Government Leadership

Regional Energy Transition Accelerator (RETA)

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

- Process heat users throughout 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 our partners:

- **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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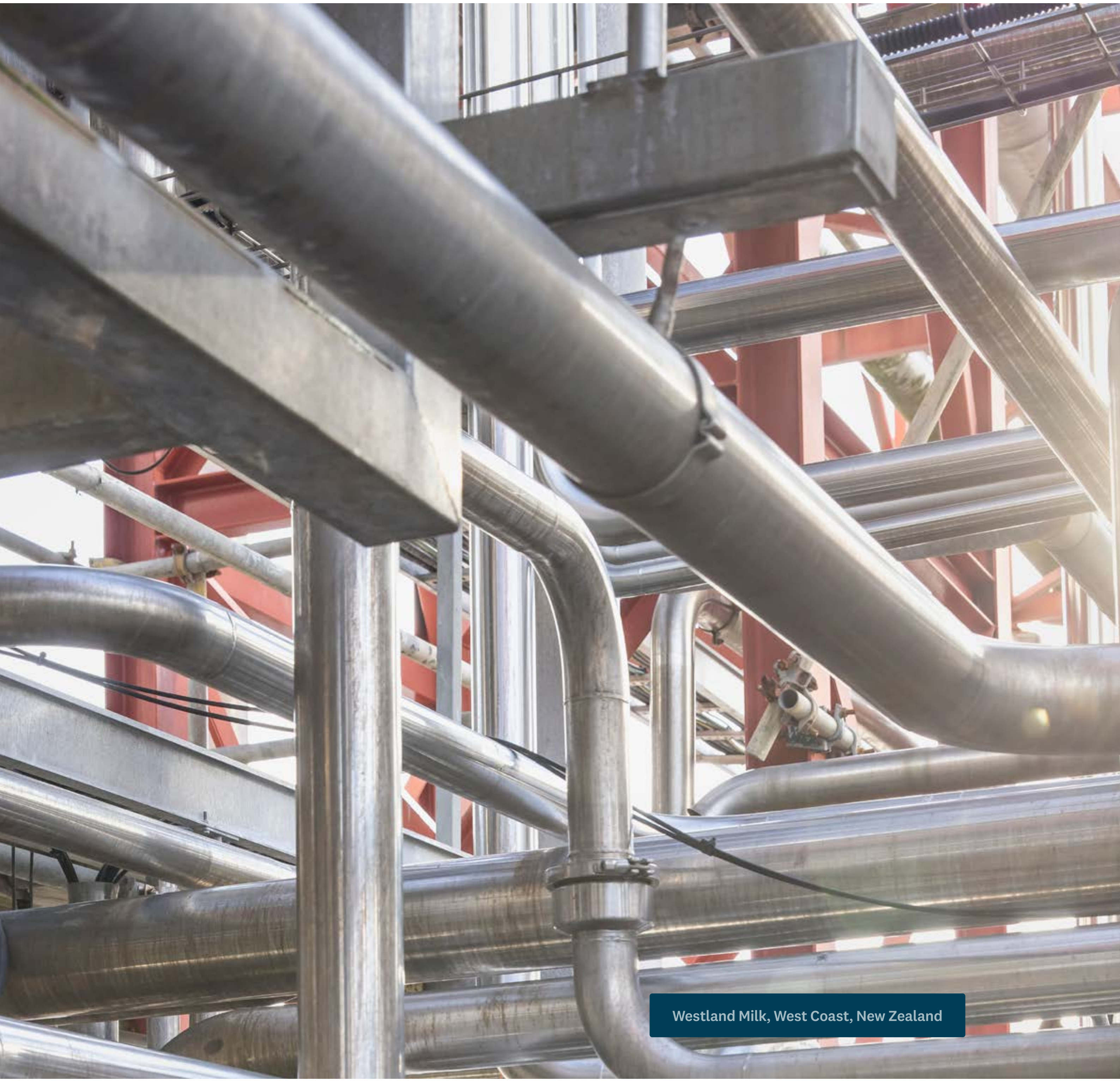
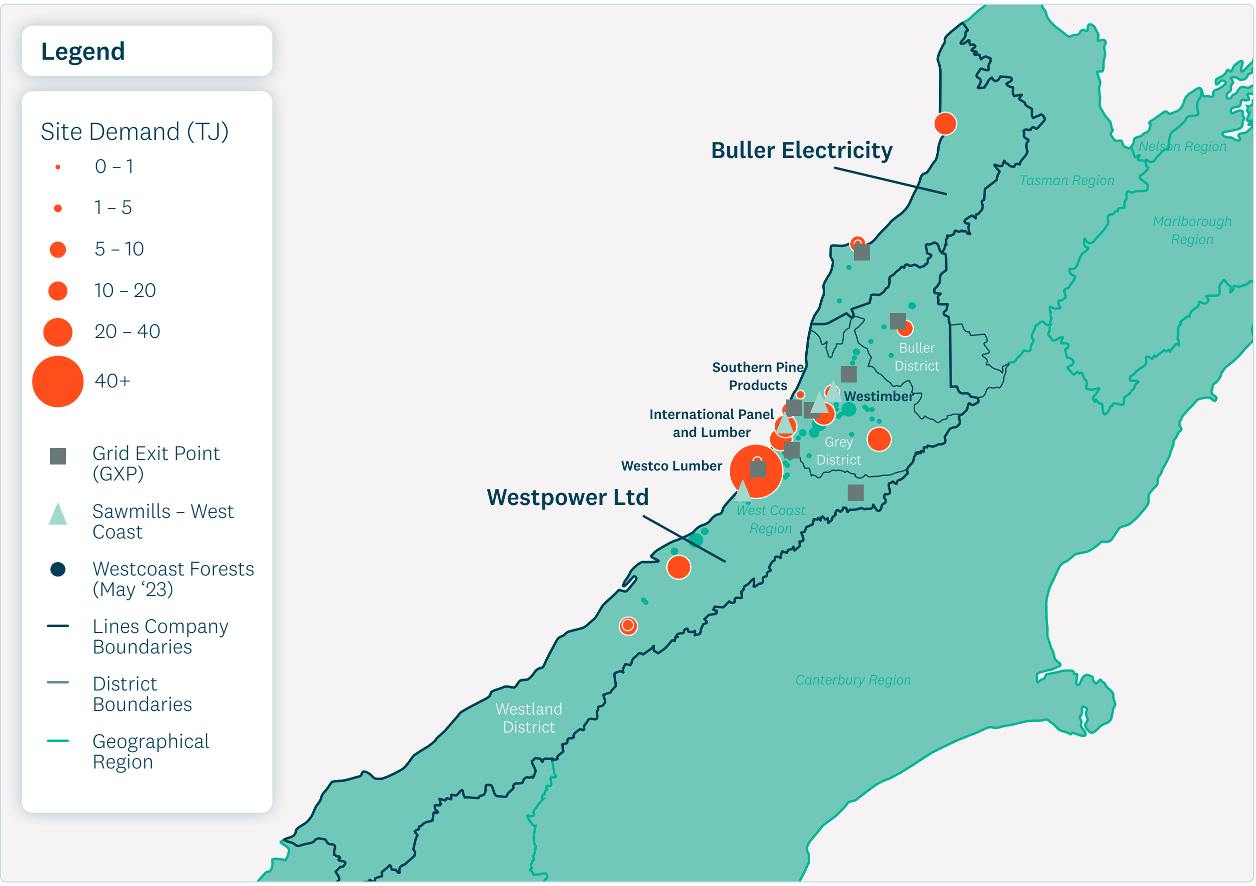


Westland Milk, West Coast, New Zealand

4 Regional overview

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

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



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

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

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

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

The 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 pa of carbon dioxide equivalent (CO_2e) emissions.

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

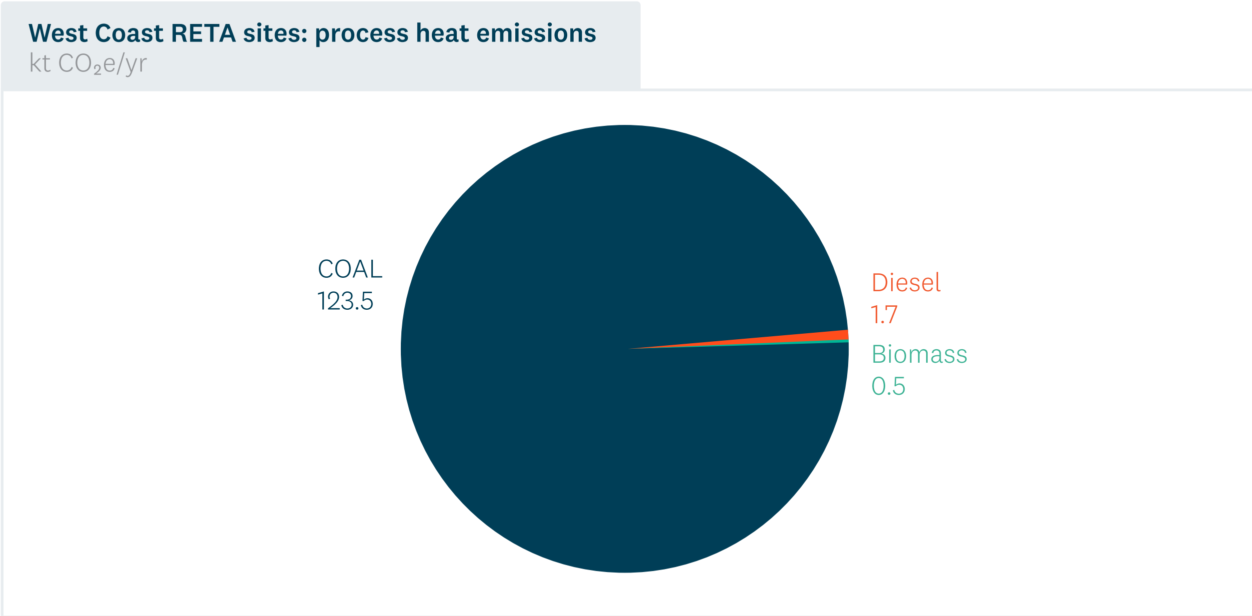
Sector	Sites	Thermal Capacity (MW)	Thermal fuel consumption (GWh/yr)	Process heat demand today (TJ/yr)	Process heat annual emissions (kt CO_2e/yr)
Dairy and meat	4	65	289	1,040	114
Industrial	5	8	24	87	8
Commercial	12	9	9	32	3
Total	**21**	**81**	**322**	**1,157**	**125**

[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.

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

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



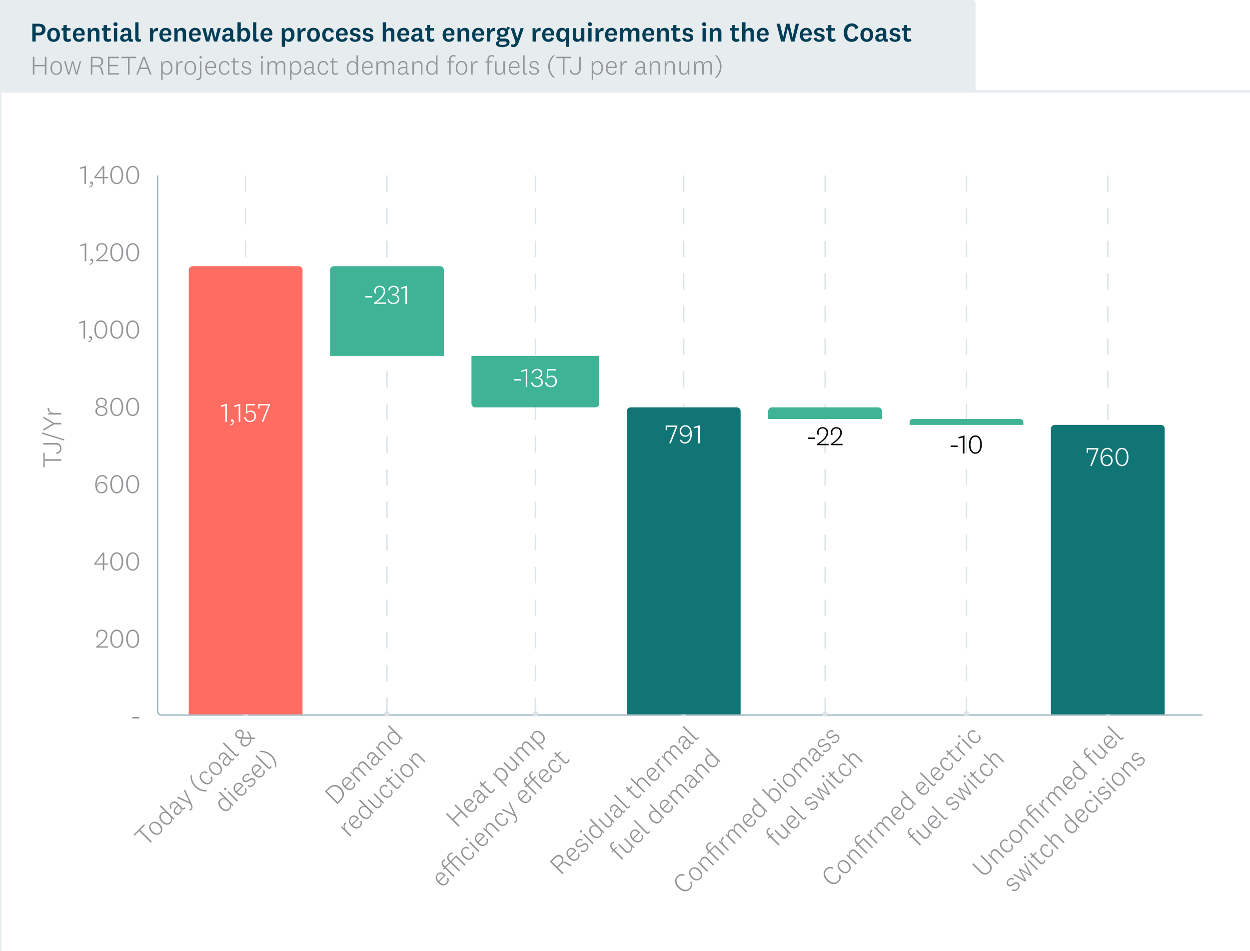
The objective of the West Coast RETA is to eliminate as much of these process heat emissions as possible. It does this by supporting organisations in their consideration of:

- 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.

Westland Milk, West Coast, New Zealand.

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

Figure 3 – Potential impact of fuel switching on West Coast fossil fuel usage, 2022-2037. Source: EECA[3]



Both biomass and electricity are considered as potential fuel sources. EECA's assessments of biomass and electricity focus on the key issues that are common to all RETA process heat sites contemplating fuel switching decisions. The availability and cost of the resources that underpin each fuel option, as well as the sufficiency of the networks required to ensure that the fuel can be delivered to the process heat users' sites. The availability and cost of supply resources and connection can then be used to simulate RETA sites' collective decisions about fuel switching under different sets of assumptions. This provides valuable information to individual process heat decision makers, infrastructure providers, resource owners, funders, and policy makers.

[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 RETA site summary

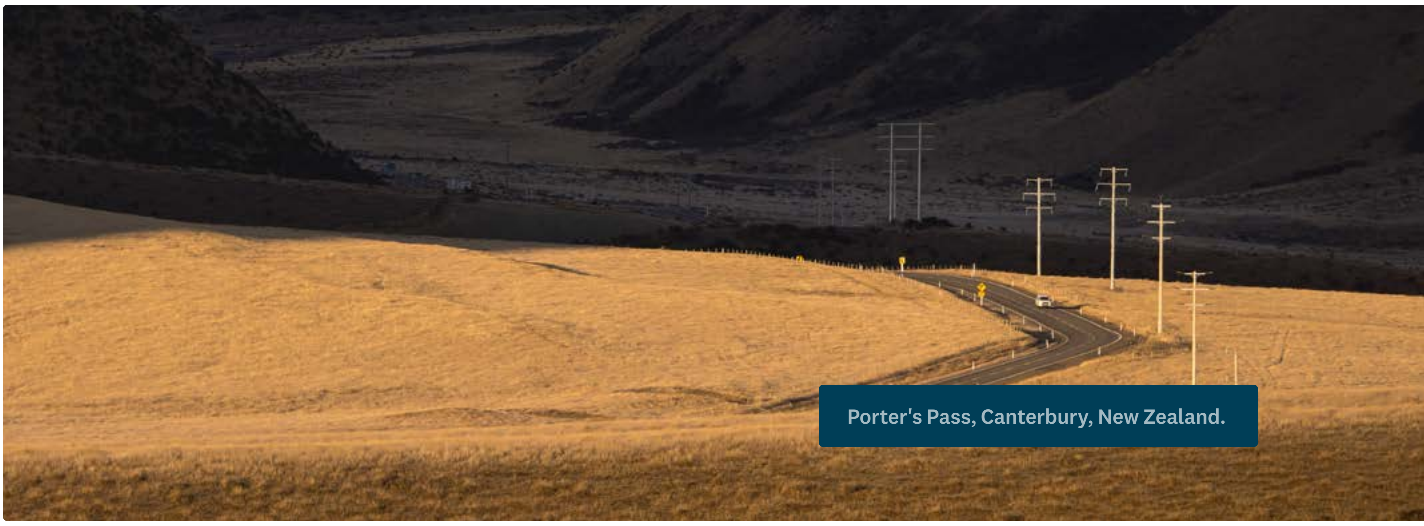
As outlined above, there are 21 sites considered in this study. Across these sites, there are 48 individual projects spanning demand reduction, heat pump and fuel switching. As Table 2 shows RETA process heat users are at different stages of these 48 projects. Twelve have already been completed. Some 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 2 – 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**

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

Below we show the expected remaining fuel demands from each site in the 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.



Porter's Pass, Canterbury, New Zealand.

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

Site name	Industry	Project status	Bioenergy required 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[3]) of biomass and 10TJ (3GWh) of electricity.

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

5 Simulated decarbonisation pathways

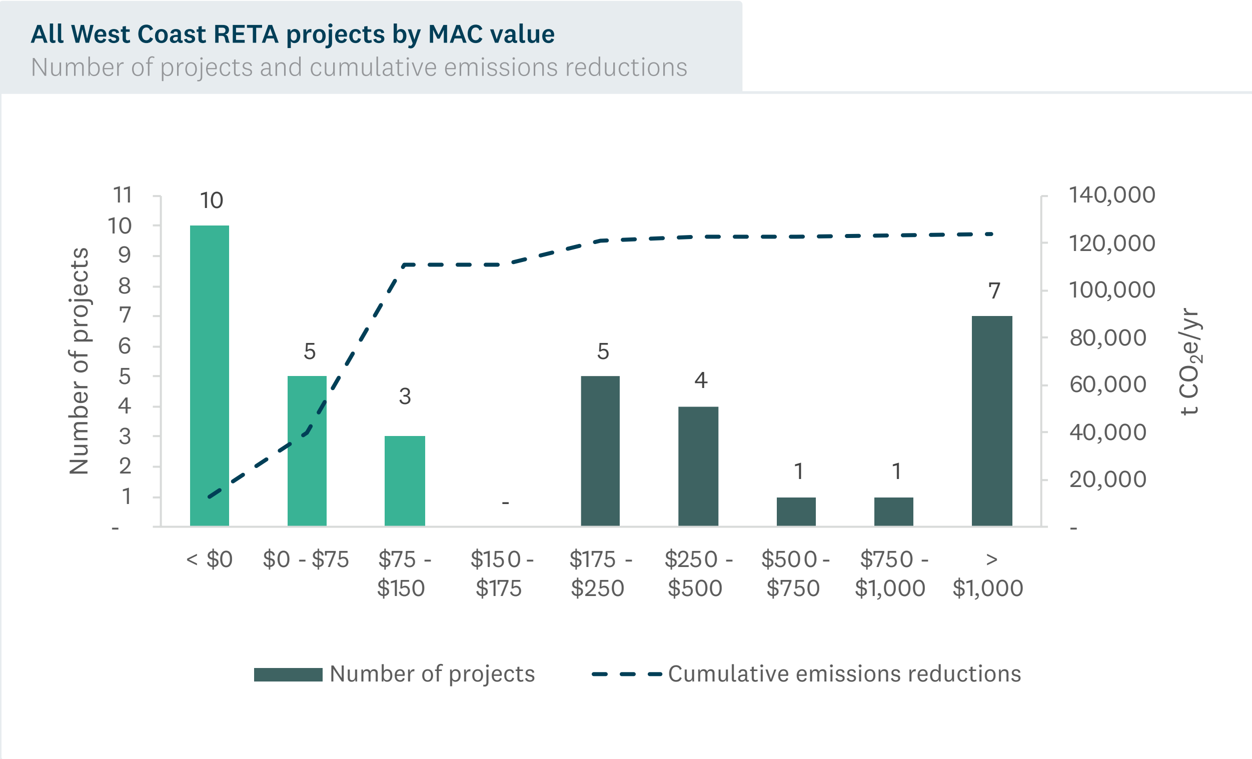
There are a range of decision criteria that individual organisations may use to determine the timing of their decarbonisation investments. Decisions are impacted by available finance, product market considerations, strategic alignment, and other factors. It is challenging to incorporate many of these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

Rather than attempt to include all these factors, we present a range of different potential pathways reflecting different decision-making criteria that process heat users (who have not yet confirmed their choice of fuel) will use. Two pathways present 'bookends' that focus exclusively on one of the two fuel options (biomass or electricity). Two others use a global standard 'marginal abatement cost', or 'MAC', to quantify the cost to the organisation of decarbonising their process heat. This is expressed in dollars per tonne of CO_2e reduced by the investment and allows us to determine the timing of the investment as being the earliest point when a decarbonisation decision saves the process heat user money over the lifetime of the investment – the point in time that the MAC of the project is exceeded by the expected future carbon price.

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

Arthur's Pass, Canterbury, New Zealand.

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



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[4].

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

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[5].
- All RETA decarbonisation projects are executed by 2037 in line with the Government's aspiration to phase out coal boilers by 2037[6]. This means that any projects that are still not 'economic' using our MAC criteria by 2036, are assumed to be executed in 2036.

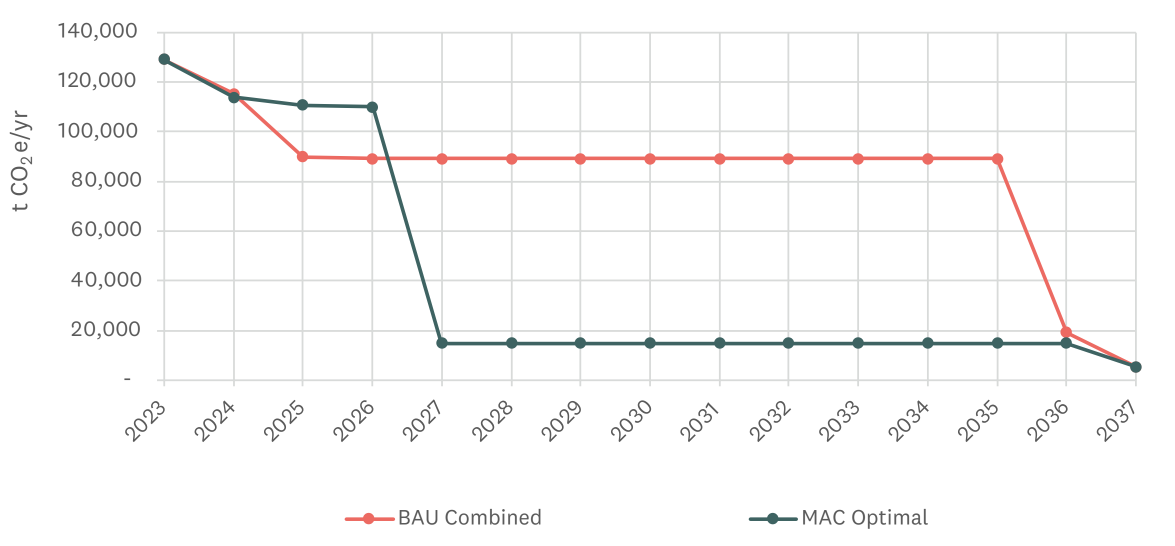
5.1 By 2027, 88% of emissions reductions are economic[7]

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.

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

West Coast pathways: process heat emissions reductions
t CO_2e/yr



The MAC Optimal pathway proceeds much faster, with the majority of emissions reductions achieved by 2027. However, this pace is likely to be constrained by practical matters such as:

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

The MAC Optimal pathway sees fuel decisions that result in 40% of the energy needs supplied by electricity in 2036, and 60% of energy needs supplied by biomass in 2036. We expand further on these outcomes in the sections below.

Before doing so, it is important to recognise the significant impact that demand reduction and heat pump efficiency projects have on the overall picture of West Coast process heat decarbonisation. As shown in Figure 3, investment in demand reduction and heat pumps meets nearly 30% of today's West Coast energy demands[8] 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.

The MAC values – and therefore the timing of each decarbonisation project – are based on a number of inputs that are uncertain, for example future electricity prices and biomass costs. Our analysis illustrates that accelerated co-funding and lower electricity prices should have a modest effect on project timing, given assumptions about their economics. The expectations that organisations hold about future carbon prices also has an effect. Factors beyond pure project economics (such as internal constraints on capital) will continue to significantly impact organisations' decisions. Co-funding can perform an important role in neutralising these barriers to undertaking good investments.

[5] 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/

[6] 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

[7] 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).

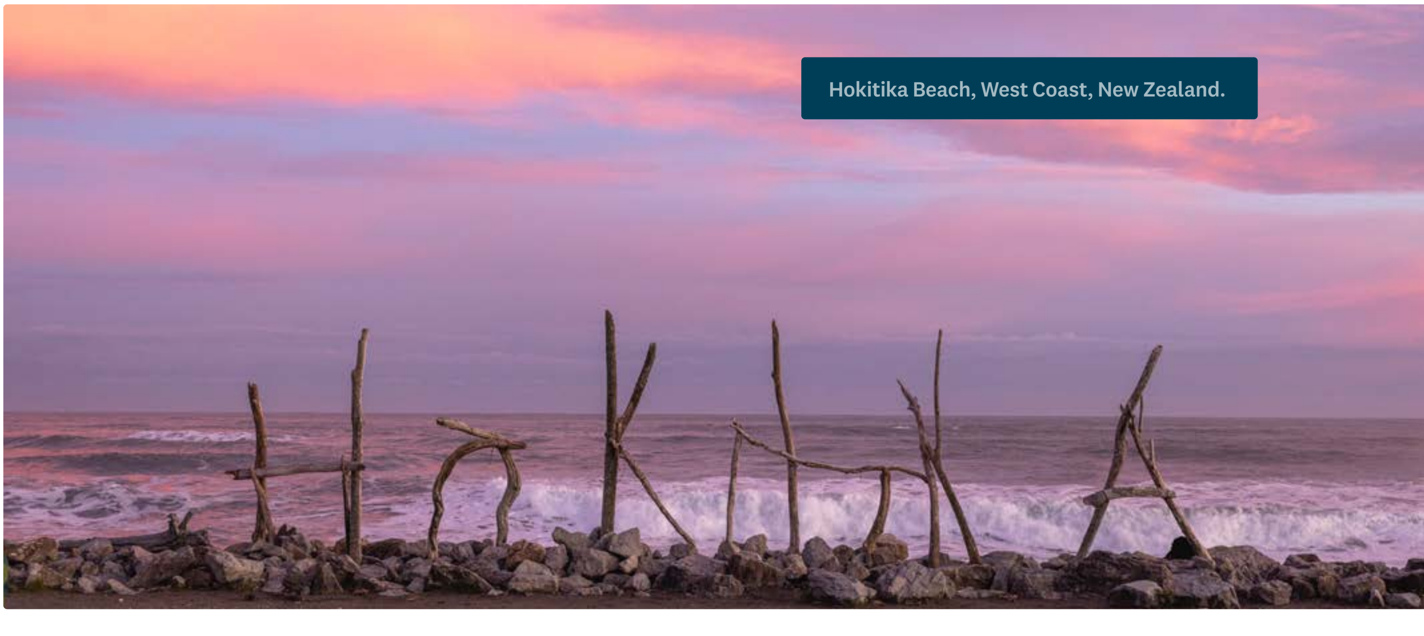
[8] This is true for both energy consumption and also the peak thermal demand required from biomass or electric boilers.

6 Biomass – resources and costs

The use of woody biomass for bioenergy requires careful consideration of emissions and sustainability. For example, depending on the source, the diversion of wood to bioenergy may change the timing of the release of emissions by a significant period (compared to the natural decomposition of biomass). Suppliers and consumers of biomass for bioenergy need to be confident they understand any wider implications of their choices. No formal guidelines or standards exist in New Zealand at this point, and EECA recommends one is developed for the New Zealand context, drawing on international standards and experience.

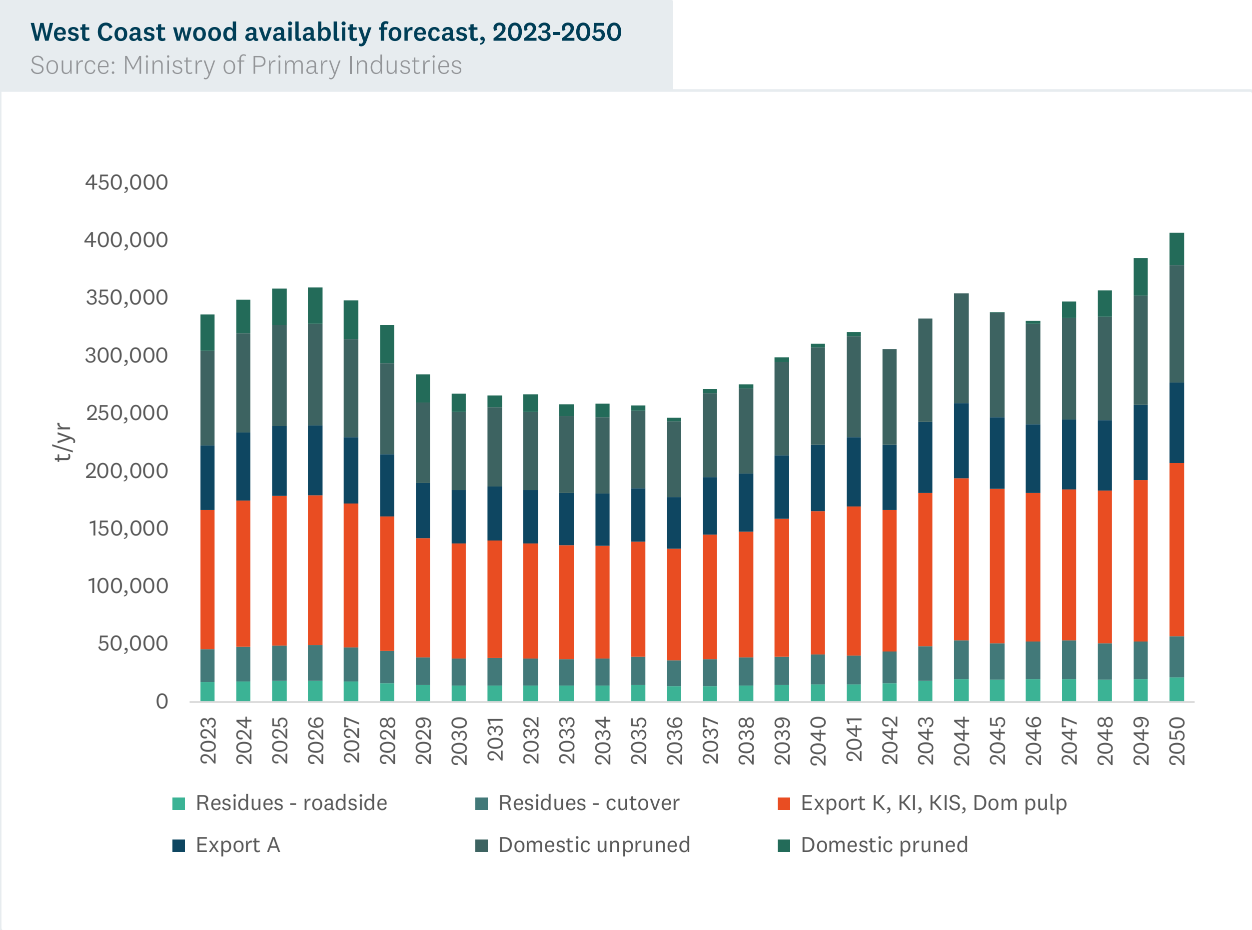
A good sense of the total availability of harvestable wood in the West Coast region requires both a top-down and bottom-up analysis (based on interviews with major forest owners), as forest owners' actual intentions will often deviate from centralised forecasts due to changes in log prices and other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

A top-down analysis suggests that an average of around **300,000t pa (2,140TJ) of wood will be harvested in the West Coast region over the next 15 years**, although volumes are significantly higher than this over the period 2023-2028 (Figure 6). The majority of this will be radiata pine. Around three-quarters will be harvested into domestic sawlogs or Export A, K, KI and KIS grades.



Hokitika Beach, West Coast, New Zealand.

Figure 6 – Wood resource availability in West Coast region, 2023-2050

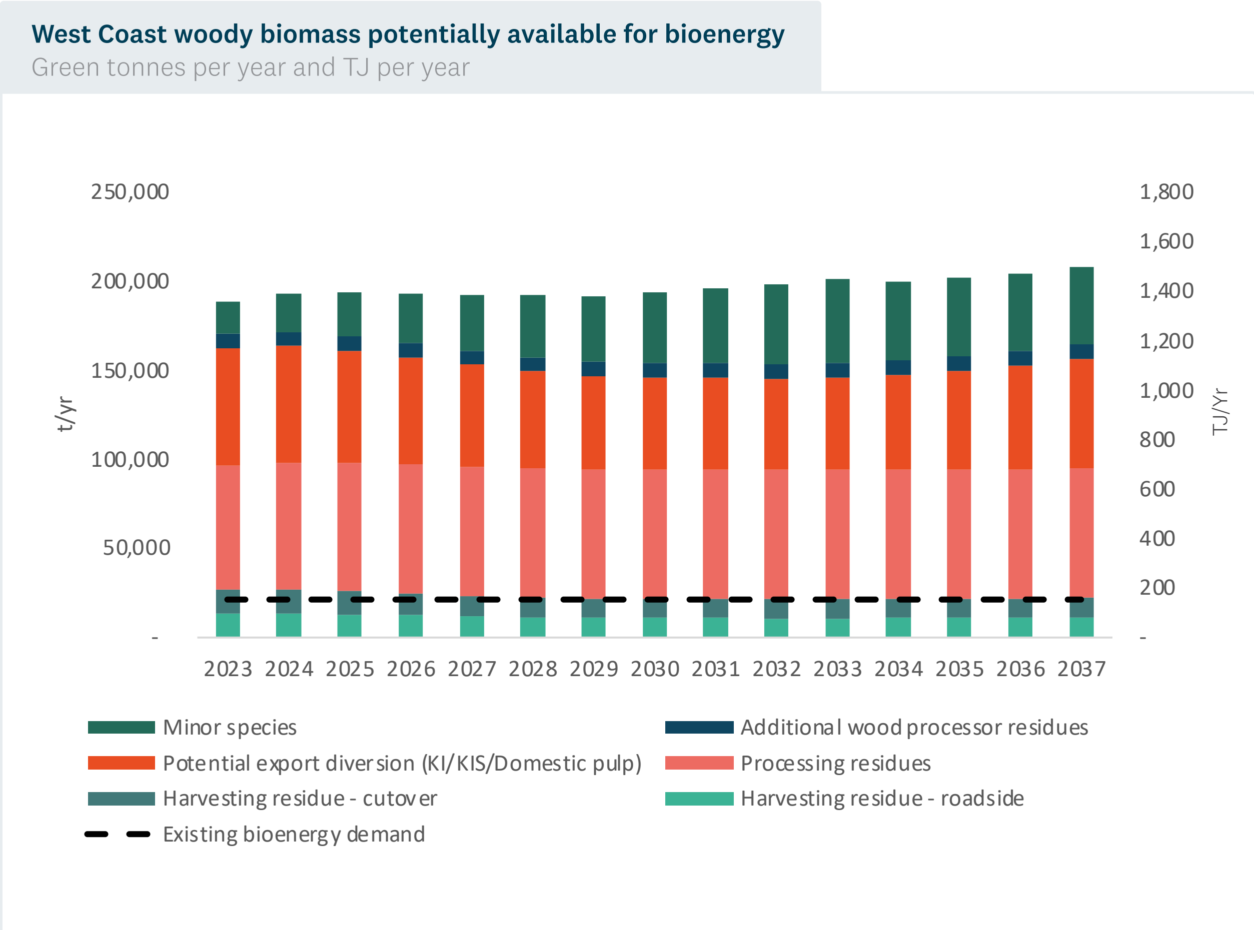


A more comprehensive view of resource availability, that combines the top-down and bottom-up analyses reveals the potential volumes that could be available for bioenergy. This analysis:

- Includes minor species (e.g. cypress and eucalyptus) that isn't accounted for in Figure 6.
- Takes a more realistic approach to estimating the potential harvesting residues (roadside and cutover) than the theoretical potential used in Figure 6.
- Considers the potential volumes arising as residues from processing sawlogs for the domestic market.
- Overlays the existing demand for bioenergy, that already draws on these resources.

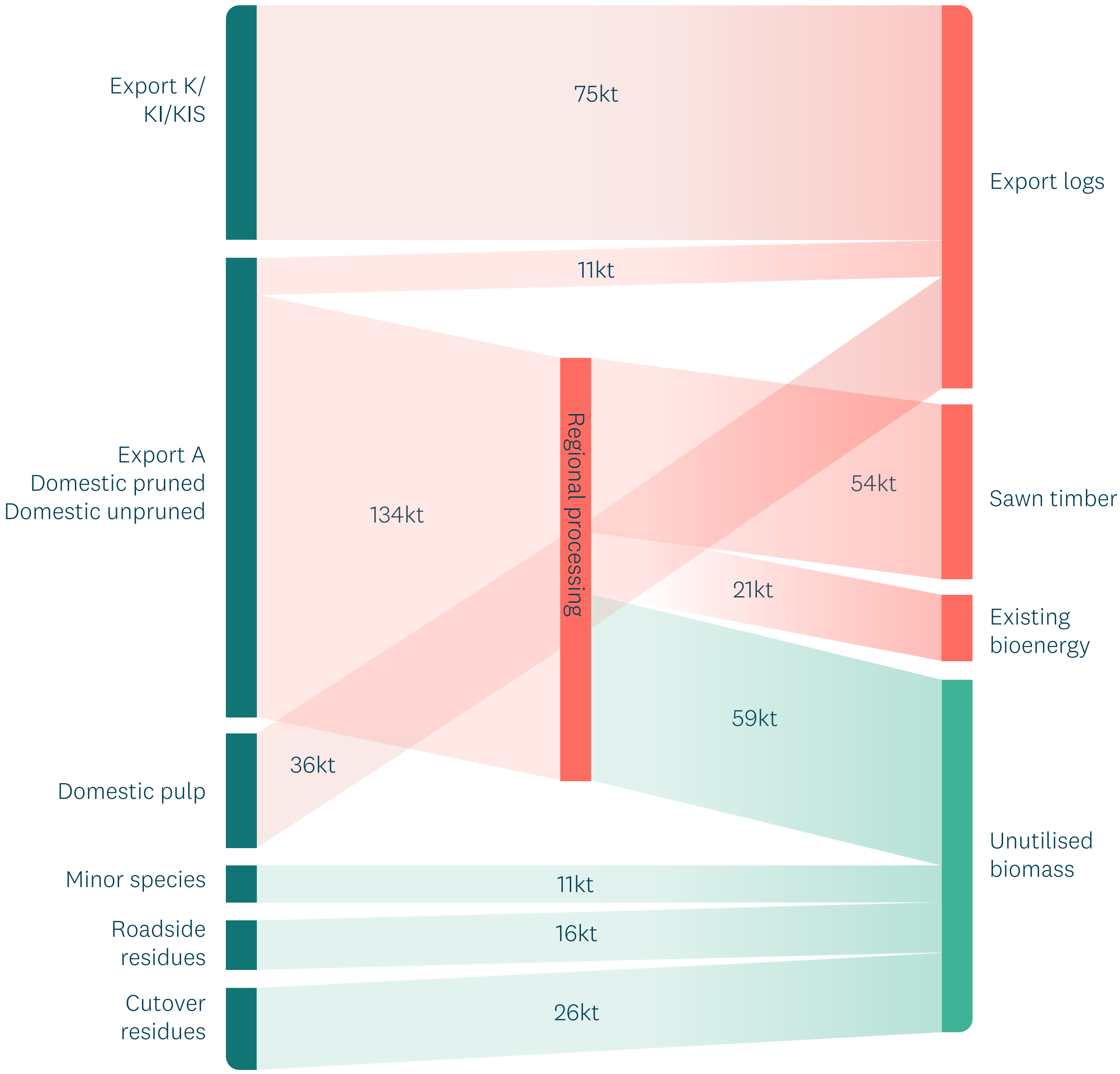
The resulting potential volumes for bioenergy is shown in Figure 7.

Figure 7 – Assessment of available West Coast woody biomass that could be used for bioenergy.



The overall analysis of the West Coast region is summarised in Figure 8. Wood flows that could – in part or in full – be diverted to new bioenergy demand from process heat are shown in green.

Figure 8 – Average wood flows over 15 years in West Coast region. Source: Ahikā, Margules Groome



Overall, EECA estimates that on average over the next 15 years, approximately 110,000t per year (800TJ) of West Coast woody biomass is currently unutilised and could be recovered for new boiler demands without disrupting low grade export markets or existing bioenergy consumers.

6.1 Impact of pathways on biomass demand

Our pathway analysis suggests harvesting and processing residues alone will be sufficient to cover 100% of new process heat demands under the MAC Optimal and BAU Combined pathways, and 67% of the Biomass Centric Pathway[9]. If minor species are included, all pathways can be met through unutilised biomass.

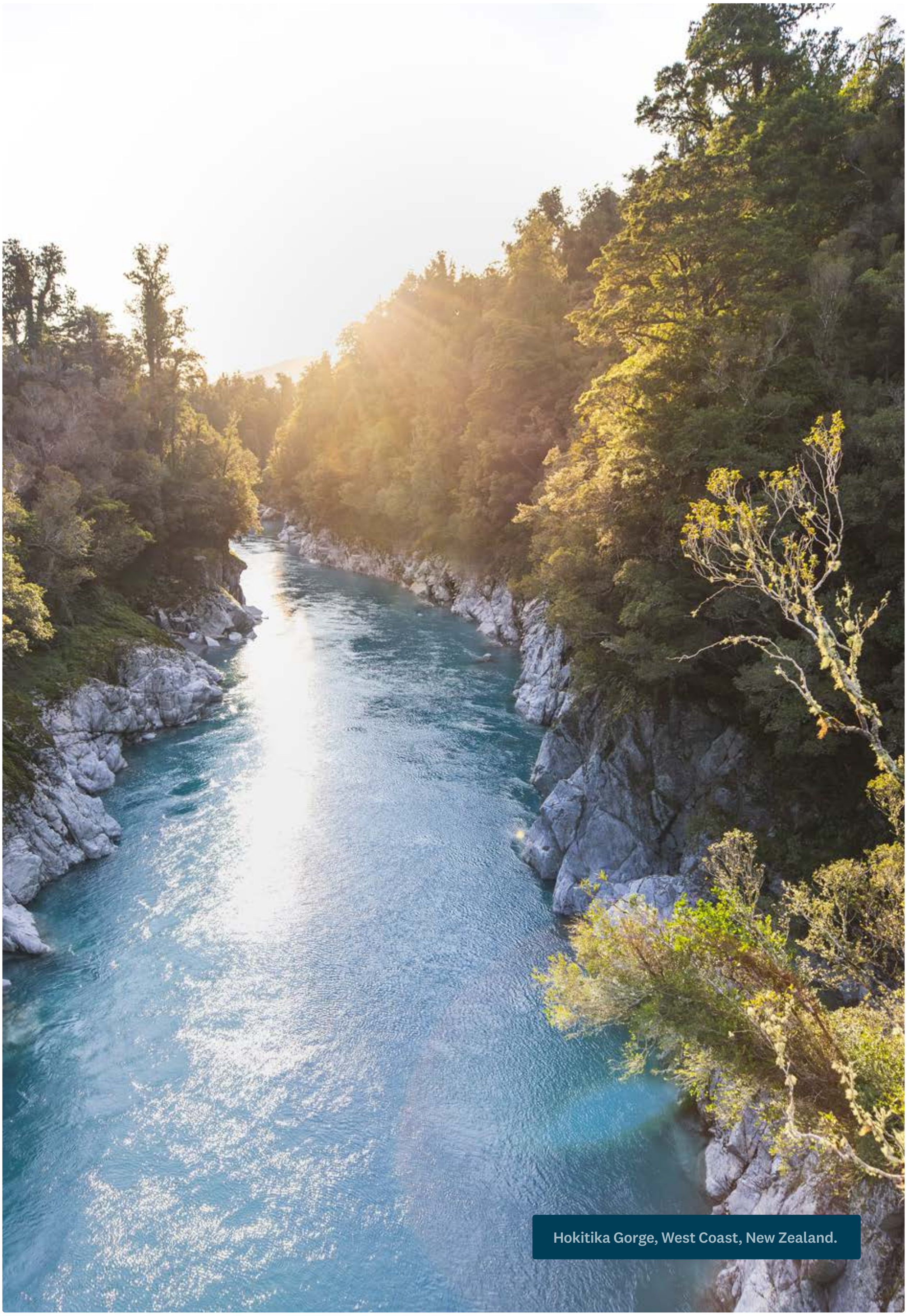
Figure 9 – Growth in biomass demand from pathways. Source: EECA

Allowing for estimated costs of procurement, chipping, storage, and delivery (to the process heat user's site), the potential cost per GJ of the various resources identified may range between $14/GJ to $17/GJ ($102/t to $122/t) for harvesting residues or processing residues. If required, the cost associated with diverting export logs also falls within this range. Our analysis suggests that, over the next 15 years, the MAC Optimal process heat market demand for processing and harvesting residues exceeds $53M on a cost basis[10], not including chipping, storage, and transport.

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

[9] Note that by the end of the 15-year period, it is assumed that surplus domestic firewood will be available relative to current demand. This is what drives the increase in net available residues over the period 2033-2037. We expect that some of this surplus will be taken up by growth in domestic firewood demand.

[10] Cost of wood chip delivered to process heat user at $13.50/GJ (wet wood), per Section 8.7. Does not include costs associated with processing into e.g. wood pellets.



Hokitika Gorge, West Coast, New Zealand.

7 Electricity – network capacity and costs

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

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

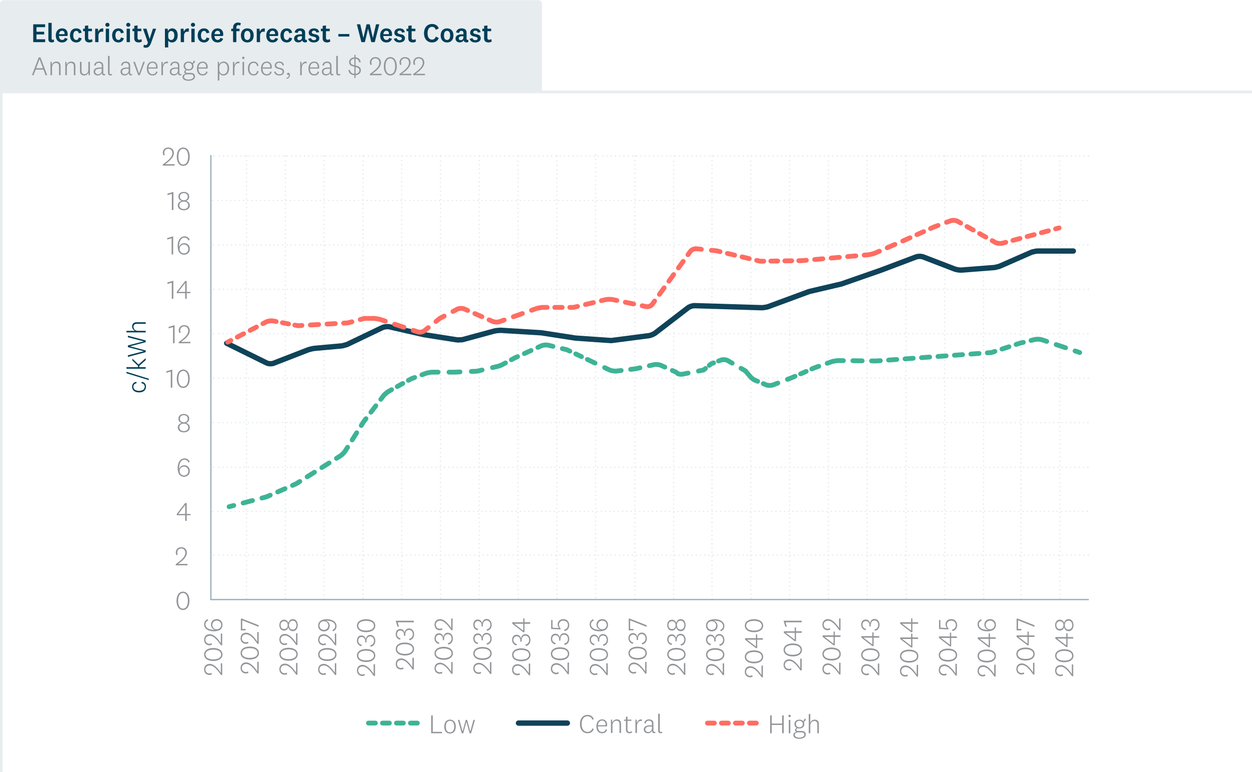
- A price for 'retail electricity' – the wholesale cost of electricity generation plus costs associated with electricity retailing.
- A price for access to the transmission and distribution networks.

As shown in Figure 10, the forecast price of **retail electricity** is expected to rise (in real terms) around 10% between 2027 and 2037 (to ~12c/kWh) under a 'central' scenario. However, different scenarios could see real retail prices higher or lower than that level by 2037.

Westland Milk, West Coast, New Zealand.

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

Figure 10 – Forecast of real annual average electricity price for large commercial and industrial demand in the West Coast region. Source: EnergyLink



Beyond 2037, this forecast sees more significant increases in electricity prices. However, it is difficult to predict pricing beyond the end of the RETA period. Some New Zealand market analyses suggest real prices may remain constant after 2035, due to the downward pressure on generation costs (especially solar and wind) as technology and scale increases. Other analyses see continued increases. We cannot be definitive about electricity prices 20 years into the future and suggest business cases consider a range of scenarios.

The EDBs serving the West Coast region are Westpower and Buller Electricity. EDBs charge electricity consumers for the use of the existing distribution network, and also pass through the charges they face for use of the existing transmission network. Where the connection of new electric boilers requires EDBs to invest in **distribution network upgrades**, the cost of these can be paid through a mix of ongoing network charges in the table above, and an up-front 'capital contribution'. Each EDB maintains policies that govern the degree of capital contribution, and process heat users should discuss these with their respective EDBs.

In addition, process heat users who connect new electric boilers directly to Transpower's grid will face equivalent **transmission charges**, although it will be eight years before the full allocation of transmission charges will be made[12]. Process heat users who connect to the EDBs networks will also face a share of these transmission costs, as determined by the EDBs pricing methodologies. A new Transmission Pricing Methodology (TPM), developed by the Electricity Authority, will apply to transmission charges in the 2023/24 year. An approximation of the potential charges faced by process heat users who electrify is presented in Table 4. These are based on each of the EDB's announced prices for the year 2023/24.

[12] This refers to the delay in calculation of Residual Charges until four years of operation, and then a further four-year transition to full Residual Charges.

Table 4 – Estimated and normalised network charges for large industrial process heat consumers by EDB

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

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.

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

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

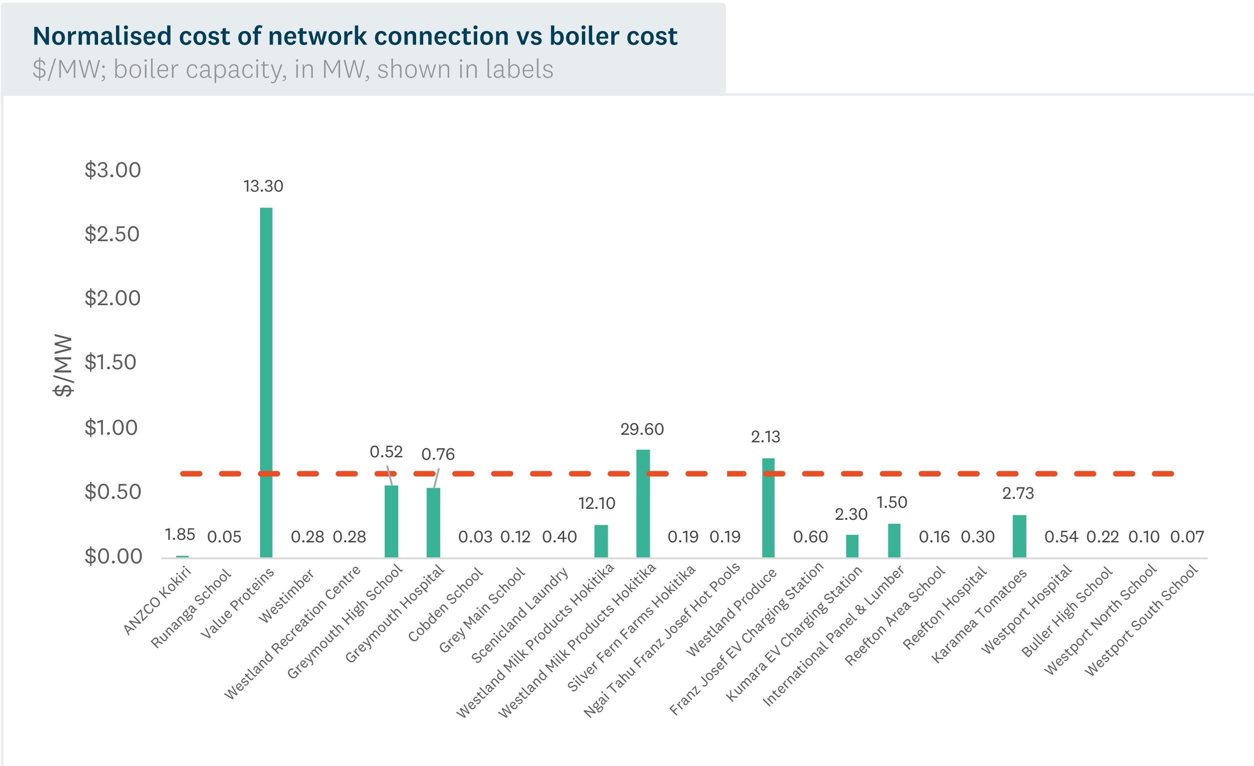
The analysis suggests that the capital cost associated with accommodating the new potential peak electricity demand from the majority of RETA process heat sites is relatively minor in complexity. The estimated costs of the equipment required to connect them is <$3M per site, and these would take between 6 and 18 months. These sites place relatively low demands on the network.

However, for sites with higher peak demands, the connections increase in complexity. If these more complex connections do not require upgrades to Transpower's network, indicative costs are between $3M and $5M. These upgrades are expected to take between 12 and 18 months.

There is only one process heat user that would require upgrades to both distribution and transmission networks. The estimated cost ranges between $6M to $24M, depending on how much of the site is electrified. These upgrades are expected to require three to four years lead time.

The costs of connection can be a significant part of the overall capital cost associated with electrifying process heat demand. Figure 11 shows each site's connection costs expressed in per-MW terms, i.e. relative to the capacity of the proposed boiler.

Figure 11 – Normalised cost of network connection vs boiler cost. Source: Ergo, EECA



The red dashed line in Figure 11 compares these per-MW costs to the estimated cost of an electrode boiler ($650,000 per MW[13]). 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.

The timeframes for connection above assume these investments are paid for by each process heat customer (i.e. are customer-initiated investments), and do not require Transpower or EDBs to obtain regulatory approval. We note that if connections also rely on wider upgrades to the network or grid (which is the case for some connections), Transpower or the EDB would have to seek regulatory approval for these investments, which could also add to the timeline.

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

[13] This is the estimate used in the development of the marginal abatement costs and pathways presented in Section 10.

7.1 Impact of pathways on electricity demand

The figures below show the pace of electricity demand growth under the different pathways, both in terms of electricity consumption and potential peak electricity demand (which drives the capacity requirements from the network).

Figure 12 – Growth in electricity demand from fuel switching pathways (unconfirmed RETA sites). Source: EECA

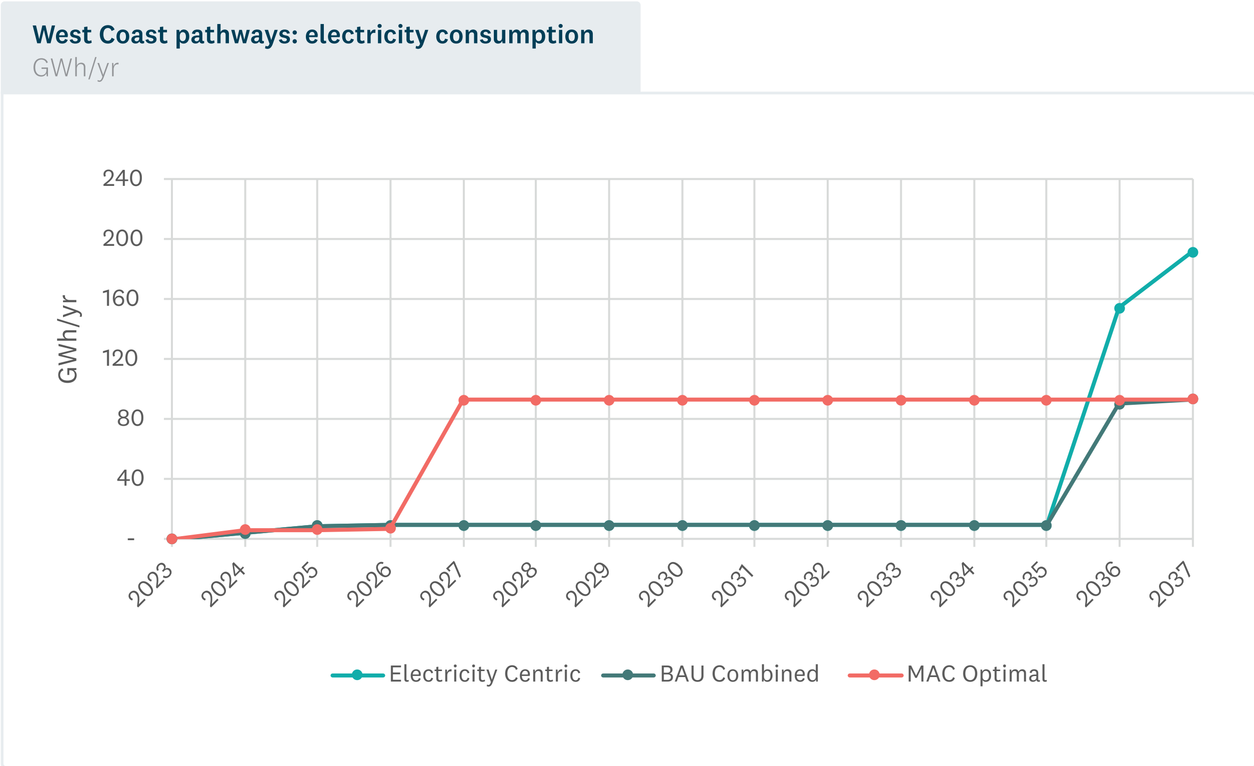


Figure 13 – Potential peak demand growth under different pathways

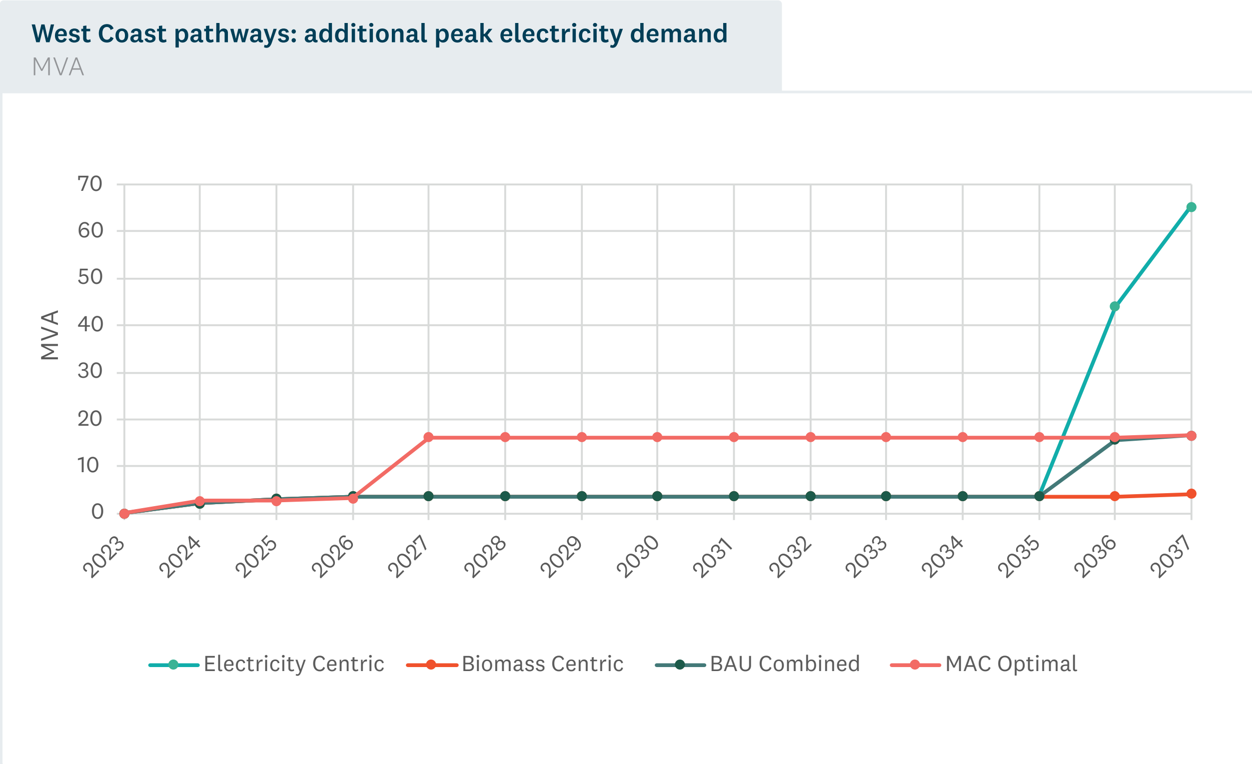


Table 5 shows how the connections potentially affect each EDB's network.

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

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

Table 5 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[14] connecting their new plant to the local networks, depending on the pathway.

[14] These are the costs described in Section 9.3.4. 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.

7.2 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 most of the time. 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.

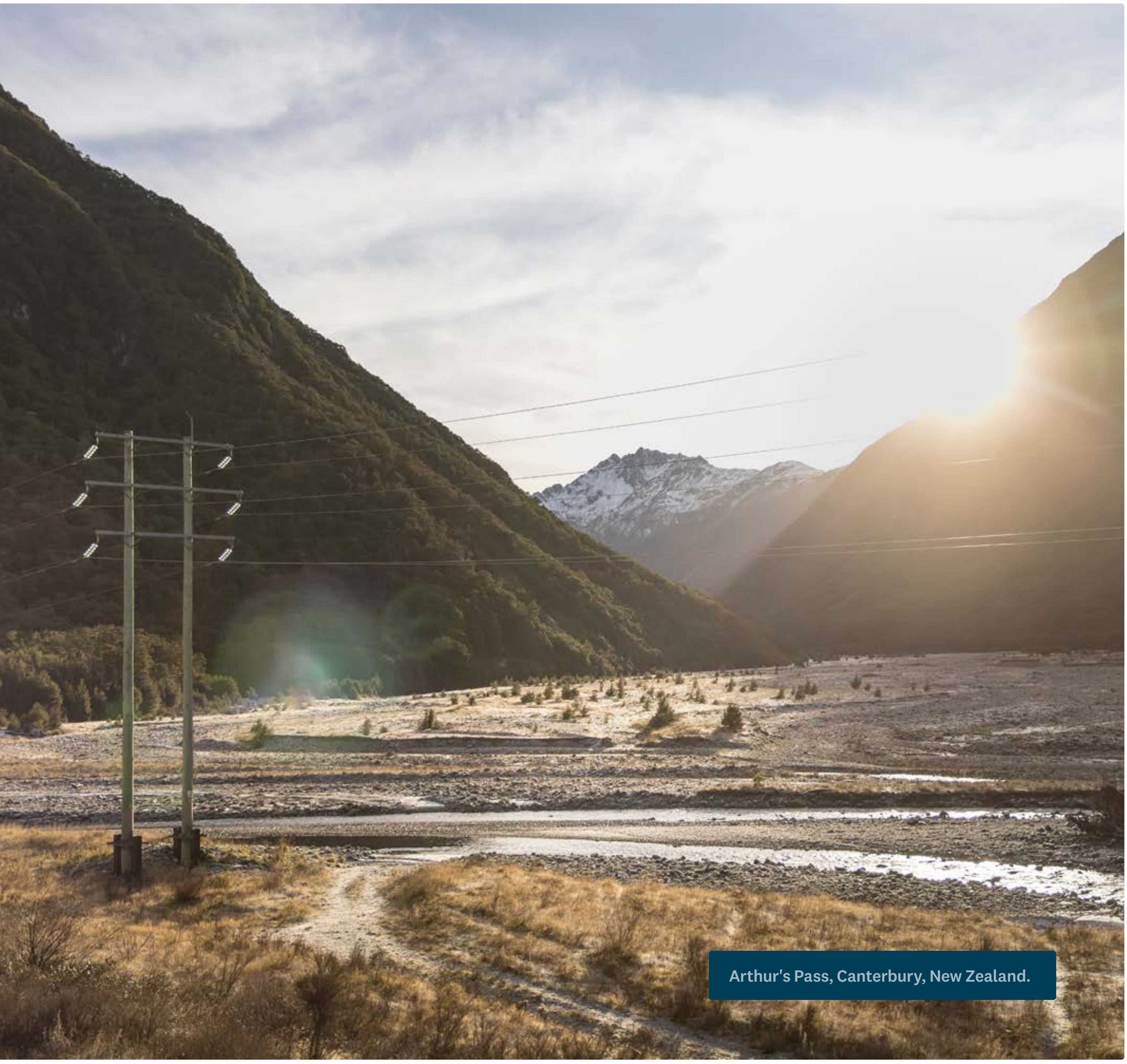
Currently, the West Coast's embedded generation is helping avoid congestion on transmission assets. The degree to which it does this from year to year demands on the output of the generation at peak times, which in turn depends on rainfall in the hydro catchments. Further investment in local hydro could 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 56MW 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.

7.3 Opportunity to reduce electricity-related costs through flexibility

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



Arthur's Pass, Canterbury, New Zealand.

8 Recommendations

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

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

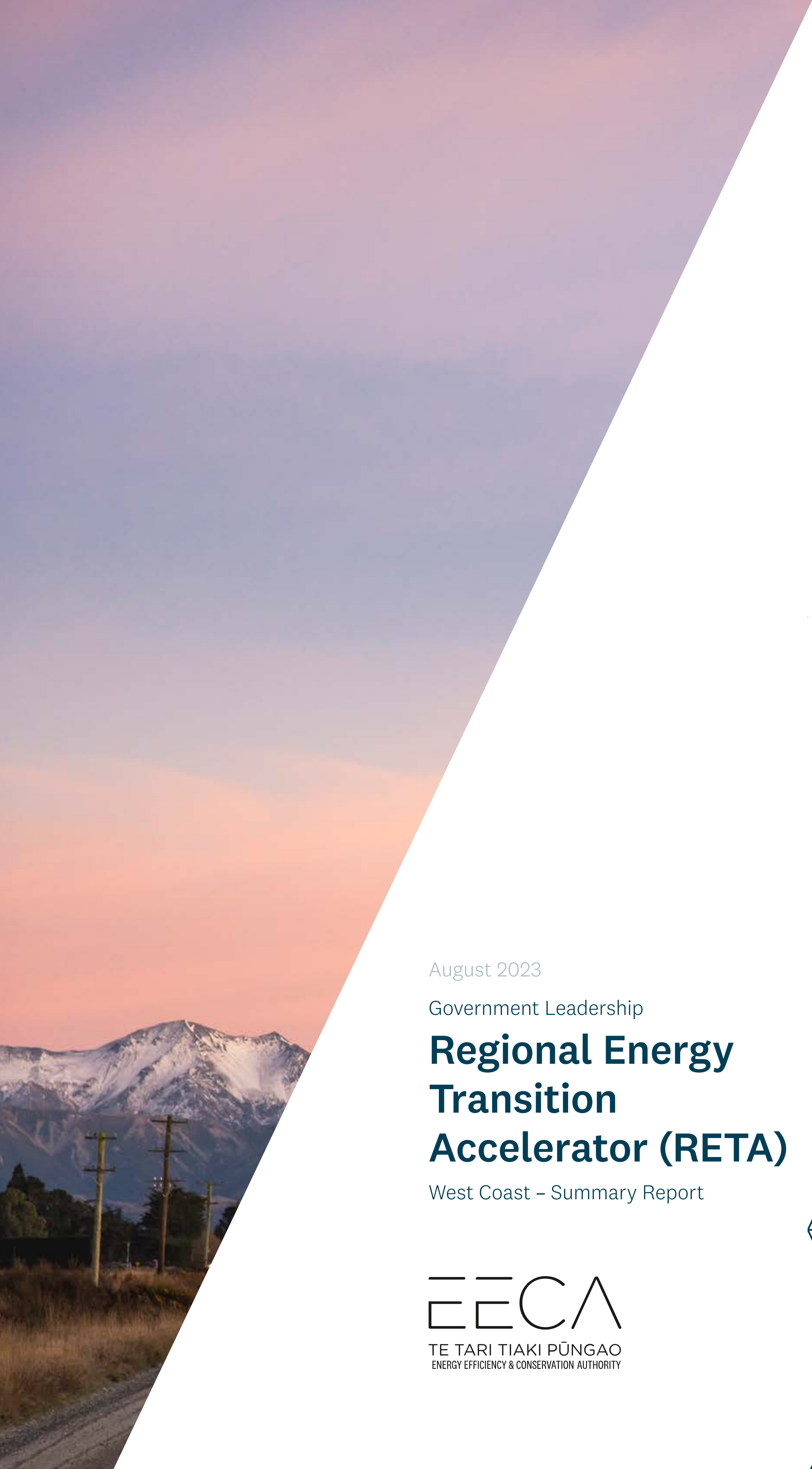
- **More analysis, and potentially pilots, should be conducted to understand costs, volumes, energy content (given the potential susceptibility of these residues to high moisture levels) and methods of recovering harvesting residues.**
- **Work should be undertaken with forest owners to understand the logistics, space and equipment required for harvesting residues.**
- **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.**
- **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.**
- **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 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 the right behaviour.**

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.**



August 2023

Government Leadership

Regional Energy Transition Accelerator (RETA)

West Coast – Summary Report

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