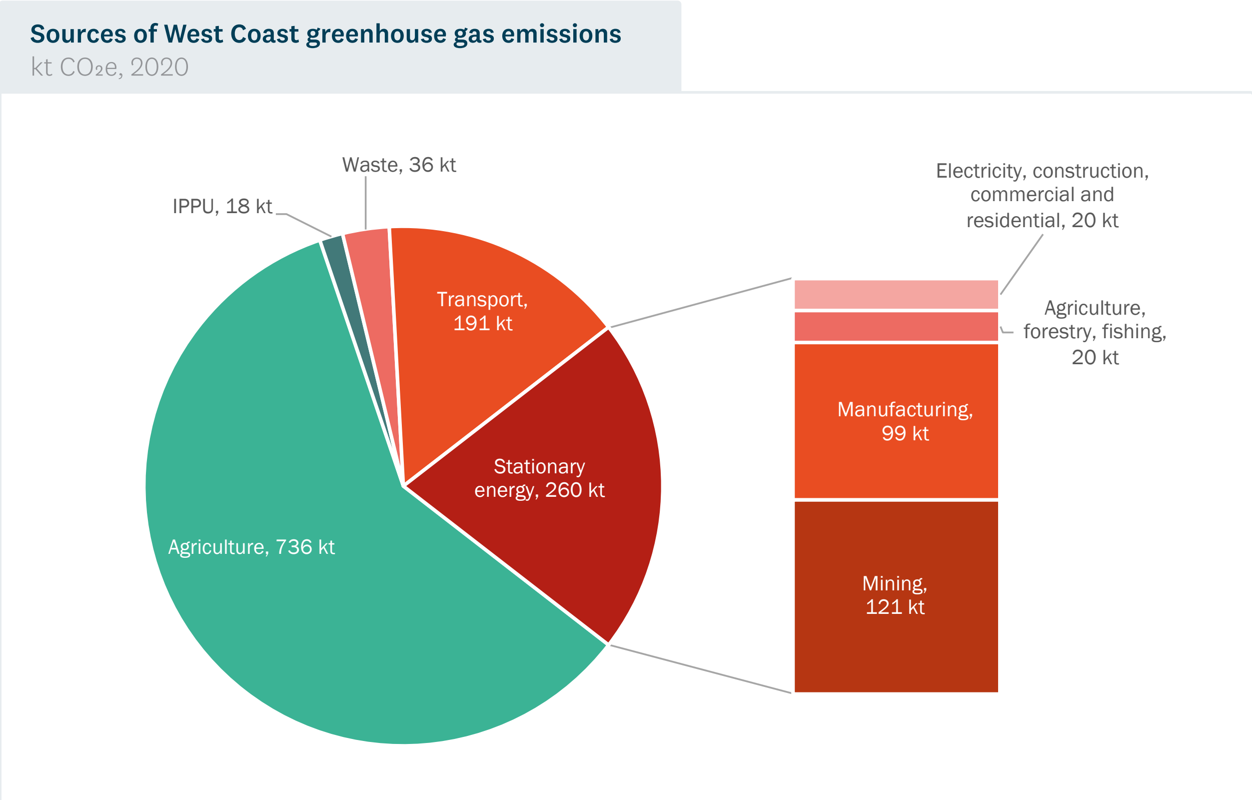
Figure 9 – The West Coast RETA region



6.2 West Coast emissions today

Like much of New Zealand, West Coast greenhouse gas emissions (expressed in carbon dioxide equivalent, or 'CO_2e') are dominated by agricultural emissions, making up 736kt (58%) of emissions out of the region's total emissions of 1,574kt (Figure 10). Energy is the second largest emitting sector, with 451kt (29%).

Figure 10 – Emissions inventory for the West Coast. Source: Stats NZ Regional Greenhouse Gas Inventory



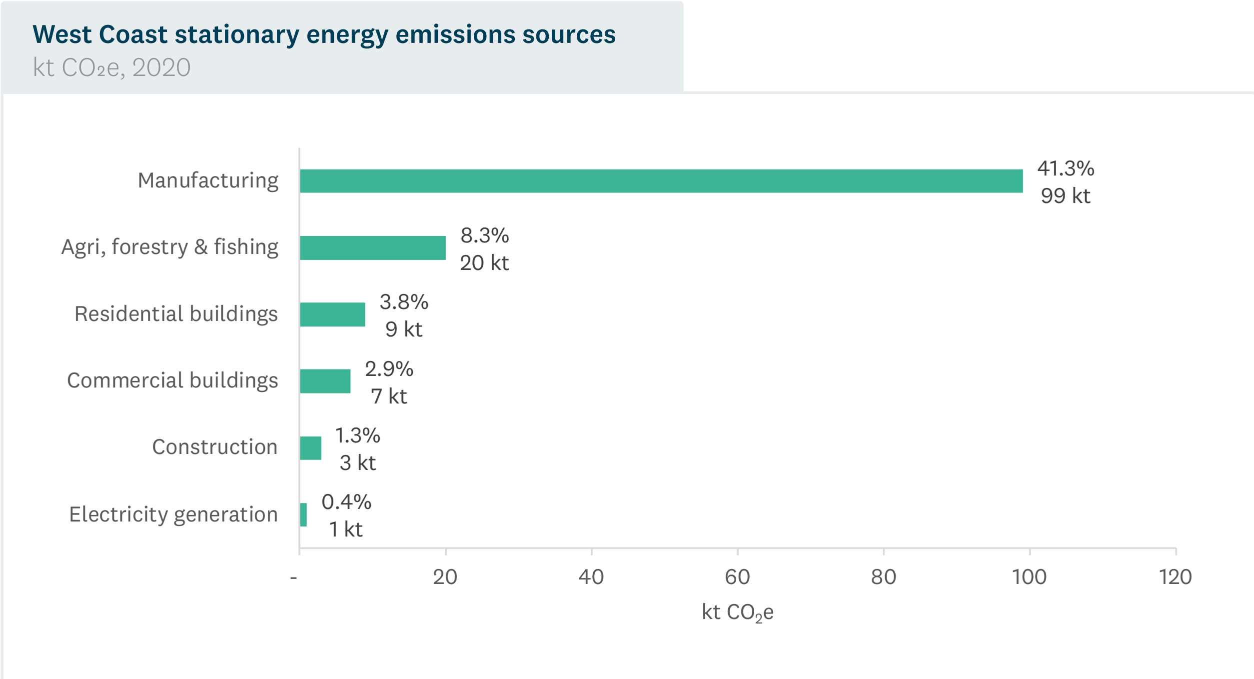
Inside energy, the emissions are split between transport emissions and 'stationary' energy. Stationary energy is a general category for any use of energy that doesn't relate to road, marine, rail or air transport, and is usually a combination of electrical appliances and the direct use of fossil fuels for creating heat (heavily dominated by process heat). Stats NZ (Statistics New Zealand) reports that stationary energy is 74% of energy-related emissions on the West Coast.

Figure 10 breaks stationary energy emissions down into industry sources. EECA understands that the 121kt of emissions produced by the mining sector actually relates to the use of diesel generators and large off-road vehicles (trucks, diggers, loaders) that are used in mining activities. While, technically, emissions from off-road vehicles would not be considered a 'stationary' use of energy, they are not included in Stats NZ's road transport category.

Ignoring mining emissions, Figure 11 shows the breakdown of the West Coast's sources of stationary energy emissions[15]. We expect the vast majority of these 139kt of emissions would be defined as 'process heat'.

[15] By removing the mining sector emissions, we are removing a genuine source of stationary emissions, from diesel generators. However, we expect that this will be a small component compared to the diesel used in large diggers and loaders, hence the error in the remaining analysis should be relatively minor.

Figure 11 – Breakdown of West Coast stationary energy emissions. Source: Stats NZ, EECA



6.2.1 Emissions coverage of the West Coast RETA

The West Coast RETA covers a total of 21 process heat sites spanning dairy, meat, industrial (e.g. sawmills) and commercial (predominantly facility heating). These are summarised in Table 3. In order to target the greatest level of emissions reduction opportunities, the sites selected represent all fossil fuelled process heat equipment above 500kW and any other sites (e.g. schools) where EECA had information from various programmes (e.g. EECA's Regional Heat Demand Database (RHDD)[16] and ETA) up to 2022.

Together, these sites contribute 125kt of process heat greenhouse gas emissions, around 90% of the stationary energy emissions shown in Figure 11.

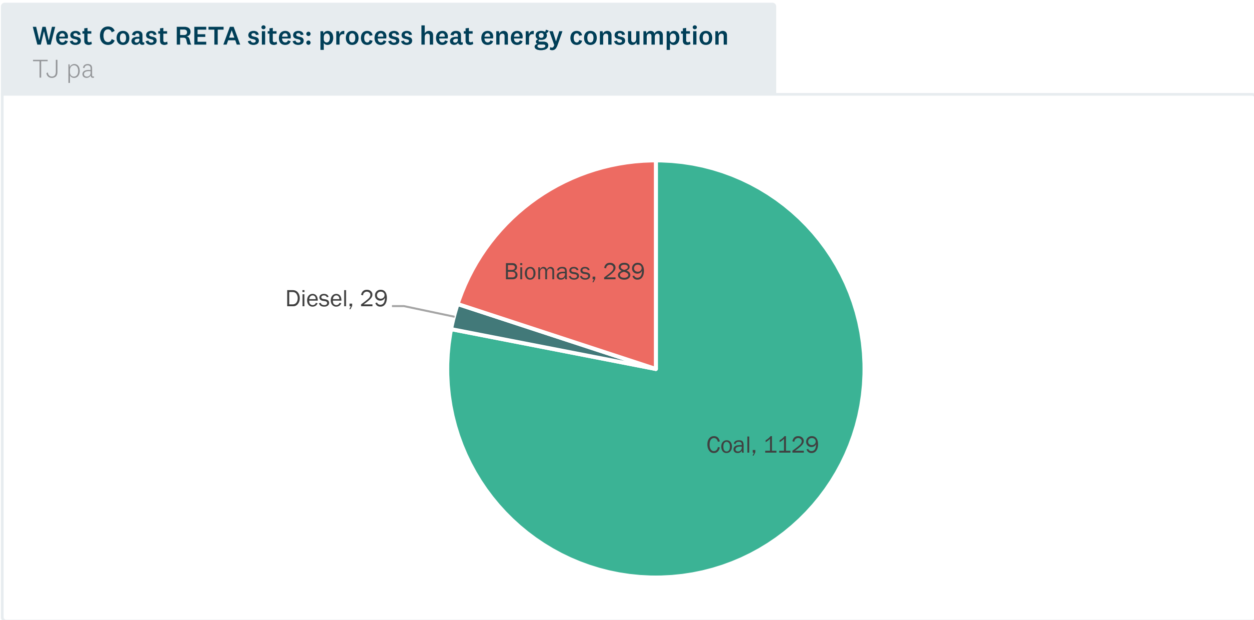
Table 3 – Summary of fossil fuelled process heat sites included in the West Coast RETA. Source: EECA

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 and meat	4	65	289	1,040	114
Industrial	5	8	24	87	8
Commercial	12	9	9	32	3
Total	**21**	**81**	**322**	**1,157**	**125**

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

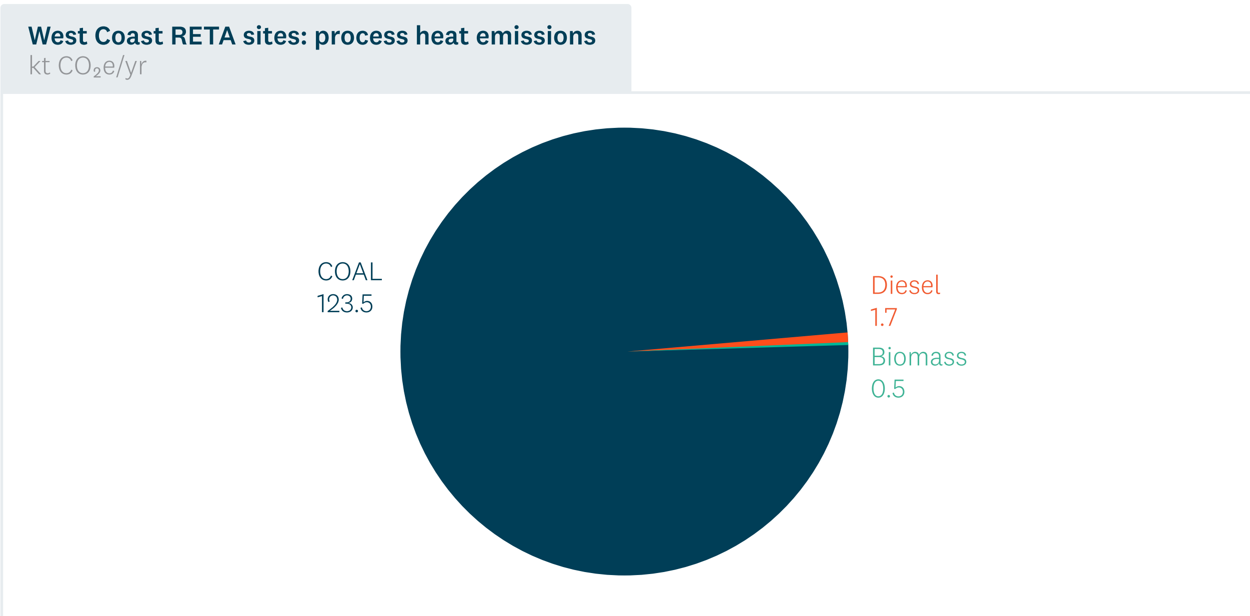
Current process heat requirements met by direct use of fossil fuels – coal, diesel and LPG – consume 1,157TJ of process heat energy per year (Figure 12).

Figure 12 – 2020 annual process heat fuel consumption in the West Coast RETA. Source: EECA



The majority of the West Coast RETA emissions[17] come from coal (Figure 13).

Figure 13 – 2020 annual emissions by process heat fuel in West Coast RETA. Source: EECA



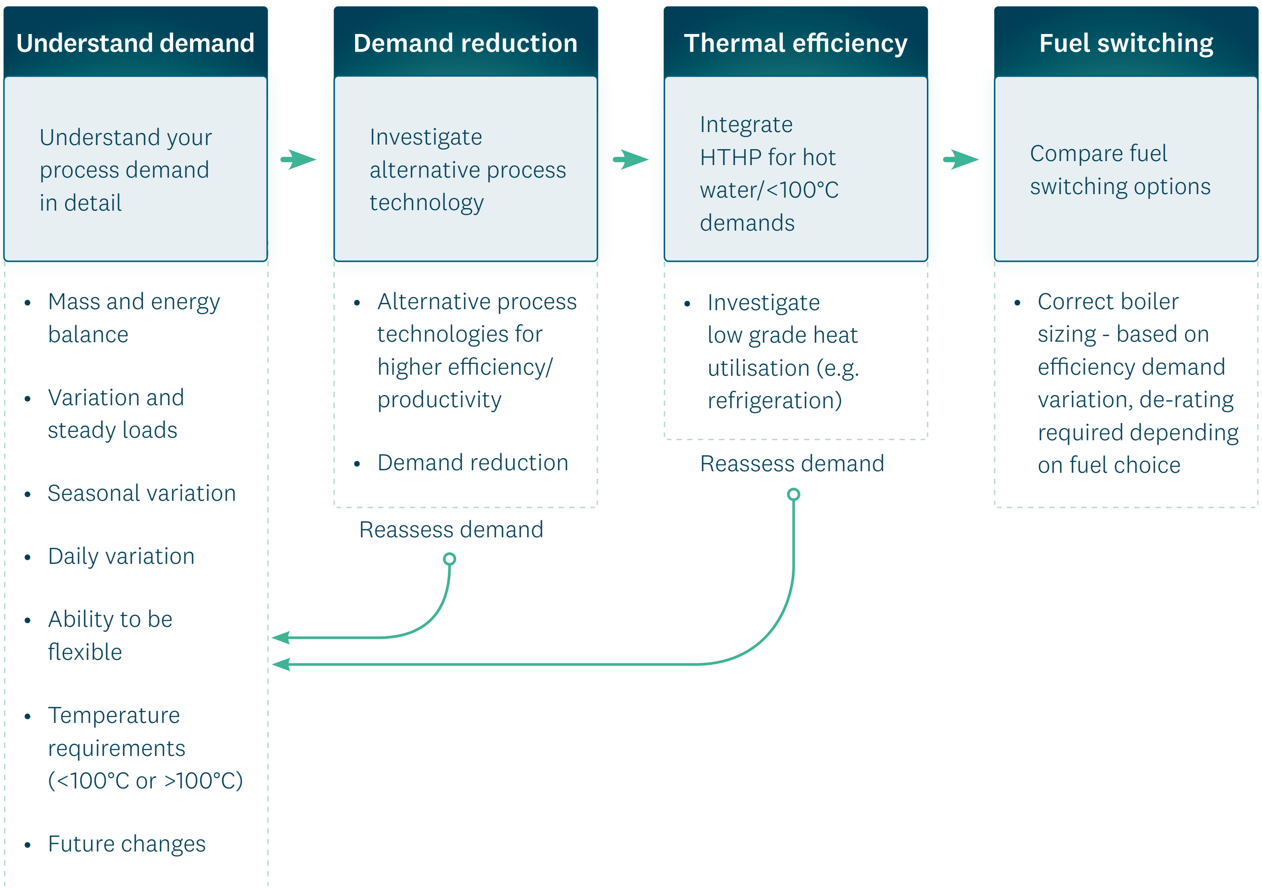
[17] Emissions factors used for fossil fuels are as follows (tCO2e per tonne of fuel): Lignite: 1.43; Sub-bituminous coal: 2.01; Diesel: 2.26; LPG: 3.03.

6.3 Process heat decarbonisation – how it works

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

Figure 14 – 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

6.3.1 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)? As will be discussed in Section 8.5, 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.

Understanding the site's demand, there are four primary ways in which emissions can be reduced from the process heat projects covered by West Coast RETA. For any given site, the four options below are not mutually exclusive – that is, 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 proceed first.

6.3.2 Demand reduction

Demand reduction includes projects such as heat recovery, temperature optimisation, equipment replacement, thermal insulation, and water flow reduction. These projects often have lower capital costs than fuel switching, providing a good return on investment and marginal abatement cost. The ability for a site to reduce demand is specific to its operations, hence sites within the same sector usually have similar project opportunities. Opportunities in the meat industry include UV sterilization, heat recovery, washdown optimisation, and pipe insulation[18]. For the dairy sector, opportunities could include waste heat recovery, 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.

6.3.3 Thermal efficiency – high temperature heat pumps for <100°C requirements

Improvements in thermal efficiency can be achieved primarily through the installation of high temperature heat pumps (HTHPs)[19]. 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.

[18] See https://www.eeca.govt.nz/insights/eeca-insights/international-tech-scan

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

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[20]. While not yet used in New Zealand, high temperature steam heat pumps producing 150°C heat[21] 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 West Coast region (outlined in Section 9).

6.3.4 Fuel switching to biomass – boiler conversions or replacements

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

Two primary and interrelated decisions when switching to biomass are:

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

[20] 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 technology can achieve significantly higher COP again.

[21] 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/

6.3.5 Fuel switching – electrification

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[22].

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 8.

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. This point is discussed more in Section 8.6.

6.4 Characteristics of RETA sites covered in this study

As outlined above, there are 21 sites considered in this study. Across these sites, there are 48 individual projects spanning the three categories discussed in Section 6.3 – demand reduction, heat pump and fuel switching. As Table 4 shows, RETA process heat users are at different stages of these 48 projects. Twelve have already been completed. 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. Approximately half of the 48 projects are unconfirmed, in that the process heat organisation is yet to commit to the final investment.

Table 4 – Number of projects in West Coast RETA by category. Source: Lumen, EECA

Status	Demand reduction	Heat pump	Fuel switching	Total
Completed	12	-	-	12
Confirmed, not completed	1	6	6	13
Unconfirmed	9	6	8	23
Total	**22**	**12**	**14**	**48**

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

As outlined above, demand reduction and heat pumps are key parts of the RETA process and, in most cases enable (and help optimise) the fuel switching decision. This RETA report has a greater level of focus on the fuel switching decision, due to the higher capital and fuel intensity of this decision. However, in assessing the required boiler capacity for each unconfirmed fuel switching project, this report assumes that every site has invested in a demand reduction project and, if relevant, a heat pump project.

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

Table 5 – Summary of West Coast RETA sites with fuel switching requirements. Green shading indicates confirmed projects; orange highlighting indicates the preferred fuel option a commercial decision-making criteria developed in Section 9.

Site name	Industry	Project status	Bioenergy required in TJ ('000t)/ yr	Electricity peak demand (MW)
ANZCO Kokiri	**Meat processing**	**Confirmed**	**N/A**	**1.52**
Greymouth Hospital	**Hospital**	**Confirmed**	**18.4 (2.56)**	**N/A**
Greymouth High School	**Education**	**Confirmed**	**2.1 (0.29)**	**N/A**
Grey Main School	**Education**	**Confirmed**	**0.7 (0.09)**	**N/A**
Runanga School	**Education**	**Confirmed**	**0.3 (0.04)**	**N/A**
Cobden School	**Education**	**Confirmed**	**0.2 (0.03)**	**N/A**
Westland Milk Products Hokitika - Stage 1	Dairy processing	Unconfirmed	563 (78.3)	**12.12**
Westland Milk Products Hokitika - Stage 2	Dairy processing	Unconfirmed	**285 (28.3)**	28.28
Value Proteins	Pet food/ rendering	Unconfirmed	**87.7 (12.2)**	13.67
International Panel & Lumber	Engineered timber	Unconfirmed	**31.4 (4.37)**	1.88
Karamea Tomatoes	Horticulture	Unconfirmed	**20.76 (2.89)**	2.49
Westimber	Sawmill	Unconfirmed	9.10 (1.27)	**0.35**
Westland Produce	Horticulture	Unconfirmed	**9.01 (1.25)**	1.98
Scenicland Laundry	Laundry	Unconfirmed	**4.98 (0.69)**	0.38

Eight sites have already confirmed their fuel of choice, representing a demand for 22TJ (3,000t[23]) of biomass and 10TJ (3GWh) of electricity.

The potential fuel switching decisions associated with the remaining eight projects[24] will be the focus of Section 9.2. We highlight in green the preferred fuel based on the MAC Optimal calculations outlined in Section 9.1.2.

6.5 Process heat energy – implications for local energy resources

All RETA decarbonisation pathways (presented in Section 9) expect that the 21 West Coast RETA sites, representing 1,157TJ per year of coal and diesel process heat energy consumption in 2022, will have switched to low emissions fuel before 2037[25]. The rate at which this might occur, and the fuel choices that 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 discussed above, some of the current consumption of fossil fuels by sites in the RETA study will be eliminated through demand reduction projects. Further, installing heat pumps could see significant efficiencies achieved, reducing the necessary size of boilers. Finally, some fuel switching investments have already been confirmed by process heat users. These components are presented in the chart below, to provide a picture of how fuel use may change over the period of the RETA study.

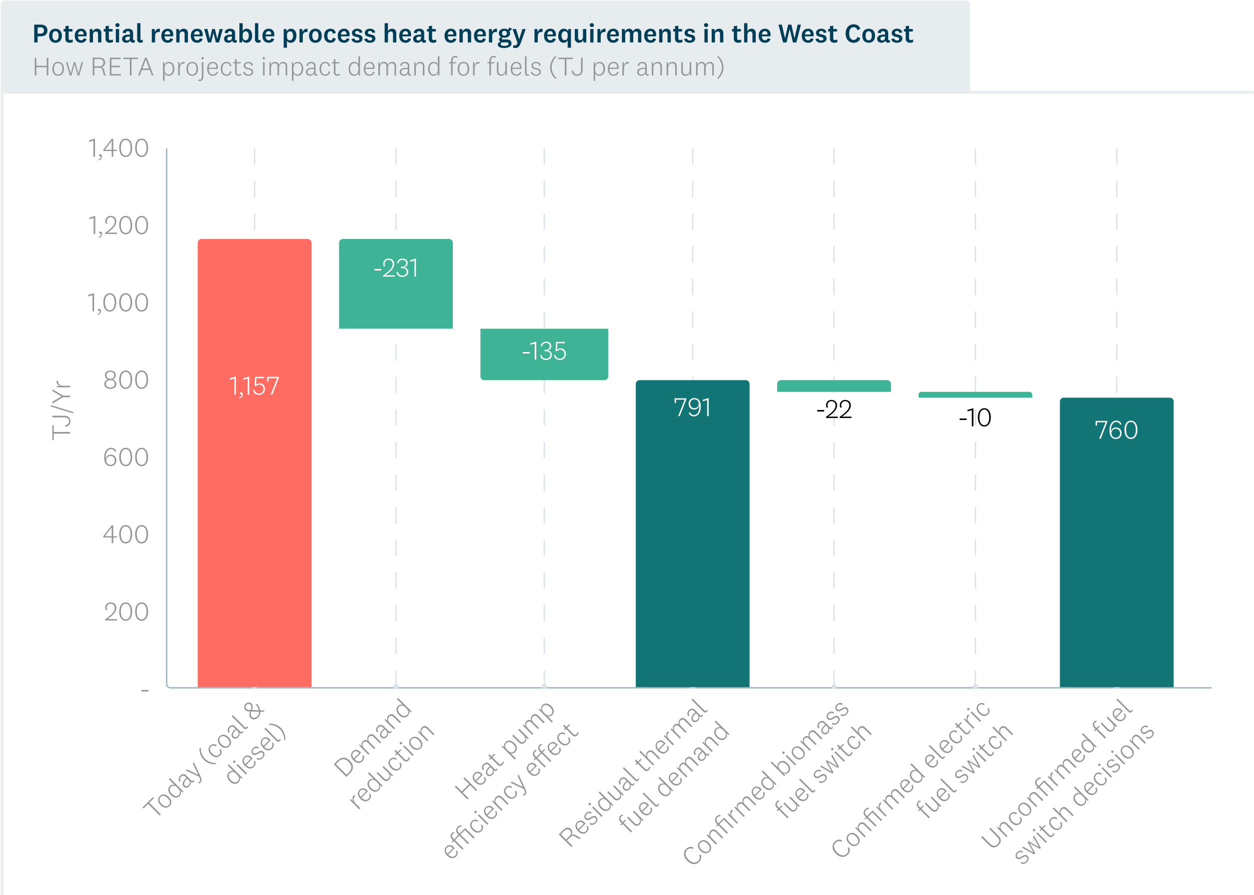
Westland Milk, West Coast, New Zealand

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

[24] Across seven sites, as Westland Milk has two fuel switching projects on a single site.

[25] All RETA decarbonisation projects are executed by 2037 in line with the Government's aspiration to phase out coal boilers by 2037. See https://www.beehive.govt.nz/release/government-delivers-next-phase-climate-action

Figure 15 – Potential impact of fuel switching on West Coast fossil fuel usage, 2022-2037. Source: EECA[26]



As 760TJ of fuel switching decisions are yet to be made[27], 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 – combined with confirmed electrification projects[28] – could result in an increase in instantaneous electricity demand of 65MW, if all sites reached their maximum outputs at the same time. This instantaneous demand would double the coincident maximum demand experienced currently by both EDBs. These electrification decisions would also increase the annual consumption of electricity by 177GWh, approximately 63% of today's gross electricity consumption[29] on the West Coast.
- If all unconfirmed boiler fuel switching decisions choose biomass, this – combined with confirmed biomass projects – could result in an increase of 116,000t per annum of biomass usage (see Section 7.7). Assuming sufficient resources were available, this is a five-fold increase in the use of biomass for heat compared to our estimate that, today (in 2022), around 21,000t of biomass is used for heat.

[26] Of the demand reduction projects, around 33% of projects are confirmed, the remaining unconfirmed. For heat pumps, 27% are confirmed, 73% are unconfirmed.

[27] The figure of 760TJ is slightly higher than the sum of biomass demands in Table 4. This is primarily due to the difference in efficiency between existing boilers and new boilers. The figures in Table 4 represent the fuel demand assuming a higher efficiency associated with a new boiler, whereas Figure 12 represents today's demand from the existing boilers.

[28] These figures also include the increase in electricity demand from expected installation of high temperature heat pumps for low temperature heat applications.

[29] The West Coast's current electricity consumption is around 300GWh per annum (source: emi.ea.govt.nz). A high percentage of gross electricity consumption on the West Coast is supplied by distributed generation that is not directly connected to the national grid – mostly hydro. Based on EDB disclosures, distributed generation generated 181GWh of energy for the year ended March 2022.

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 9.

Westland Milk, West Coast, New Zealand.

7 Bioenergy

7.1 Approach to bioenergy assessment

This section considers the availability and potential cost of wood resources in the West Coast region as a potential source of bioenergy for process heat fuel switching. While there are other sources of biomass (e.g. landfills), the focus is on major sources that could collectively provide up to 106,351t per annum – which would be the demand should all RETA sites[30] 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 then to:

- Consider the total availability of biomass from forestry in the region, including those sources that are not currently being recovered from – 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 also provides an assessment of where the wood is expected to flow through the supply chain – via processors to domestic markets, or export markets – and acts as a check on the top-down assumptions. Interviews also highlight volumes that are currently being utilised for bioenergy purposes.
- 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 (in the near term) the ability to divert wood to bioenergy for process heat.
- 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[31] 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 West Coast 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 has the potential to help potential users make indicative commercial judgments about the attractiveness of biomass, in the quantities required, relative to other fuel switching alternatives.

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

[31] Biomass Centric is a scenario where all unconfirmed fuel switching decisions choose biomass. MAC Optimal uses a commercial decision-making framework to determine the optimal fuel choice, and the timing of the fuel switch. See Section 9.2 for more detail.

Only biomass sources within the West Coast region are considered. There are other regions in New Zealand where bioenergy supply potentially exceeds the demand[32]. Conceivably, these resources could be transported to the West Coast, albeit with additional considerations and impacts (e.g. transport emissions). EECA will consider these opportunities and impacts once more regions are covered.

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, and as outlined in New Zealand's Emissions Reduction Plan (ERP), biofuels are a potential low-emission alternative to existing oil-derived transport fuels, and the ERP included an action to implement a sustainable biofuels obligation[33]. This requires further analysis, as EECA does not currently have reliable estimates for the likely local demand for biofuels.

7.2 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.**

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.

[32] Halls (2018) regional resource studies show areas like the Bay of Plenty and Gisborne with more supply than demand.

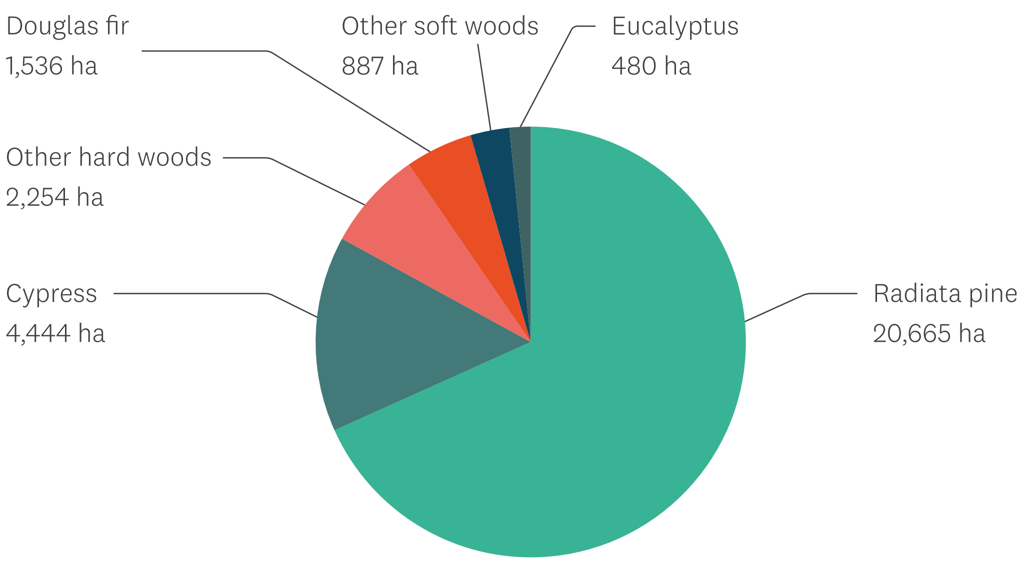
[33] We note though that although the first Emissions Reduction Plan included a sustainable biofuels obligation, this has been indefinitely paused – see https://www.stuff.co.nz/environment/climate-news/131176812/prime-minister-chris-hipkins-opens-a-hole-in-the-carbon-budget

7.3 Regional wood industry overview

The West Coast region has approximately 30,266ha of planted forests. These forests are dominated by radiata pine and cypress (Figure 16); other species include Douglas fir, softwoods, eucalypts and hardwood species.

Figure 16 – Area and species planted in West Coast (as at 1 April 2021)

West Coast region: area planted by species



The focus of our analysis below is on radiata pine, cypress and Douglas fir, but there has been allowance for minor species in the overall resource assessment.

The forestry and food processing sector have partnered with Government to develop a Forestry and Wood Processing Industry Transformation Plan[34] which is focused on increasing the total area of forestry and getting greater value from wood. This includes significantly increasing the areas of trees on farms and increased domestic processing. Additional domestic processing within New Zealand may result in greater quantities of processing residues being available as an energy fuel. Increased planting of trees on farms also contributes to environmental and community benefits so is expected to occur over the next few years.

[34] https://www.mpi.govt.nz/forestry/forest-industry-and-workforce/forestry-and-wood-processing-industry-transformation-plan/

7.3.1 Forest owners

The region is dominated by one large forest owner (Ngāi Tahu Forestry), which accounts for 80% of total planted forestry.

Table 5 – The West Coast region forest estates

Status	Radiata pine (ha)	Douglas fir (ha)	Cypress (ha)	Minor species (ha)	Total
Ngāi Tahu Forestry	17,365	1,394	3,980	1,436	24,175
Remaining estates	3,300	142	464	2,185	6,091
Total	**20,655**	**1,536**	**4,444**	**3,621**	**30,266**

Ngāi Tahu Forestry is the only corporate forest company on the West Coast. The company was established in 2000 when Ngāi Tahu Holdings Corporation purchased land subject to Crown Forestry licences. The Ngāi Tahu Forestry portfolio comprises approximately 54,000ha of land and forestry interests in North Canterbury, Otago and the West Coast. For this assessment area, Ngāi Tahu forestry has 24,175ha of forestry in the Buller, Grey and Westland Districts.

7.3.2 Wood processors

There are five major processors in the West Coast, 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 and hoggings.

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

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

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

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

Hogging is a product created from dry offcuts. The offcuts are processed through a size reduction machine known as a hogger.

7.3.3 Additional wood processor residues (WPR)

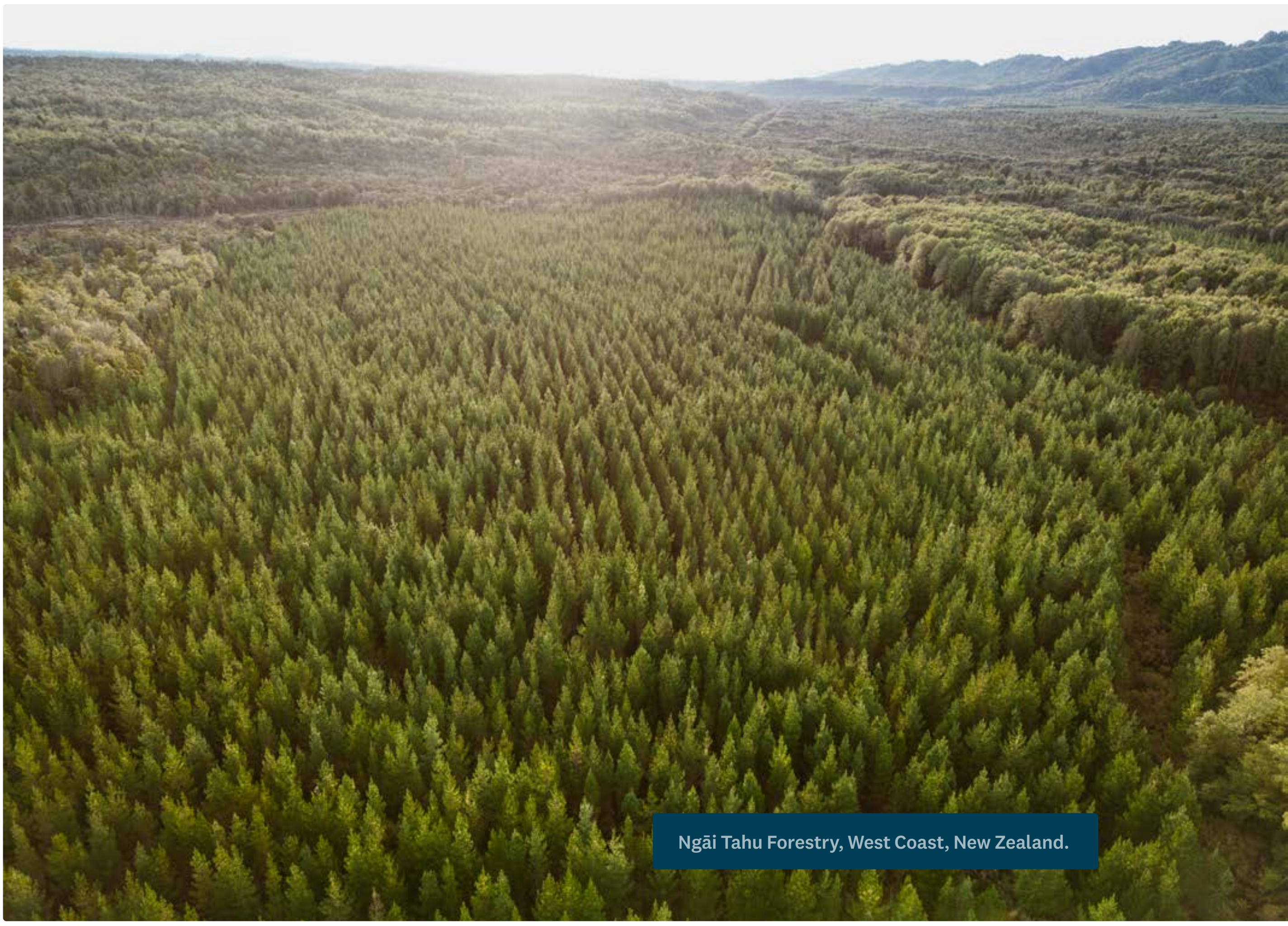
The International Panel and Lumber company in Greymouth manufactures plywood by transforming logs into sheets of plywood. The manufacture process is not able to convert the entire log into sheets of plywood and each log produces a 140mm round pole that has been partially dried. These poles could be an alternative source of bioenergy if it is hogged. Ahikā estimates newly available volumes of 8,000 tonnes per year.

7.4 Assessment of wood availability

This section considers:

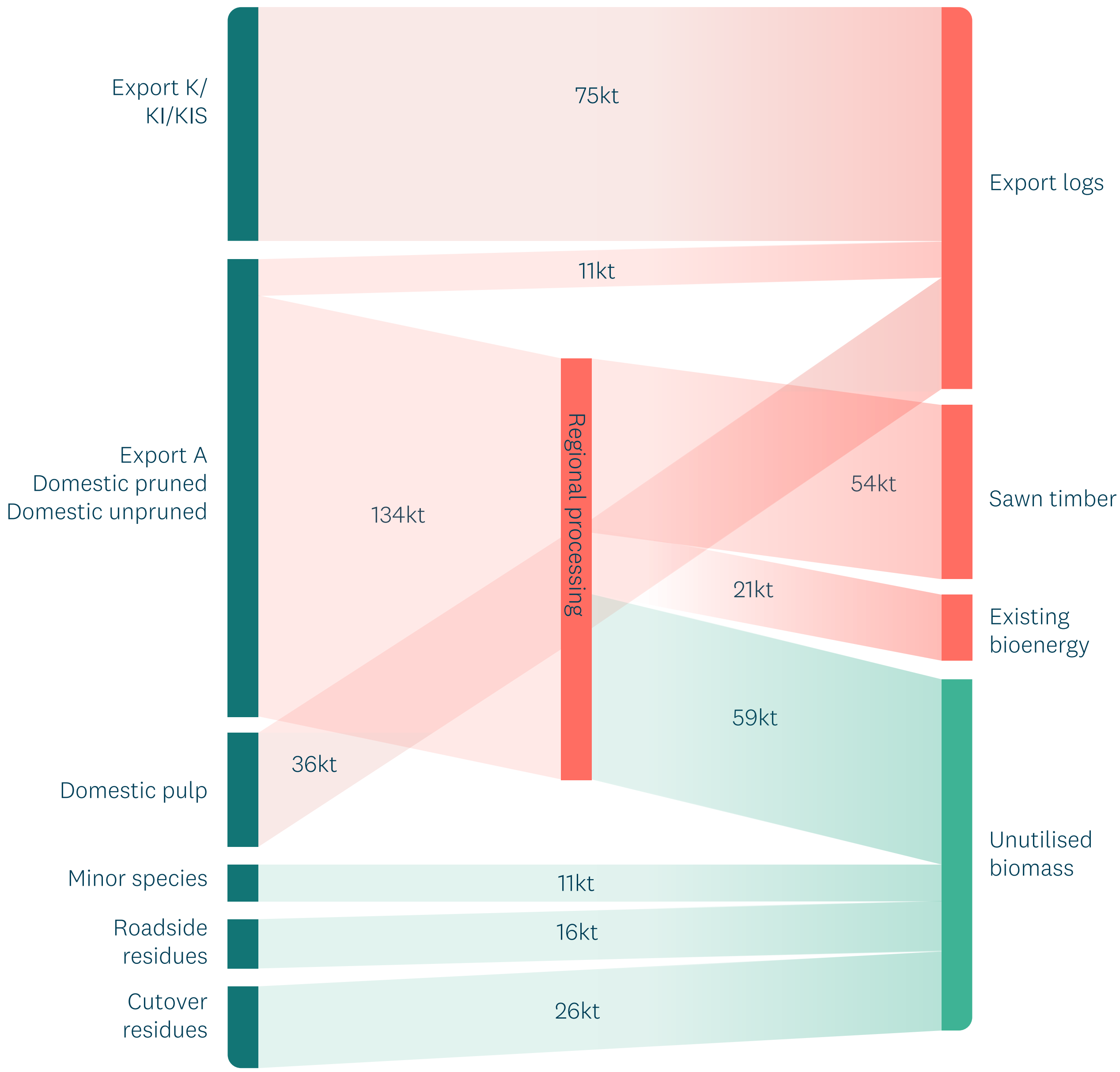
- The total wood, and the grades of wood, expected to be harvested in the region over the next 15 years.
- What the existing markets are for that wood, including the role of any processors in the region, and existing bioenergy uses.
- How much of that wood (including harvesting and processor residues)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

The outcome of this section is summarised in Figure 17. Wood flows that could – in part or in full – be diverted to new bioenergy demand from process heat are shown in green.



Ngāi Tahu Forestry, West Coast, New Zealand.

Figure 17 – Wood flows in West Coast. Source: Ahikā, Margules Groome



7.4.1 The Wood Availability Forecast

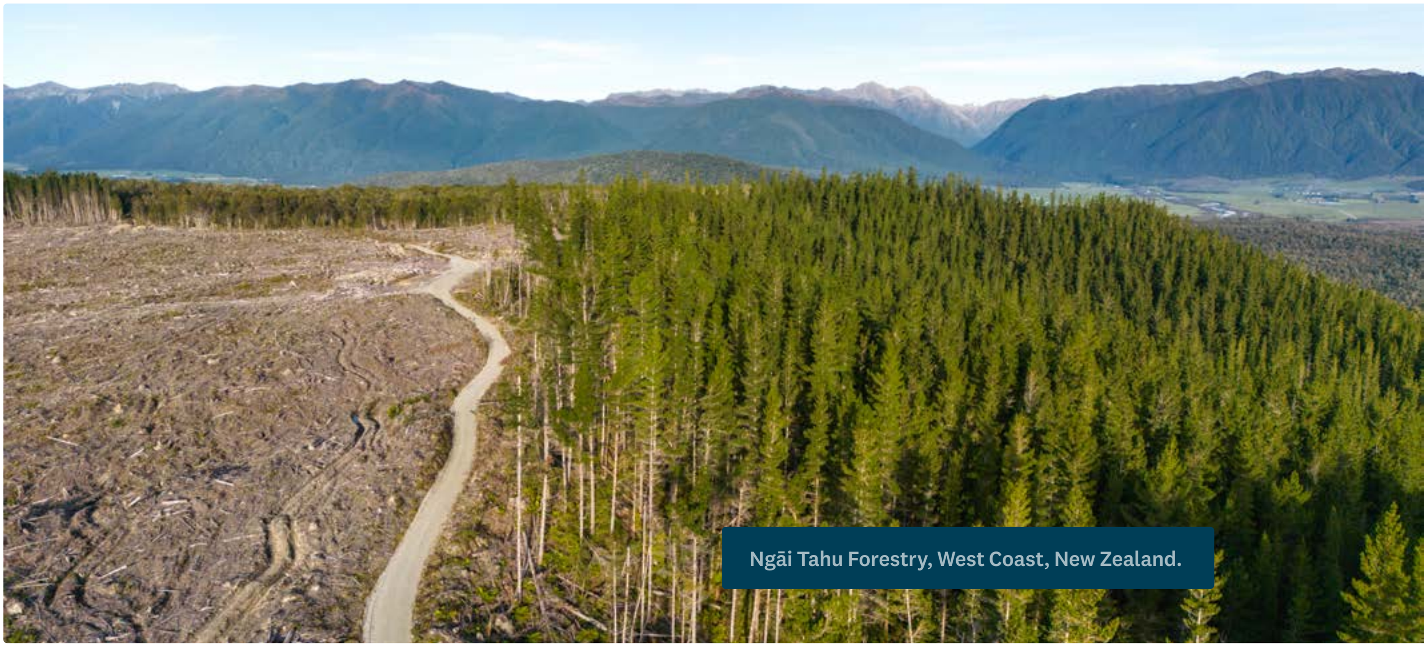
The Ministry for Primary Industries' (MPI) Wood Availability Forecast (WAF) provides a recognised starting point for the volume of resource that is in the West Coast forests, as well as when that resource is likely to come to market.[40]

In Figure 18 total volumes are broken down into log grades using national exotic forest description (NEFD) data and the log-grade split for West Coast forest owners 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 West Coast market.

Key log grades are:

- Export grade – this includes A, K, KI and KIS grades logs exported to Asia.
- Domestic grade – this includes Pruned, Unpruned, and Pulp log grades. These grades go to domestic markets including wood processors and firewood.
- Harvesting residues – a by-product of harvesting and a primary source for bioenergy and firewood. It is commonly referred to as 'billet' wood. Here it is split into '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.

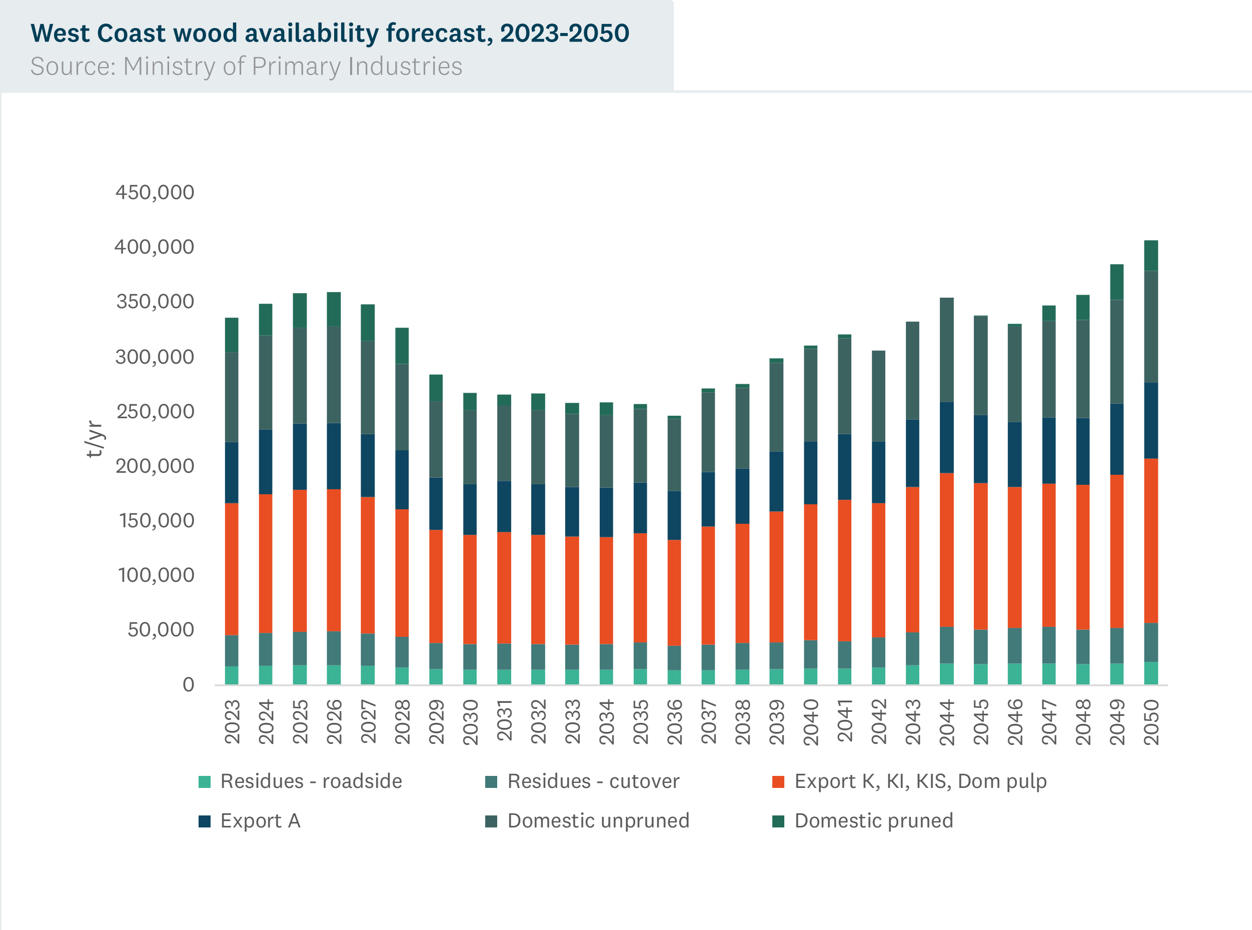
Export and pulp grade volumes are sent to Canterbury and Nelson markets for processing (Daiken New Zealand) and to the Port of Lyttleton. Domestic grades are utilised on the West Coast by local processors but can also be sent to Canterbury and Nelson by rail or truck.



Ngāi Tahu Forestry, West Coast, New Zealand.

[40] These forecasts are prepared routinely for all regions of NZ. However, these regional boundaries do not align with the focal area of this study. To complete this forecast, permission was granted by the Ministry for Primary Industries for Margules Groome to create a forecast for the specific area.

Figure 18 – West Coast wood availability forecast, 2023-2050. Source: Ministry of Primary Industries[41]



As can be seen from Figure 18, the total available wood resource falls over the period 2026-36 and increases shortly after the end of the RETA study period (2037). This occurs due to the age distribution of the existing forests (around half of radiata pine is more than 15 years old), combined with the assumptions in the WAF model regarding when forests are harvested.

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

The large-scale owner holds 80% of the modelled resource and small-scale owners hold 20%. 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.

[41] Most of the domestic pulp volumes are assumed to be diverted to export KIS, hence they are grouped with the export categories. This diversion follows the closure of one of the production lines at Daiken's Rangiora site.

7.4.2 Minor species

In the West Coast, minor species account for 8,000 hectares in the NEFD, and Ngāi Tahu Forestry accounts for nearly 70% of the minor species that include spruce, cypress, eucalyptus and other hardwoods. It is assumed that the minor species are recovered at a rate of 370 tonnes per hectare, and that 20%-40% of this could be used for bioenergy. Averaged over 2023-2037, and accounting for the age class distribution, minor species could thus contribute 33,302 tonnes per year as bioenergy.

7.5 Insights from interviews with forest owners and processors

The results of the Wood Availability Forecast modelled was 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.

7.5.1 Processing residues

Five 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.

The main residues from wood processors are:

- **Sawdust** – the residue from sawing logs and 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** – created onsite from all viable offcuts and sold for landscaping, animal bedding or 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.
- **Hogging** – in this situation a product that is created from dry offcuts. The offcuts are processed through a size reduction machine known as a hogger.

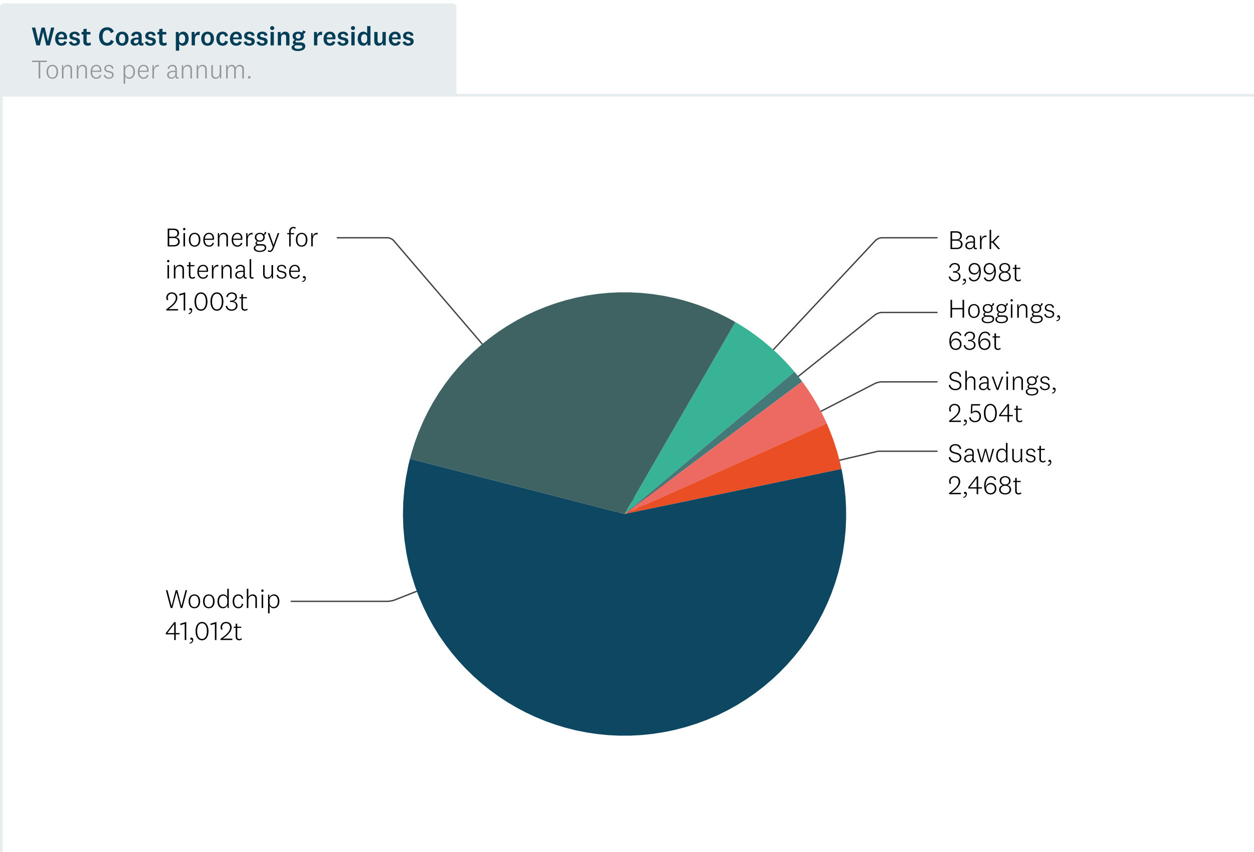
Table 6 shows the types of processing residues readily available from West Coast processors.

Table 6 – Products readily available for bioenergy from processors in the West Coast

	Sawdust	Woodchip	Shavings	Hogging	Bark
International Panel & Lumber		x	x		
NZ Sustainable Forest Products		x			x
Southern Pine Products	x	x	x	x	x
Westco Lumber	x	x	x		x
Westimber	x	x			

The interviews conducted suggest that there are, on average, 71,621t of processing residues created in the West Coast, the majority of which is woodchip (Figure 19). Another 21,000t of these residues are already being utilised for bioenergy in the form of wood pellets and boiler fuel. The remainder – primarily post peelings (50,618t) – are unutilised and are stockpiled by the processors.

Figure 19 – West Coast processing residues, tonnes per year (15-year average). Source: Ahikā Interviews



7.5.2 In-forest recovery of biomass

In-forest residue volumes were estimated by Margules Groome as part of the WAF[42]. In-forest volumes have been split into two categories:

- **Roadside** – 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.

No harvesting residues are currently being recovered. Based on interviews with the main forest company, in-forest residues are currently not recovered due to:

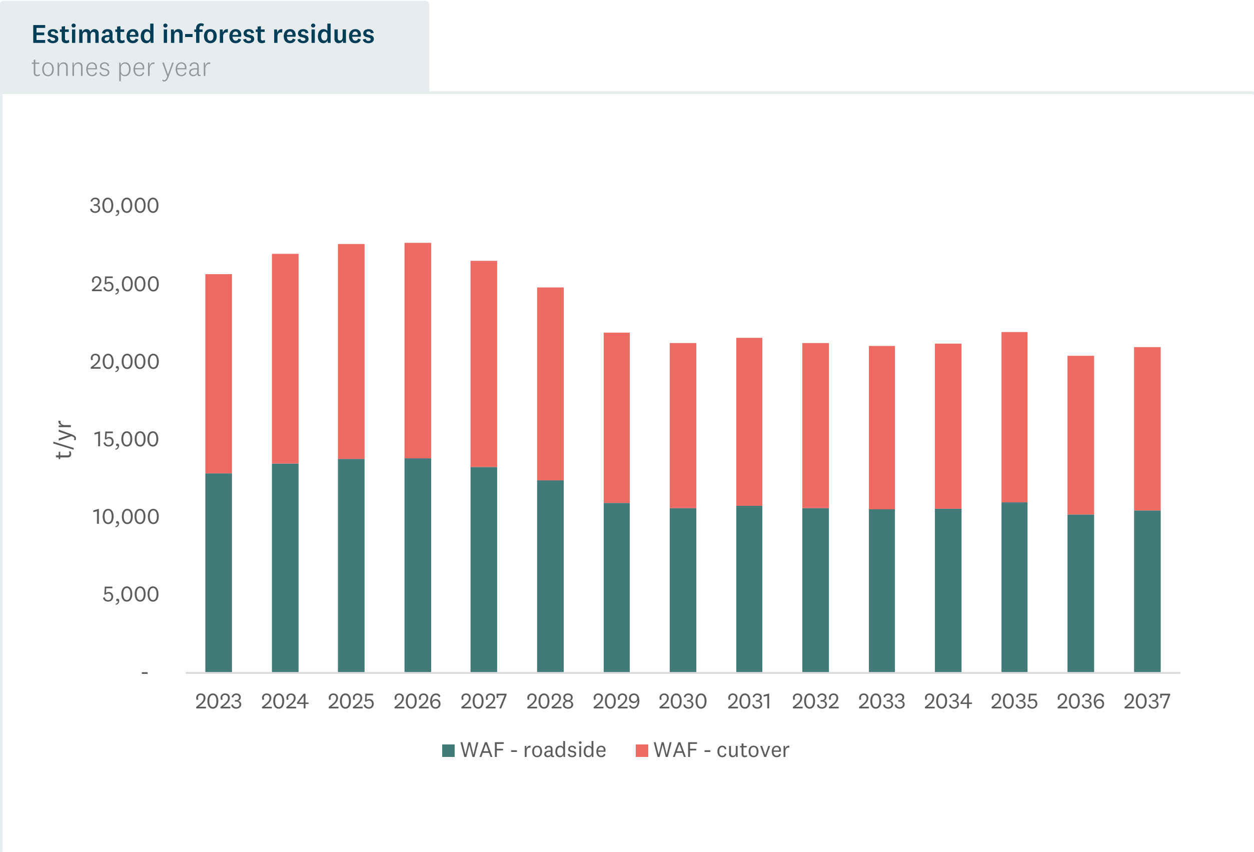
- The instability of soils, which impacts the area available for processing logs in forest. To keep the processing area small, the logs are two-staged (the process of grading the logs occurs at two sites), which is expensive for residue recovery.
- The costs associated with creating one-stage processing being expensive due to getting suitable aggregate to site to stabilise soils.
- There being no demand for bioenergy from these residues.
- The log rate would need to be at least $50 per tonne for crews to be motivated enough to recover.

A more definitive estimate of cutover recovery resources and cost requires an assessment of the underlying terrain, as recovery on steep hauler country is likely to be substantially lower than on ground-based country. This information was not available for the West Coast RETA. We have scaled back assumed recovery of harvesting residues from the theoretical potential in the WAF, using expert opinion[43]. This applied more pragmatic recovery factors for different volumes, based on assumed methods of recovery (ground-based and hauler-based). The net effect was that only 75% of the roadside volumes, and 45% of the cutover volumes from Figure 18 above were used in the final assessment. The resulting volumes are shown in Figure 20.

[42] As noted above, this estimate was based on the research of Hall (1994), Robertson and Manley (2006) and Visser (2010, 2018).

[43] Margules Groome, 2023.

Figure 20 – Estimated in-forest residues based on practical recovery factors



Kumara Hydro Station, West Coast, New Zealand.

7.6 Summary of availability and existing bioenergy demand

Figure 21 below shows our overall assessment of the forest (and forestry by product) resources in West Coast.

Figure 21 – Assessment of available West Coast woody biomass that could be used for bioenergy.

West Coast woody biomass potentially available for bioenergy
Green tonnes per year and TJ per year

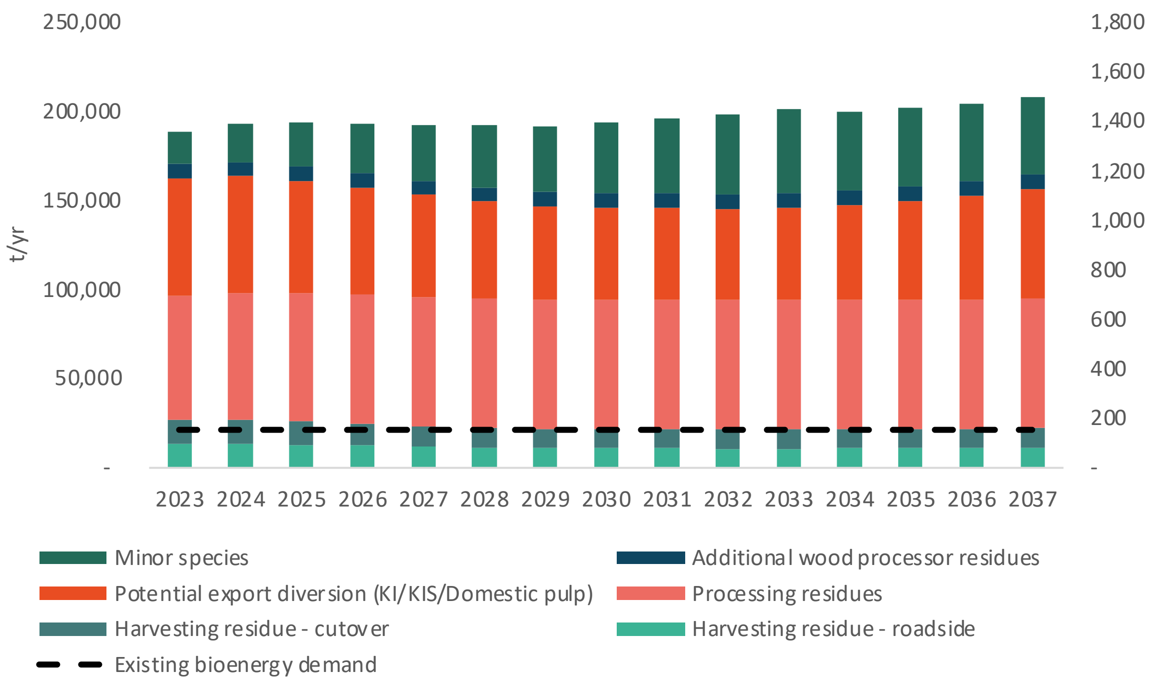


Figure 21 shows there is significant scope to increase the use of bioenergy from the relatively low level today. However, there are several factors to consider:

- Ideally, the consumption of bioenergy should not disrupt domestic markets for timber; hence domestic pulp, A-grade and K-grade timber are only shown for reference and are not likely to be used for long-term bioenergy requirements.
- The preservation of existing bioenergy users' access to fuel.
- The price of collecting, processing, storing, and delivering the bioenergy to potential users.
- The stability of the resources through time, as investors in bioenergy as a fuel will want at least medium-term certainty on availability and price.

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

7.7 Cost assessment of bioenergy

Since bioenergy markets are very much in their infancy, the approach is to base prices on either an estimate of the costs of extracting the resource, or to 'shadow price' 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.

7.7.1 Cost components

Margules Groome developed a calculator to estimate delivered bioenergy prices for the various products identified in this assessment. A key cost component is the cost of transporting the material from source to a hypothetical processing location, which for the West Coast region has been assumed to be the Westland Milk plant. Depending on the source, prices have been determined as follows:

- **Diverted export volume** – all the volume from the West Coast is assumed to be transported from Greymouth to Lyttleton. The difference between the transport cost to Lyttleton 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.
- **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. This methodology is also used to calculate the bioenergy cost for material sourced from the harvesting of minor species.
- **Wood processing residues** – the price for the wood processing residues is the sum of the cost of the material at the processing mill plus the cost of transporting it to the hub. It is assumed that the material is already in a form that could be consumed for energy production, hence only storage, handling and hub margin costs are added.

Table 7 and Figure 22 show these costs in terms of mass and (in $/t biomass) and energy equivalent ($/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 7; this will need more detailed consideration by process heat users contemplating conversion to biomass.

Table 7 – Sources and costs of biomass resources in the West Coast region. Source: Margules Groome (2023), average value 2023-2037 [44]

Bioenergy source	Cost of biomass source ($/t)	Harvesting and collection[45] ($/t)	Chipping and storage ($/t)	Transport to process heat user[46] ($/t)	Total cost delivered to user's site ($/t)	Total cost delivered to user's site[47] ($/GJ)
Processor residues	$45.85	$0	$10[48]	$46	**$102**	**$14.20**
Roadside residues (incl. collection)			$25		**$106**	**$14.77**
Minor species	$20	$11.55	$25	$55	**$111**	**$15.49**
Cutover residues			$25		**$122**	**$16.96**
Export grade KI and KIS logs	$82.08		$25	$3	**$110**	**$15.29**
Export grade K logs	$102.66		$25	$3	**$130**	**$18.15**
Export grade A logs	$115.05		$25	$3	**$133**	**$18.53**
Pruned sawlogs	$107.20		$25	-$15.32	**$178**	**$24.80**

[44] In-forests costs have been removed for confidentiality purposes.

[45] In-forest recovery costs have accounted for concerns about soil stability.

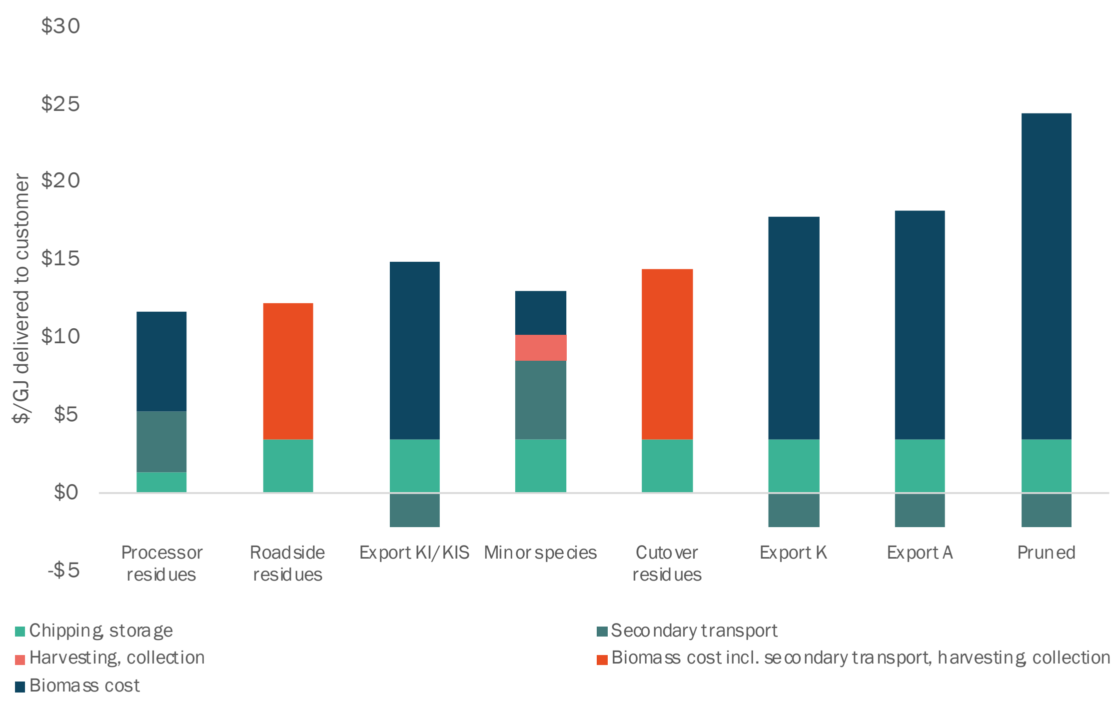
[46] This includes both primary transport from the forest to the Westland Milk hub and secondary transport from the hub to the end-user. For secondary transport, we have assumed $18/t ($2.50/GJ) over a distance of 60km from the hub. This is consistent with previous reports (PF Olsen (2023)). This cost can vary between $11/t (30km) and $33/t (120km), but we have chosen 60km as a mid-point. On the assumption that the hub was located at Westland Milk, the secondary transport component would be deducted from the final cost when calculating the cost of biomass to Westland Milk. Not also that for volumes diverted from export, a reduction in transport costs is warranted, as these are currently transported from the West Coast to Lyttleton for export, and this component is saved if they are used locally.

[47] 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). We expand on this comparison in Section 9.

[48] Processor residues do not need chipping, only storage.

Figure 22 – Estimated delivered cost of potential bioenergy sources, average value 2023-2037.[49] Source: Margules Groome (2023)

Estimated delivered cost of potential bioenergy sources
Wet wood equivalent (55% moisture content)



We reinforce that we retain domestic pruned sawlogs and export grade A logs in the analysis not because we believe these are sustainable or practical sources of bioenergy. Rather we use them in the supply curve to represent 'scarcity values' if our scenario analysis below should indicate that other more plausible and sustainable sources of bioenergy are insufficient.

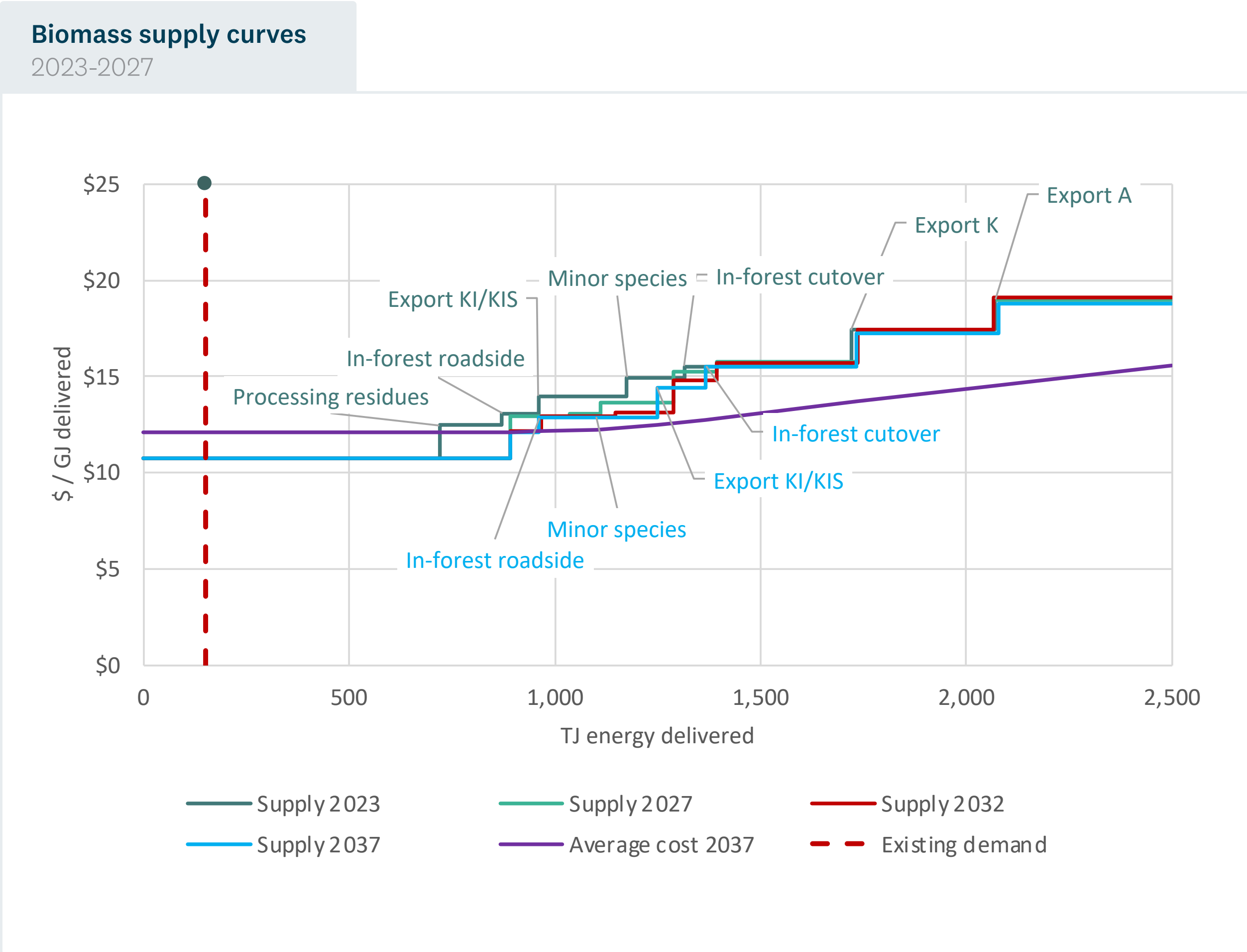
7.7.2 Supply curves

To convert these costs into an indicative market supply curve, we use the corresponding volumes for each category of resource from the analysis in Section 7.6 above. Since the supply of near-term bioenergy resource availability varies through time, we produce three supply curves (in addition to current) – one for each of the five year periods in the next 15 years. This is shown in Figure 23.

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 Westland Milk hub.

[49] As noted above for roadside and cutover the cost breakdown between underlying biomass costs, harvesting, collection etc is confidential. Hence these are displayed as a single cost component.

Figure 23 – Biomass supply curves through to 2037. Source: Margules Groome, Ahikā



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

- If early biomass customers secure long-term contracts for lower cost processor residues or in-forest residues (indicated by the dashed lines), they will still have access to those resources, at the agreed price, for the duration of those contracts. This is regardless of what is happening in the rest of the market. As each subsequent process heat user switches fuels, they will contract for the lowest cost resource that has not already been secured by an earlier adopter. Hence the supply curves in Figure 23 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.

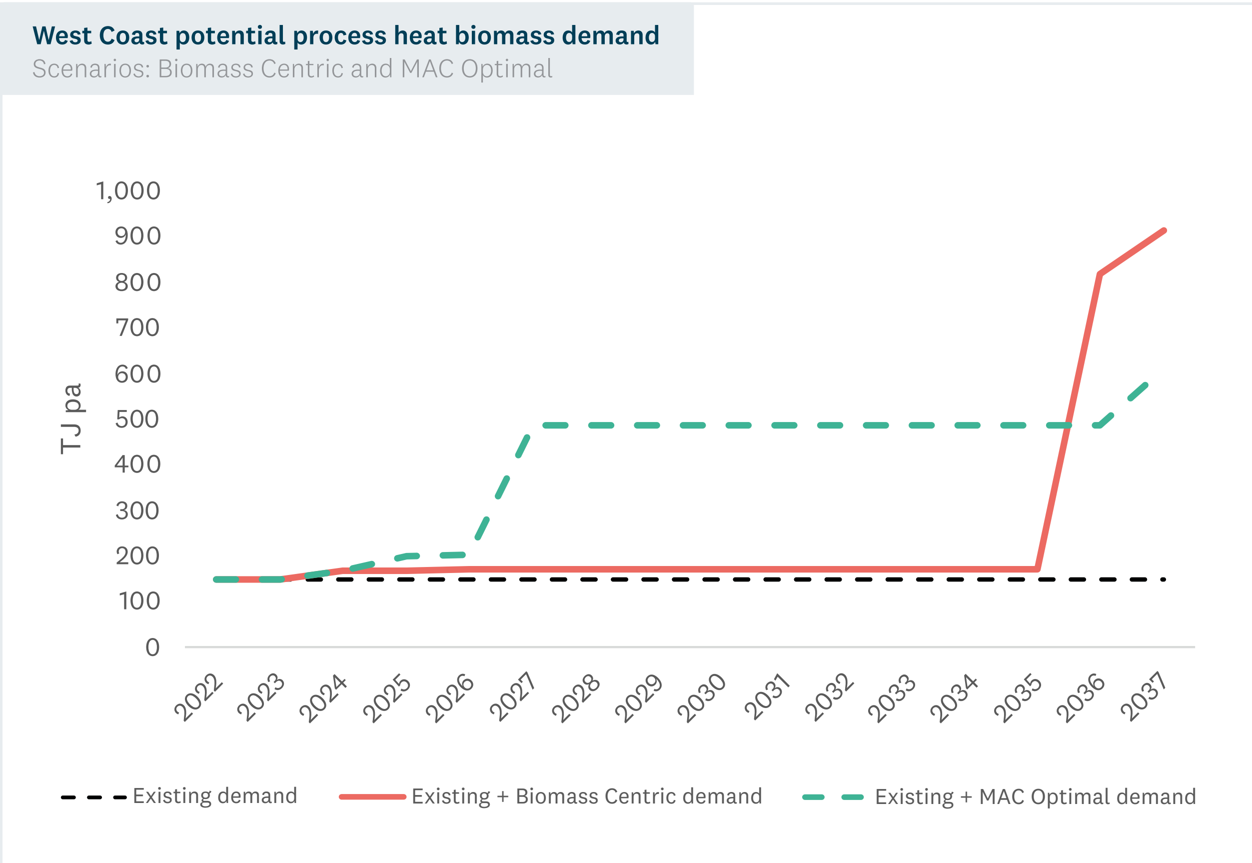
7.7.3 Scenarios of biomass costs to process heat users

With a nascent bioenergy market, there is no price history to draw on to use to calibrate price forecasts. To get an indication of what prices may be, we overlay plausible demand scenarios on each of the three supply curves above. Recall that these supply curves are based on a forecast of the costs of accessing these resources in 2022, with no additional margin applied, which is only intended to provide a proxy for potential future price scenarios.

These demand scenarios include the present consumption of bioenergy (~21,003t per year), and assumes this continues throughout the 2023-2037 period.

Our demand curves through time (Figure 24) illustrate a scenario where biomass is selected as the fuel for every boiler conversion in the RETA study[50] – 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 the dates in each organisation's ETA pathway, or, in the case where no date is set, 2036.

Figure 24 – West Coast region bioenergy demand for process heat, for 'Biomass Centric' pathway. Source: EECA



[50] Note committed switches to electricity are excluded.

Below we overlay the various increments in demand on the three supply curve periods.

Figure 25 – Biomass supply and demand in 2027. Source: Margules Groome, EECA

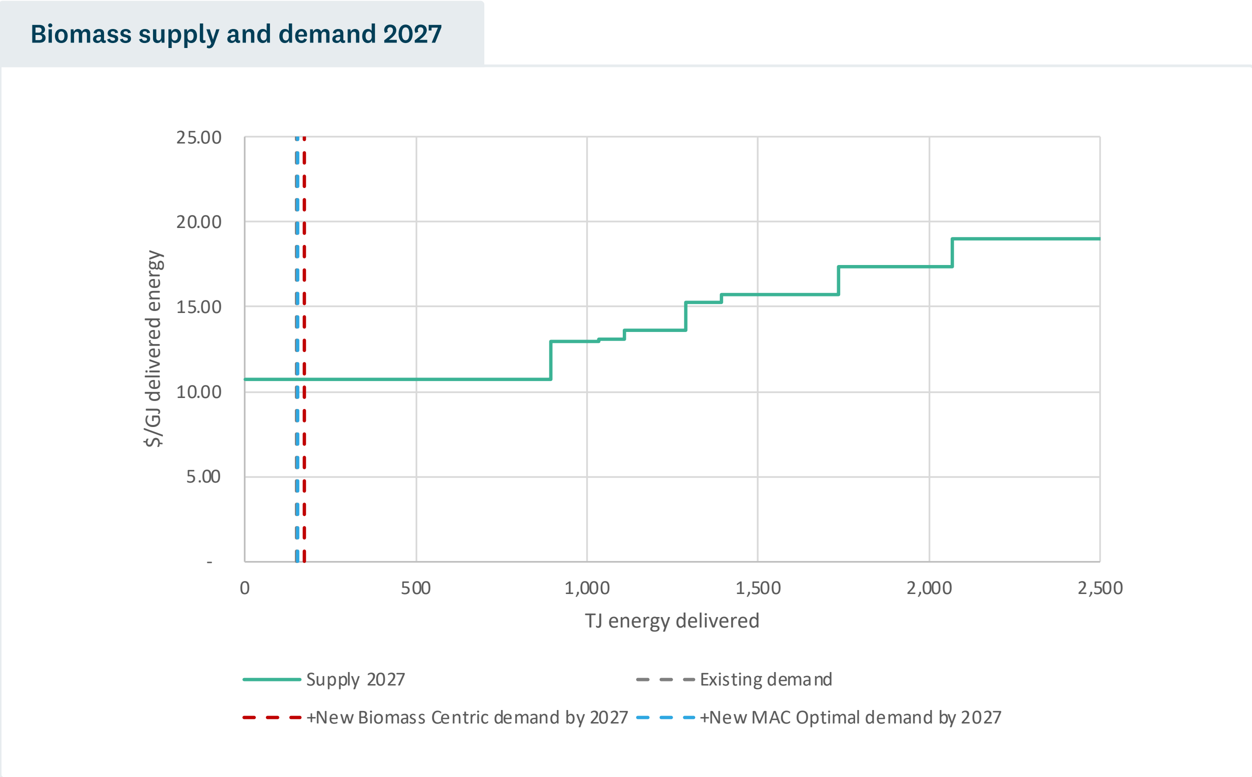


Figure 25 illustrates that both pathways see a minor increase in the use of biomass compared to today. By the end of 2027, both pathways are only utilising processing residues.

Figure 26 – Biomass supply and demand in 2032. Source: Margules Groome, EECA

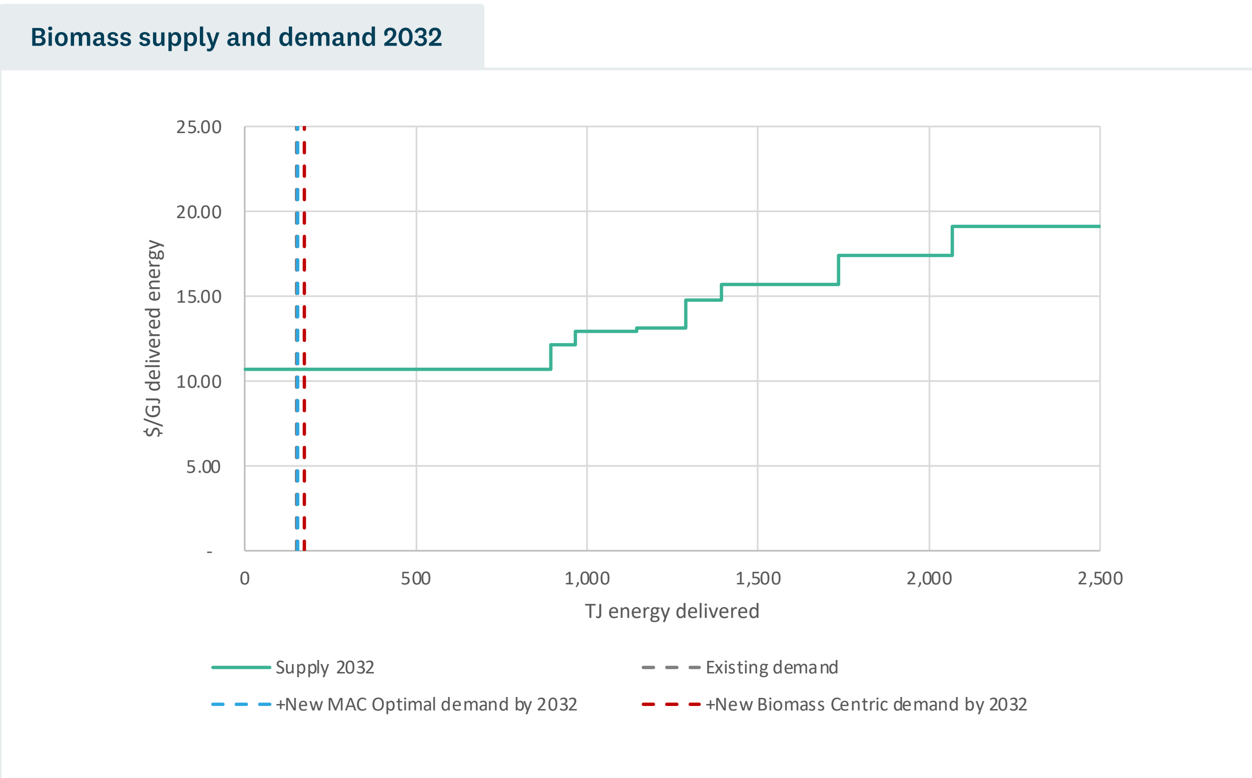
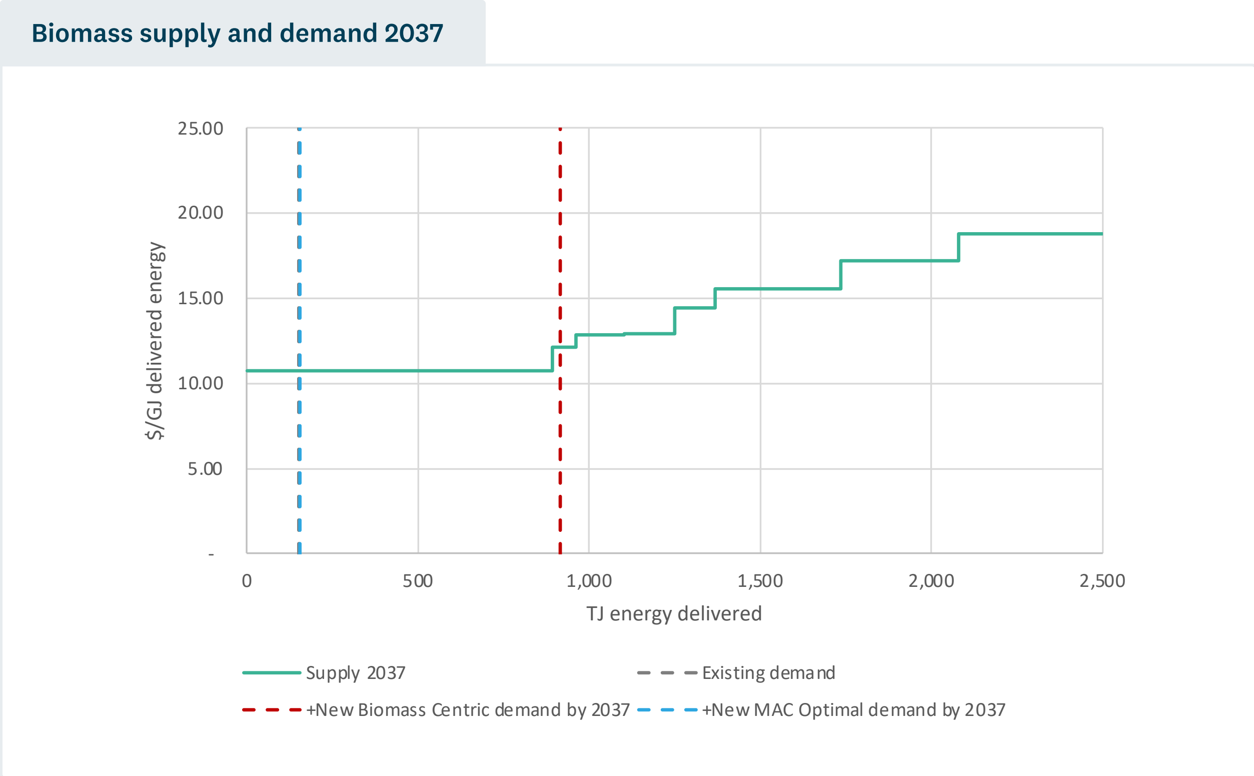


Figure 26 shows that no significant change in demand occurs between 2028 and 2032, with the processing residues continuing to be the only source of biomass use.

Figure 27 – Biomass supply and demand in 2037. Source: Margules Groome, EECA



In 2033-37, the MAC Optimal pathway is similar to existing demand (154TJ) and is only using processor residues. Demand from the Biomass Centric pathway increases significantly compared to 2032 (914TJ from 172TJ), and can all be met by processor residues and some in-forest roadside biomass.

8 Electricity supply and infrastructure

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

The availability of electricity generation to meet the demand from process heat users is largely determined at a national 'wholesale' level, from a network of power stations around the country. This supply is transported to an individual 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), that 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 often referred to as 'grid exit points', or 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).

Electrification of process heat often leads to significant increases in demands on local electricity networks. Networks are primarily concerned with any increase in the highest level of instantaneous electricity demand – known as 'peak demand'. This is what EDBs design their networks to cope with.

The wholesale electricity market is designed to ensure that supply of electricity matches the demand for electricity at every instant. Moreover, the market is designed to incentivise owners of generation to invest in new power stations when demand increases – for example, as a result of the electrification of process heat. As long as the electricity transmission network is relatively unconstrained, this generation investment can occur anywhere in the country, and be delivered to the new sources of demand.

While the national wholesale electricity market will invariably ensure there is enough supply to meet demand at every point in time (at a price), transmission of power can be a challenge. In some cases, increases in electricity demand will be beyond the existing capability of the local distribution network, and possibly beyond the capacity of Transpower's high-voltage transmission network.

Hence the primary questions for a process heat user considering electrification are:

- What is the price of electricity is likely to be, including the costs of wholesale generation, electrical losses, transmission and distribution[51]?
- Is the existing capacity in Transpower and the EDBs' networks[52] is 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 user (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 in order to reduce the cost of upgrades or electricity?

This section covers these four topics.

Amethyst Hydro Scheme, West Coast, New Zealand.

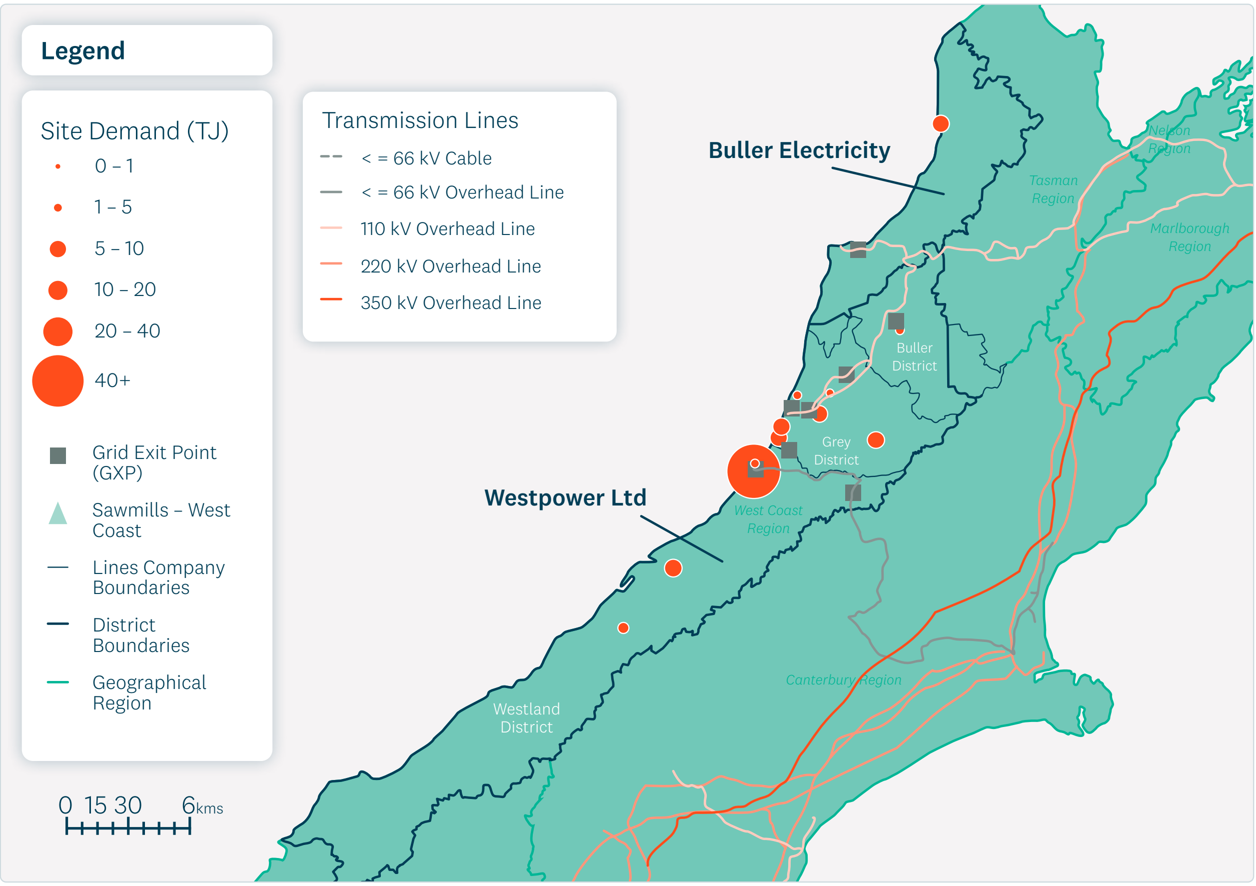
[51] As explained below, this includes metering, regulatory levies and other costs which consumers pay for.

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

8.1 Overview of the West Coast electricity network

Figure 28 below shows the region's high-voltage grid (owned by Transpower), including the eight GXPs[53] where local EDBs – Westpower and Buller Electricity – take supply from the national grid. The seven RETA sites considering electrification of process heat (see Table 4), plus three electric vehicle charging stations, are also displayed. Each connects to one of these EDB networks, noting that some (e.g. Westland Milk) connect very close to the GXP itself, due to their size. Electrification of process heat at these sites may result in direct connection to Transpower's grid.

Figure 28 – Map of West Coast transmission grid, location and peak demand of RETA sites



An unusual aspect of the West Coast network is that the EDBs often own assets in a GXP that would ordinarily be owned by Transpower. This means that, for some upgrades that require investment at a GXP, the discussion will be with the distributor rather than Transpower.

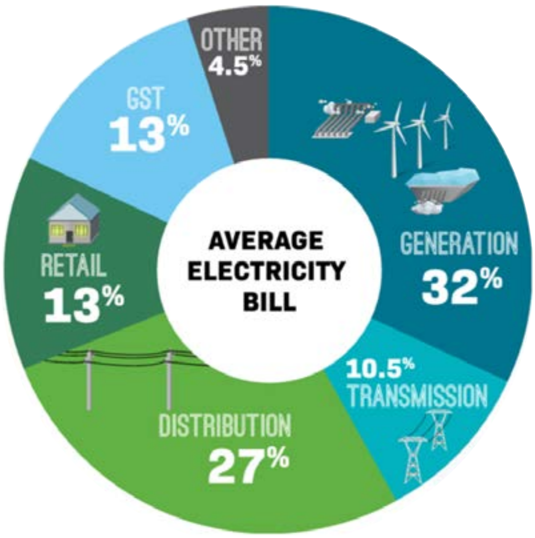
[53] Including Atarau GXP which is to be dismantled.

Another notable aspect of the West Coast region is the high degree of local hydro generation, some of it embedded[54]. The 12 currently operating schemes produce, on average, 174GWh per annum[55], around 60% of West Coast electricity demand. Development West Coast's Renewable Energy Strategy[56] reports that around 47MW of new hydro stations have applied for, or have successfully achieved, resource consent. EECA estimates that these new stations could provide an additional 250GWh[57] of generation, thus making the West Coast more than self-sufficient for its electricity needs (on an annual basis).

8.2 Retail electricity prices

Retail electricity prices, that would be faced by most of the sites[58], are a reflection of the average wholesale cost of electricity plus the network charges levied by 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 30 – Components of the bill for a residential consumer. Source: Electricity Authority



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

[55] Buller Electricity and Westpower disclosed that 181GWh of distributed generation entered their networks in the year ending June 2022.

[56] EnviroStrat (2022), West Coast Renewable Energy Strategy, available at https://westcoast.co.nz/news/te-tai-poutini-west-coast-renewable-energy-strategy/

[57] EnviroStrat (2022) only provided the MW capacity. We calculated the potential energy produced from these new stations using the same capacity factor achieved by the existing West Coast stations – 60%.

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

However, while all of the components in Figure 30 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 publishes average domestic (household) electricity prices for 42 locations around the country. This can give us a sense of the cost of electricity in the West Coast relative to other parts of the country, and the role that the major components in Figure 30 play.

Figure 31 – Quarterly domestic electricity prices in NZ, including GST. Source: MBIE.

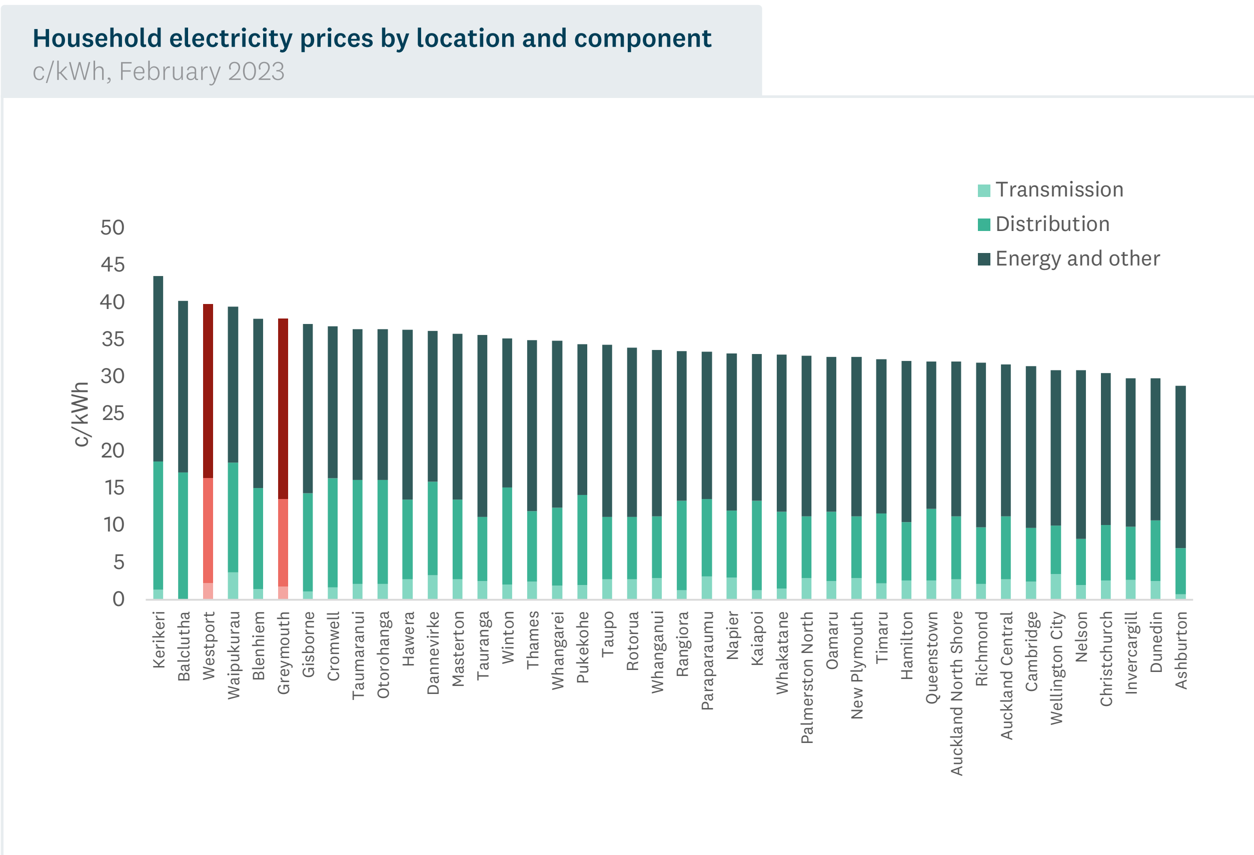


Figure 31 shows that the West Coast is one of the most expensive regions in the country for household electricity[59]. This is likely to be for a number of reasons, including the relative sparseness of population (relative to the geographic size of the region, and thus the size of the distribution network) and the need to import power from the wider South Island using transmission lines that will have relatively high transmission losses.

[59] Note that 'energy and other' in the chart relates to the generation, retail and other components of Figure 30. 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.

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[60], but it is important that process heat users considering electrification engage with electricity retailers and EDBs to obtain tailored estimates relevant to their project.

8.2.1 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. 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 thus 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[61]) 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[62].

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 now, EnergyLink developed three scenarios of supply and demand, including fuel costs, carbon costs and investment costs associated with new supply.

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

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

[62] 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 NZ'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 has not included these effects in the scenarios produced for this project.

8.2.2 Retail prices

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[63]. Hence 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.

Thus 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[64] 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 further in Section 8.2.4 and 8.2.5.
- Energylink prices include the effects of high-voltage transmission losses to the nearest GXP in the West Coast 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 the West Coast, distribution losses are very high, due to the long and 'stringy' nature of the grid: the distance from the north to the south of the West Coast network is equivalent to the distance between Auckland and Wellington. Hence the distribution losses for sites connecting at 11kV or 22kV typically range between 1.05 and 1.08[65].
- Energylink produce prices for four time 'blocks' each month – business day daytime, business day nighttime, other day daytime and other day nighttime. 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 (see Section 8.6).

This is a relatively orthodox approach to modelling the electricity tariffs that process heat users may experience. 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[66]. 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.

[63] 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.

[64] 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 component of retailer margin may also be included in fixed daily charges from the retailer.

[65] 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.

[66] For example, Meridian's process heat electrification programme pricing.

8.2.2.1 Scenarios considered

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

- **Low price scenario** – Assumptions that would lead to lower electricity prices compared with the central scenario, through, for example, lower demand, lower fuel costs, or accelerated[67] build of new power stations.
- **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.

The three scenarios used are outlined in Table 9 below. More detail on these assumptions is available in EnergyLink's report[68].

Table 9 – Electricity market scenarios considered. Source: EnergyLink

Scenario driver	Central price scenario	Low price scenario	High price scenario
NZAS at Tiwai Pt	Remains	Closes in 2025	Remains
Demand growth[69]	46TWh by 2032; 63TWh by 2048	As for central scenario but ~5TWh lower from Tiwai exit	50TWh by 2032, 70TWh by 2048
Coal price	USD85/t	USD70/t	>USD100/t
Gas price	Medium	Low	High
Initial carbon price[70]	NZD75/t	NZD75/t	NZD75/t
Generation investment behaviour[71]	Neutral	Aggressive	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 2033	Huntly Rankines dry year and retired by 2030 Huntly CCGT retired 2037

[67] There is a limit to which the market will pursue accelerated or restrained investment – one would consistently suppress prices while the other consistently raise prices. This eventually has a feedback loop on other investors' intentions in terms of the profitability of their investment, and thus the timing of their investment (to the extent they can secure financing). However, we believe the degree of acceleration implied by EnergyLink's assumptions is plausible.

[68] Regional Electricity Price Forecasts: EECA Regional Energy Transition Accelerator Program, EnergyLink, May 2022.

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

[70] 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.

[71] 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[72]. 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[73], 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. Thus, 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[74].
- 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%.

8.2.3 Price forecasts

Annual average (nominal) price forecasts are presented below for the period 2026-2048. For the central scenario, real electricity prices increase by 10% by 2037. After 2040 the central and high scenarios see real prices increase at a faster pace, principally because of the impact of electrification of transport and process heat on electricity demand.

As is shown in Figure 32, the impact of Tiwai's exit (combined with the other assumptions in the low scenario) significant. While this is a lower end on the range of prices, other forecasts (e.g. Climate Change Commission) show similar impacts from the Tiwai closure, albeit with shorter duration[75].

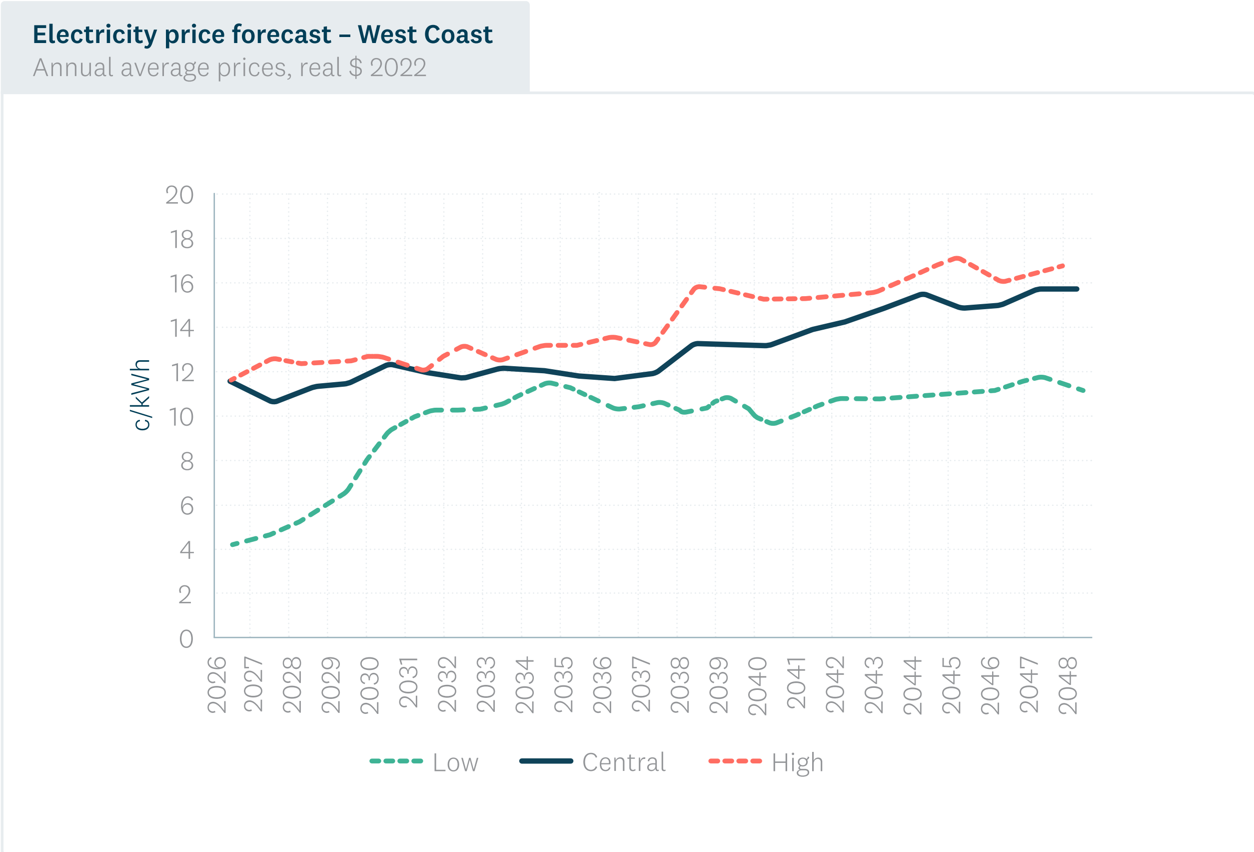
[72] "In real terms, the cost of building, owning and operating new wind generation falls at rates calibrated against actual wind projects in New Zealand, with adjustments for the cost of financing projects. The cost of grid-scale solar farms also falls in real terms, but as there are no such projects 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.

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

[74] 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.

[75] The shorter duration of the price suppression in the CCC's modelling is likely to be due to the fact they did not combine a Tiwai exit with the other price-suppressing variables (e.g. low gas prices, lower decarbonisation demand, lower coal prices) in EnergyLink's modelling.

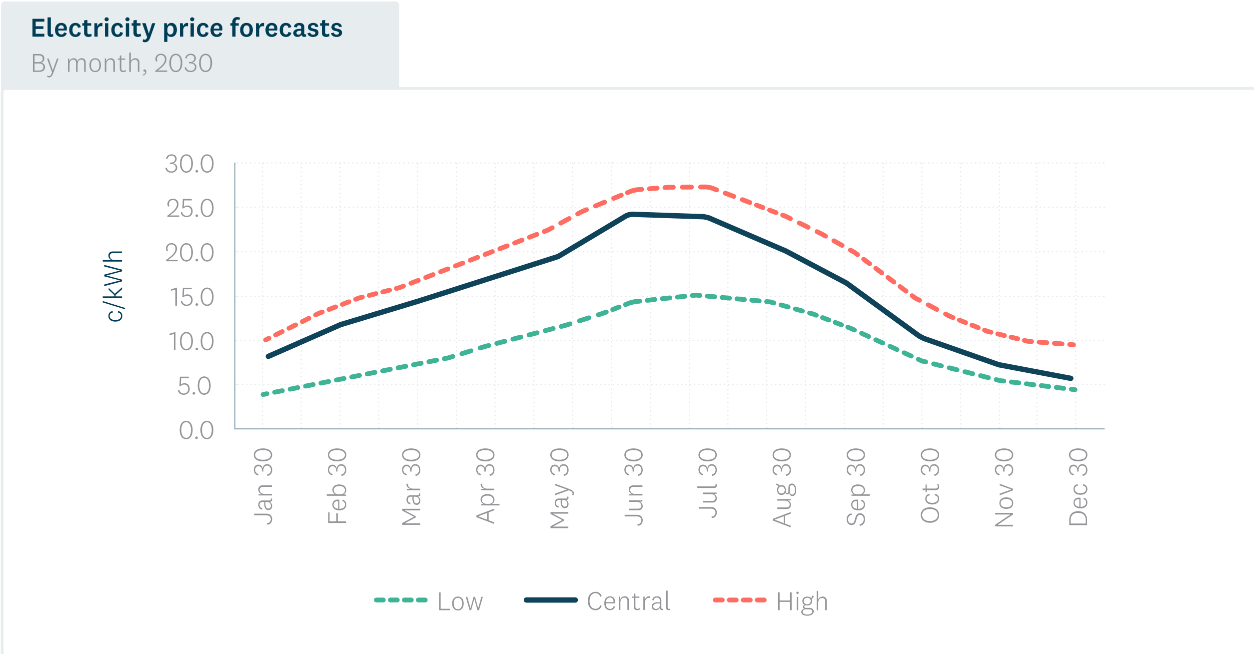
Figure 32 – Forecast of real annual average electricity prices for large commercial and industrial demand on the West Coast. Source: EnergyLink

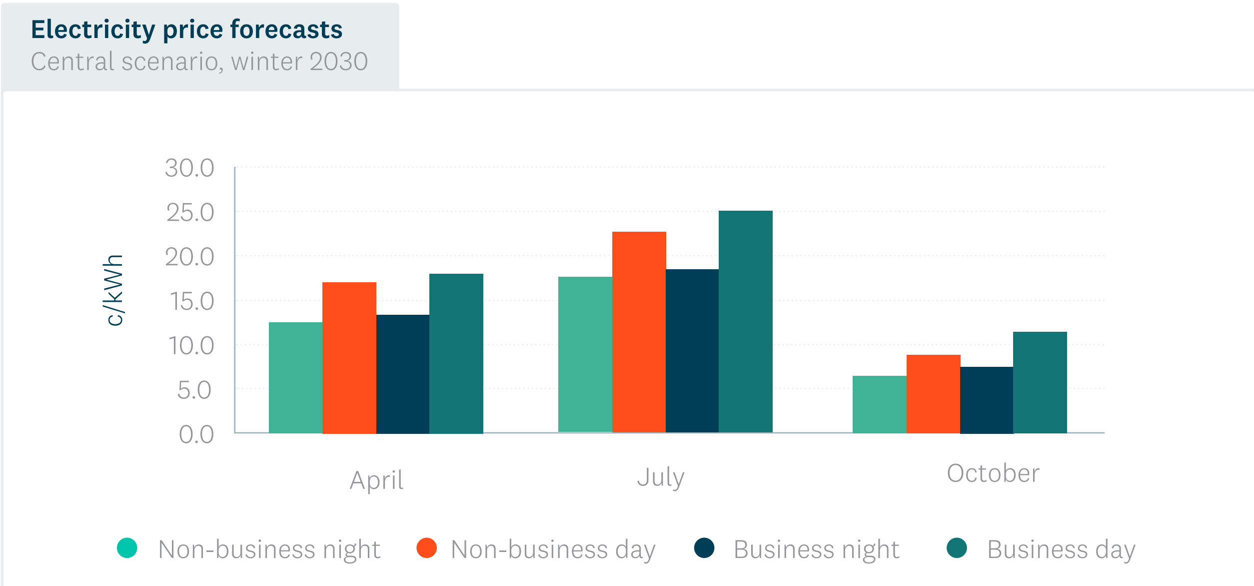


Beyond 2037, this forecast sees more significant increases in electricity prices. However, it is difficult to predict pricing beyond the end of the RETA period. Some New Zealand market analyses suggest real prices may remain constant after 2035, due to the downward pressure on generation costs (especially 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.

As outlined earlier, the price forecasts are actually produced at a finer resolution than the annual average series in Figure 32. Figure 33 zooms in on 2030, showing (a) the variation over the year in the three scenarios, and (b) the variation between day type, and time of day.

Figure 33 – Electricity price forecasts by month and by time block in April, July and October 2030. Source: EnergyLink





The shape of electricity prices over the year reflects the expected nature of national winter demand (winter peaking – lighting and heating) coupled with lower winter inflows into alpine lakes. However, this is somewhat inversely correlated with some of the sites considered in this study, particularly dairy, who experience the lowest levels of demand during winter. Hence the volume-weighted price paid for electricity at these sites could be materially different from the annual average prices shown in Figure 32 above.

As noted above, the prices that a retailer will charge a process heat user will include the network loss factor discussed above (typically 1.05-1.08). EnergyLink's prices do not include this component.

8.2.4 Distribution network charges

EDBs levy charges on electricity customers for the use of the distribution network, except for those large customers who connect directly to one of Transpower's GXPs. As monopolies, EDBs are permitted under the Commerce Act to recover the cost of building and operating the distribution network plus a regulated return percentage. The total amount EDBs can earn is regulated by the Commerce Commission, while the way they charge (generally referred to as 'distribution pricing'[76]) 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'[77].

Most businesses considering electrification of process heat would likely fall into a 'large customer', 'industrial' or medium voltage (11kV/22kV) category of charging for the two EDBs in the West Coast. The three main factors used by these EDBs for pricing in these categories are:

i. Volumetric charges (c/kWh, much like retail prices).

ii. Demand charges (usually related to the highest level of demand reached by the site over a year[78], or the demand level during times when the whole network experiences its highest demand[79], 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).

While EDBs often use a combination of these factors for an individual customer, rarely would they use all. For large customers, it is typical to see (ii) and (iii) used.

The specific pricing for a site will be agreed with the EDB concerned. However, for the modelling outlined in Section 9, we have developed indicative distribution pricing for a generic large user inside each EDB area based on 2023/24 pricing schedules. These charges – for both distribution and transmission (see discussion in Section 8.2.5) – are shown in Table 10 below. The charges in the table do not reflect the exact pricing structures each EDB uses – we have approximated the effect of different variables[80] in order to simplify the charges for the purposes of modelling. This also provides process heat users with an indicative magnitude of charges. Note Buller Electricity did not report transmission and distribution components separately.

[76] 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/industry/distribution/distribution-pricing/

[77] The 2023-24 pricing schedules and methodologies for the two West Coast network companies can be found at Buller Electricity https://bullerelectricity.co.nz/pricing-documents/ and https://www.westpower.co.nz/pricing-methodology-and-tariff-charges.

[78] Often referred to as 'anytime maximum demand', or AMD.

[79] Sometimes referred to as 'coincident peak demand'.

[80] For example, we use estimated profiles to covert Buller's variable charges to $/MVA equivalent. We also assume a power factor of 0.95 when converting MW-based charges to MVA-based charges.

Table 10 – Estimated and normalised network charges for large industrial process heat consumers by EDB; $ per MVA per annum

EDB	Distribution charge	Transmission charge	Total charge
Buller Electricity	Not available	Not available	$365,000
Westpower	$121,000	$76,600	$197,600

The difference in prices between networks 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.

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. In the scenario where part or all of the EDB is owned by a consumer trust, the calculation of charges should also take account of any redistribution of profits back to consumers by the EDB. This is the case for Westpower, where a portion of its financial surplus each year is returned to consumers via a special discount. For larger electricity consumers, this discount is equivalent to $12.66/MWh in 2023[81]. The effective network charge paid, after discount, is therefore lower than the figures in Table 10, but will vary for each process heat user depending on their potential electricity consumption volumes.

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[82]. 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[83].

[81] See Westpower Pricing Methodology 2023, Appendix B.

[82] 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, thus reducing the retailer's costs, and share this benefit with the process heat users in any number of ways.

[83] See https://www.ea.govt.nz/projects/all/distribution-pricing/

8.2.4.1 Contributions to the capital cost of accommodating new demand

In Section 8.3, we provide estimates of the capital costs that EDBs (and, for some large users, Transpower) would incur in order to upgrade their network to accommodate a particular process heat user's electrification decision. As outlined in Section 8.5, EDBs are also considering how they can use 'non-network solutions' – demand response from consumers, distribution-scale batteries, and distributed generation – to defer the need for more capital-intensive upgrades. As many of these solutions will be owned by the consumer, the emerging world of network infrastructure investment is seeing a greater role for consumers than has historically been the case.

The charges in that section are presented as total capital costs. Precisely how the process heat user pays for these upgrades, however, is usually more complex than a simple up-front payment. There are a variety of ways that EDBs can recover these costs (assuming that it is the EDB that constructs the new assets[84]). These ways are presented in the EDB's 'capital contribution' policies. These policies recognise the fact that new demand is subject to the cost-recovery charges outlined above, and hence, over time, a component of the cost of new assets will be recovered through these charges. Hence the EDB 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, the EDB may design customer-specific charges (often including a larger fixed component than indicated in Table 10 above), tailored to the process heat user's expected demand and location in the network[85].

The exact methodology used to determine the quantum of capital contribution it requires from new electricity demand varies between EDBs. It is important that process heat users contemplating electrification meet with their EDB to discuss how this will work in their particular situation. For the pathway modelling outlined in Section 9, we assume that EDBs contribute 50% of the capital costs associated with distribution network upgrades required to connect process heat users.

8.2.5 Transmission network charges

Like EDBs, Transpower is permitted under the Commerce Act to earn a certain amount of revenue to cover the costs of owning and operating the national grid. Again, like EDBs, they are permitted to recover this revenue via charges on its customers for the use of the transmission grid, including any upgrades to the grid that might be required to accommodate increased demand on Transpower's grid assets.

Where a consumer connects directly to the grid, Transpower will charge this consumer directly. Otherwise, they are passed through[86] by the local EDB. This is a topic picked up further below.

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.

[84] In some situations, dedicated assets may be constructed by a third party.

[85] As an example, see EA Network's pricing for ANZCO Seafield, Talley's Fairfield, Mt Hutt and Highbank Pumps at EA Networks (2022): https://www.eanetworks.co.nz/assets/PDFs/Disclosures/PricingSchedule2023.pdf

[86] Without any markup by the EDB.

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[87]. Alongside the new TPM, the Electricity 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)[88].

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.

8.2.5.1 Overview of the TPM

There are three basic components of the new TPM, plus a range of adjustments that are outlined further below. The three components are:

- **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.
- **Benefit-based charges (BBC)** – These charges relate to specific investments where the beneficiary identification is more complex than for connection assets[89], but the beneficiaries have been established by the Electricity 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 West Coast region (see Section 8.3), the associated transmission charges would be calculated in accordance with the BBC methodology. It is difficult to estimate at this point in time what the likely quantum of charges would be, as the Electricity Authority won't determine the allocations amongst the various beneficiaries until the investment is formally considered.

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

[88] We note that these guidelines did not include direction as to how EDBs or retailers present the transmission charges on the customer's bill. Thus 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.

[89] 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.

- **Residual charges** – For the remainder of the existing transmission network not covered by BBC charges[90], 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 as Appendix 1 to this report.

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 in order 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.

[90] Pre-2019 grid assets, not including the seven relatively recent grid upgrades listed in Appendix A of the TPM.

8.2.5.2 What does the TPM mean for RETA sites?

As noted above, our various references to 'customers' of Transpower, and thus 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'[91] of the grid give a lot of 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[92]. 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.

EDBs have published their pricing schedules for the 2023/24 pricing year – the first year that the new TPM applies. That said, Buller Electricity has successfully achieved a 'pause' in one significant component of the new TPM charges until such time as their judicial review application against the Electricity Authority and Transpower is resolved.

In the case of Westpower, however, the new TPM has been incorporated, and thus the 2023/24 prices provide distribution-connected RETA sites with an indication as to how significant the impact of the new TPM is on their charges. For Westpower, we have estimated that the transmission component of the bill is approximately 76,000 per MW of connection size, per year.

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 be 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.

[91] Either energy usage over time, or peak demand, for example.

[92] Residential demand tends to be more "peaky" than many forms of non-residential demand.

Arthur's Pass, Canterbury, New Zealand.

8.3 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 individual RETA site, given the current capacity of the West Coast network. 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 a number of judgments and estimates. Each site contemplating electrification should engage with their EDB to obtain more refined estimates and potential options.

We stress that the assessment of spare network capacity, costs, and lead times presented below is changing all the time. The policy and regulatory space for the electricity sector is in a state of change as it incorporates decarbonisation and the emergence of new technologies. This in turn is leading to a greater number of consumers considering the technology they buy and how they reduce their consumption of fossil fuels. Hence Transpower and EDBs exist in a context which is changing far more quickly than it did, say, 20 years ago.

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

As an illustration of this, Figure 34 shows the number of enquiries Transpower alone is facing in each of its planning regions. Of the 313 enquiries they face nationally, 75% have need dates prior to 2025[93]. Transpower reports that of the nine[94] enquiries in the West Coast, a third are for network upgrades, the remainder are for generation connections.

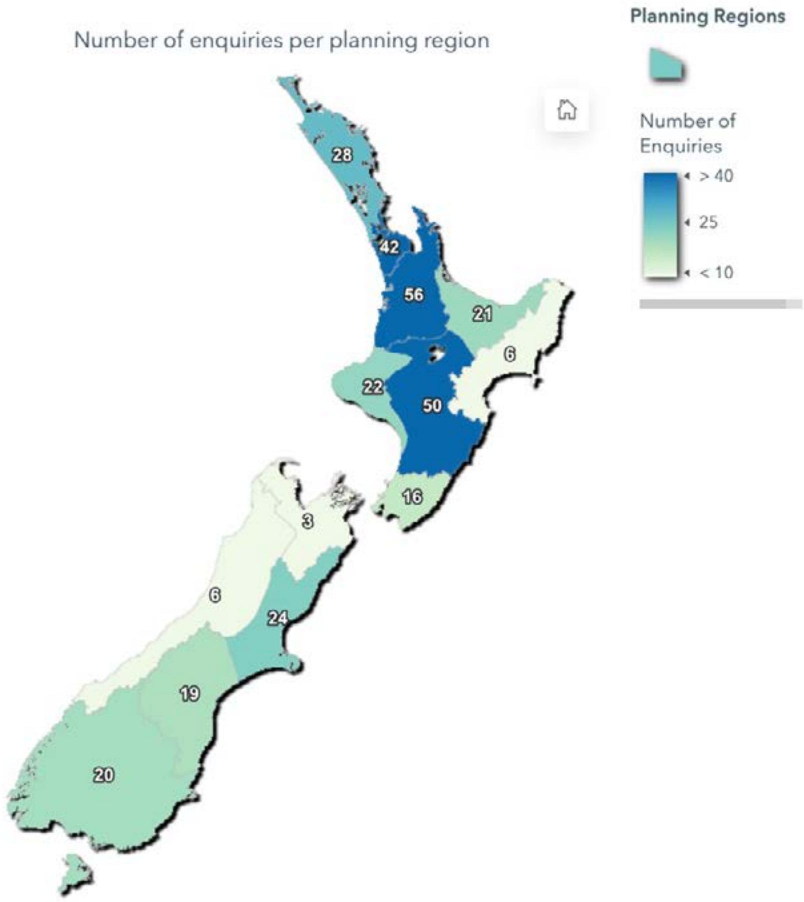
It is going to be challenging for Transpower and EDBs to scale up their resourcing to cater to this new demand.

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

[93] As at May 2023.

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

Figure 34 – Number of grid connection enquiries per region, May 2023. Source: Transpower



8.3.1 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 RETA 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.

Where possible, we have included additional public EV charging stations, where EECA are aware of these.

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

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

8.3.2 Network security levels N and N-1

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

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 very short in duration (a small number of hours per year) and often 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.
- The degree to which the site adds to that peak at the time it occurs (usually referred to as ‘coincident demand’).

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 two 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[95].
- N security – A failure of any single component of the network at forecast peak demand may result in service interruption.

N-1 is generally provided through building redundancy into network assets, relative to the expected (peak) demand.

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.

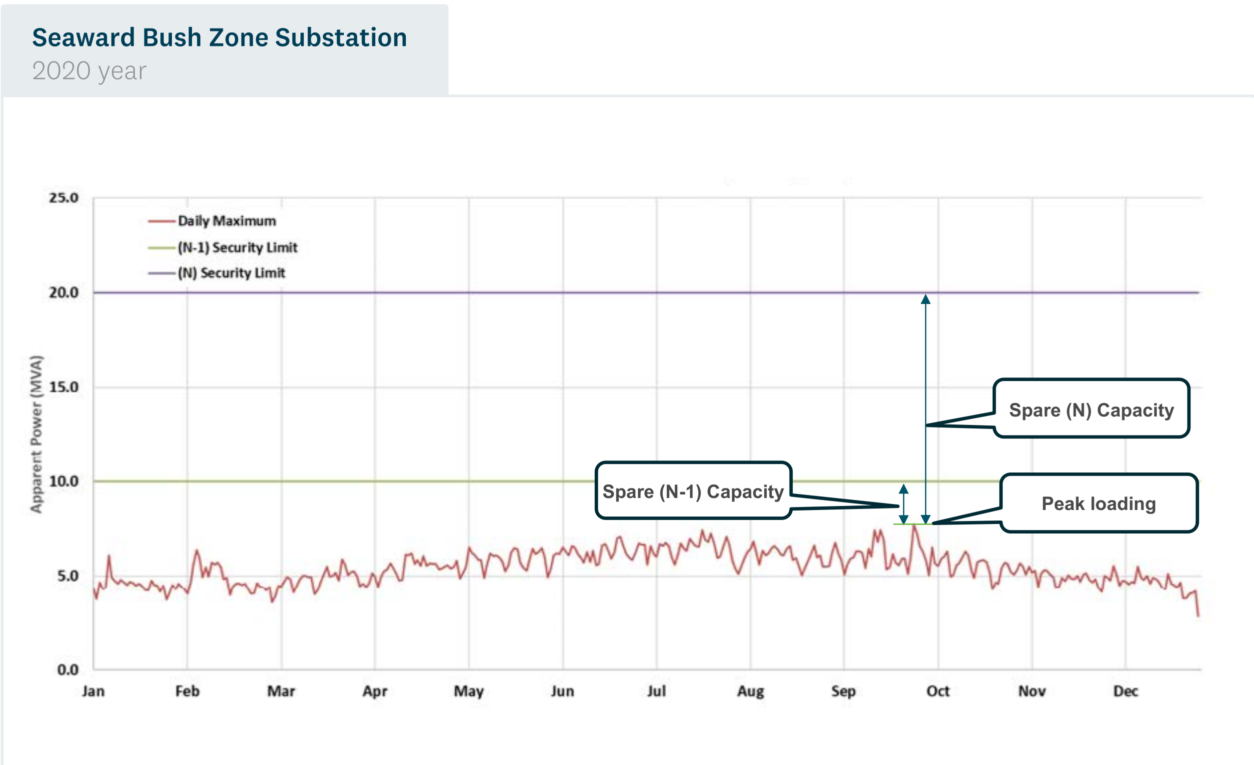
95 This means that undue interruptions in supply or the spreading of a failure must not occur. Furthermore, the voltage must remain within the permitted limits and the remaining resources must not be overloaded.

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

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. 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.

Figure 35 illustrates the difference between the available capacity for N and N-1 security for a zone substation.

Figure 35 – Illustration of N and N-1 security capacity at Seaward Bush zone substation. Source: Ergo

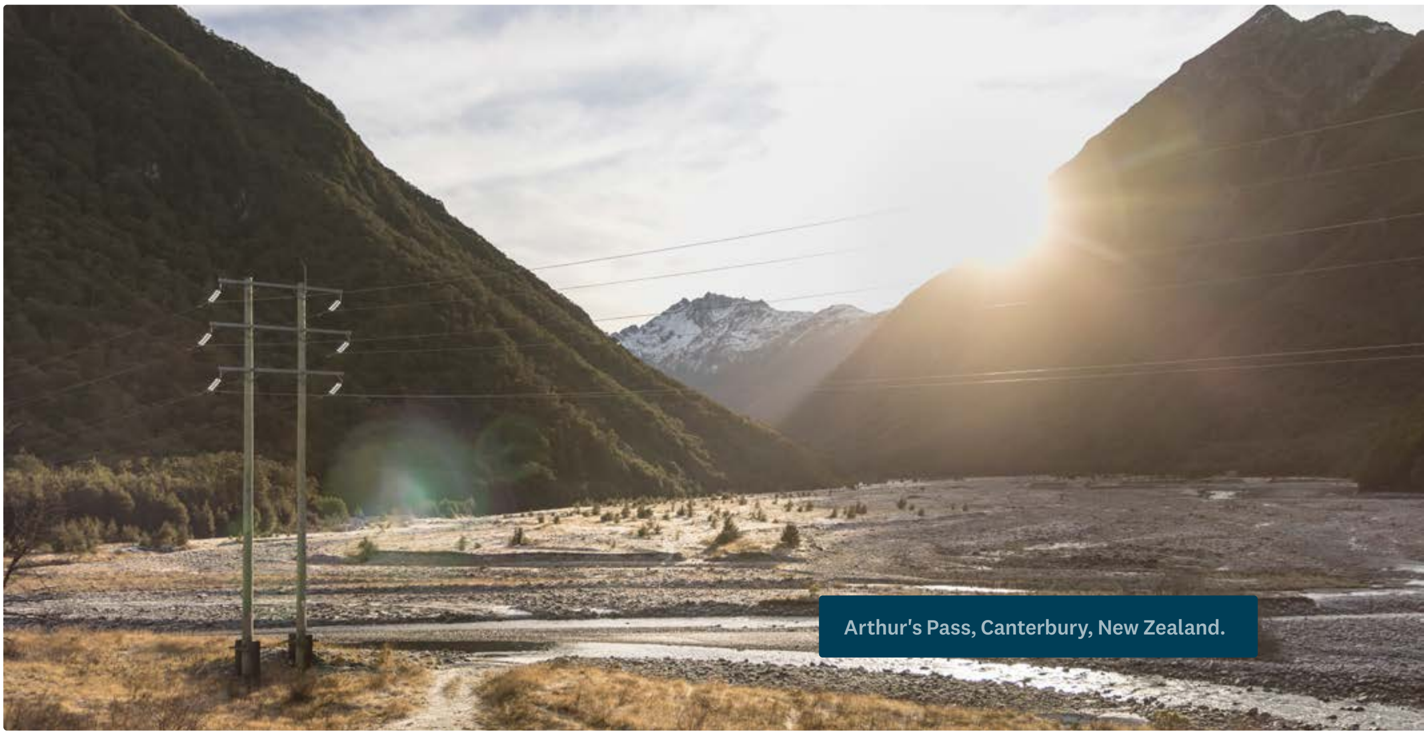


For the purposes of this report, Ergo, determined the amount of spare capacity by using Transpower's prudent peak demand forecast[96] for the coming year (2023), rather than actual observed peak demand as inferred by Figure 35 above. The use of a prudent forecast recognises that there are a range of 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.

However, as discussed in Section 8.5, 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).

8.3.3 Impact on transmission investment

The electrification of the RETA sites will increase the electricity demand Transpower will observe at five of the eight West Coast GXPs shown on Figure 28 above. A number of these GXPs, and the connecting grid lines, have very little spare N-1 capacity remaining. This is summarised in Figure 36. For the avoidance of doubt, Figure 36 shows the capacity headroom at each GXP – that is, the difference between Transpower's prudent demand forecast (for 2022) and the N or N-1 capacity at the GXP (as published by Transpower).


Arthur's Pass, Canterbury, New Zealand.

[96] 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.

Figure 36 – Spare capacity at Transpower's West Coast grid exit points (GXPs). Source: Ergo

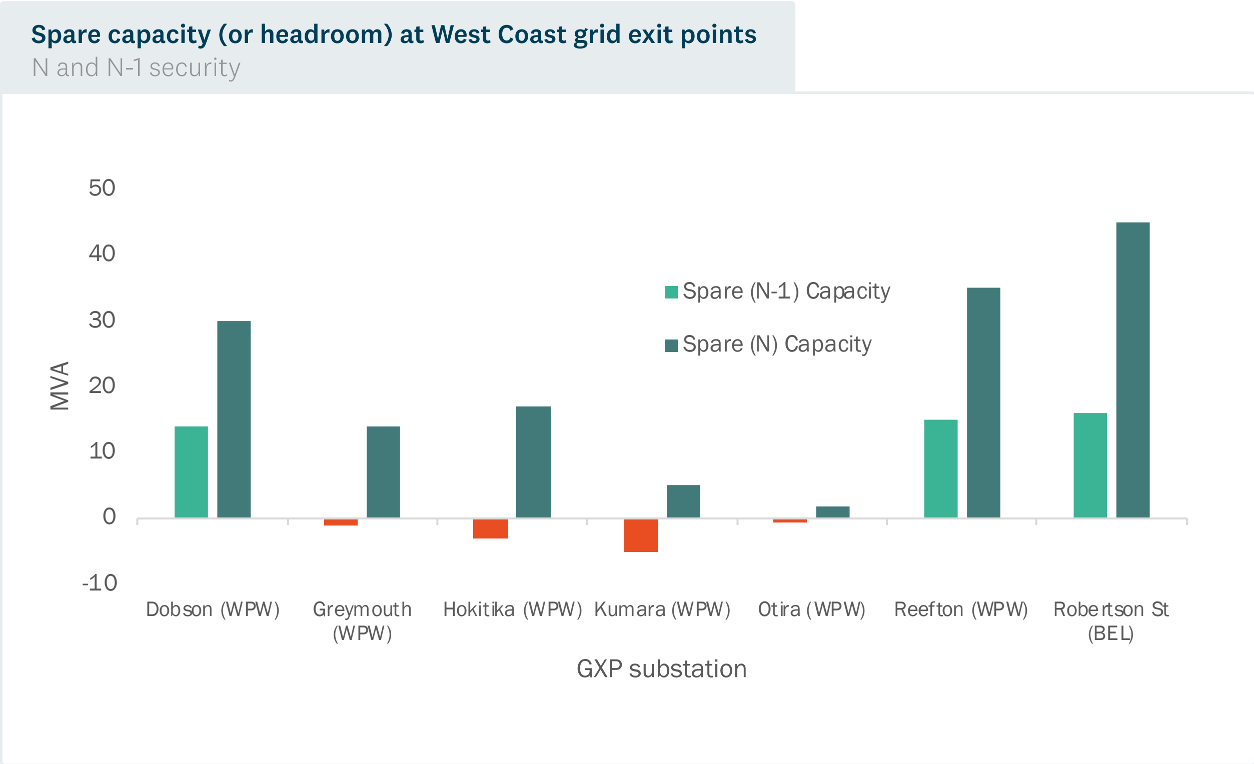


Figure 36 infers that there are relatively high levels of spare N-1 capacity at Dobson, Reefton and Robertson Street, but we note that these values do not consider the transmission line capacity and voltage constraints.

For those sites with limited spare capacity left, we comment below on any planned transmission upgrades[97]. These are summarised in Table 11.

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

Table 11 – Spare grid exit point (GXP) capacity in the West Coast and Transpower's currently planned grid upgrades.

GXP	EDB	RETA sites analysed	Spare N-1 GXP capacity	Planned Transpower GXP upgrade
Dobson	Westpower	ANZCO Kokiri Runanga School Value Proteins Westimber	Moderate	Minor upgrades to the Dobson substation ($0.1m) will raise the N-1 limit from 17MVA to 24MVA
Greymouth	Westpower	Westland Recreation Centre Greymouth High School Greymouth Hospital Cobden School Grey Main School Scenicland Laundry	None	No – substation limited by Westpower transformers
Hokitika	Westpower	Westland Milk Products Westland Milk Products Silver Fern Farms Ngāi Tahu Franz Josef Hot Pools Westland Produce Franz Josef EV Charging Station	None	New capacitor banks at Hokitika ($0.5m) Circuit overload protection scheme (SPS) on Hokitika-Otira circuit ($0.5m) Transformers limiting GXP capacity owned by Westpower.
Kumara	Westpower	Kumara EV Charging Station International Panel & Lumber	None	No – GXP capacity limited by Westpower-owned transformers.
Reefton	Westpower	Reefton Area School Reefton Hospital	High	No
Robertson St/ Orowaiti	Buller	Karamea Tomatoes Westport Hospital Buller High School Westport North School Westport South School O'Connor Home	High	No

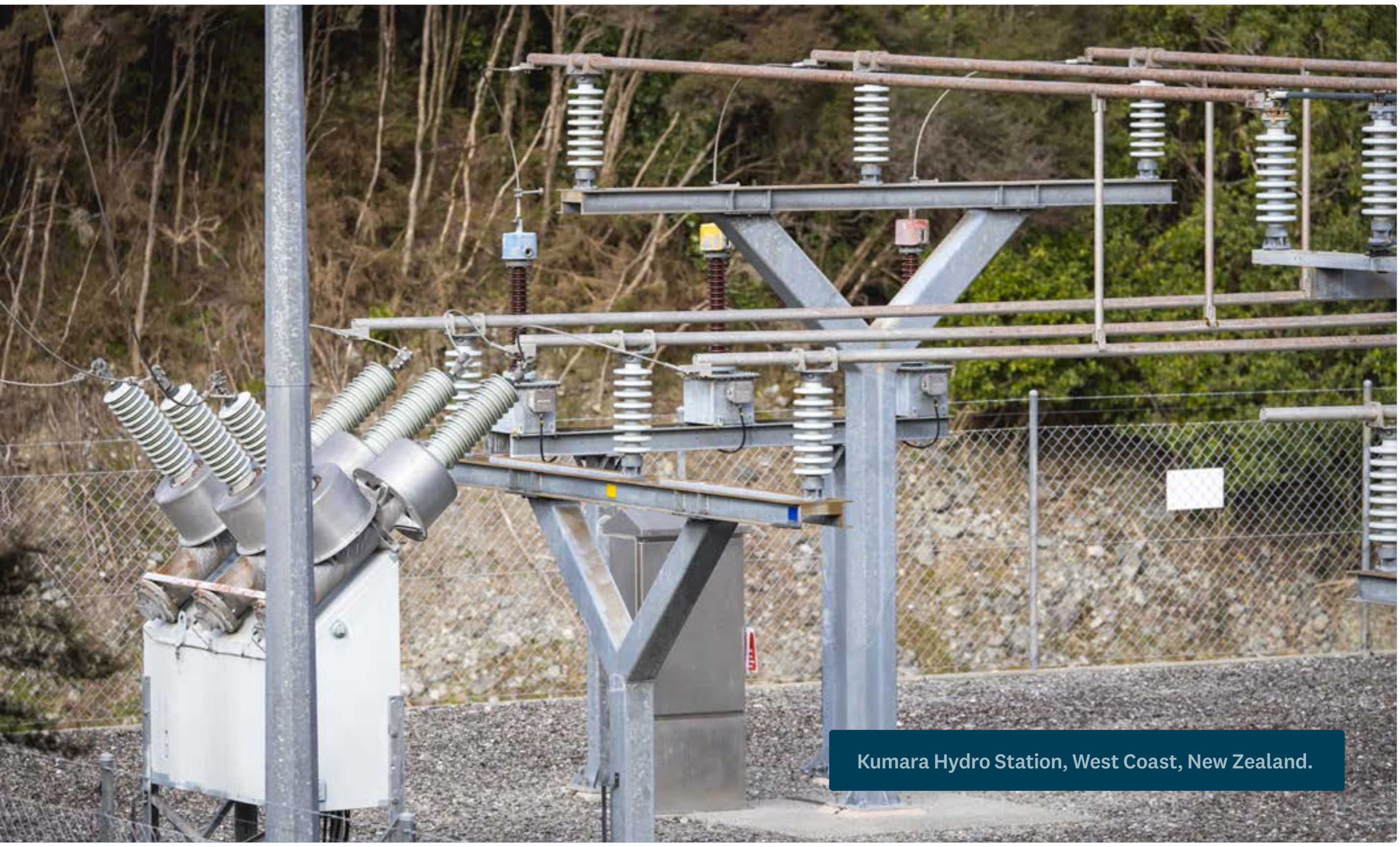
An unusual characteristic of the West Coast is that the local EDBs own assets at each GXP that would ordinarily be owned by Transpower. Hence, where it is these assets that are limiting spare capacity, the decision to upgrade these assets is in the hands of the EDB rather than Transpower. Alongside the transmission upgrades noted in the table above, several significant distribution upgrades are planned by EDBs which would also support the connection of process heat users. Here, it is the EDB's responsibility to judge whether the proportion of time that N-1 is exceeded is worth capital investment. This is a risk-based decision, and both Buller Electricity and Westpower have frameworks which drive these analyses.

Further, the West Coast network does not form part of the national grid backbone. As a result, investments in additional transmission are based on an economic analysis (driven by customer – i.e. EDB – needs) rather than a strict requirement for N-1 capacity at all times.

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

- In some of the cases above where no spare capacity exists today, the planned upgrades in Table 11 will accommodate the connection of new electrified process heat users.
- At GXPs where there are no planned upgrades, the connection of multiple 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. This is covered further in Section 8.5.

The allocation of costs for transmission upgrades is a complex topic. The site-specific costs presented in Section 8.3.4 below only include the costs of transmission upgrades in two instances[98], where the upgrade is necessary to accommodate that process user. 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 more in detail in Section 8.2.5 above. We analyse the potential for such a situation, from the perspective of RETA process heat users, in Section 8.4.



Kumara Hydro Station, West Coast, New Zealand.

[98] Westland Milk Products Stage 2, and Westland Produce.

8.3.4 Analysis of impact of individual RETA sites on EDB (distribution) investment

The majority of RETA sites will connect to the distribution (rather than transmission network). Here we present an analysis of whether the existing distribution network can accommodate each RETA 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. 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[99].

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

- **Minor** – The 'as designed' electrical system can likely connect the site with minor distribution level changes and without the need for substantial infrastructure upgrades. Some connections may require infrastructure which takes additional time to procure from international suppliers or implement (e.g. transformers, underground cabling).
- **Moderate** – The 'as designed' electrical system requires some infrastructure upgrades including new connections into the local zone substation, upgrades at the local zone substation, and/or upgrades to the sub-transmission[100] network.
- **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 for directly (i.e. they are customer-initiated investments) there is no need for approval from the Commerce Commission.

Were this not the case, the timelines for regulator approval would need to be added to the timelines below.

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

[99] 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

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

In particular, the nature of information available at the time of this assessment, and the complexity of the task, necessitated a set of assumptions about how the various sites could be accommodated within the network. 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[101]. The analysis presented here calculated these based on the publicly disclosed loading and capacity information in Transpower's 2022 Transmission Planning Report and the EDBs 2022 Asset Management Plans.
- 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 below assumes that, for example, if the site currently presently has (N-1) security, infrastructure upgrades are recommended to maintain this. Ergo's report[102] 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[103] could save significant amounts of money where expensive upgrades are required to maintain N-1 security.
- 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 8.4, 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. As a rule, 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.

[101] Zone substations are large substations within the distribution network.

[102] See Ergo (2023).

[103] 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.

- The estimates of the time required to execute the network upgrades. The estimates below 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.

The cost estimates below only include the incumbent network operator's distribution/transmission equipment 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).

It also should be reiterated that the assessments in the following three sections are for each site in isolation of any consideration of other related RETA sites, and the timing of load growth (both from RETA sites as well as the wider growth as discussed in Section 8.3.1. This theme is returned to in the next section.

Table 12 lists the connections that are categorised as 'minor' in nature.

Westland Milk, West Coast. New Zealand.

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

Site	Transpower GXP	Network	Peak site demand (MW)	Total cost[104] ($M)	Timing
ANZCO Kokiri	Dobson	Westpower	1.85	$0.03	6-12 months
Buller High School	Robertson St	Buller Electricity	0.22	$0.00	3-6 months
Cobden School	Greymouth	Westpower	0.03	$0.00	3-6 months
Franz Josef EV Charging Station	Hokitika	Westpower	0.60	$0.00	3-6 months
Grey Main School	Greymouth	Westpower	0.12	$0.00	3-6 months
Greymouth High School	Greymouth	Westpower	0.52	$0.29	6-12 months
Greymouth Hospital	Greymouth	Westpower	0.76	$0.41	12-18 months
International Panel & Lumber	Kumara	Westpower	1.50	$0.4	12-18 months
Karamea Tomatoes	Robertson St	Buller Electricity	2.73	$0.90	18-24 months
Kumara EV Charging Station	Kumara	Westpower	2.30	$0.4	12-18 months
Ngāi Tahu Franz Josef Hot Pools	Hokitika	Westpower	0.19	$0.00	3-6 months
Reefton Area School	Reefton	Westpower	0.16	$0.00	3-6 months
Reefton Hospital	Reefton	Westpower	0.30	$0.00	3-6 months
Runanga School	Dobson	Westpower	0.05	$0.00	3-6 months
Scenicland Laundry	Greymouth	Westpower	0.40	$0.00	3-6 months
Silver Fern Farms Hokitika	Hokitika	Westpower	0.19	$0.00	3-6 months
Westimber	Dobson	Westpower	0.28	$0.00	3-6 months
Westland Produce[105]	Hokitika	Westpower	2.13	$1.65	12-18 months
Westland Recreation Centre	Greymouth	Westpower	0.28	$0.00	3-6 months
Westport Hospital	Robertson St	Buller Electricity	0.54	$0.00	3-6 months
Westport North School	Robertson St	Buller Electricity	0.1	$0.00	3-6 months
Westport South School	Robertson St	Buller Electricity	0.07	$0.00	3-6 months

[104] We reiterate that these costs do not include costs associated with the installation of distribution transformers/switchgear on the site.

[105] Ergo assessed both a 0.44MW heat pump as well as a 2.13MW electric boiler. The latter is shown here; the cost for a heat pump is $0.77M with a 12 to 18 month timeframe.

Below, we consider the impact on the need for more substantial upgrades should a number of these minor complexity, at an individual GXP, choose to electrify their process heat.

Table 13 lists the connections that are categorised as ‘moderate’, while Table 14 lists the connections that are categorised as ‘major’.

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

Site	Transpower GXP	Network	Peak MW	Total cost ($M)	Timing
Westland Milk Products Hokitika – Stage 1	Hokitika	Westpower	12.12	$3.12	18-24 months
Value Proteins	Dobson	Westpower	13.3	$15.34	18-24 months

Table 14 – Connection costs and lead times for major complexity connections. Source: Ergo

Site	Transpower GXP	Network	Peak MW	Total cost ($M)	Timing
Westland Milk Products Hokitika – Stage 2	Hokitika	Westpower	29.60	$27.28	36-60 months

8.3.5 Westland Milk

The categorisation and costs in Table 14 assumes the Westland Milk can achieve its Stage 1 (12MW) electrification with some significant investment in Westpower’s distribution network, but without requiring major upgrades to Transpower’s transmission network.

However, as shown in Figure 35, Hokitika GXP is already exceeding its N-1 level based on Transpower’s prudent demand forecast for 2023.

Ergo’s assumption here is that Westland Milk Stage 1 could be connected on a N security basis, on the understanding that Transpower will invest in a special protection scheme (SPS) within the next few years[106]. The SPS is expected to allow Hokitika demand to exceed the N-1 limit – potentially up to the N security limit of 40MVA – on the basis that, should a part of the local transmission system fail, demand can be quickly reduced to a level under the N-1 limit.

The degree to which this puts some consumers ‘at risk’ from being interrupted by the SPS requires detailed system analysis. However, Ergo provided detailed demand data which shows that the actual peak demand at the Hokitika GXP in 2021 was a little over 15MW. This is below the N-1 capacity of Westpower’s transformers (20MVA), and Transpower’s prudent peak forecast of 24MW in 2023. Adding a 12MW load to this would lead to the N-1 capacity of the transformers being exceeded by 7MW, but well under the N security capacity of 40MVA.

[106] Transpower’s Transmission Planning Report states that an SPS will be required by 2025.

Ergo simulated a half-hourly electricity demand profile at the Hokitika GXP where Westland Milk electrified Stage 1. This used electricity demand data from 2021 to simulate existing Hokitika demand. Figure 37 shows the results.

Figure 37 – Simulated demand at the Hokitika GXP if Westland Milk electrified Stage 1 (12MW). Source: Ergo.

Simulated half-hourly demand at Hokitika GXP
2021 actual and simulated Westland Milk demands

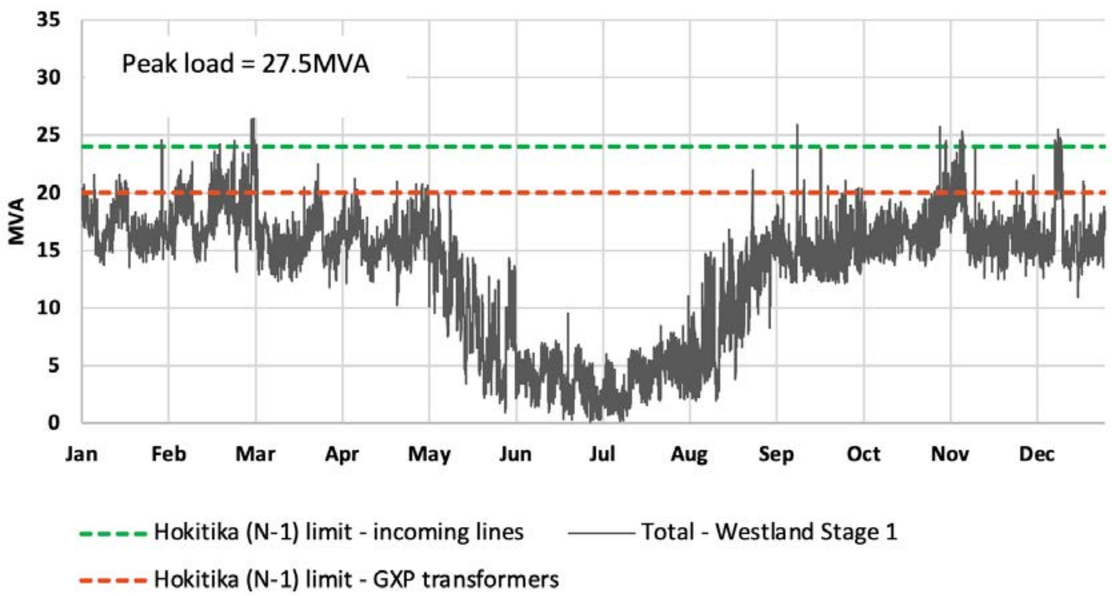


Figure 37 shows both the N-1 capacity of Westpower's transfomers, and the N-1 limit on Transpower's line between Otira and Hokitika (27MVA).

On the assumption that existing Hokitika demand continue to behave as it did in 2021, demand at the GXP following the implementation of Westland's Stage 1 electrification would exceed the N-1 capacity of Westpower's transformers around 5% of the time. If all other Hokitika RETA sites electrified (not shown), the N-1 transformer limit would be exceeded 9% of the time. This would require a discussion with Westpower as to how Hokitika customers would be affected by a transformer fault; this could be achieved by an automatic interruption of Westland Milk's supply, should a failure occur, that would only be enabled during the 5%-9% of the time that demand exceeded the 20MVA N-1 limit. This would be substantially lower cost than investment in upgraded transformers at the Hokitika GXP, but may not be acceptable to Westland Milk's operation.

In either case, total demand at Hokitika would rarely exceed Transpower's N-1 Hokitika-Otira line limit (<0.3% of the time). If an SPS (as described above) was enabled, Westland Milk's demand would only be 'at risk' from a transmission line fault 0.3% of the year. Given the high reliability of transmission assets – usually in excess of 95% – the combined probably of interruption would be very small.

A proper analysis of the interruption risk – whether from an SPS or a transformer fault – is needed in order to be definitive. This analysis would need to take into account demand growth that may come from other sources, for example population growth and electrification of transport, as well as how this demand profile may vary from the 2021 data used to produce Figure 36. It would also need to consider how the proportion of time the SPS is operative changes with the generation patterns of current distributed generation.

If Westland Milk electrified both Stage 1 and Stage 2, even the N security limit at Hokitika would be exceeded – i.e. the current assets do not have the capacity to absorb the new demand. Ergo's assessment of the necessary investment included new transmission assets, which makes up the bulk of the $24M of upgrades required, including:

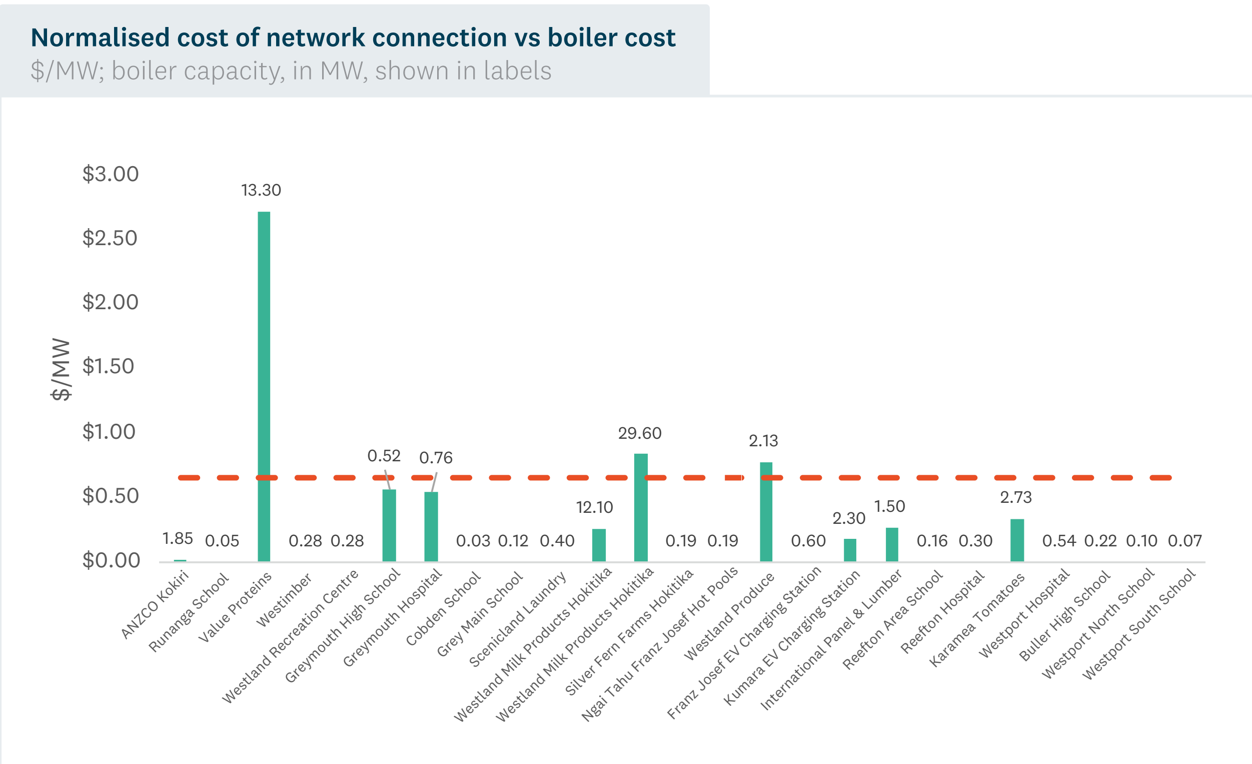
- A new 66/11kV transformer, coupled with associated switchgear, at Hokitika.
- A capacitor bank at Hokitika (as planned by Transpower).
- A new ~50km long 66kV line between Hokitika and Dobson.

We discuss these investments in the broader West Coast context, including the prospect of further investment in local generation, in Section 8.5 below.

8.3.6 Summary

The network connection costs presented above vary significantly in magnitude. But it is worth viewing these costs through the lens of the size of the boiler installation. Figure 38 shows each site's connection costs expressed in per-MW terms, i.e. relative to the capacity of the proposed boiler.

Figure 38 – Normalised cost of network connection vs boiler cost. Source: Ergo, EECA



The red dashed line in Figure 38 compares these per-MW costs to the estimated cost of an electrode boiler ($650,000 per MW[107]). The figure shows not only a wide variety of relative costs of connecting electrode boilers, but that for three cases, the connection cost more than doubles the overall capital cost associated with electrification.

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

8.4 Collective impact on upgrade costs

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

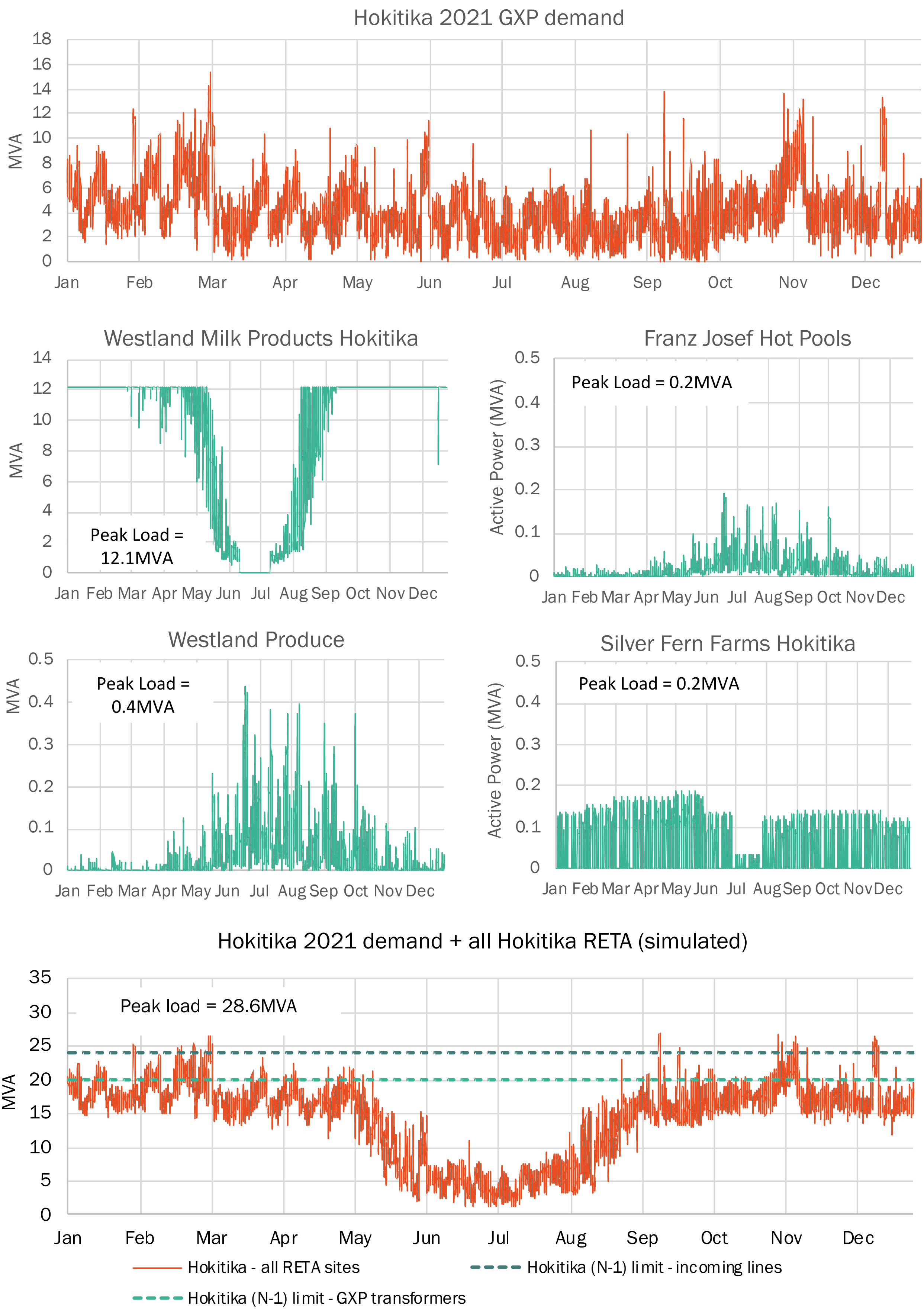
Assessing the impact on peak network demand, should all sites electrify, is often not as simple as adding the combined individual peak demands from each of the sites.

The amount of spare capacity at a GXP is determined at the highest overall electricity demand once the sites have electrified. However, RETA sites may have quite different patterns of demand over the year – some peak in winter (swimming pools, schools) while others (e.g. dairy) peak in summer. In other words, not all individual site 'peaks' happen at the same time. Further, they may not occur at the same time as the existing demand peaks.

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 RETA site. Ergo obtained half hourly historical demand data for each West Coast GXP for 2021, 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 2021, had all RETA sites been electrified. Figure 39 shows the components of the simulation for the Hokitika GXP (assuming Westland Milk electrified Stage 1, but not Stage 2).

[107] This is the estimate used in the development of the marginal abatement costs and pathways presented in Section 9.

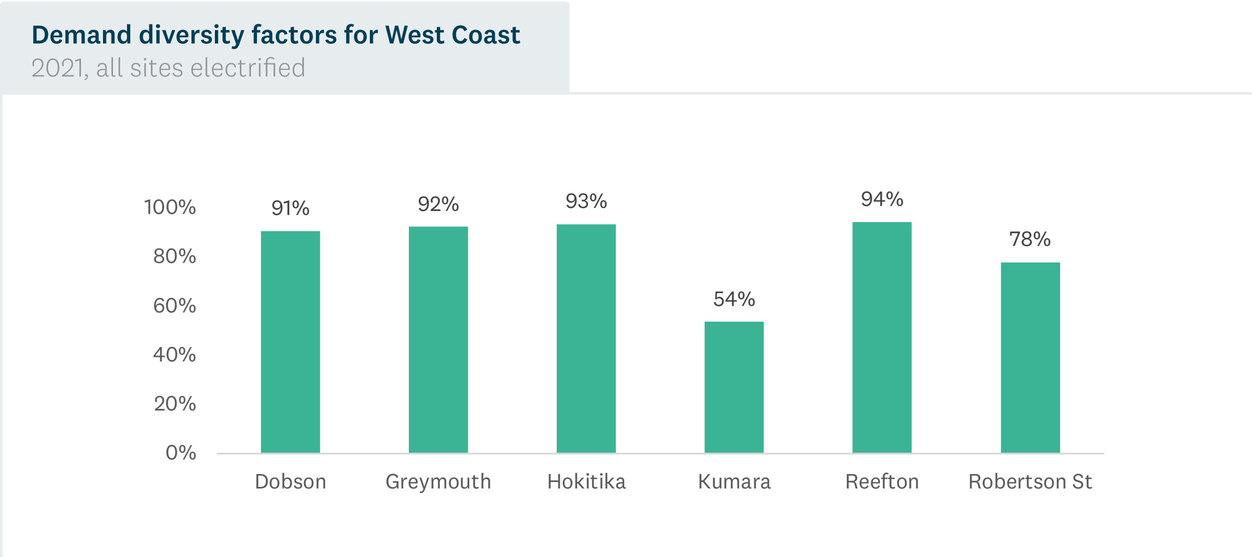
Figure 39 – Simulation of impact on Hokitika GXP demand from all RETA site electrification



The bottom panel shows the simulated outcome from all sites electrifying. Importantly, the resulting peak GXP demand observed in late March is 28.6 MVA, which is lower than the simple addition of all individual RETA site peaks (15.21MVA) to the 2021 Hokitika peak demand (15.4), which would have suggested the new peak is 30.6MVA. The effect of demand diversity amongst the different Hokitika RETA sites is that the combined peak is 93% of what a simple addition would have suggested. We refer to this as a diversity 'factor'.

Ergo repeated this analysis across all GXPs. The resulting demand diversity factors are shown in Figure 40.

Figure 40 – Demand diversity factors for West Coast GXPs. Source: Ergo

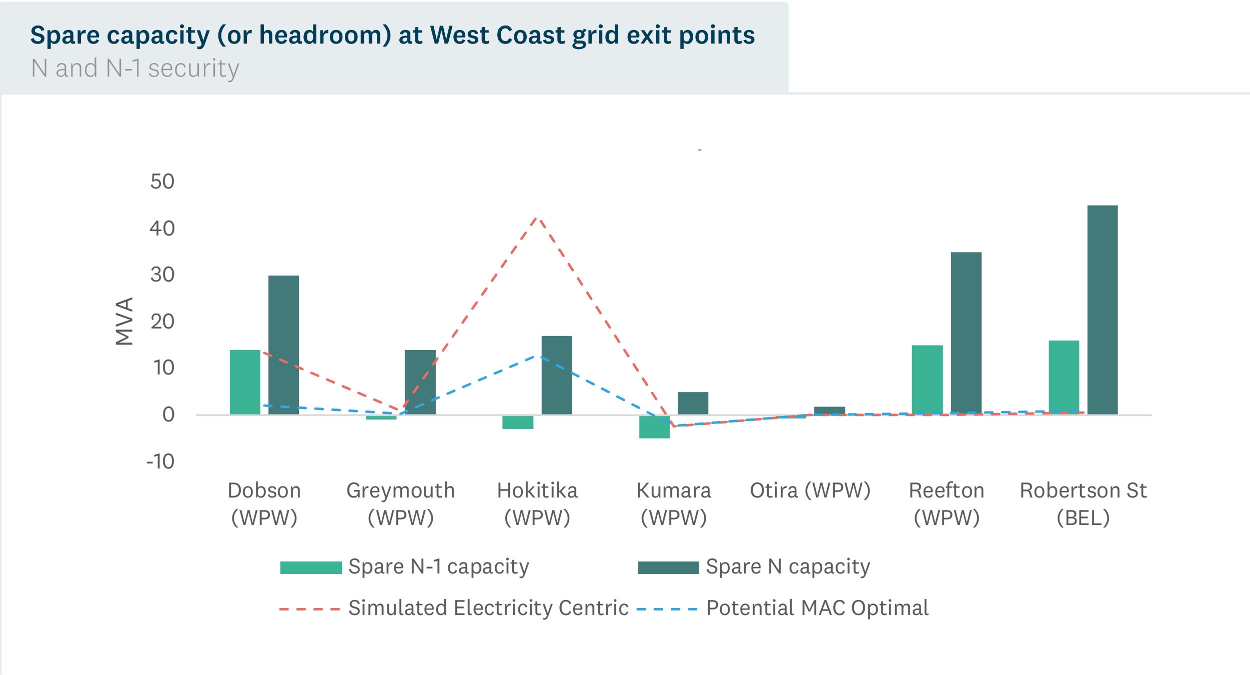


We can use these diversity factors to determine the impact of all sites electrifying on spare capacity. Figure 41 shows the amount of spare capacity at each GXP if that would be used under two scenarios:

- The 'Electricity Centric' pathway, where all of the West Coast RETA sites choose to electrify, including both Westland Milk Stage 1 and Stage 2 (red dashed line).
- A 'MAC Optimal' pathway, where only those sites that have lower marginal abatement costs than biomass (see Section 9.1) electrify (blue dashed line).

Section 9.2 describes these scenarios more fully. Note that the dashed lines in Figure 41 assume that none of the sites actively manage their demand to avoid system peaks; again, this is a conservative view of peak demand.

Figure 41 – Potential combined effect of site decisions at each GXP. Source: Ergo



On this analysis:

- In the Electricity Centric scenario, electrification at Dobson, Greymouth and Kumara would cause those GXPs to exceed their N-1 capacity (more than is currently the case), and Hokitika would exceed its N capacity. However, Dobson would only exceed N-1 for only very short periods of time, which would likely be tolerable.
- In the MAC Optimal scenario, electrification causes N-1 to be exceeded at Greymouth, Hokitika and Kumara.

However, as outlined earlier, Transpower's conservative prudent demand forecast suggests that these GXPs will imminently exceed N-1 even without any additional demand from process heat users that choose to electrify. For most GXPs, the electrification of multiple RETA sites has only a small additional effect on the assessment of spare capacity. In most cases, whether or not additional investment in capacity is warranted will be a negotiation between the EDBs and Transpower. If this is a risk-based decision, the change to the risk of interruption may still be tolerable.

The main exception to this is Hokitika, where the degree of investment required is fundamentally related to whether Westland Milk decides to only electrify stage 1 (MAC Optimal pathway) or both stage 1 and 2 (Electricity Centric scenario). We discussed these decisions in Section 8.3.4, which showed:

- How the Special Protection Scheme (SPS) planned by Transpower could accommodate the 12MW increase in demand from Westland Milk Stage 1, allowing the Hokitika GXP to exceed N-1 security for limited periods of time (once demand diversity was taken into account), if Westland Milk was comfortable with the resulting small risk of interruption.
- The electrification of Stage 2 of Westland Milk alone would require significant grid upgrades, including a new 66kV transmission line between Hokitika and Dobson, costing $24M in total.

The costs associated with these changes were included in the site-related costs developed in Section 8.3.4, and are included in the economic assessment of electrification in Section 9.

8.5 Security of supply on the West Coast

While the West Coast is home to a significant amount of local hydro generation, it is still a net importer of electricity at most times. The lines that provide this import capability come both from the north (via Murchison) and the south (via Otira). Due to the electrical characteristics of these two sets of lines, the circuits from Murchison provide the majority of the import capacity. Currently there is a moderate amount of headroom in the lines from Murchison. However, should significant electrification of process heat occur, this headroom will be eroded.

In a simulated summer scenario, we have explored whether significant electrification would cause these import lines to reach their N-1 capacity limits. We have used Westland Milk's Stage 1 and Stage 2, along with Value Proteins proposed load to explore this, as they would represent the largest increases in demand in the region. For an increase in demand at Hokitika of ~42MW (Westland Milk's Stages 1 and 2) and 13.5MW at Dobson (Value Proteins), the Kikiwa-Murchison-Inangahua 110kV lines are still marginally within their N-1 limits. However, this load increase would require significant infrastructure upgrades in the network including:

- A new 66/11kV transformer, coupled with associated switchgear, at Hokitika
- A capacitor bank at Hokitika (as planned by Transpower)
- A new 66kV line between Hokitika and Dobson

These investments are the same as those included in Ergo's assessment of the required upgrades for Westland Milk's Stage 2 (see Section 8.3.5).

Currently, the West Coast's embedded generation is helping avoid congestion on transmission assets. The degree to which it does this from year to year demands on the output of the generation at peak times, which in turn depends on rainfall in the hydro catchments. Further investment in local hydro could impact the need for future transmission investment in the following ways:

- Additional generation investment in the northern part of the West Coast, such as the 25MW hydro station consented at Ngakawau, would help take the pressure off the Kikiwa-Murchison 110kV lines noting that, even with a combined increase of 55.5MW from Westland Milk and Value Proteins, they still meet N-1 in our modelled scenario without Ngakawau.
- Investment in the mid-West Coast region, such as the proposed 16MW-20MW Waitaha hydro station, expected to connect at Hokitika at 66kV, could enable WMP to increase their load beyond the Stage 1 requirements, but a full Stage 2 expansion (42MW total increase in load at Hokitika) will definitely require the new 66/11kV transformer at Hokitika ((a) above), and very likely require network investments (b) and (c) listed above, despite the injection of generation from Waitaha.

The potential for these more significant network upgrades, and the interplay with local generation investment, requires a high degree of coordination and collaboration between Transpower, EDBs, the key process heat users driving the increase in demand (Westland Milk and Value Proteins), and the hydro generation investors. This coordination needs to start well in advance of the need for upgrades, as planning new transmission lines takes many years. Further, information sharing needs to be frequent as each organisation, and the wider region, refines its views and intentions with the passage of time.

8.6 The role of flexibility in managing costs

8.6.1 Why flexibility?

At its simplest, demand-side flexibility is a consumer's ability to be flexible with when they consume electricity is consumed. By modifying usage in response to a range of 'triggers' (changing price, a network constraint or failure) sites can reduce costs, and 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 network capacity upgrade requirements.
- 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.

8.6.2 How to enable flexibility

The analysis above 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.
- 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.

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[108]. 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.

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 8.2.1 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.

[108] This is part of NZ's wholesale market design, whereby large loads and generation are paid to be on standby in the event that a large system component fails, thus causing frequency to fall.

ii. **Minimising retail costs** – Section 8.2.3 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 32). Some pricing arrangements may have more granular prices (e.g. different prices for each 4-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 8.2.4, 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 8.3 outlined that a key factor is the current spare capacity at peak times in the existing network. Flexibility in electricity consumption can potentially reduce the cost of network upgrades in two different ways:

- Ensuring demand from the site is reliably[109] 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 8.3.2), 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[110] reduce demand so that the network remains stable.

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 totwo 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[111].

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

[110] 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.

[111] 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.

Of course, altering the production of process heat in order to provide flexibility services (i) to (v) above has consequences (and potentially cost implications) for the site. Lost production during high priced periods, for example, must be recovered at another time – depending on the nature of the process, the flexibility may be limited.

However, there are a number of ways in which thus flexibility can be enabled. if the site can increase its use of thermal storage (e.g. hot water[112]), this can enable flexibility. Alternatively, as mentioned above, 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.

8.6.3 Potential benefits of flexibility

Enabling flexibility in these ways will increase cost, but may be more than offset by the reduction in electricity costs or the capital contribution to network upgrades. The benefits of enabling flexibility – in terms of reduced consumption costs and capital requirements for network upgrades – could be significant. Further, as the electricity system reduces its use of fossil fuels (coal, natural gas and diesel) in line with emissions prices, and instead builds lower cost wind and solar, the system will require more flexibility from other sources, including consumers. This flexibility could well become a premium product.

There have been a range of analyses of the potential value (to the system) of demand flexibility in the New Zealand system. These range from $150,000 to $300,000[113] per annum 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. However, the Electricity Authority's independent Market Development Advisory Group (MDAG) estimated the electricity cost reductions that an existing process heat site could realise in a future system with a very high degree of renewables[114]. 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.

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

[113] 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*.

[114] https://www.ea.govt.nz/projects/all/pricing-in-a-renewables-based-electricity-system/consultation/price-discovery-in-a-renewables-based-electricity-system/, specifically the Demand Side Flexibility case studies available at https://www.ea.govt.nz/documents/1254/DSF-case-studies-FINAL-1.pdf

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.

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8.6.4 Who should process heat users discuss flexibility with?

RETA sites should consider their ability to provide flexibility, and 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**[115] – to assess the degree to which the site's response to these signals can be automated.

[115] Examples of flexibility providers include Enel X and Simply Energy.

9 Decarbonisation pathways

As outlined above, a primary driver for the RETA approach is to identify where the collective decisions of process heat users, and potential providers of low-emissions process heat fuel (biomass or electricity), give rise to 'system' challenges and opportunities. These challenges and opportunities may not be apparent to individual RETA projects, as they only become apparent when the collective impacts of many RETA project decisions are considered. If these challenges and opportunities can be anticipated, and 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.

This section also uses the information from the previous sections to consider different scenarios of the pace and magnitude of electricity and biomass uptake across the whole West Coast region. We refer to each of these scenarios as 'decarbonisation pathways'.

9.1 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 West Coast RETA, other estimates use the information outlined in Sections 7 and 8 above.

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 (GIDI and State Sector Decarbonisation Fund)
- 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 the majority of emissions from the West Coast RETA sites.

However, for sites where individual ETA data was not available, estimates based on other data available to EECA were made. For demand reduction and low temperature heat (<100°C) opportunities, if ETA data was unavailable, the information in Table 15 was used:

Table 15 – Assumptions regarding heat pump and demand reduction opportunities where ETA information is unavailable. Source: Lumen

Sector	Proportion of total heat demand < 100°C	Peak demand reduction (%)
Laundry	20%	5%
Pool Heating	100%	12%
Horticulture	0%	18%
Meat processing	100%	26%
Pet food & rendering	5%	5%
Engineered timber	0%	2%
Sawmill	0%	4%
Dairy Processing	N/A	4%

Ngāi Tahu Forestry, West Coast, New Zealand.

To determine likely fuel switching decisions across a range of industries and boiler sizes, the fuel option (biomass or electricity) which has the lowest marginal abatement cost (see below) is chosen. The assumptions about the key parameters associated with these decisions are:

- Existing fossil fuel boilers are estimated to be 78% efficient.
- Biomass boilers are estimated to be 80% efficient.
- Electric boilers are estimated to be 99% efficient.
- Capital costs for new boilers were derived from specific individual ETAs where available, or derived from wider ETA data where unavailable.
- Biomass cost estimates have followed a cost path of $10.50/GJ ($97/t) for smaller volumes and $13/GJ ($115/t) for a large user. This reflects the supply curves illustrated in Section 7.7, which include the cost of delivery to a central biomass hub at Westland Milk. To reflect the price to the end user, we add costs associated with processing (for pellet manufacture) and secondary transport to a process heat user's site, as well as an indicative $3/GJ margin for organisations who facilitate the biomass chipping, storage and transport. This translates into $310/t and $350/t (respectively) for biomass processed into pellets or dried wood chip.
- A conservative view of electricity upgrade costs required for each site has been incorporated as per Section 8.
- Variable electricity costs have used the central pathway from Section 8.2, along with estimates for distribution and transmission network prices discussed in that section. In some cases we have substituted currently available retail market pricing[116] – targeted at process heat users in the South Island – for the near-term prices from Section 8.2.

However, 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[117].
- 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.

[116] For example, Meridian's process heat electrification programme pricing.

[117] 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.

9.1.1 Calculating marginal abatement costs

For the pathways that involved an optimisation of fuel switching decisions, we need a simple way to determine which fuel they would choose (and when).

There are a range of other factors organisations face when deciding when to make a decarbonisation decision, and which fuel to choose. These factors will invariably include the cost of the decision, but also may include confidence in future fuel supply, competitor behaviour, funding and financing or consumer expectations. However, these softer factors are harder to model quantitatively.

Our simulated 'optimal' decision making framework presumes that the decision regarding which fuel to switch to, and when, is purely about the change in cashflows (capital and operating) arising from the project. Using discounted cashflows analysis, at an appropriate discount rate, we can 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 calculated as:

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

The project costs included in the calculation include all capital, operating and fuel costs, but must not include the future estimated (Scope 1) costs of surrendering NZUs to New Zealand's Emissions Trading Scheme, as this is implied by the MAC[118].

9.1.2 Using MAC values to support investment decision-making

There are two ways MAC values can support a process heat user's investment decision:

- **Fuel choice** – If there is more than one option available (i.e. biomass or electricity), the MAC also gives a relative ranking of the options expressed in terms of their marginal abatement cost. As stated above, the MAC value effectively provides a 'cost of carbon reduction' expressed in $/tCO2e. 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.

[118] In the same way that calculating the levelized cost of energy must not include any revenue from selling the energy, as the LCOE gives the price at which the decision maker would be indifferent.

New Zealand's cost of carbon is set primarily through the Emissions Trading Scheme (NZ ETS); however the quarterly carbon auctions which determine this price only reflect the current supply of, and demand for, carbon reduction 'units'. 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 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 thus its impact on the business) *in the future*[119], should it continue to consume coal, diesel or LPG. 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 then, it is entirely understandable that an investor might 'wait and see' if the increases materialise, before committing investment.

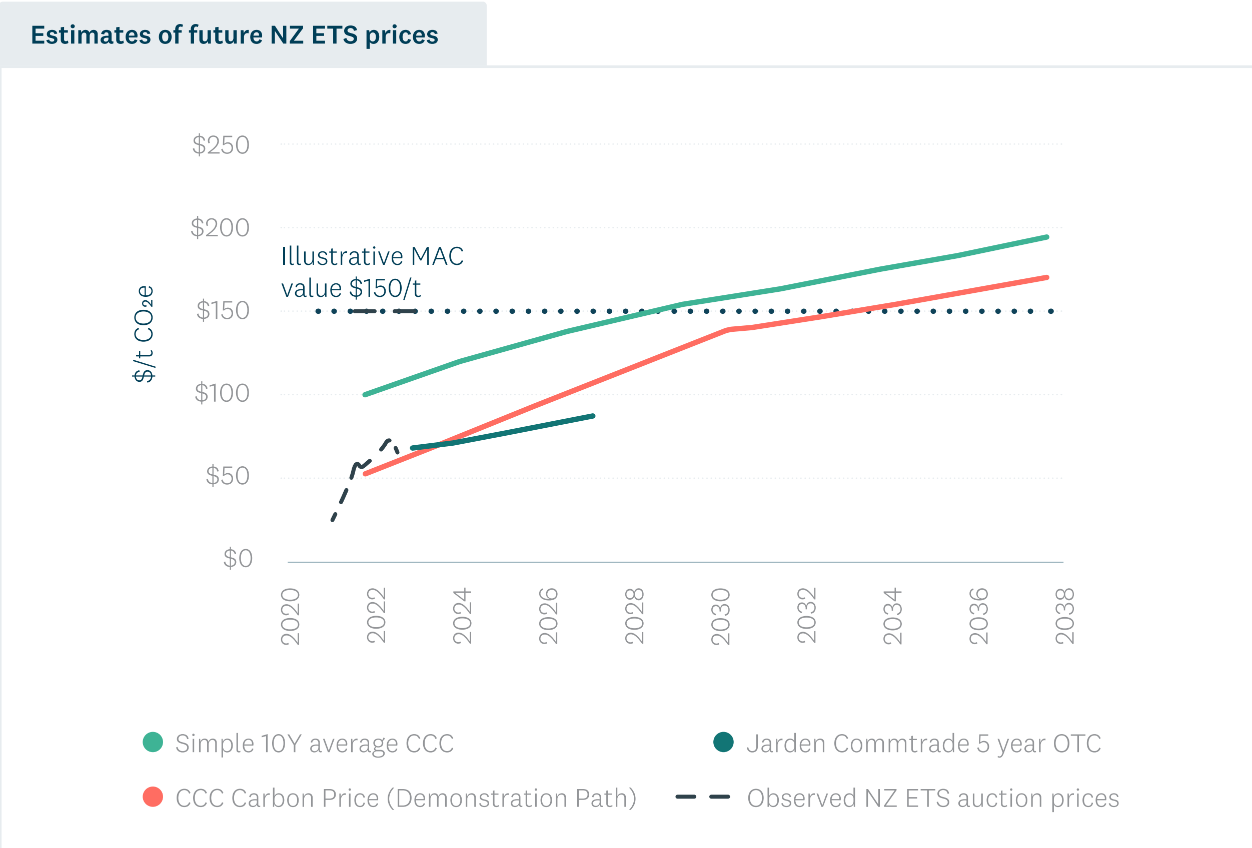
One view on future carbon prices is the Climate Change Commission's carbon price pathway from its 'Demonstration Path'[120] (represented as the red solid line in Figure 42). Technically, this is not a 'forecast'; rather, it is the series of modelled carbon prices (to 2050) which consistent with New Zealand meeting its aspirations around carbon reduction. Whether or not carbon prices actually follow that pathway depends largely on whether government policies and resulting decisions by consumers and businesses meet the 'emissions budgets' recommended by the CCC.

Hokitika, West Coast, New Zealand.

[119] 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.

[120] See https://www.climatecommission.govt.nz/news/dive-into-the-data-for-our-proposed-path-to-2035/

Figure 42 – 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 42.

The black dashed line shows the outcomes of actual NZ ETS auctions (held each quarter). These are the result of the bids by organisations that need to purchase New Zealand Units (NZUs), cleared against the volumes made available by the government (at reserve prices).

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 2023[121]. It will likely include the effect of the failed ETS auction that took place in March.

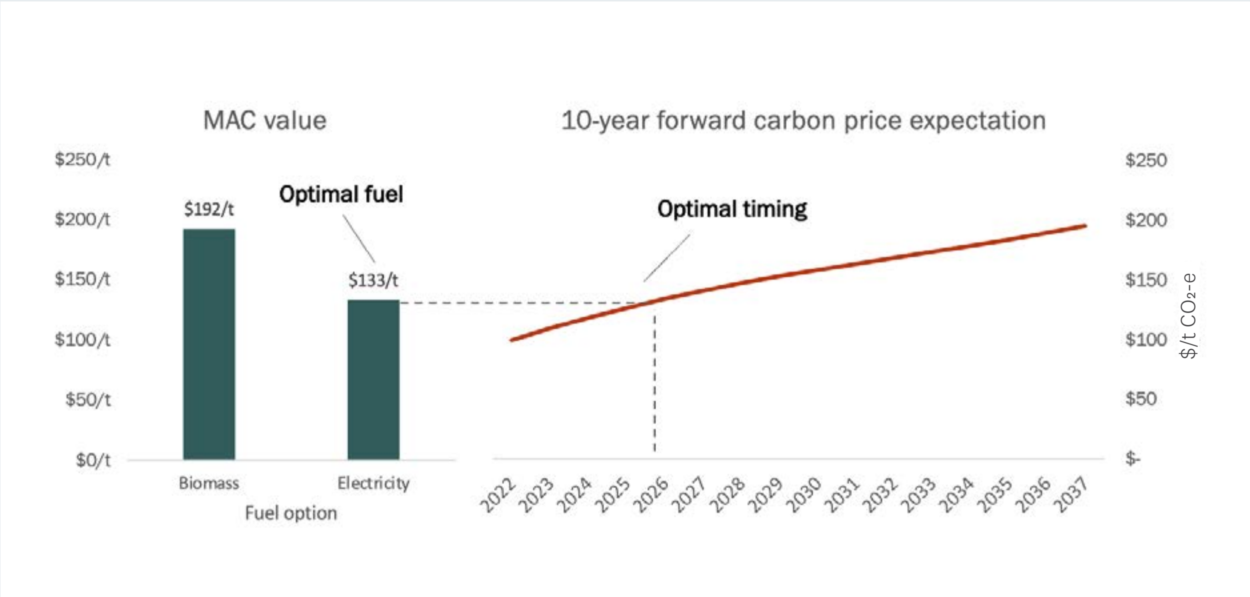
Different future views on carbon prices, and different ways of using those views, could have quite different impacts on the timing of decarbonisation projects proceeding. Assuming that the CCC Demonstration pathway is a good forecast of carbon prices, Figure 42 shows that a project with a $150/t MAC value would not be committed until 2033 if the decision maker used the current carbon price to trigger the decision, but would proceed earlier – in 2028 – if they used the simple average of the next 10 years of carbon prices implied by the CCC Demonstration path.

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

For this report, we have chosen to use the 10-year forward average of the CCC's demonstration path 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 36[122].

The overall framework for how we use MAC values to create the 'MAC Optimal' pathway below is shown in Figure 43.

Figure 43 – Illustration of how MACs are used to determine optimal decision making



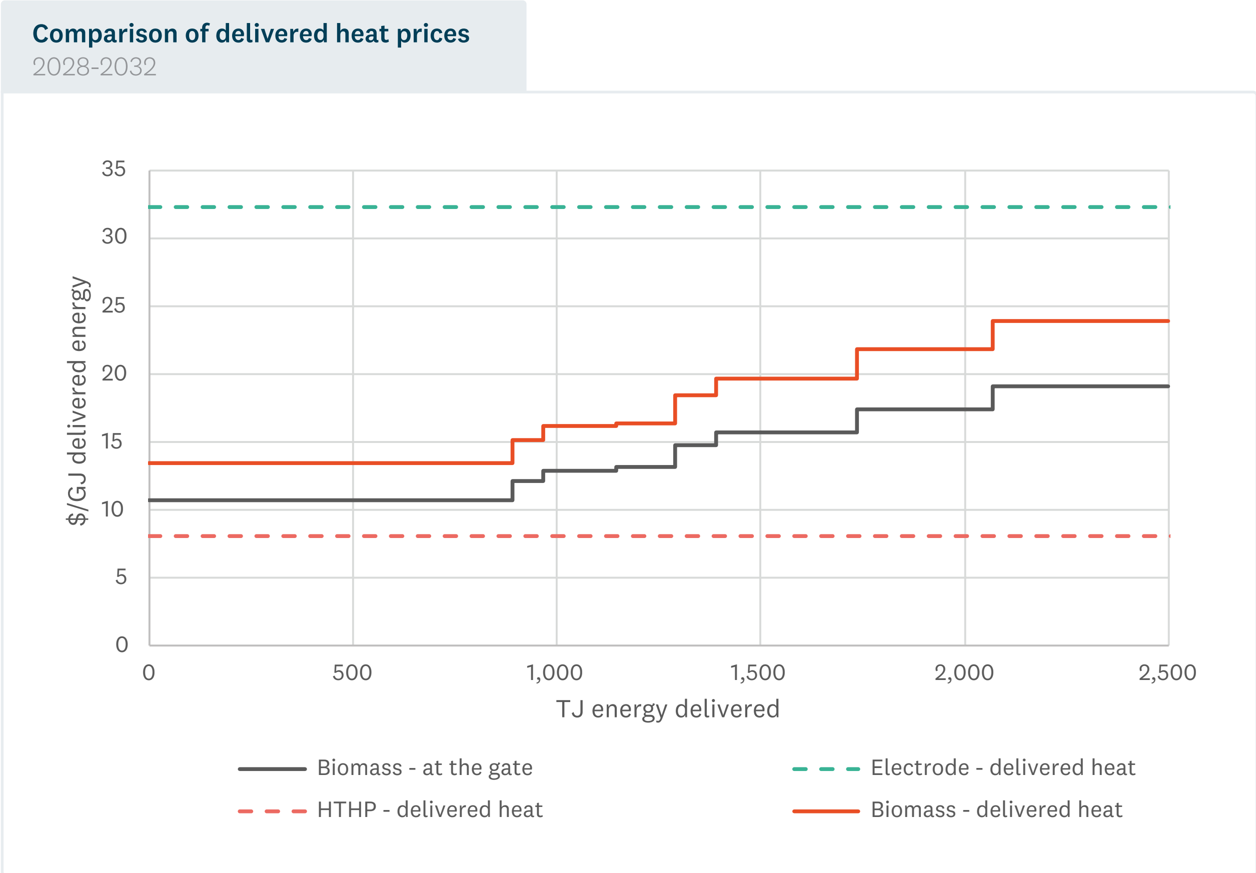
9.1.3 The impact of boiler efficiency on the 'price of heat'

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. 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 4 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 44, we illustrate the difference between these cost concepts using the bioenergy supply curve from Section 7.7 (for a biomass decision) and the electricity price path from Section 8.2 (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.

[122] 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.

Figure 44 – Comparison of the variable costs of biomass and electricity from a delivered heat perspective. Sources: PF Olsen, Ahikā/MG, EnergyLink, EECA.



Westland Milk, West Coast, New Zealand.

9.1.4 Resulting MAC values for RETA projects

The range of marginal abatement costs for projects are illustrated in Figure 45 below. Individual MACs have been calculated for each site's demand reduction and heat pump projects, as well as the optimal choice of fuel for boilers. These charts include all 36 confirmed and unconfirmed projects, but do not include the 12 projects (primarily demand reduction) that have been completed (see Table 4).

Figure 45 – Number of projects by range of MAC value. Source: EECA

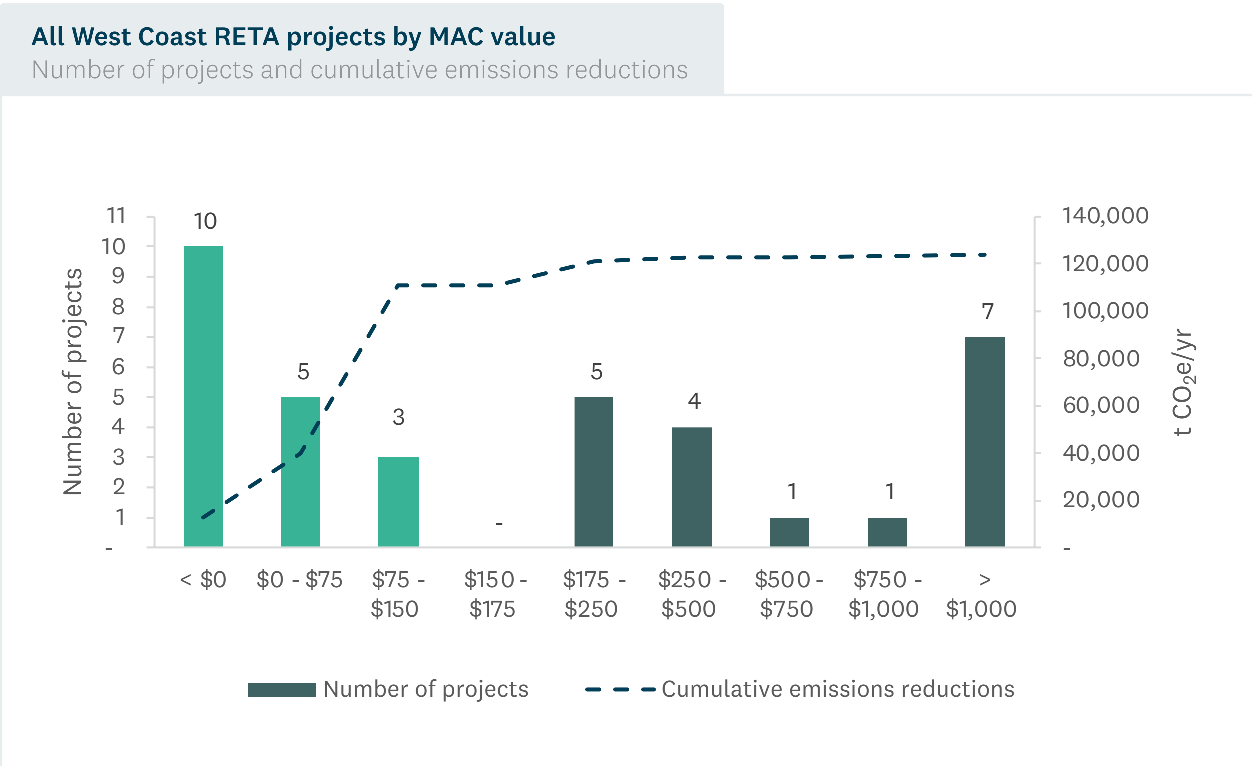
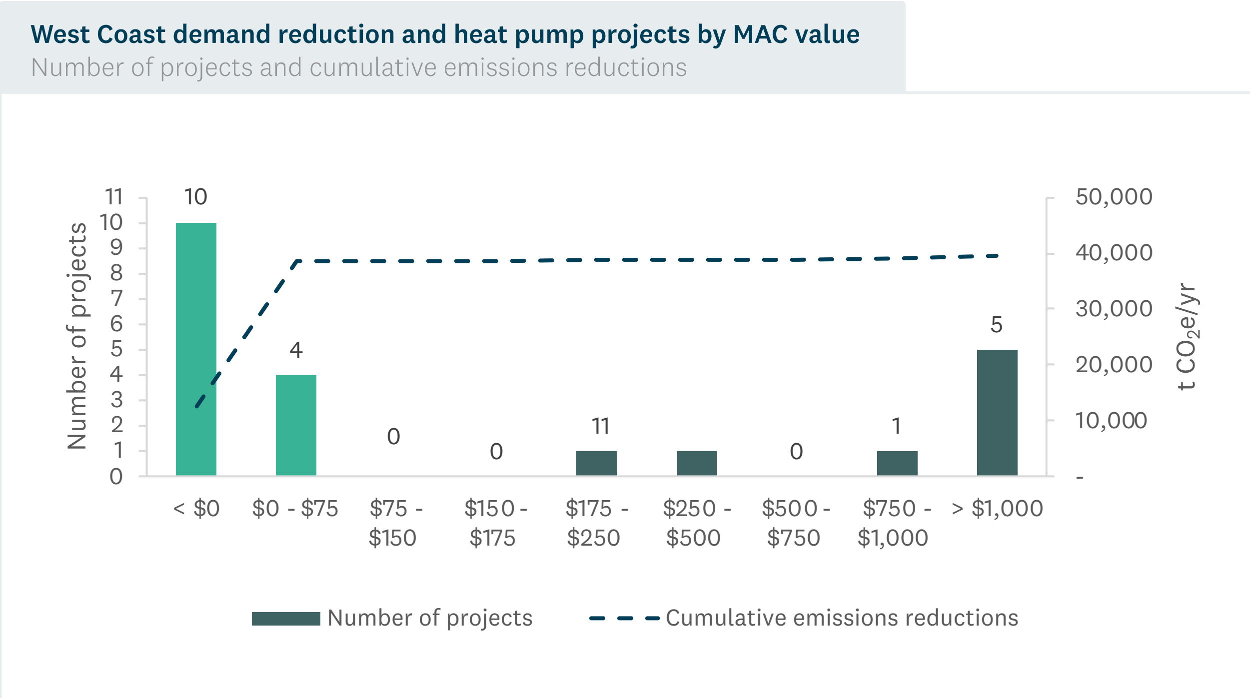


Figure 45 shows – highlighted in green – the 19 projects with MAC values less than \$150/tCO_2e, that would have a positive net present value (NPV) – at some point in the period to 2037 – if NZ ETS prices rose in line with the Climate Change Commission's Demonstration Path carbon price projections. The figure also shows that these 19 projects would deliver 88% (110,000t CO_2e) of the total emissions reductions from all RETA projects. 15 projects, delivering 32% of the total RETA emissions reductions, would be economic at today's carbon prices.

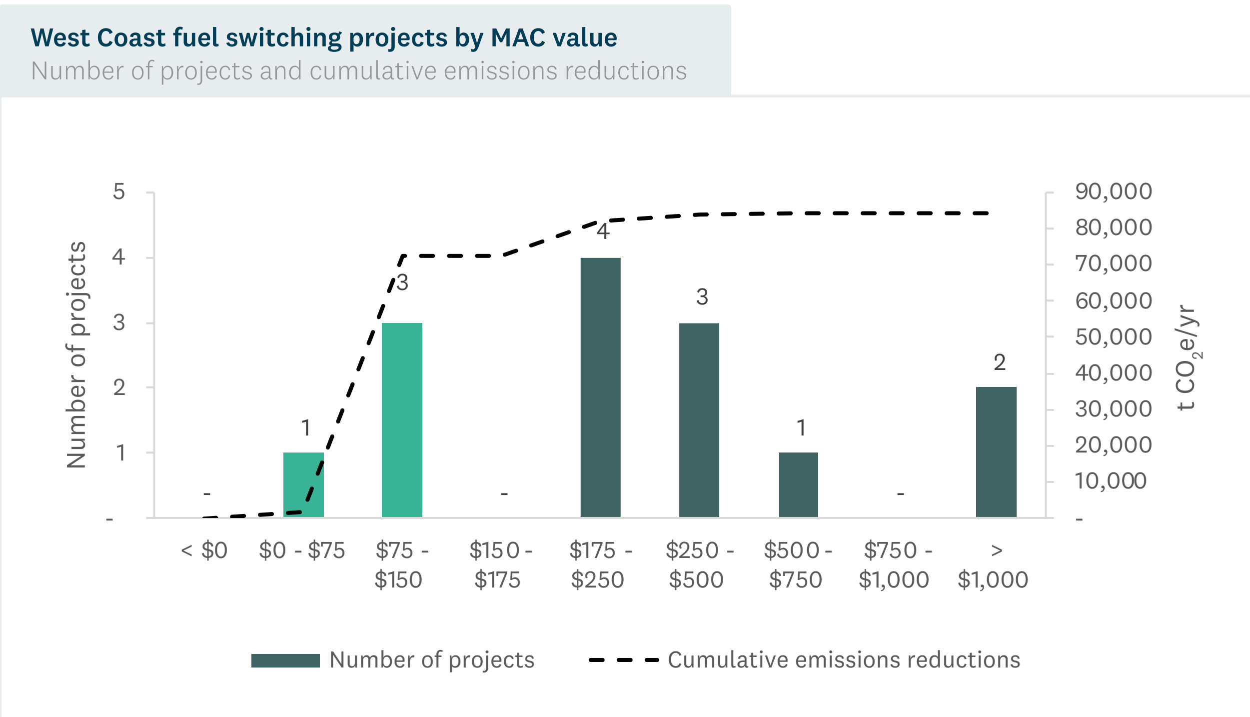
Figure 46 shows that 14 of the 19 lower-MAC 'economic' projects are demand reduction and heat pump projects, delivering 40kT of emissions reductions.

Figure 46 – RETA demand reduction and heat pump projects by MAC value. Source: EECA



Fuel switching projects have higher MAC costs (Figure 47) reflecting the various combination of site-specific factors, such as the lumpy nature of potential electricity upgrade costs as calculated in Section 8 (where relevant); the operating profile over the year; and the overall utilisation of the boiler capacity. Notwithstanding that, five of these fuel switching projects are economic within the period, delivering 72,000t of emissions reductions – 58% of the total RETA process heat emissions.

Figure 47 – RETA fuel switching projects by MAC value. Source: EECA



For the remaining projects that have higher MAC values, there could be a range of ways cost reductions could be achieved to make the remaining projects more viable over the term of the RETA. For example, securing access to lower cost biomass resources, enabling plant flexibility to reduce the cost of electricity connections and/or electricity consumption, or access to targeted co-funding. We consider the impact of co-funding, amongst other scenarios and sensitivities, below.

9.2 Indicative pathways

Indicative pathways for decarbonisation have been prepared on the following basis. 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, consistent with the Carbon Neutral Government Programme[123].
- All RETA decarbonisation projects are executed by 2037 in line with the Government's aspiration to phase out coal boilers by 2037[124]. This means that any projects that are still not 'economic' using our MAC criteria (illustrated in Figure 43) by 2036, are assumed to be executed in 2036.

The pathways were then developed as follows:

Pathway name	Description
Biomass Centric	All unconfirmed fuel switching decisions proceed with biomass at the timing indicated in the organisation's ETA pathway. If not indicated, timing was set at 2036.
Electricity Centric	All unconfirmed fuel switching decisions proceed with electricity as the sole fuel at the timing indicated in the organisation's ETA pathway. If not indicated, timing was 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 was set at 2036.
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 ten-year rolling average of future carbon prices[125].

[123] This programme prioritises the phaseout of coal-fired boilers from the public sector, with the focus on largest and most active by the end of 2025. See https://environment.govt.nz/what-government-is-doing/areas-of-work/climate-change/carbon-neutral-government-programme/about-carbon-neutral-government-programme/

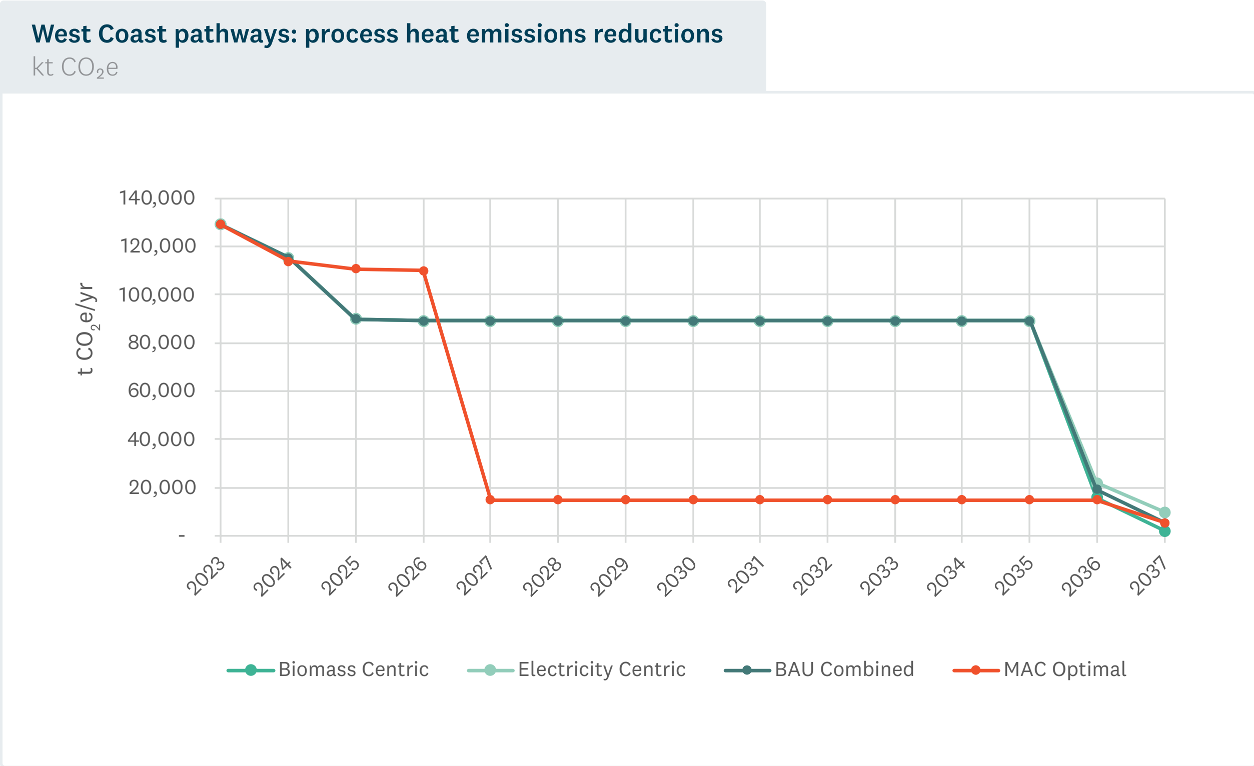
[124] All RETA decarbonisation projects are executed by 2037 in line with the Government's aspiration to phase out coal boilers by 2037. See https://www.beehive.govt.nz/release/government-delivers-next-phase-climate-action

[125] We use the Climate Change Commission's assumed future NZ ETS prices (demonstration pathway) as our forecast of future carbon prices.

9.2.1 Pathway results

All pathways eliminate between 93% and 98%[126] of process heat emissions in the region (a reduction of between 119kt and 123kt out of a total of 125kt), but at significantly different pace (Figure 48). Note that both the 'Centric' pathways, and the BAU Combined pathway follow the same trajectory and thus overlap in the majority of the figure.

Figure 48 – Emissions reduction trajectories for different simulated pathways. Source: EECA



The MAC Optimal pathway achieves the fastest emissions reductions, with nearly 90% of emissions reductions achieved by 2027. Under the other pathways, most emissions reductions aren't achieved until in 2036. The cumulative difference between the MAC Optimal and the other pathways, is 633kt CO2e – exclusively long-lived greenhouse gases – across the period 2022 to 2036.

[126] Residual emissions at the end of each pathway relate to Scope 2 emissions from the varying amounts of electricity consumption. As outlined earlier, electricity is modelled to have a Scope 2 emissions content of 100kg per MWh of electricity, per published guidance from the Ministry for the Environment on accounting for greenhouse gas emissions.

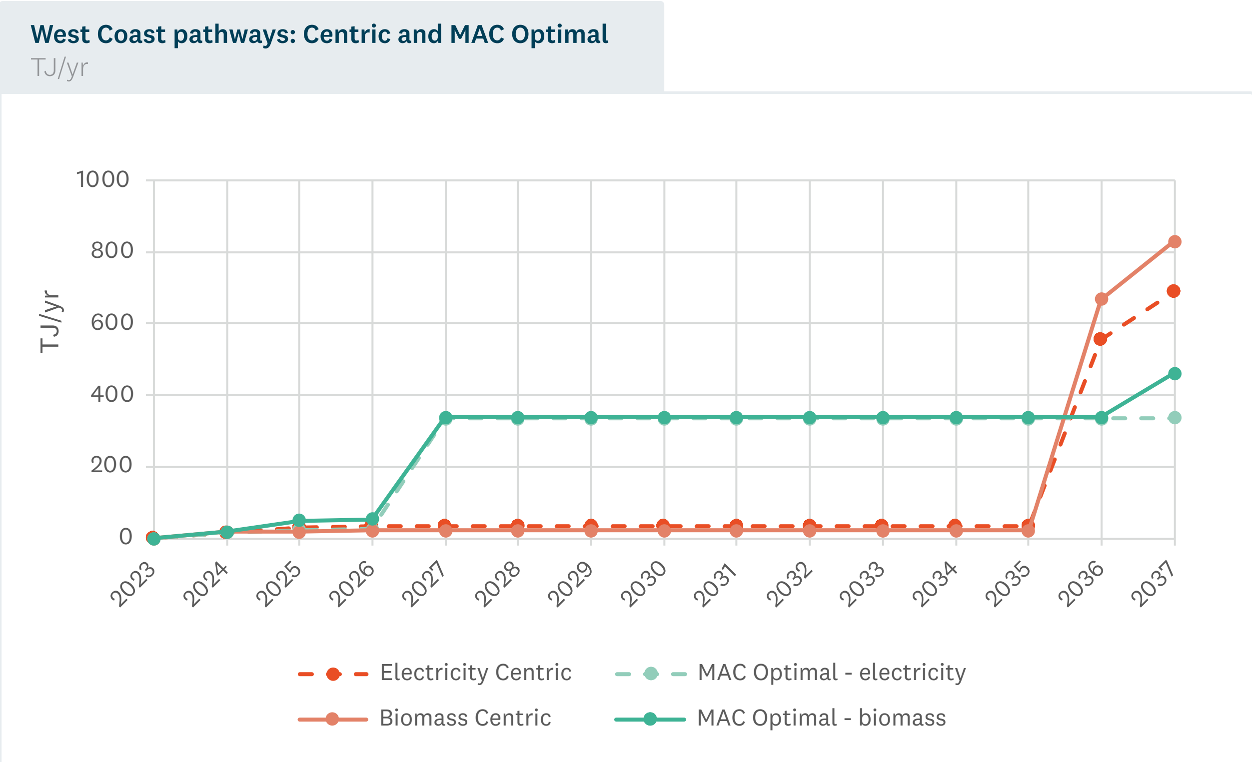
9.3 Pathway implications for fuel usage

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

- Biomass Centric, Electricity Centric
- MAC Optimal

As shown in Figure 49, the Biomass Centric and Electricity Centric pathways understandably deliver the highest demands in 2036 for each fuel – 690TJ for electricity, and 830TJ for biomass. The pathways that use MACs to determine fuel switching decisions result in a more diverse set of fuel decisions, with around 60% of the energy needs supplied by biomass (with a consumption of 460TJ of delivered energy), and 40% of energy needs supplied by electricity (with 335TJ of delivered energy).

Figure 49 – Simulated demand for biomass and electricity under various RETA pathways. Source: EECA



The pathways show the significance of the timing of the Westland Milk decision. The two stages of this decision account for between 522TJ (if electricity) to 650TJ (if biomass) of energy consumption, depending on which fuel is chosen. In the Centric pathways, the Westland Milk decision does not occur under the end of the pathway horizon, based on the 2037 date for coal phaseout (see footnote 128). Under the MAC Optimal approach, the optimal MAC values for the two stages (Stage 1 – electricity; Stage 2 – biomass) are similar enough to trigger both stages in the same year (2027).

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

9.3.1 Implications for electricity demand

Figure 50 shows the growth in electricity demand in each of the pathways.

Figure 50 – Growth in electricity demand from fuel switching pathways (unconfirmed RETA sites). Source: EECA

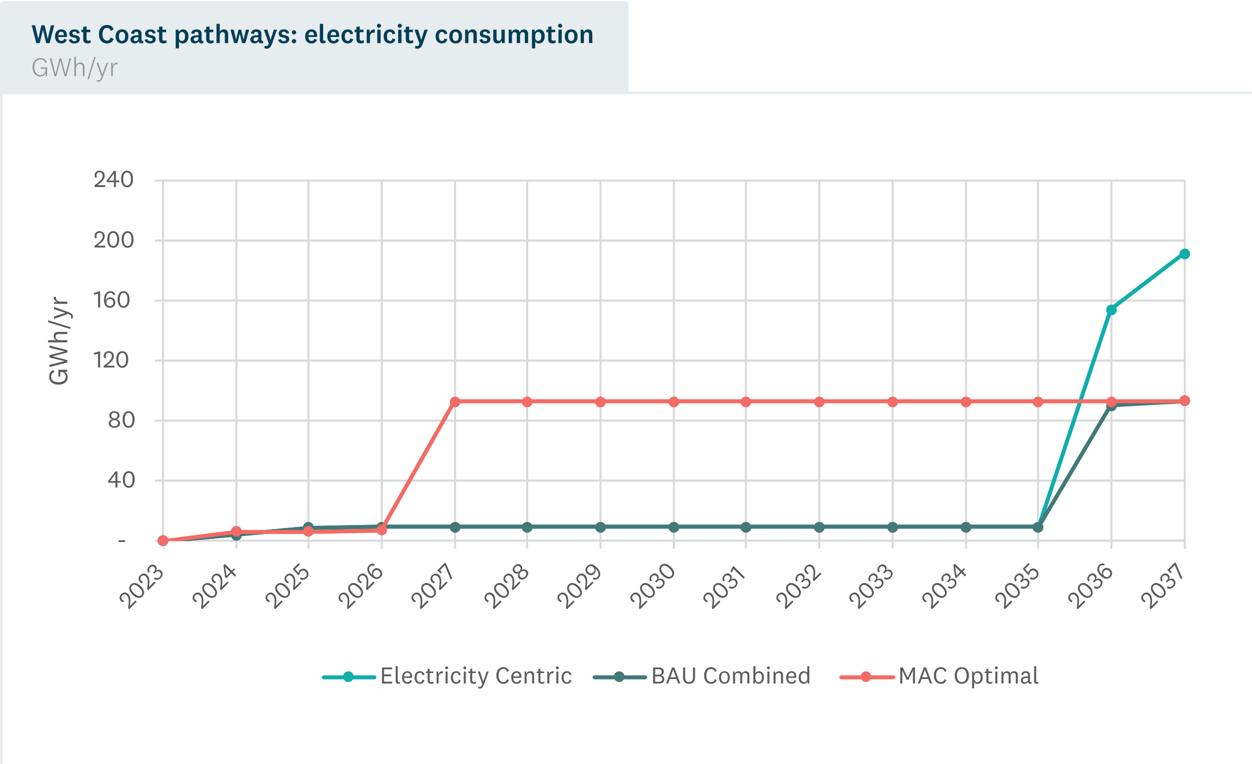
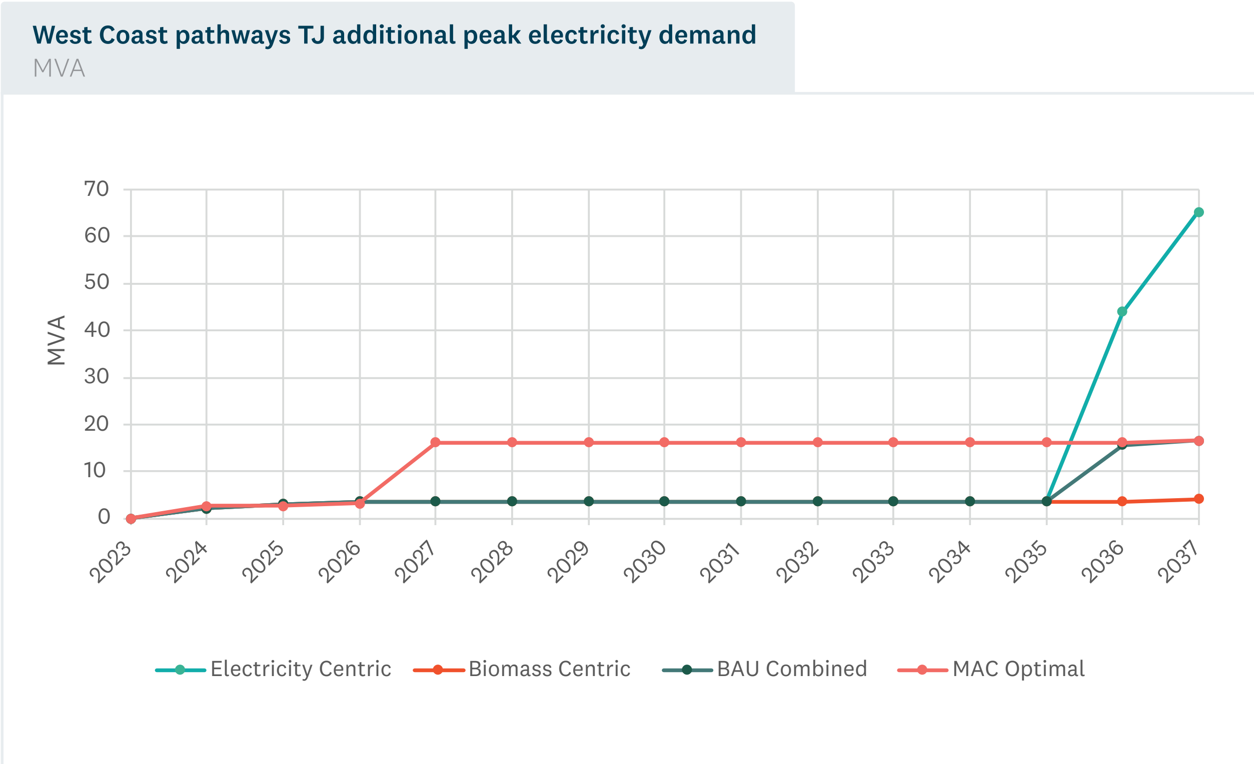


Figure 50 reinforces that the use of MACs to simulate decision making accelerates electrification projects – particularly Westland Milk (stage 1) to 2027. In an Electricity Centric world, electricity consumption on the West Coast would grow by around 65% compared today, although not until 2036. Under the MAC Optimal and BAU Combined worlds, consumption would only grow by 30%. The majority of this growth would, again, not be observed until 2036 in the BAU Combined pathway, but would be realised in 2027 in a MAC Optimal pathway.

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 51 illustrates the potential increase in peak demand, for each pathway. This is determined by adding together the maximum demand from each boiler, without taking account of demand diversity (as outlined in Section 8.4).

Figure 51 – Potential peak demand growth under different pathways



Included in Figure 51, for completeness, is the electricity demand that would result from the Biomass Centric pathway. These represent the electrification projects that have either already been confirmed, or those where electricity is the only option (e.g. heat pump projects).

The difference between the scenarios through time – which reflects the degree of uncertainty faced by network planners – is quite significant. At any point in time, the additional peak demand from the electrified boilers could vary from 16MW as early as 2027 (if a MAC Optimal world eventuates) to 65MW, but not until 2036 (in an Electricity Centric pathway).

That said, we reinforce these contributions to peak network demand are upper bounds (in each pathway), as they assume that all electrified boilers reach their maximum consumption at the same time of day and time of year (i.e. coincident peak demand). This is a conservative assessment, as there is likely to be a diversity amongst peak demands as outlined in Section 8.4; as well as commercial incentives to shift this peak demand away from the time the wider network peaks. Hence the impact of flexibility and diversity on capacity upgrades depends on a range of factors that need to be considered more fully.

9.3.1.1 EDB analysis

The implications of these peak demand growth scenarios will be different for each of the distribution network companies, as their existing networks have different levels of spare capacity (as outlined above).

Section 8.3 highlighted that there can be material differences between adjacent networks in terms of unused capacity; these differences exist for a range of historical reasons. This can lead to quite different relative connection costs for projects connection in each region. While we showed the variability in individual connection costs in Figure 37, Table 16 shows how the connections potentially affect each EDB's network.

Table 16 – 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)
Westpower	62	$33.8	16	$1.6
Buller Electricity	3	$0.5	0.6	$-
Total	**65**	**$34.3**	**16.6**	**$1.6**

Table 16 shows that Westpower will experience the largest increase in process heat-related electricity demand, irrespective of whether the Electricity Centric or MAC Optimal pathway results. The connection cost estimates suggest that between $3M-$46M will be spent by process heat organisations and EDBs[127] connecting their new plant to the local networks, depending on the pathway.

[127] These are the costs described in Section 8.3.4 Note that the sharing of this capital cost between process heat users and EDBs depends on the capital contributions made by EDBs, as outlined earlier.

9.3.2 Implications for biomass demand

Figure 52 shows the growth in biomass demand (in both tonnes and TJ per annum) arising from each of the pathways. The MAC Optimal and BAU Combined pathways result in less than half the final demand from the Biomass Centric pathway.

Figure 52 – Growth in biomass demand from pathways. Source: EECA

We can also see that the estimated volumes of unutilised harvesting and processor residues (after existing bioenergy demands are removed[128]) are sufficient to meet the biomass demand under the MAC Optimal and BAU Combined pathways. This is shown as the lower dashed line in Figure 52. Note that the assessment of these resources is based on a more conservative estimate of recoverable volumes, as outlined in Section 7.5.2.

The Biomass Centric pathway would require additional resources beyond residues. The higher dashed line adds potential biomass from minor species, which would allow the final energy demand from a Biomass Centric pathway to be met, albeit at a higher cost.

[128] See Section 7.5.

9.4 Sensitivity analysis

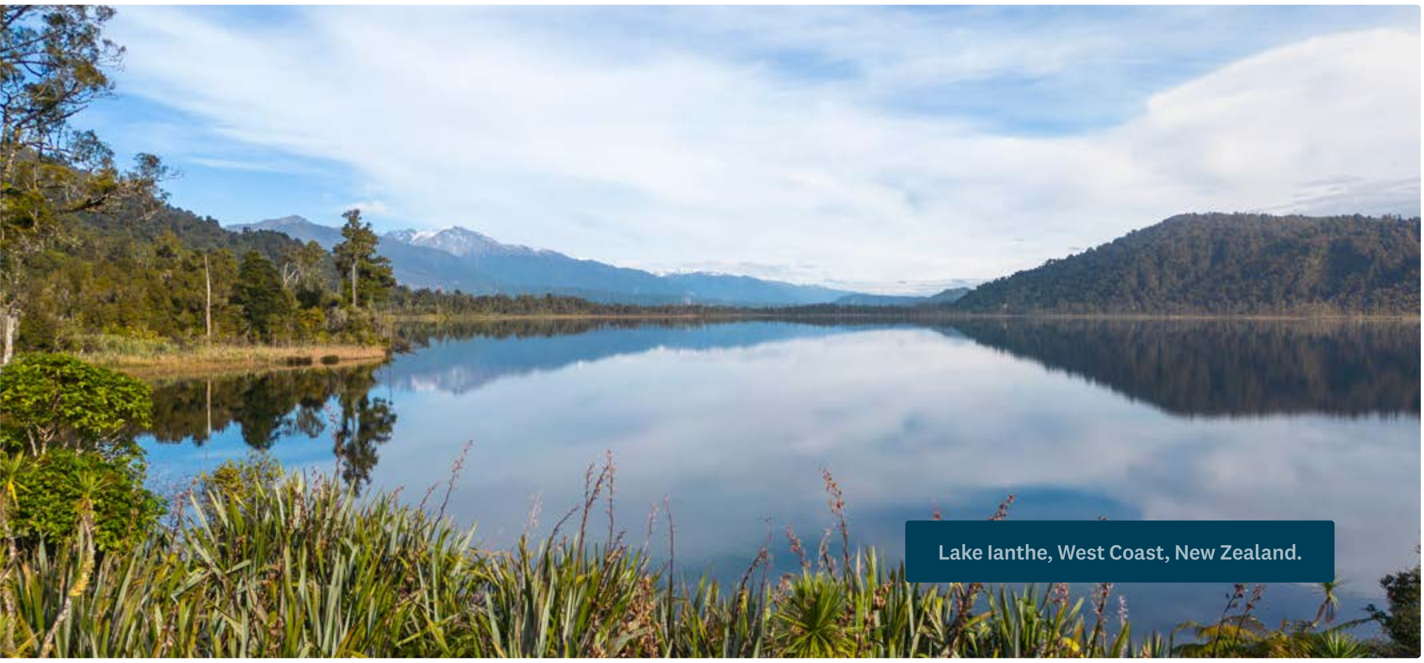
EECA acknowledges that there are a range of factors which determine each organisation's final decision on fuel switching. The net present value (NPV) of a project (at the expected carbon price) is only one factor, albeit an important one for owners and shareholders. However, capital constraints, competing priorities, risk appetite, uncertainty about future costs, 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 (electricity and biomass). Electricity has a combination of fixed (per-annum use-of-network charges) and variable costs.
- The uncertainty regarding the magnitude of up-front upgrade costs required to connect an individual RETA site to the electricity network (including the degree to which flexibility in plant consumption could reduce these costs).
- 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 variability in underlying costs is to look at how close the MAC values for the competing fuels.

For the seven RETA sites where the fuel switching decision is still unconfirmed, and both electricity and biomass is being considered, Figure 53 shows that three out of the eight projects have differences between electricity and biomass MAC values of over $300/t. It would take a considerable change in underlying costs to change the optimal fuel decision.



Lake Ianthe, West Coast, New Zealand.

Figure 53 – Difference between electricity MAC value and biomass MAC value; sites that are considering both options. Source: EECA.

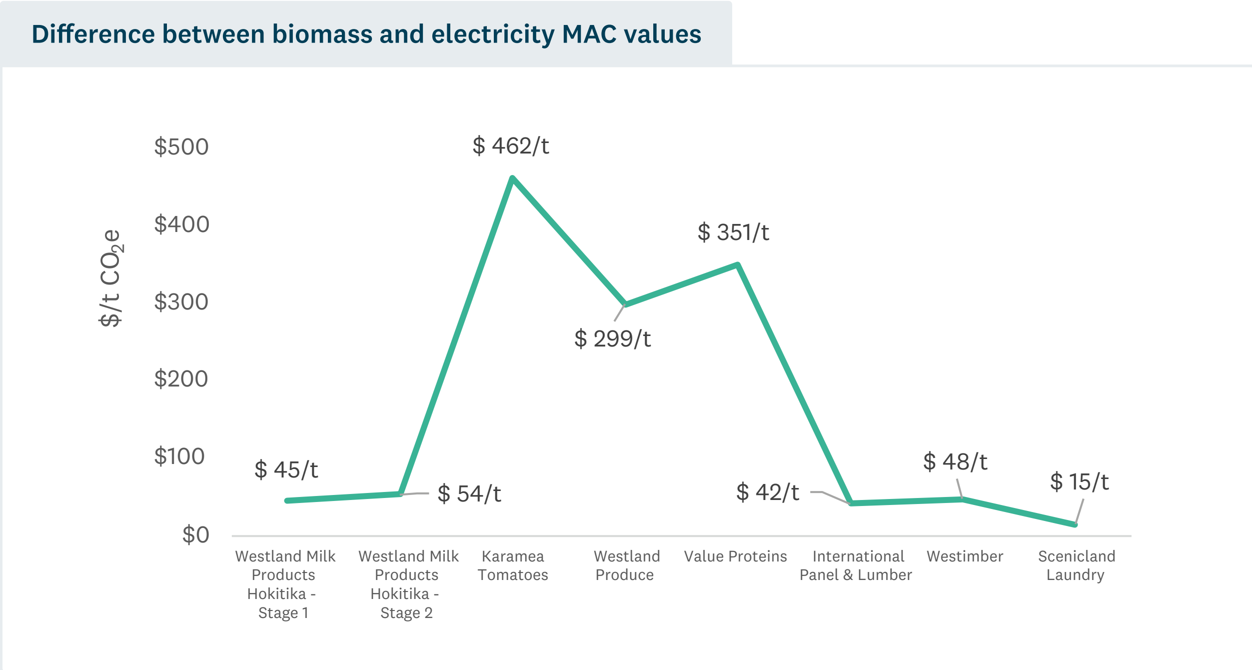


Figure 53 shows there are six projects where the difference in MAC values is less than $60/t. For these projects, plausible deviations from EECA's input estimates used in this analysis could change the decision. To illustrate the sensitivity of these MAC values for the eight projects in Figure 53:

- A 20% change in up-front capital costs (including network upgrade costs) for either electricity or biomass can change the MAC value of fuel by around $21/tCO₂e on average (7% of the average MAC value), and up to $76/tCO₂e for one project.
- A change the incremental[129] operating costs (including fuel procurement) of 20% could change the MAC value by $32/tCO₂e on average (13% of the average MAC value), and up to $121/tCO₂e for one project.

Hence it is plausible that these changes could alter the relativities of the two fuels, and therefore the fuel switching choice. Even if the fuel switching decision didn't change, the change in MAC could accelerate or delay the timing of the fuel switch, in the MAC Optimal pathway.

These illustrative changes also highlight that, all things being equal, changes in the lifetime OPEX of a fuel switching investment has around twice the impact on the MAC value as the upfront CAPEX. While the CAPEX component requires the greatest focus in terms of the funding and financing of the investment, it is the cost of fuel over the 20-year lifetime of the decision that dominates the economics.

Beyond up-front capital and ongoing fuel prices, there are a range of other factors which may change the MAC value and therefore the decisions made by process heat users. For example, a restriction in the availability of sustainable biomass may arise, meaning organisations who commit to decarbonisation late in the RETA period are only able to electrify.

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

To test the impact of potential changes on the pathways, EECA undertook the following four sensitivities:

- Amending the MAC Optimal pathway to include acceleration co-funding from the GIDI fund. GIDI co-funding has been applied to projects in a consistent manner.
- The use of Energylink's 'low' price scenario, from Section 8.2.2.1, to determine the price of electricity.
- Allowing for a greater quantity of harvesting residues to be economically recoverable than assumed in our analysis.
- Amending the decision criteria for the timing of a decarbonisation investment, from when the average of the 10-year carbon price forecast exceeds the MAC, to when the current year carbon price exceeds the MAC (as discussed in Section 9.1.2).

Below we discuss these sensitivities.

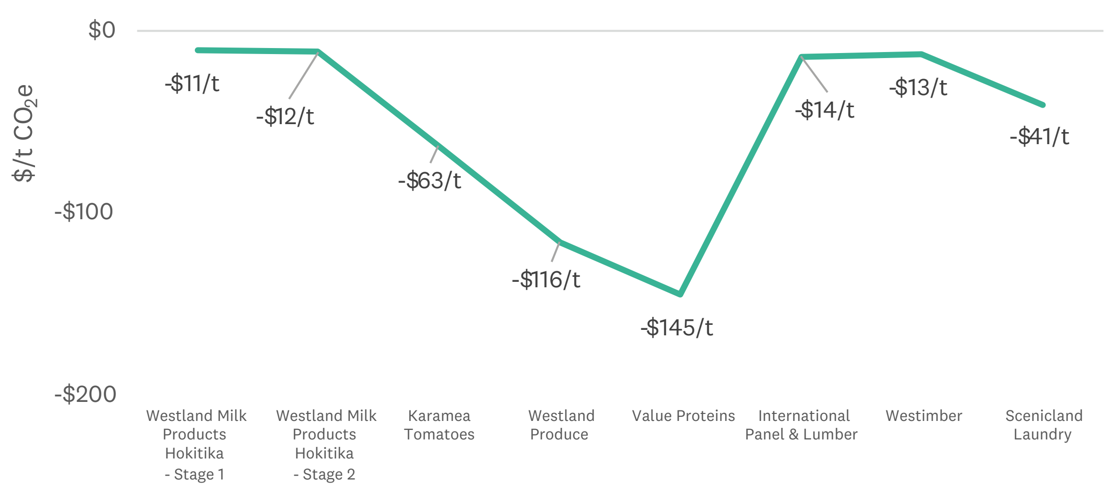
An additional model of optimal decisions was conducted using TIMES-NZ. TIMES-NZ is an optimisation model of the whole energy system (in this case, just the West Coast region) and is thus able to optimise individual process heat user decisions based on available biomass and electricity supply and costs. This is a slightly different approach to our MAC-based analysis.

9.4.1 Acceleration co-funding

For the eight fuel switching projects that are unconfirmed, the impact of a simulated government GIDI co-funding, applied in a consistent manner to each project, is to lower the MAC value. The impact of cofounding is different for each project, as shown in Figure 54.

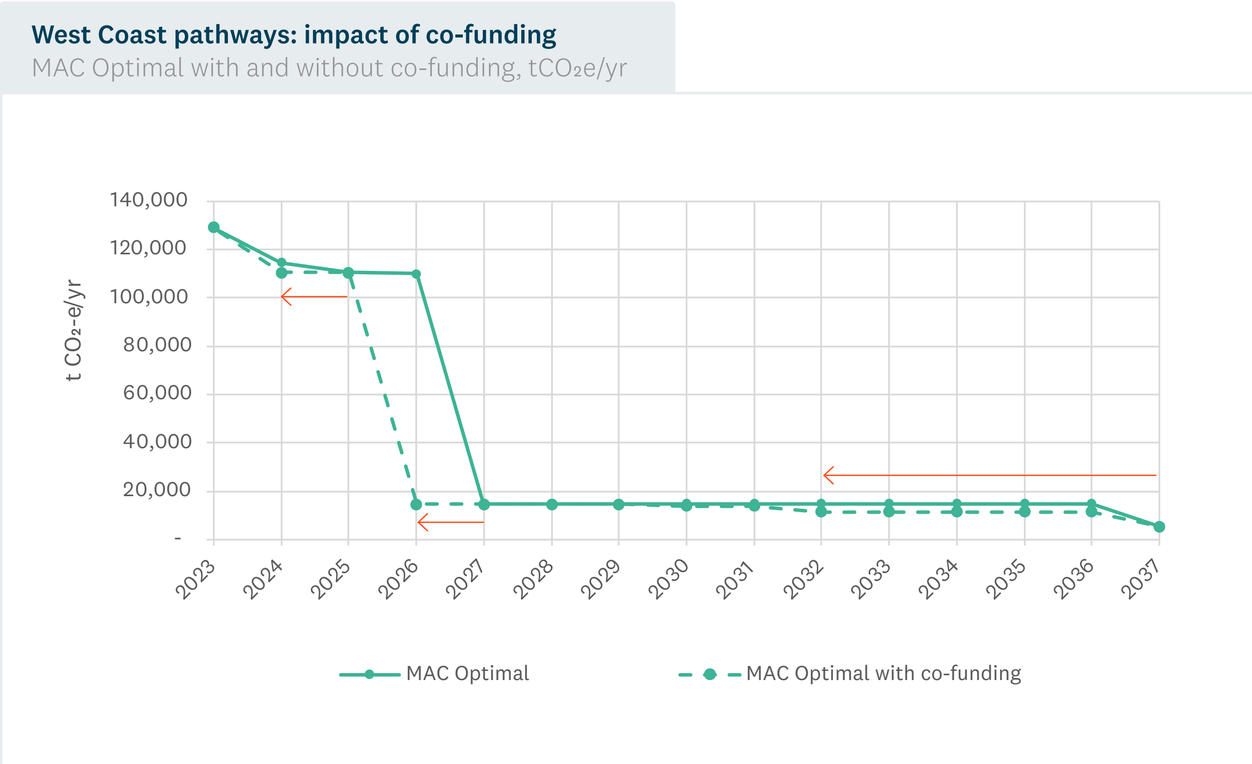
Figure 54 – Impact of government co-funding on fuel switching MAC values

Impact of government co-funding on optimal MAC values



While the co-funding changed the MAC value, it did not change the optimal fuel decision. It did, however, accelerate the timing of some projects (to 2024, 2026 and 2032, indicated by the red arrows), as the lower MAC value resulted in an earlier decision being optimal. This is illustrated in Figure 55.

Figure 55 – Range of MAC values and cumulative emissions reductions with co-funding – fuel switching only. Source: EECA



MACs are only one measure of how a process heat organisation will make a decision with respect to the timing of its decarbonisation investment – the degree to which, over the long term, the investment will lead to a better outcome for the business. But the investments contemplated in Figure 55 involve significant up-front funding requirements. While many businesses have access to the commercial financing products needed to fund decarbonisation projects, most have constraints on the amount they can borrow from these sources, leading to competition for limited pools of internal capital. Decarbonisation projects are often deprioritised due to less attractive internal rates of return than other projects, or because decarbonisation is considered a lower priority than, for example regulatory compliance, or investing in expanded production.

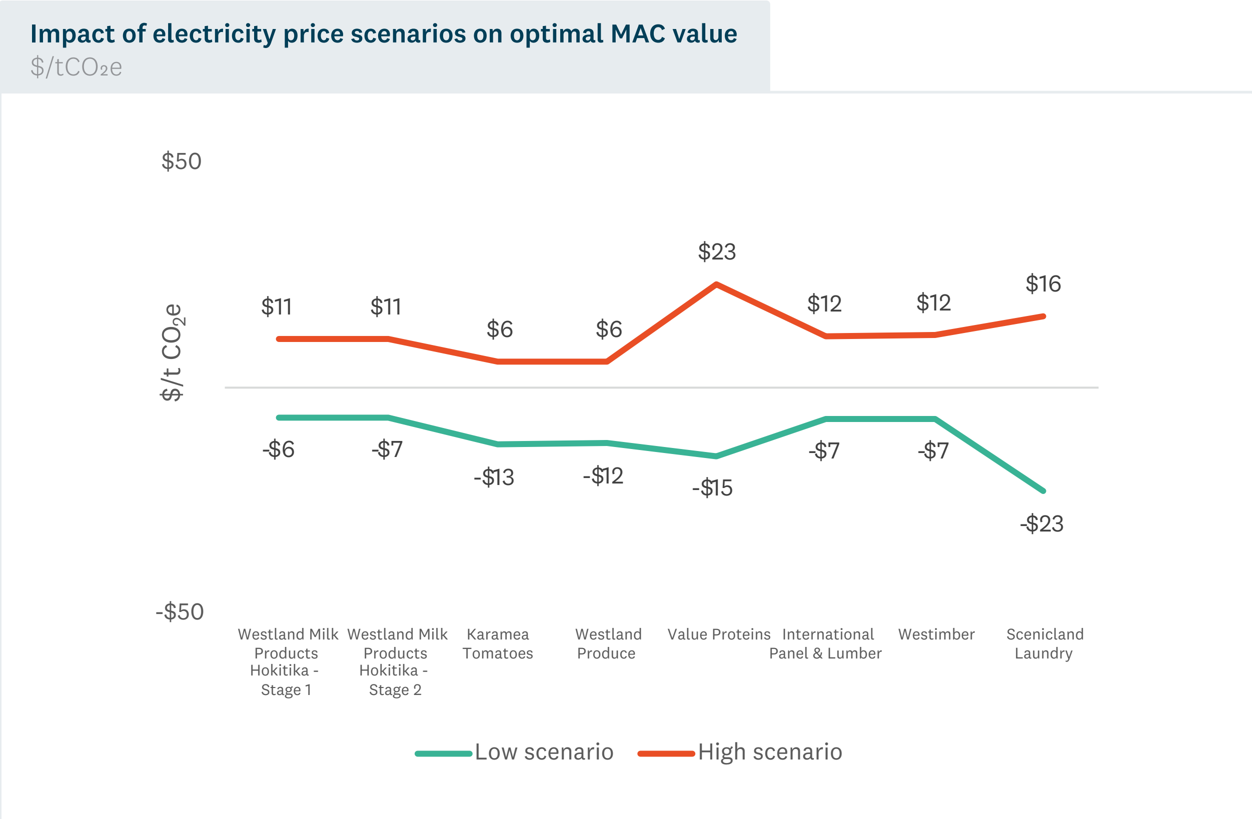
Hence the impact of co-funding on MACs alone only tells part of the story. The presence of decarbonisation co-funding may also overcome these wider constraints, even if it has a relatively small effect on the project's economics. Even projects that appear to be economically efficient may not occur (or not occur quickly enough) without an injection of government support.

9.4.2 Lower electricity prices

As highlighted by Energylink (and discussed in Section 8.2.2.1), there are a range of factors that could lead to electricity prices that are materially different to its 'central' scenario used for the analysis in this chapter.

Adopting Energylink's 'high' or 'low' scenario changed the MAC value by a modest amount, as shown in Figure 56.

Figure 56 – Impact of Energylink's electricity price 'low scenario' on MAC values



Neither electricity pricing scenario was material enough to change the timing or optimal fuel for each project. The relatively small effect is largely due to the use of a market-based retail tariff that was lower than EnergyLink's price forecast, for number of projects, in the first 10 years of the project. Hence a sensitivity analysis that used a different EnergyLink scenario only changed the second 10-year period of the MAC calculation. The impact of this latter period on the MAC value will be significantly muted by present-value discounting.

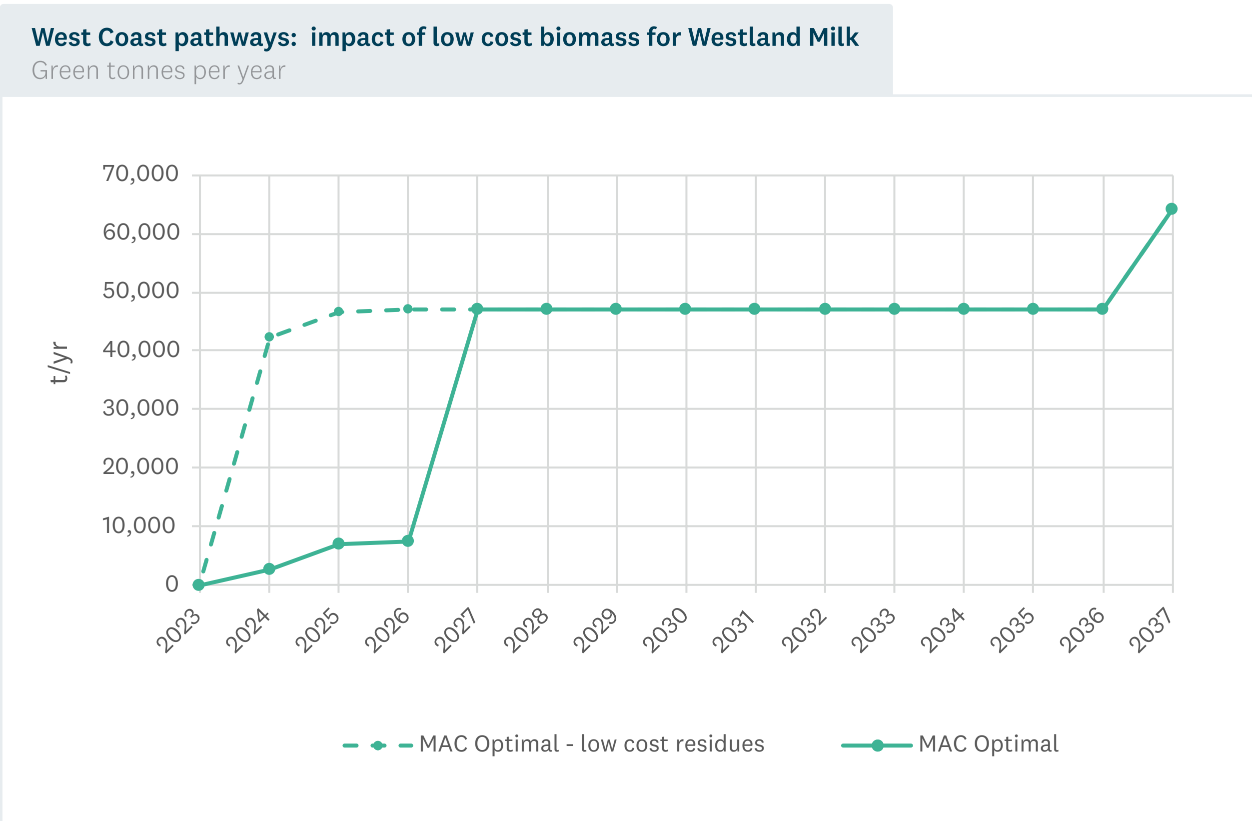
9.4.3 Large boiler conversion to biomass and limitation on resources

In Section 7.6 we presented the overall availability of woody biomass as a boiler fuel in the West Coast. While a WAF-based assessment of harvesting and processing residues suggested there was nearly enough residues to meet the demand from all sites switching to biomass, we adopted a more conservative forecast of residue availability, based on pragmatic factors. As a result, large sites paid a higher price for biomass once the lower-cost residues were fully utilised (in accordance with the supply curves presented in Section 7.7.2).

In this sensitivity, we adopt an ambitious scenario where readily available biomass, costing \$21/GJ[130], can supply the entire market. In a Biomass Centric scenario, this would require 150,000t of residues or, for example, minor species at that low cost.

These revised costs of biomass reduce the MAC values for Westland Milk by \$23/tCO_2e, because, in the base case, only Westland Milk faced the higher priced resources. While these lower costs did not change any decision between electricity or biomass, it did accelerate Westland Milk's investment in biomass for Stage 2 by three years, seeing it implemented in 2024, resulting in a reduction in cumulative long-lived greenhouse gas emissions of nearly 270,000tCO_2e.

Figure 57 – Low cost biomass pathway vs MAC Optimal

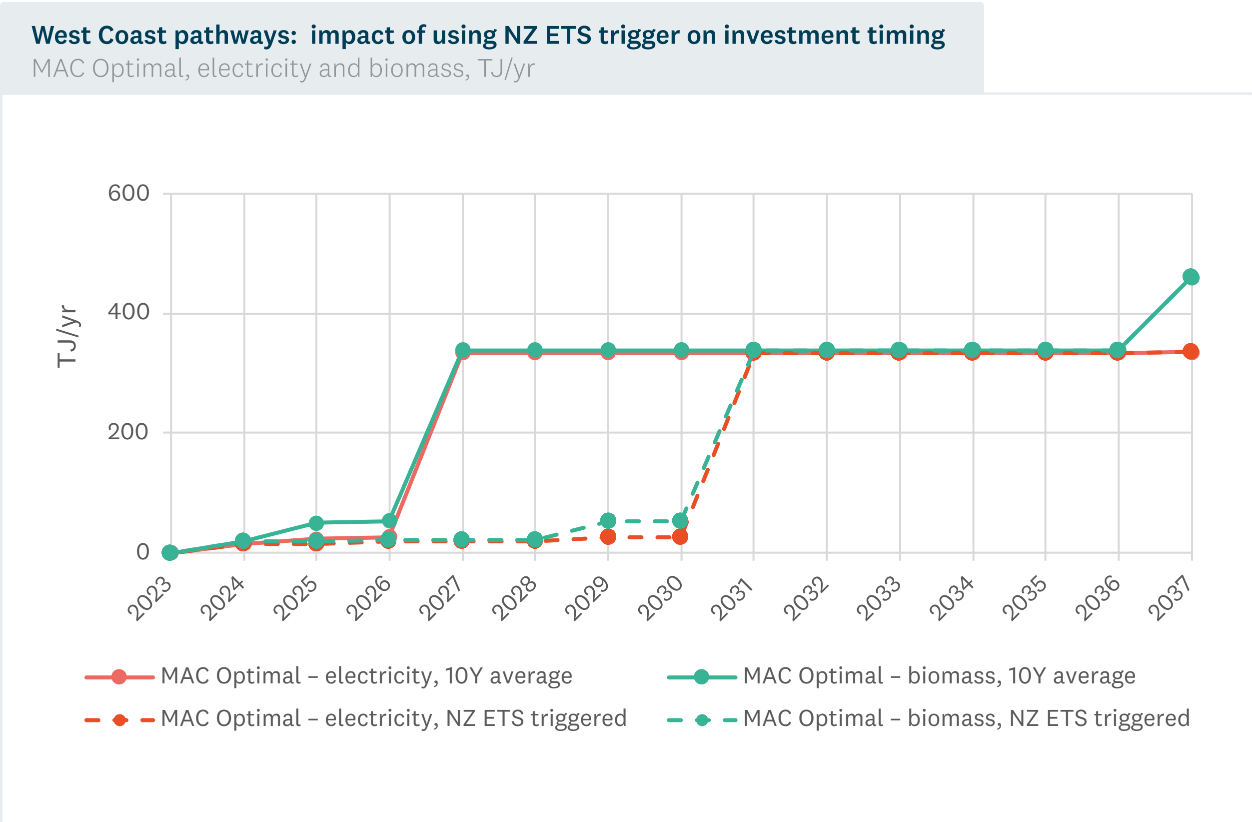


[130] Delivered to a process heat user; for Westland Milk, the price is \$18.50/GJ, as the secondary transport from the hub to the process heat user is not required, since Westland Milk is assumed to be the hub.

9.4.4 Amending the decision criteria for investment timing

This sensitivity compared the demand for biomass and electricity under two decision making criteria – the 10-year future average carbon price (used for the MAC Optimal pathways above) versus simply waiting for the present-day carbon price to exceed the MAC value of the project.

Figure 58 – Comparing MAC-based decision making criteria



The 'current year' criterium leads to approximately 4-year delays in a number of projects. This is a result of the CCC's carbon price scenario increasing through time; hence a forward-looking 10-year average will always be higher than the present day carbon price, and will thus trigger investments earlier (all other things being equal).

10 Insights and recommendations

The RETA 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.

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

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

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

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

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

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

A 'whole-of-system' perspective would go further than this RETA to incorporate other sectors. The transport[131] sector will, in all likelihood, 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 a RETA more complex, but more insightful in identifying system challenges and solutions.

[131] The analysis presented in Section 8.3 included some proposed public charging infrastructure for electric vehicles.

10.1 Biomass – insights and recommendations

The analysis above shows that comprehensive extraction and conversion of estimated processor and harvesting residues (after the deduction of the existing consumption of these residues) has the potential to supply 100% of the MAC Optimal pathway biomass demand and 65% of the Biomass Centric demand. If more process heat users switch to biomass than predicted by the MAC Optimal pathway, additional biomass (e.g. minor species) will need to be harvested at some point over the period, likely triggered by Westland Milk fuel switching decisions.

Cutover residues may be more complex and more expensive to recover than modelled here, although we have used a pragmatic assessment based on expert opinion. We addressed a more optimistic view with our sensitivity analysis, and this led to an acceleration of decarbonisation.

Our analysis suggests there are likely to be at least 11 process heat users seeking biomass as a fuel (including confirmed fuel switching projects). There needs to be a high degree of coordination between these organisations and the major forestry company (Ngāi Tahu) to ensure all parties – on the supply side and demand side – have the confidence to extract, process and consume residue-based biomass as a long-term option. There are a number of opportunities to increase this coordination and confidence, including:

- More analysis – and potentially pilots – are required to understand costs, volumes, energy content (given the potential susceptibility of these residues to high moisture levels) and methods of recovering cutover residues.
- In tandem, work should be undertaken with forest owners to understand the logistics, space and equipment required for harvesting residues.
- Where forestry companies outside the region are recovering, storing and using harvesting residues for bioenergy, these can be used as exemplars and case studies for other regions to learn.
- 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[132] and greater transparency about (anonymised) prices and volumes being offered or traded.
- 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.

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

10.2 Electricity – insights and recommendations

Electricity has a more established delivery infrastructure, and a vibrant 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. 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 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.

As noted above, EDBs on the West Coast also own some of the grid-level supply infrastructure, which reinforces how critical EDBs are to coordinating the assessment of overall network capacity and any resulting need for investment.

10.2.1 The role we need EDBs to play

Given the pace of change, EDBs need to proactively engage with process heat users to:

- Stay abreast of process heat users' intentions regarding timing of electrification decisions. This will enable EDBs to accommodate their intentions in their network plans and make efficient use of network resources.
- 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.

A related opportunity is for the network companies to provide a stronger coordinating function for each region's large electrification initiatives.

10.2.2 Information process heat organisations need to seek from EDBs and (where relevant) Transpower

- **What their likely electricity consumption means for network upgrades.** The screening-level estimates provided in Section 8 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.
- More specifically, if the largest process heat users are contemplating significant electrification, EDBs, **Transpower and these users need to work collaboratively to understand the implications for the grid.** These implications include the network security requirements of the process heat users and the region; the potential impacts of increased peak electricity demand on the key transmission lines serving the region; and what role investment in new local generation (e.g. hydro) could play in reducing the need for costly grid upgrades.

- **The risks and cost trade-offs of remaining on N security relative to N-1 (or N-0.X if available).** The EDB 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.
- **A clear process, timeframes and information required for obtaining network connection[133].** 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).
- **Network charges and network loss factors relevant to their connection location.** As outlined in Section 8, we have estimated an average level of network charges across the three EDBs involved in this West Coast RETA, but the network charges for any individual process heat customer will depend on their particular location.
- **How flexibility in their electricity consumption and/or the level of network security they desire could impact the cost of connecting them to the networ**k. 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, e.g. through:**
  - Early and bulk procurement of critical long lead time equipment (items such as transformers, switchboards, cable, conductors etc).
  - Consideration of expedited delivery (often suppliers will expedite for a premium or offer air freight options.
  - Paralleling design and build activities where possible to reduce durations.
  - 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 they offer which lock on a fixed set of prices over multiple years.** This avoids process heat organisations being exposed to unexpected price rises.
- **What tariffs they are offering 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.

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

10.2.4 Information that process heat users need to provide retailers, EDBs and (where relevant) Transpower

In order 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.

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

This RETA 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 UK) 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.

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.

Practically speaking, this means that process heat users who are considering electrification should take into account:

- If there is flexibility in network security, process heat users should consider the degree to which their own loads could be modified (e.g. time-shifted through use of hot water storage) in order to accommodate network constraints, and/or quickly interrupted in the event a failure of a network component occurred.
- In principle, there are potentially significant benefits in having flexibility in their electricity demand (e.g. through maintaining a backup fuel/boiler system) that can respond to extended periods of electricity market stress (e.g. resulting from prolonged periods of low hydro inflows, sunshine or wind). That said, there are a number of logistical matters that would have to be considered to implement this, which EECA has not analysed.

- 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[134].

10.3 Pathways – insights and recommendations

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

While 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:

- Some pathways saw sufficient growth in the next five years that could result in progress being slowed by supply availability (biomass resources or network capacity). Given the likely lead times of bringing new biomass resources 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, appears scant. Ministries such as **Ministry for the Environment need to work with reputable organisations to develop scenario-based forecasts of future carbon prices that decarbonising organisations can incorporate into their business cases.**
- The pathways also demonstrated how government co-funding could potentially accelerate decarbonisation of the West Coast process heat. **EECA encourage process heat users to enquire about government co-funding where the economics of decarbonisation are challenging; where they are economic, EECA encourages organisations to explore the potential for acceleration.**

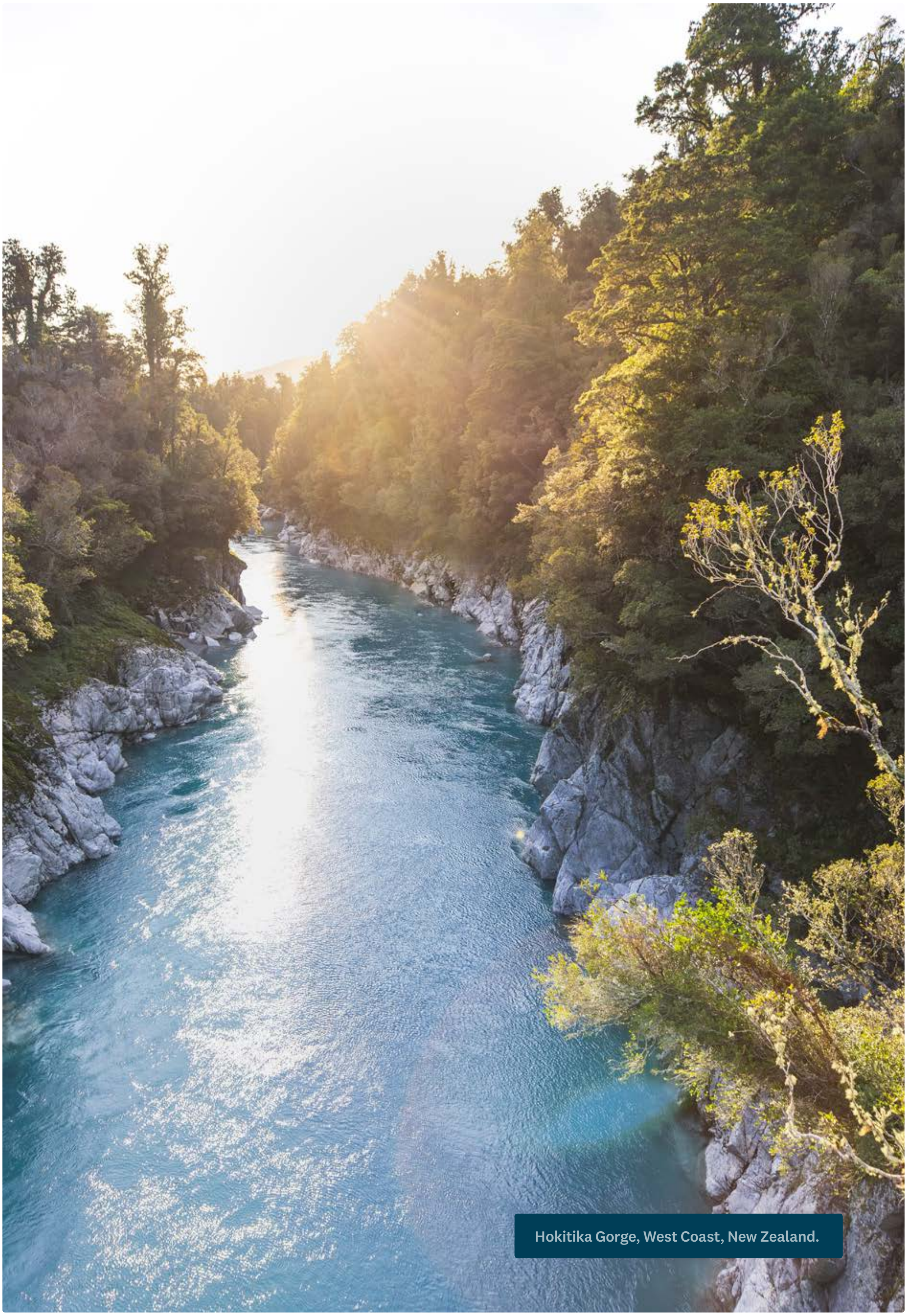
Other than public EV charging infrastructure, the pathways do not incorporate the potential for the growth in bioenergy and electricity for transport to compete with process heat. EECA will continue to develop the analysis to incorporate this in future analyses.

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

10.4 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.**
- **Work should be undertaken with forest owners to understand the logistics, space and equipment required for harvesting residues.**
- **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 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.**
- **EDBs should proactively engage with process heat users 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 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 should share sufficient information about network demand to help process heat users determine whether they can limit the extent to which they increase peak demand on the network, and the nature of network security standards.**
- **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 expand future iterations of regional analyses to include transport as a decarbonising decision that will compete for electrical network capacity and biomass.**
- **Ministries (such as the 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.**
- **Process heat users should enquire about government co-funding where the economics of decarbonisation are challenging; where they are economic, EECA encourages organisations to explore the potential for self-funded acceleration.**



Hokitika Gorge, West Coast, New Zealand.

11 Appendix: Worked Transmission Pricing Methodology (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. As such, this has not been reviewed, or endorsed by Transpower.

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, connection charges (CC), benefit-based charges (BBC), and residual charges (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'.

11.1.1 Connection charges

The grid exit point (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 demand 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.[135] 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 20.

Table 17 – 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 21.

Table 18 – 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

[135] The network's AMD can be different to the sum of customers AMD as customer's AMD can occur at different times.

11.1.2 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 TPM Appendix A.

The investments and allocations that apply for the GXP are given in Table 22.

Table 19 – BBI projects and allocations for the GXP

BBI	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 recovered costs of the above projects then the benefit-based 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 Electricity 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 five years of data lagged by 1-2 years. In this case we assume n[136]-4 to n-2 inclusive, the years 2018 to 2021 inclusive. 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 23.

Table 20 – Worst case BBC allocation to the process heat user

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
Allocation	16.5%	16.0%	15.7%	15.3%	15.1%	14.8%	14.5%	14.3%	14.0%
Process heat user BBC	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M

Appendix A BBIs are fixed allocations but do change for adjustments made for new customers, exiting customers, and substantial changes in consumption (amongst other things). 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 have to be reduced by a factor to keep the adjustment revenue neutral.

136 Here, n refers to the current year.

The customer's allocation is increased based on Transpower's assessment of what the new plant's consumption would have been over this period if it were fully operational. As the new electrode boiler is going to increase the consumption at the GXP by 138 GWh and the 2014-2017 average consumption is 452 GWh, 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 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. Once connected, if the new boiler's consumption proves to be more than 25% higher than used in allocation of charges, 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 24.

Table 21 – BBC for the process heat user with electrode boiler

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
Process heat user BBC	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M
+ boilers	$0.325M	$0.325M	$0.325M	$0.325M	$0.325M	$0.325M	$0.325M	$0.325M	$0.325M
Total	$0.500M	$0.500M	$0.500M	$0.500M	$0.500M	$0.500M	$0.500M	$0.500M	$0.500M

We have seen above that the addition of other new connections, unless very large or there are a large number, can make little difference to BBC.

To illustrate how new BBIs might affect the process heat user's charges we take the example of a potential upgrade of the HVDC (say a fourth cable across the Cook Strait). If this project were to cost $80M, which gives a very approximate $5M in additional costs per annum, and the benefits flowed through as per the TPM Appendix A HVDC allocations, then the process heat user would attract a further $25k each year in BBC.

11.1.3 Residual charges

Residual charges are currently 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 $AMDR_{baseline}$[137] is different to the one that applies for CC. However, we will assume the same allocation factor for AMD applies for the $AMDR_{baseline}$, i.e. that the process heat user will get 16.5% of the RC. If we assume there is no significant difference in total EDB consumption, then there will be no significant difference in the allocation of RC to the process heat user. In practice, this will depend on many factors including changes in consumption within the GXP network and elsewhere. This gives RC for the process heat user as shown in Table 25.

Table 22 – 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 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 26.

Table 23 – 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.

[137] Anytime Maximum Demand for Residual Charges baseline.

11.1.4 Summary of charges

Table 27 summarises the outputs of Table 20, Table 23, and Table 25 to give the forecast allocation of transmission charges to the process heat user without the proposed electrode boiler.

Table 24 – Forecast allocation of transmission charges to the process heat user

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
CC	$0.08M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.07M	$0.06M
BBC	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M	$0.175M
RC	$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 28 summarises the outputs of Table 21, Table 24, and Table 26 to give the forecast allocation of transmission charges to the process heat user with the proposed electrode boiler.

Table 25 – Forecast allocation of charges to the process heat user with boiler

MW	2023	2024	2025	2026	2027	2028	2029	2030	2031
CC	$0.14M	$0.14M	$0.14M	$0.14M	$0.13M	$0.13M	$0.13M	$0.13M	$0.13M
BBC	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M
RC	$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 28 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.


Porter's Pass, Canterbury, New Zealand.

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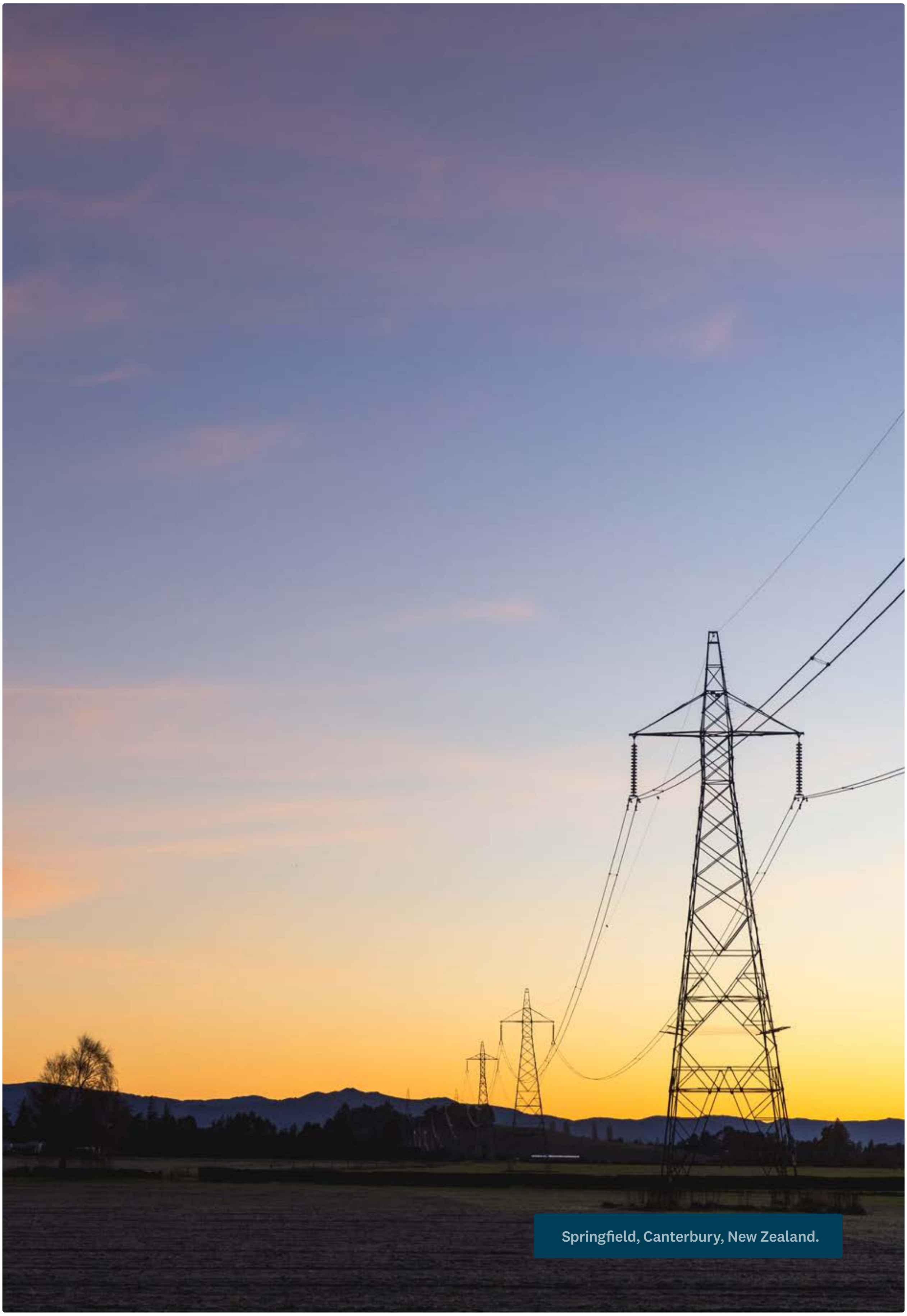

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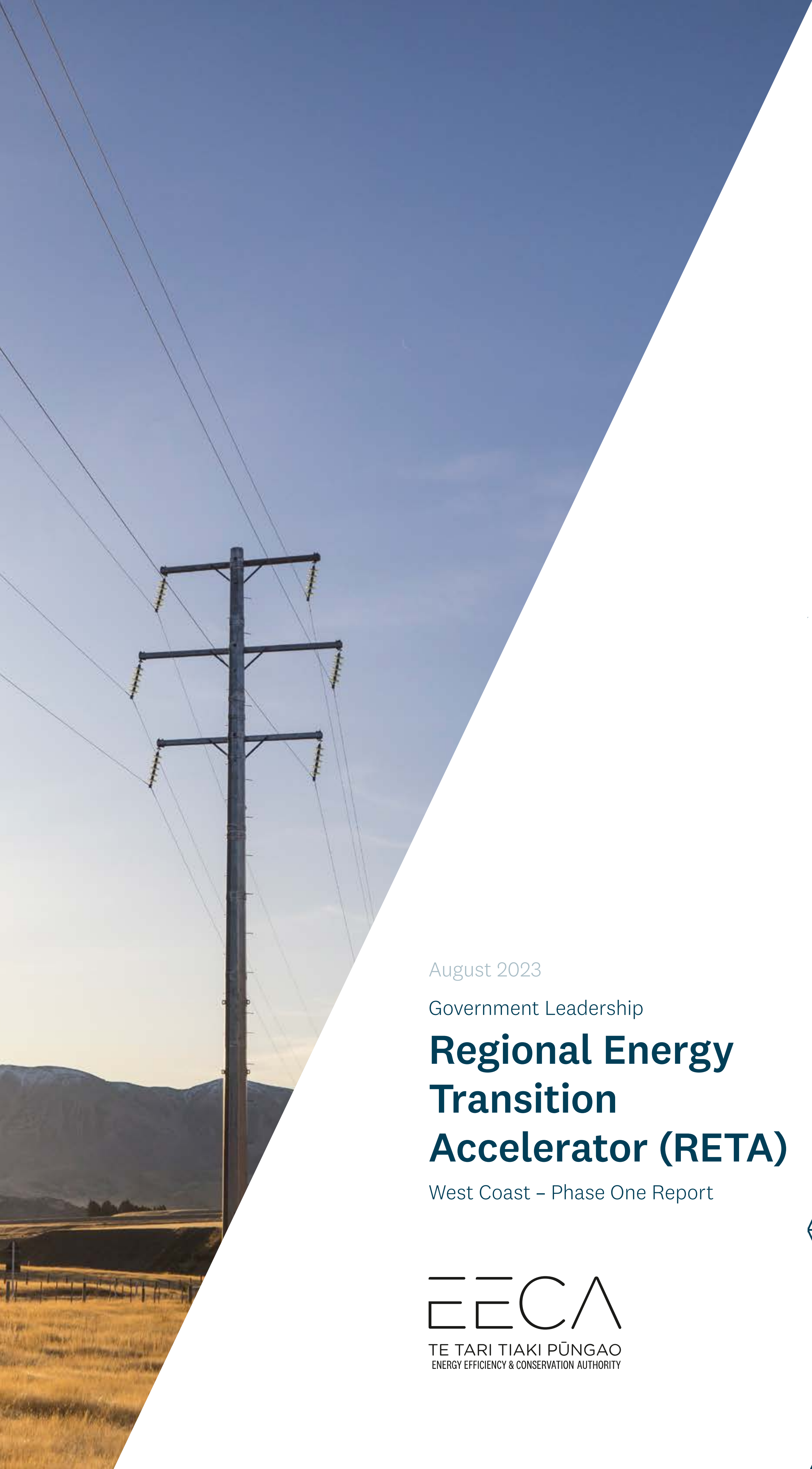

August 2023

Government Leadership

Regional Energy Transition Accelerator (RETA)

West Coast – Phase One Report

EECA
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ENERGY EFFICIENCY & CONSERVATION AUTHORITY