Government Leadership

Regional Energy Transition Accelerator (RETA)

Southland - Phase One Report

October 2022

TE TARI TIAKI PŪNGAO
ENERGY EFFICIENCY & CONSERVATION AUTHORITY

1 Foreword

Climate change is one of the most urgent environmental issues of our time. Reducing emissions that result from the use of fossil fuels by industry in the generation of heat, is critical to meeting New Zealand's net-carbon zero targets. At present, burning fossil fuels to supply process heat results in over 8 million tonnes of CO_2e or about 28% of New Zealand's overall energy emissions per year.

While the picture is similar in Southland, the region is in a strong position to accelerate its transition to a low-emissions future. Southland has good local carbon reduction potential – with supportive and proactive local businesses, prevalent use of coal but an ongoing appetite for change, the presence of an established local biomass industry, and strong renewable electricity infrastructure.

EECA's first-of-a-kind Regional Energy Transition Accelerator (RETA), aims to – through understanding unique region-specific opportunities and barriers – develop a well-informed and coordinated approach to support the fast-tracking of decarbonisation projects across Southland.

The report concludes phase one of RETA activity and provides a common set of information for all organisations considering process heat decarbonisation in the years ahead. It leverages learnings from site-specific decarbonisation work that has already been carried out by manufacturers across the region and provides information on the readiness of regional supply-side systems. Earlier work also made it clear that areas like fuel supply and infrastructure would benefit from being tackled collectively at a regional level.

EECA is proud to have worked so collaboratively with Great South, Iwi, and others from across the demand and supply side – in particular Transpower, Powernet, Meridian, local biomass suppliers and forest owners, workstream leads and medium to large industrial energy users. We are indebted to this group for the input and feedback provided, and the openness with our analysts and modelers – the findings and recommendations are much richer for it. Our RETA workstream leads have provided not only expertise, but enthusiasm and commitment that has led to a comprehensive, and we hope extremely valuable, piece of work.

We must commit to doing more, faster – for the public good first and foremost. But also, to help businesses and regions across New Zealand transition to a low emissions economy and take advantage of the opportunities that emerge with clean energy and clever technologies.

The RETA demonstrates the belief that providing the best possible information, taking a systems-level perspective and co-ordinating across a local energy ecosystem to tackle regional problems with regional solutions, will improve the cost-benefit equation for all involved in this challenge.

We now look forward to working alongside the key players in the region as we all continue along the journey.

Andrew Caseley
Chief Executive, EECA

EECA

> *We must commit to doing more, faster – for the public good first and foremost.*
>
> Andrew Caseley, Chief Executive, EECA

2 Acknowledgments

This is the first RETA project undertaken by EECA and its partners, and as such, 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
- Great South
- Local lines company PowerNet
- National grid owner and operator Transpower
- Regional forestry companies
- Wood processors
- Electricity generators and retailers

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

- **DETA Consulting Limited** – process heat demand-side assessment[1]
- **PF Olsen Limited** – biomass cost analysis[2]
- **Ahikā Consulting Limited** – biomass availability analysis[3]
- **Ergo Consulting Limited** – electricity network analysis[4]
- **Energy Link Limited** – electricity price forecast[5]
- **Wayne Manor Advisory Limited** – report collation, publication and modelling assistance

[1]DETA (2022), *Regional ETA – Southland*, 8 May 2022.

[2]PF Olsen (2022), *Southland Biomass Cost Forecast*, May 2022

[3]Ahikā (2022), *Southland Region Bioenergy Availability Assessment*, 11 May 2022

[4]Ergo (2022), *Southland Electrical Network: Spare Capacity and Load Conversion Opportunity Report*, June 2022

[5]EnergyLink (2022), *Regional Electricity Price Forecasts: EECA Regional Energy Transition Accelerator Program*, May 2022

The Southland region is the focus for New Zealand's first Regional Energy Transition Accelerator (RETA).

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Bluff - Southland, New Zealand. Credit: Videocopter

4 Executive summary

The Southland region is the focus for New Zealand's first Regional Energy Transition Accelerator (RETA).

The Southland RETA brings together information about process heat decarbonisation plans from EECA's "Energy Transition Accelerators" (ETAs) with individual organisations as well as the Heat Plant Database Project (HPDP) completed by Powernet, Transpower and EECA. While ETAs and the HPDP focus on the decarbonisation pathways and plans of individual organisations, the RETA expands this focus to consider barriers and opportunities for regional supply-side infrastructure (e.g. networks and regional resources) to better support decarbonisation decisions.

This report is the culmination of phase one of the RETA process. This first planning phase 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 on supply side infrastructure.
- Surface issues, opportunities, and recommendations.

The second phase of the RETA focuses on implementing recommendations from phase one that remove barriers or accelerate opportunities for decarbonisation.

The 40 sites covered by the Southland process heat RETA either have boilers larger than 500kW, or are sites for which EECA has detailed information about their decarbonisation pathway. Together, these sites collectively consume 1,518GWh/5,460TJ of energy, primarily in the form of coal, and currently produce 519kt pa of greenhouse gas emissions. This represents 88% of scope 1 manufacturing and commercial stationary energy emissions in the region.

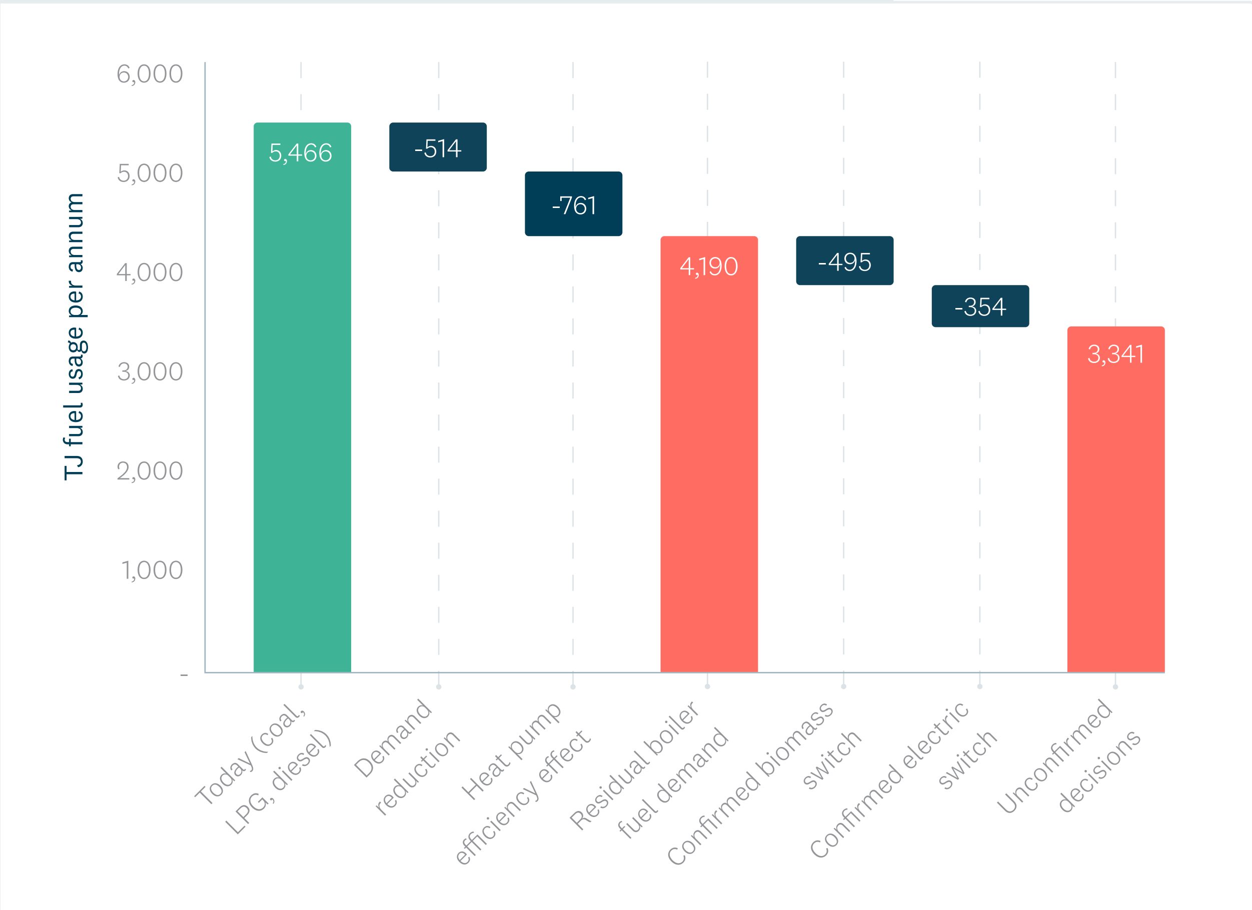
Sector	Sites	Thermal capacity (MW)	Process heat demand (GWh pa)	Process heat demand (TJ pa)	Process heat annual emissions (ktCO2e pa)
Dairy	5	205	1,168	4,205	403
Meat	7	68	256	921	87
Industrial	4	16	40	140	12
Commercial[6]	24	46	54	194	17
Total	**40**	**336**	**1,518**	**5,460**	**519**

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

The Southland RETA objective 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 peak heat demand through process optimisation), thermal efficiency (for example installation of highly efficient heat pumps), and switching away from coal as a fuel, to a low-emissions energy source such as biomass and/or electricity.

The figure below[7] illustrates the potential impact of RETA sites on fuel demand, both as a result of decisions already taken, and decisions yet to be made.

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



The main focus of this report is the fuel switching decision. Both biomass and electricity are considered as potential fuel sources.

This should not take away from the importance of efficient demand reduction and thermal efficiency measures for reducing energy consumption and right-sizing the boiler investment, which in turn affects decision making around fuel switching.

[7] Figure 6 in the main report.

EECA's assessment of biomass and electricity focuses on the key issues that are common to all RETA 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, which provides valuable information back to individual process heat decision makers, infrastructure providers, resource owners, funders and policy makers.

Biomass summary

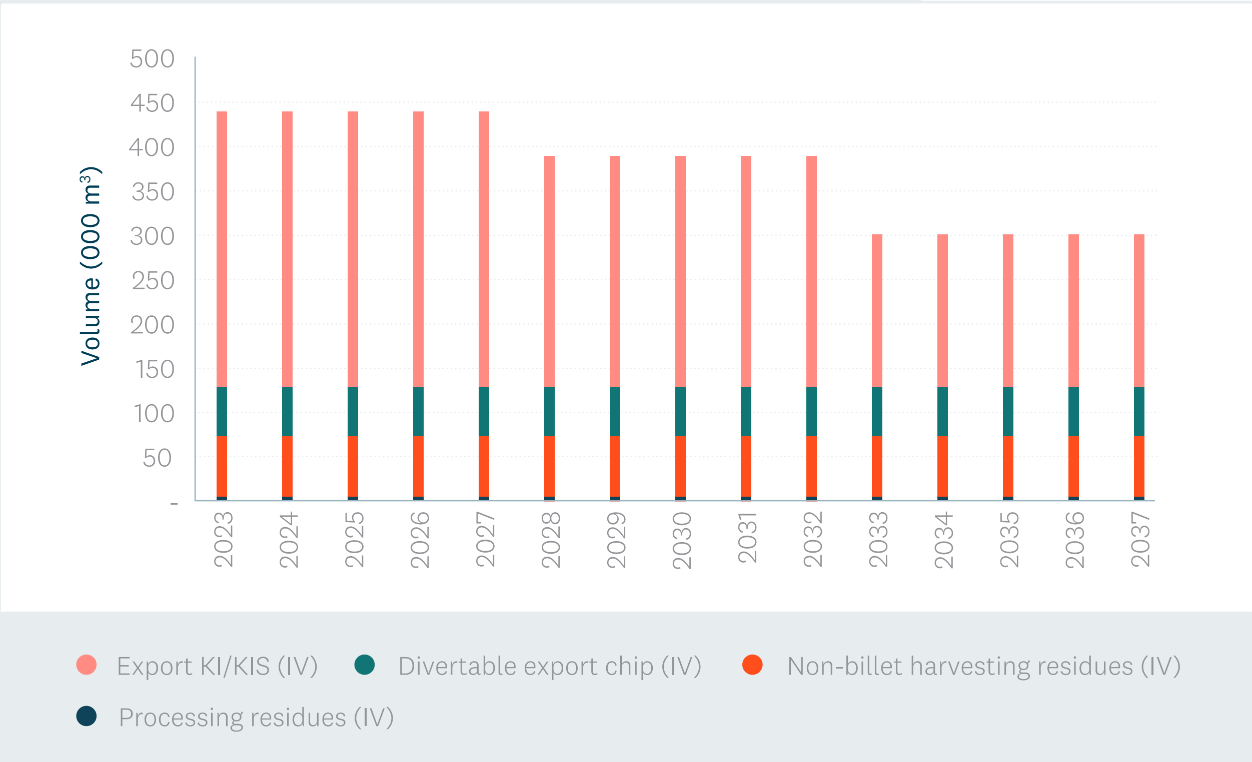
- The use of woody biomass for bioenergy requires careful consideration of emissions and sustainability. Depending on the source, the diversion of wood to bioenergy may change the timing of the release of emissions by a significant period, and/or result in land use change including additional deforestation. The potential for these undesirable consequences to occur domestically should be manageable within existing arrangements. However, diversion of wood currently destined for international markets could see these consequences occur in other countries, beyond the reach of New Zealand's domestic arrangements. Organisations contemplating the use of biomass need visibility of any global consequences of their decisions, such as an increase in deforestation or unsustainable land use.
- A good sense of the total availability of harvestable wood in Southland 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.
- A top-down analysis suggests that an average of around **1,000,000t pa of wood will be harvested in Southland over the next 15 years**. The majority of this will be radiata pine, especially in the short term, but there will be a growing amount of Douglas fir as time progresses. The majority of this wood will be harvested into export A, K, KI and KIS grades.
- A bottom-up analysis, based on interviews with owners, provides a more conservative view of volumes, especially in the latter part of the period.
- Over half of these forecast volumes are destined for export markets, with the remainder going to domestic timber markets (including the Daiken MDF factory at Mataura).
- EECA estimates that **205,000t pa of harvest residues could be recovered**. A little over half this amount is currently being recovered and is destined for bioenergy markets (e.g. firewood), while the rest is not currently utilised.
- Interviews with sawmills suggested that the majority of the processing resides are currently sold to Daiken's MDF plant. There are less than 4,000t of processing residues (mostly sawdust and bark) which are currently unutilised.

Overall, EECA estimates that, on average over the next 15 years, there is around 380,000t (2,740TJ) pa of Southland woody biomass that could be recovered and/or diverted in the near term to a bioenergy market. This includes an assumption that some lower grade export logs could be diverted with little change to the timing of the release of greenhouse gas emissions from this wood. This is sufficient to supply a pragmatic scenario of process heat fuel switching decisions but it would not be able to serve a high demand scenario where all RETA sites converted to biomass, without needing the diversion of high sales grade (export A and pruned) logs.

The figure below[8] shows the breakdown of the woody biomass that is available in the near term for bioenergy.

Near-term availability of woody biomass for process heat in Southland

Radiata pine, Douglas fir and Eucalyptus, 2023-2027, interview-based



[8] Figure 13 from the main report.

- Allowing for estimated costs of procurement, chipping, storage and delivery, the potential cost per GJ of the various resources identified may range between:
  - $9/GJ – $12/GJ for harvesting residues and processing residues
  - $14/GJ – $18/GJ for diverted export chip and low grade KIS logs
  - $21/GJ – $23/GJ for higher export-grade unpruned logs
  - $29/GJ for pruned logs

  The degree to which these resources are used is a commercial decision, which would include a comparison with alternatives in terms of cost and feasibility.

Electricity summary

- The availability of electricity to meet the demand from process heat users is largely determined at a national “wholesale” level. Supply is transported to an individual RETA site through electricity networks – a high voltage network owned by Transpower, and a lower voltage network, owned by “Electricity Distribution Businesses” (EDBs), that connects individual consumers to the boundary of Transpower’s grid (known as GXPs).

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

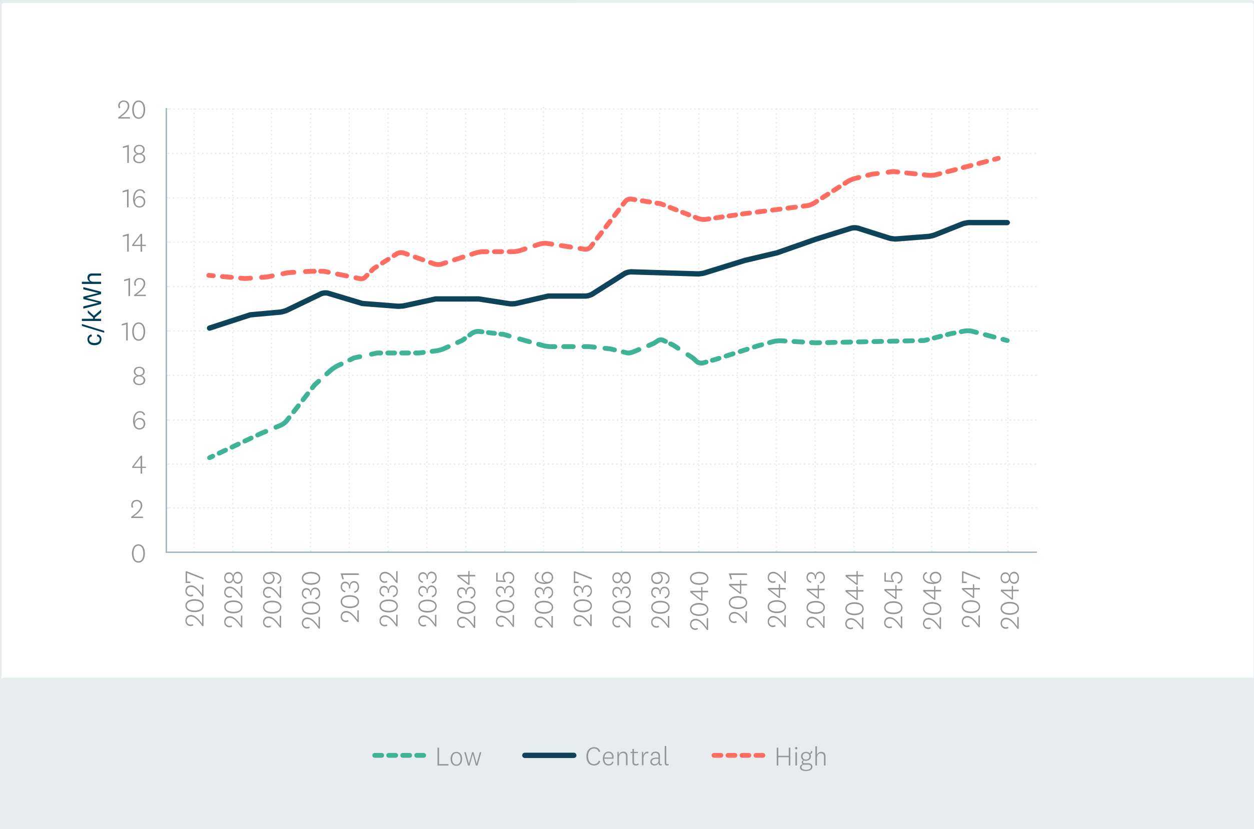
- The current “spare capacity” of Transpower and the EDBs’ networks to supply electricity-based process heat conversions.
- The cost of any upgrades required to accommodate the peak electricity demand of a process heat user (as well as any other consumers looking to increase electricity demand on that part of the network).
- 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 rarely occurring short lived outages, and/or its 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.**

- Our analysis suggests that, for networks, accommodating the new peak electricity demand from the majority of RETA sites is minor in complexity, and the estimated costs of the equipment required to connect these sites is <$1m. These sites place relatively low demands on the network.

- However, for sites with higher peak demands, the connections increase in complexity. If the connections do not require upgrades to Transpower's network, indicative costs are between $3m and $16m, while the largest consumers requiring upgrades to both distribution and transmission networks are approaching $60m in required upgrade costs.
- These costs 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.
- As shown in the figure below[9], the forecast price of electricity (via a retail contract) is expected to rise (in real terms) around 10% between 2027 and 2037 (to ~11c/kWh) under a "central" scenario. However, different scenarios could see real retail prices 2c/kWh higher or lower than that level by 2037.

EnergyLink retail electricity price forecast
Annual average prices; Real $2022



[9] Figure 29 from the main report.

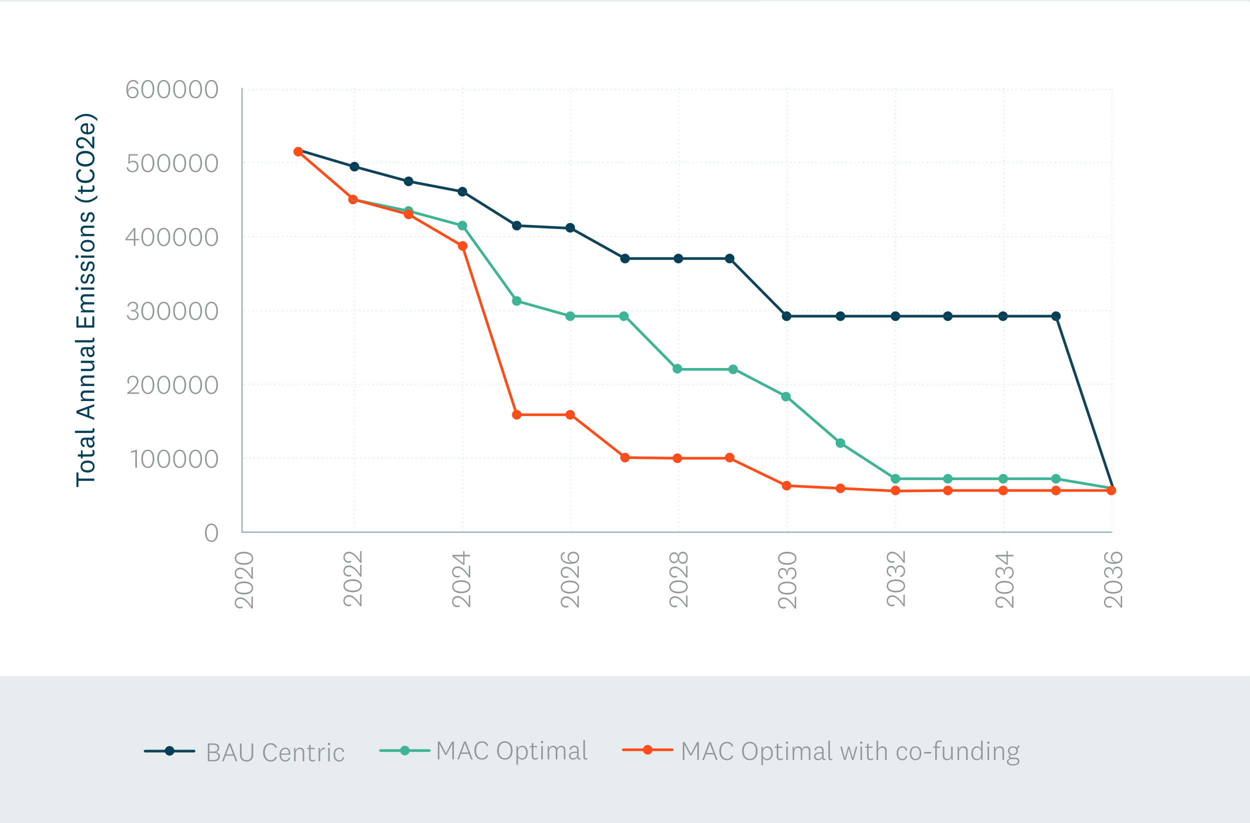
Decarbonisation pathways

EECA has developed various pathways (or scenarios) of decarbonisation by simulating the decisions of the Southland RETA sites based on a range of information and assumptions about the factors that drive each of these decisions (including decisions already committed to). Different decision-making frameworks give rise to the following three "pathways":

- BAU Centric – where each fuel (biomass or electricity) is the fuel chosen for every (unconfirmed) fuel switching decision, and is timed as per each site's ETA, where available, or 2036[10] if not.
- MAC Optimal – where the decision with the lowest marginal abatement cost (MAC) is made by each unconfirmed site.
- MAC Optimal with EECA acceleration co-funding (e.g. Existing GIDI fund) – as for MAC Optimal, but with co-funding applied in a consistent manner across all unconfirmed projects.

As shown in the figure below[11], by 2036 all pathways eliminate nearly 90% of process heat emissions in the region (a reduction of 464kt out of a total 519kt), but at significantly different paces.

Southland RETA simulated emissions reduction pathways



[10] The target of 2037 relates to the Government's preferred option to phase out the use of coal at existing sites for low and medium temperature process heat requirements through national environmental standards. See https://consult.environment.govt.nz/climate/phasing-out-fossil-fuels-in-process-heat/supporting_documents/phasingoutfossilfuelsinprocessheat.pdf

[11] Figure 34 from the main report.

The BAU Centric pathway, which uses the project timings in the individual ETAs (or 2036 where unavailable), is the slowest decarbonisation path. Around half the emissions reductions are assumed to occur in 2036.

The MAC Optimal pathway proceeds at a similar smooth pace as the linear approach, with the majority of emissions reductions achieved by 2030.

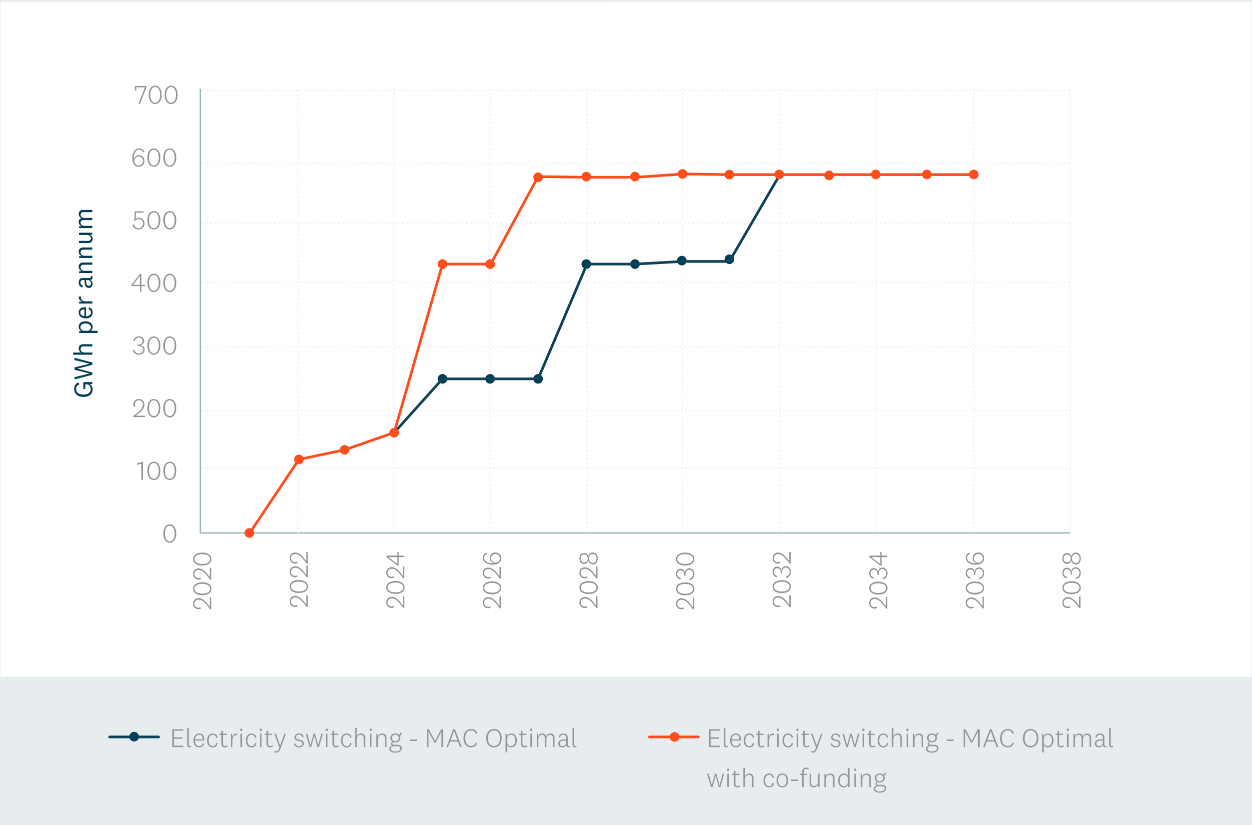
The MAC Optimal pathway with acceleration co-funding essentially results in 96% of emissions reductions having a MAC value of less than $150/t (up from 75% with no co-funding) and doubles the pace of decarbonisation, with 70% of the decarbonisation occurring by the end of 2025. The cumulative difference between the BAU Centric approach, and MAC Optimal with co-funding, is 2.9M tCO2-e across the period 2022–2036.

Fuel use under different pathways

Both the MAC Optimal pathways (with and without acceleration co-funding) see fuel decisions that result in 45% of the energy needs supplied by biomass (with a consumption of 476GWh, or 1,130TOJ, of delivered energy), and 55% of energy needs supplied by electricity (with 576GWh of delivered energy).

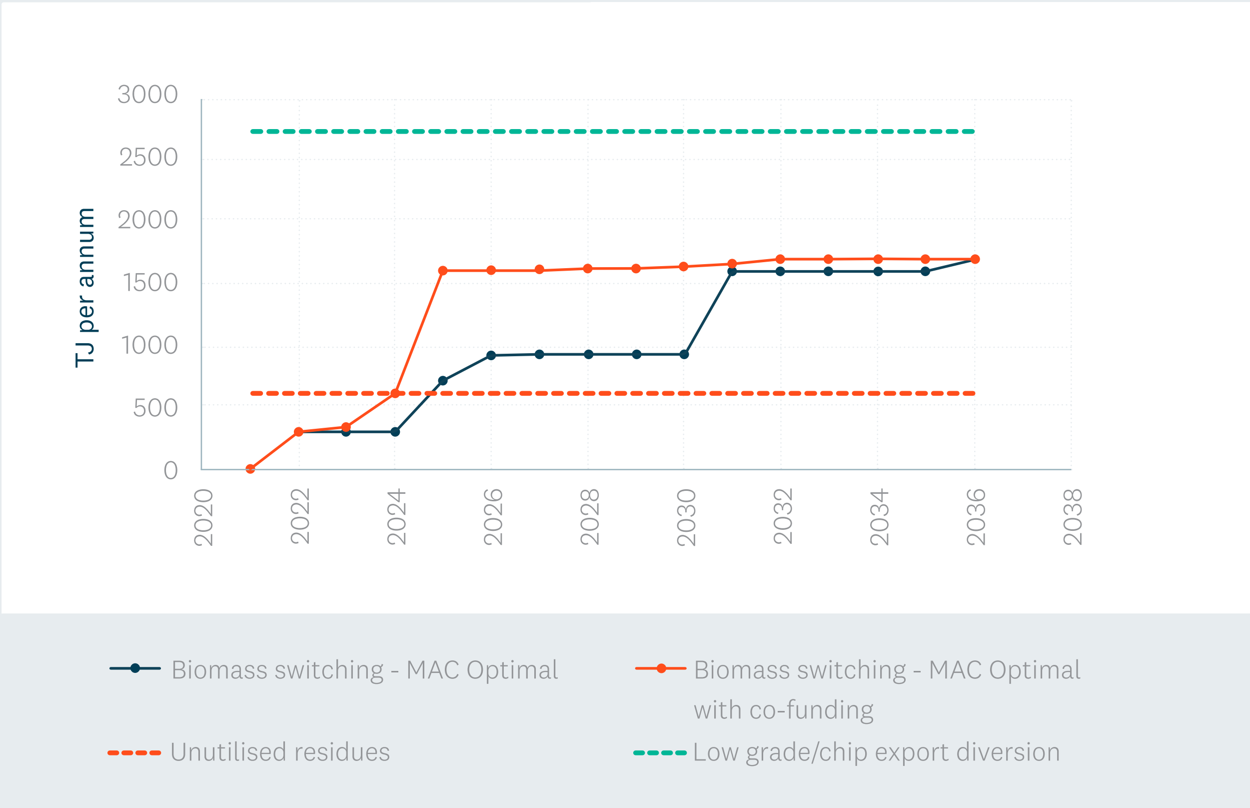
The figures below[12] show the effect of acceleration co-funding on the pace of decarbonisation, for both electricity and biomass.

Electricity demand from boiler fuel switching
Unconfirmed RETA process heat projects



[12] Figure 37 and Figure 38 from the main report.

Biomass demand from boiler fuel switching
Unconfirmed RETA process heat projects



The biomass figure shows that by 2024, the estimated volumes of unutilised harvesting and processor residues will be exhausted, almost irrespective of the pathway. Meeting the remaining demand from fuel switching projects will require diversion of export chip and export low-grade logs to domestic bioenergy.

Recommendations

The Southland RETA analysis and pathways have provided a first-of-a-kind regional perspective on both the supply and demand sides of process heat decarbonisation. It has illuminated and quantified a number of system-wide insights about the sufficiency of low-emissions fuel supply to meet decarbonisation demand.

These insights highlight the dynamic effects that exist between the decisions made by decarbonising organisations, and the decisions made by owners and investors in common infrastructure. The supply and demand side of the process heat "market" is changing quickly; our analysis is based on what is known at the time of writing, some of which will be superseded in the years to come. This motivates a more dynamic approach to production of RETA-type analysis, to ensure these owners have the best information possible to guide their decisions.

While we make detailed observations and recommendations in the report, they can be summarised as:

- Good decisions rely on good information and both biomass and electricity network owners need ways to improve the flow of information to RETA process heat users, and vice versa.

  Recommendation: More frequent information exchange needs to occur between process heat users and owners of resources and supply network infrastructure. EECA could play a role here by publishing periodic (2-3 yearly) updates on the key variables illuminated by RETA studies, such as costs, prices and volumes for fuels supplied and consumed.

- Coordination of buyers and sellers requires a special focus through a transition, especially where the collective decisions of multiple individual sites may imply different infrastructure or resource investments than any one site in isolation. The wholesale electricity market is effectively a mechanism for coordination and assists the decisions of both buyers and sellers; these structures do not exist (and may never exist in the same form) for biomass, or network infrastructure. Hence the institutional job of coordination becomes very important.

  Recommendation: More efficient coordination mechanisms need to be developed than the somewhat ad-hoc processes used today, to achieve the best use of resources to meet demand.

- The use of woody biomass for bioenergy requires careful consideration of emissions and sustainability. Depending on the source, the diversion of wood to bioenergy may change the timing of the release of emissions by a significant period, and/or result in land use change including additional deforestation. Potential buyers of biomass for process heat need clarity regarding the global life-cycle impacts of diverting wood away from export markets, to give consumers confidence about the net effect their decisions are having on global resources and emissions.

  Recommendation: A thorough assessment of the global sustainability impacts of diversion of export wood to local bioenergy usage is developed and published.

- A central theme in the assessment of the costs of both electricity network upgrades and the consumption of electricity as a fuel was flexibility: the ability of a site to leverage its ability to temporarily curtail or shift demand (potentially at short notice) to reduce the magnitude and thus cost of any network upgrades required to accommodate it, and also reduce the retail cost of the power it consumes. In some situations, flexibility may only be able to be embedded in the system at the point of design – i.e. now – and thus process heat investors need good signals that enabling this flexibility will be rewarded.

  Recommendation: More information needs to be developed and published to illustrate and quantify the benefits of flexibility for process heat users, while electricity distributors and retailers need to ensure that they are accommodating and rewarding flexibility through the tariffs they offer process heat users.

- There is an interplay between the use of biomass as a low emissions source of process heat, and its use for other low emissions energy services. Transport is the most obvious extension, given the potential for both biofuels and electricity to underpin decarbonisation. This could result in competition for the same resources, with consequential impacts on availability and cost.

  Recommendation: Future RETA studies need to consider other industries that are considering decarbonisation decisions, especially those that are competing for the same fuels (biomass and electricity).

- There are a range of uncertainties highlighted in this report (for example resource costs, and carbon prices) that could change whether process heat users choose electricity or biomass.

  Recommendation: Future development of RETA pathways make greater use of sensitivity analysis to illustrate how a variety of factors may influence the choice of low emissions fuel.

- Finally, EECA's analysis demonstrated how government co-funding could substantially accelerate the decarbonisation of Southland's process heat.

  Recommendation: EECA encourages 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.


Wairakei Geothermal (Contact) - Wairakei, Taupō, New Zealand

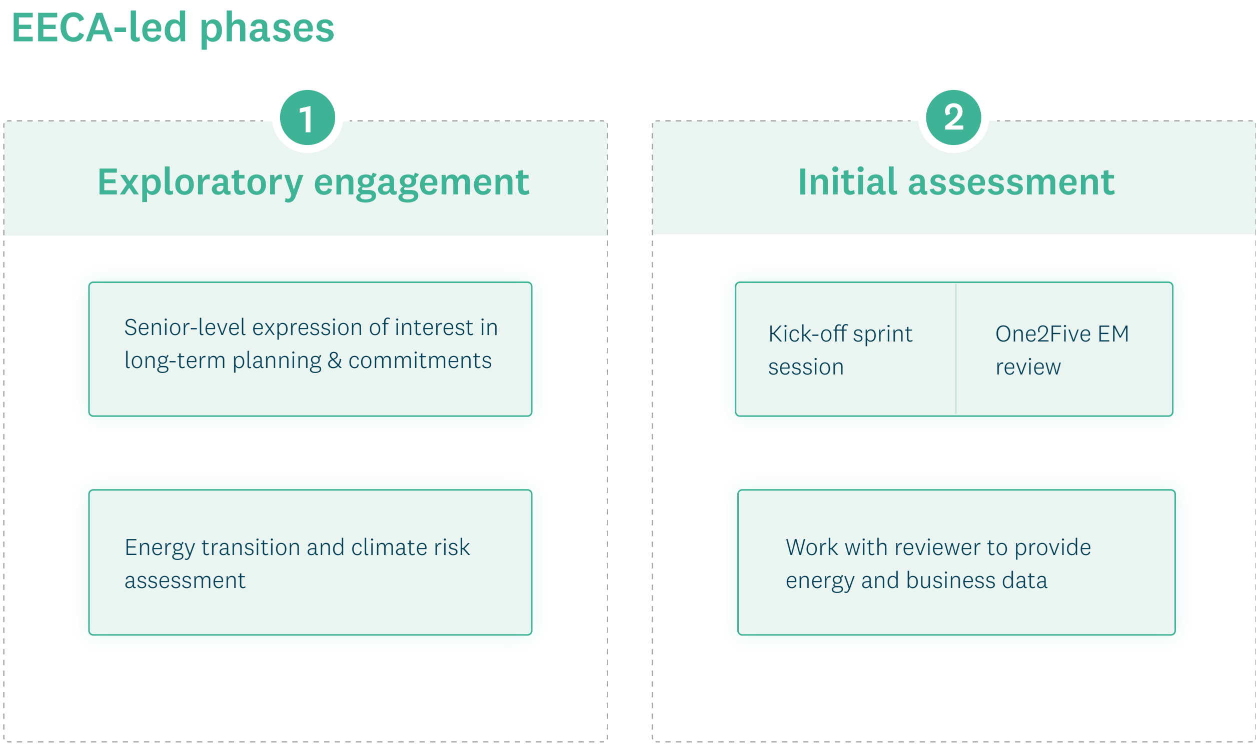
5 Introduction

EECA has run the Energy Transition Accelerator (ETA) programme since 2019.

5.1. The ETA programme

The programme aims to support New Zealand's largest businesses to make technically and economically viable 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 prepare for the future, by capitalising on the energy and carbon saving opportunities that are in the pipeline now, and beyond 2030. An overview of the ETA programme is shown in Figure 1 below.

Figure 1 - Overview of ETA programme. Source - EECA



All existing EECA business tools remain available as appropiate (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)

5.2. New Zealand's first process heat RETA - Southland

The number of companies that EECA assisted in the Southland region created an opportunity for a Regional Energy Transition Accelerator (RETA) pilot. This would give EECA the ability to use some of the information collected in individual ETAs to develop a first-of-a-kind analysis of regional process heat decarbonisation pathways. This analysis would inform coordination and information challenges faced by individual organisations when dealing with process heat problems that were collective in nature, such as the need for common infrastructure or new markets.

There are two stages of a RETA project – planning, and implementation. 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 on 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.

This report is the culmination of the RETA planning stage.

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

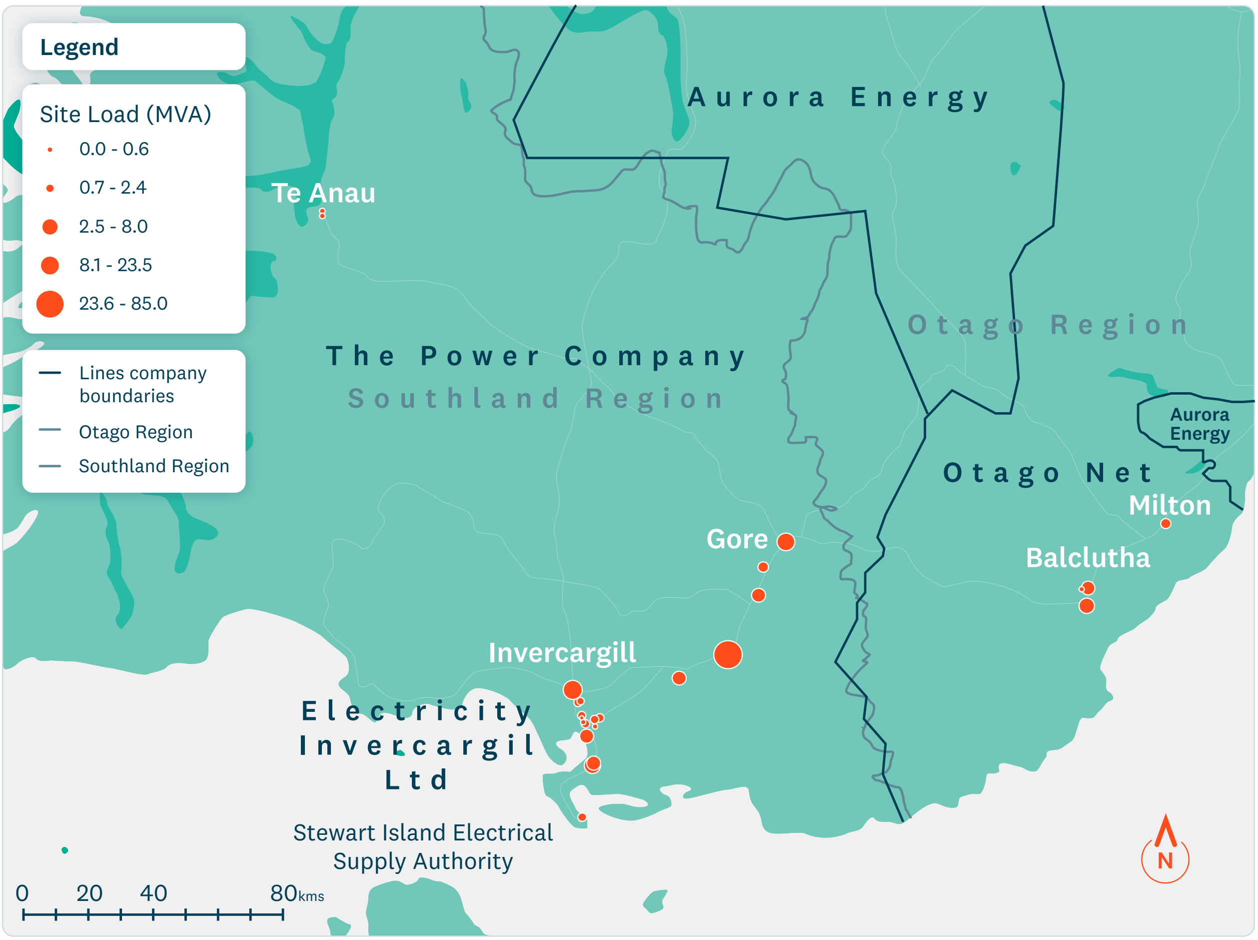
Wairakei Geothermal Power Station - Taupo, New Zealand

6 Southland process heat - the opportunity

6.1. The Southland region

The area of study encompasses the Southland region, but also includes parts of South Otago as a result of the inclusion of decarbonisation projects in Balclutha and Milton. Figure 2 illustrates the region considered in this report, with the process heat sites located and sized according to their peak electricity demand.

Figure 2 - The Southland RETA region

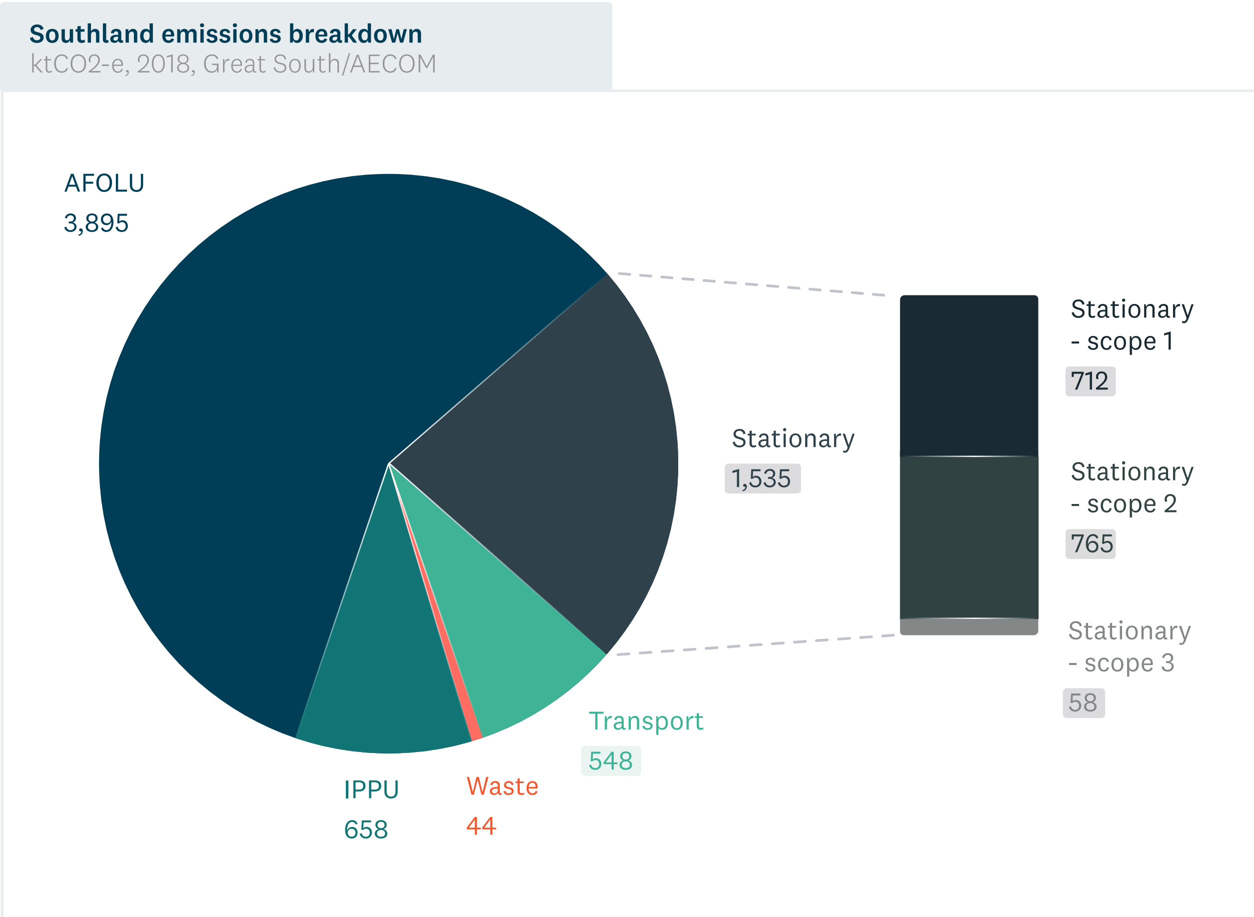


6.2. Emissions in Southland

AECOM's assessment of Southland's emissions, commissioned by Great South, reports that overall, Southland is responsible for an estimated 9.7% of New Zealand's total gross emissions.[13]

Stationary energy emissions are the second-largest source of greenhouse gas emissions in the Southland region (Figure 3) behind agriculture[14], and represent approximately a quarter of total Southland emissions.

Figure 3 - Southland emissions breakdown. Source: AECOM



In the stationary energy emissions category, direct emissions from coal, gas, diesel, petrol, LPG, biodiesel and wood (i.e. Scope 1 emissions) totalled 712kt. Of that, around 80% (590kt) came from the manufacturing and commercial sectors. This 590kt represents approximately a third of total stationary energy emissions (1,535kt) and 21% of non-agriculture emissions. It is also more than the emissions from the entire Southland transport fleet. EECA understands that the vast majority of these emissions come from process heat users.

These scope 1 process heat emissions are the target of the Southland RETA.

[13] AECOM (2018), *Southland Regional Carbon Footprint 2018*, report prepared for Great South, October 2019.

[14] In 2018, agriculture contributed 6.1m tCO2-e to emissions. In the chart above, this was offset through 2.2m tCO2-e of sequestration from forestry.

6.3. Emissions coverage of the Southland RETA

The Southland RETA report covers a total of 40 process heat sites spanning dairy, meat, industrial (e.g. sawmills) and commercial (predominantly facility heating). These are summarised in Table 1. In order to target the greatest level of emissions reduction opportunities, the sites selected represent all fossil fuelled boilers above 500kW and any other sites (e.g. schools) where EECA had information from various programmes up to 2022.

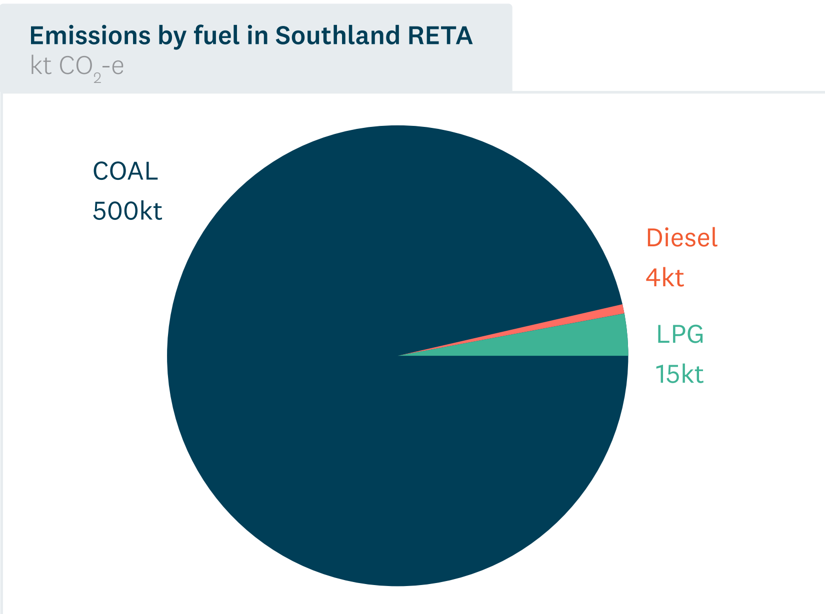
Together, these sites contribute 519kt of greenhouse gas emissions, approximately 88% of scope 1 manufacturing and commercial stationary energy emissions highlighted above.

Table 1 - Summary of sites included in Southland RETA. Source: EECA

Sector	Sites	Thermal capacity (MW)	Process heat demand (GWh pa)	Process heat demand (TJ pa)	Process heat annual emissions (ktCO2e pa)
Dairy	5	205	1,168	4,205	403
Meat	7	68	256	921	87
Industrial	4	16	40	140	12
Commercial[15]	24	46	54	194	17
Total	**40**	**336**	**1,518**	**5,460**	**519**

The majority of Southland RETA emissions come from coal (Figure 4), as suggested by the regional heat demand database.

Figure 4 – 2020 Annual Emissions by fuel in Southland RETA. Source: EECA



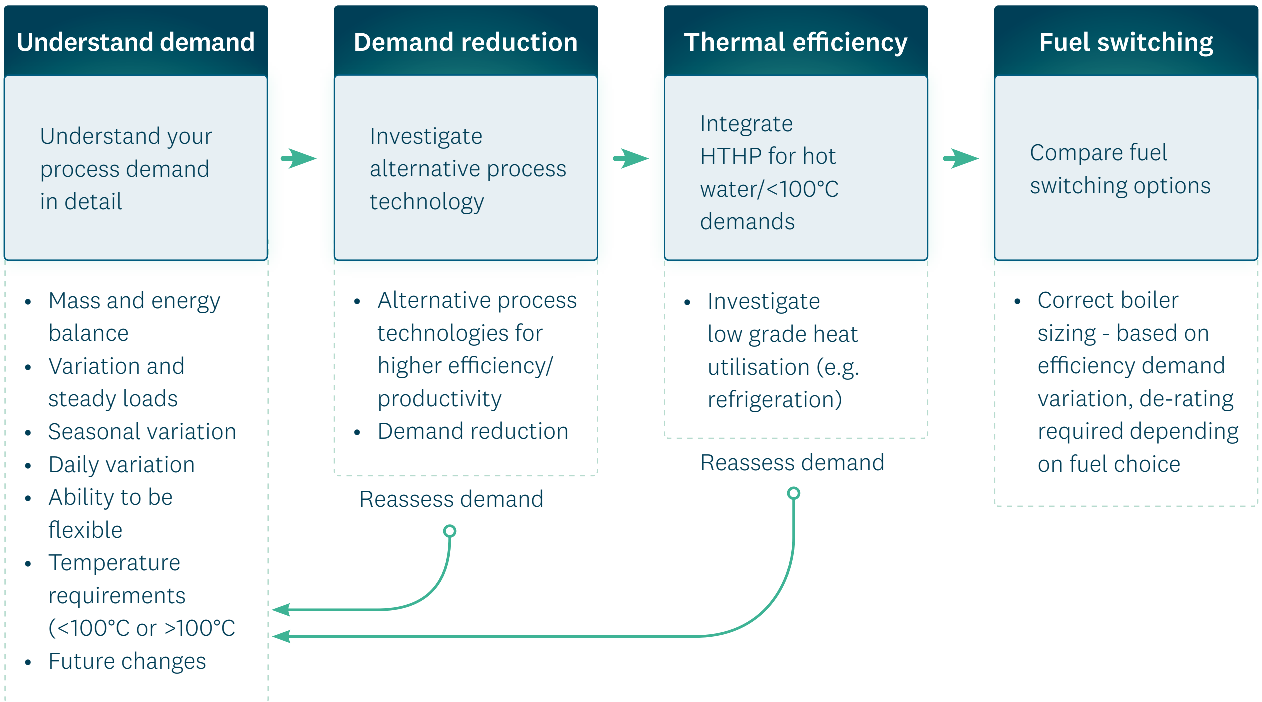
[15] The commercial sector includes schools, hospitals and accommodation facilities.

6.4. 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, there are a number of initial steps in the decision-making process which can reduce energy consumption and emissions before the major fuel 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 5 provides an overview of the main steps in the decisionmaking process.

Figure 5 - Key steps in process heat decarbonisation



As part of the fuel switching step above

Electricity

- Electrode boiler
- Network capacity increase required?
- Ability to flex demand to minimise cost
- Electricity tariff

Biomass

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

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 Sections 8 and 8.7, this flexibility can reduce the cost associated with any electricity network upgrades required to accommodate the project, and can also mean a financial reward for the process heat user through a variable ("time-of-use") electricity tariff.

Having understood the nature of the site's demand, there are four primary ways in which emissions can be reduced from the process heat projects covered by the Southland RETA. For any given site, the four options below are not mutually exclusive i.e. a number of options could be executed. Moreover, some of the options below are precursors for others – for example, in order to minimise the cost of a new boiler, demand reduction projects should proceed first.

Demand reduction

Demand reduction includes projects such as heat recovery, temperature optimisation, equipment replacement 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.[16] 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.

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

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). As a result of their high efficiency, opportunities to use HTHPs where heat requirements are lower than 100°C are highly likely to be economic. These projects vary from site to site, but can provide heating for process water, potable water on industrial sites or HVAC on commercial sites.

Furthermore, where a site has a range of heat requirements, heat pump projects are generally 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 CoP of 3-5 can typically be achieved.[17] While not yet available on the market, high temperature steam heat pumps, producing 150°C heat, also have the potential to decarbonise much of New Zealand's industry, within the 15 year timeframe contemplated by EECA's RETA decarbonisation pathways for Southland (outlined in Section 9).

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 boiler will be replaced, 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 age and condition, and will have implications for the type of biomass used.
- 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 can be retrofitted to process wood pellets or chip. 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 readily available. There is a lack of supply of wood pellets across the country, which is likely to continue until large producers enter the market.
- As outlined later, EECA has not considered in detail the logistical and emissions impact of transporting biomass but note that wood pellets will have lesser transport requirements due to their higher energy density.
- Some wood chip (undried) and hog will have a high moisture content which will affect the performance of the overall process.

[17] Heat pump systems coupled to refrigeration systems can achieve Coefficient of Performance (CoPs) of 8 or more.

- The inconsistency of hog fuel means greater interaction is required (increasing operational cost), and requires major modifications to the facility (e.g. fuel handling and storage facilities), which increases the capital cost. The use of hog fuel is also likely to require de-rating of the boiler due to moisture content.[18] However, the fuel is significantly cheaper than wood pellets, potentially making it viable.

- The available space on site is also important. Wood pellets take up significantly less space than wood chip or hog, although pellets must remain dry.

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 are more expensive to run. Operationally these boilers are ~25% more efficient than biomass, with fast response times and low maintenance costs.[19]

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 are likely to structure prices in a way that rewards the heat user for shifting their 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 8.7.

[18] If the current boiler is used to its maximum capacity for some periods, then the impacts of de-rating to accommodate wetter fuel must be taken into account when sizing the replacement boiler.

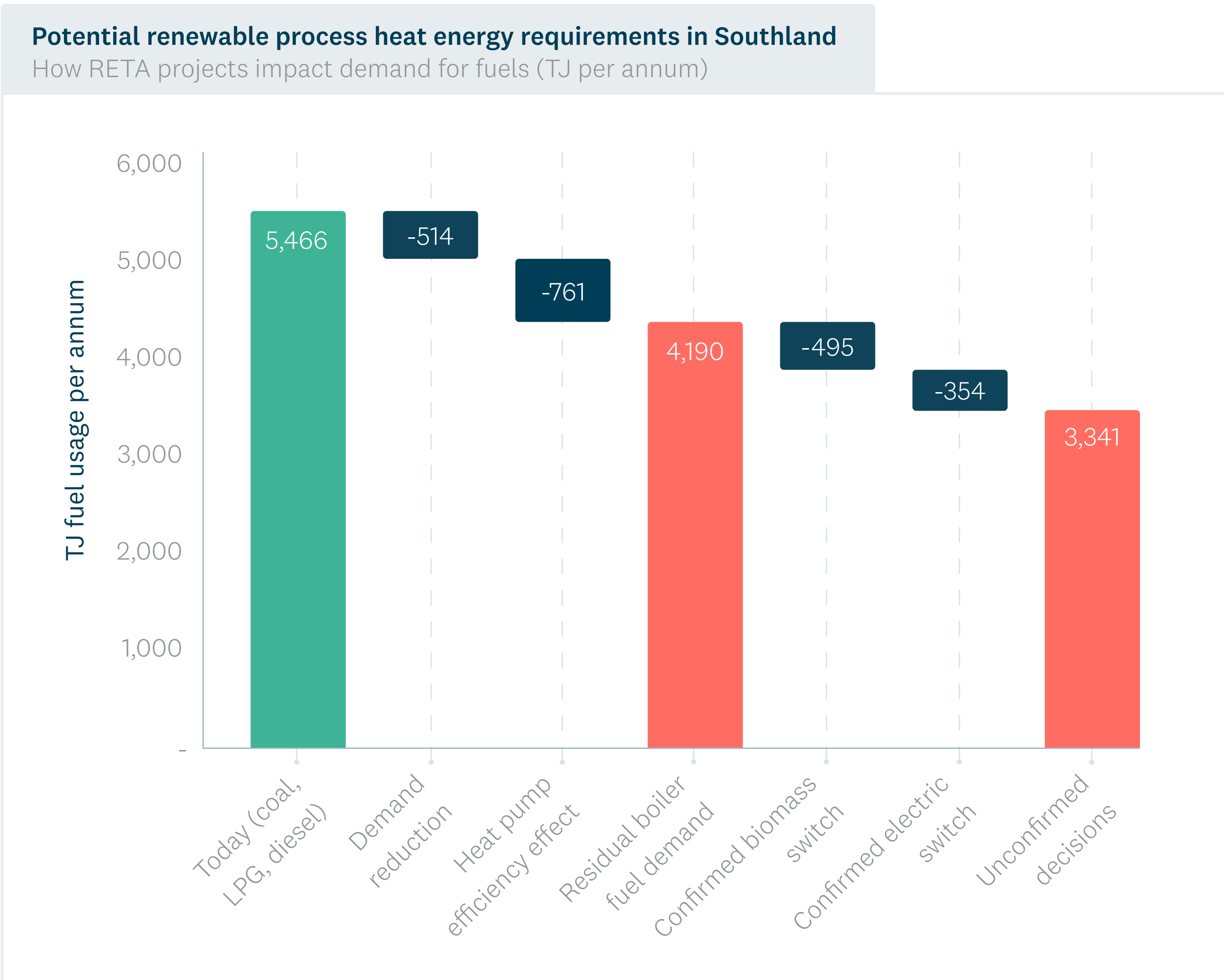
[19] See https://genless.govt.nz/assets/Business-Resources/Electrode-electric-resistance-steam-generators-hot-water-heaters-for-low-carbon-process-heating.pdf

6.5. Process heat energy uses – implications for local energy resources

All RETA decarbonisation pathways (presented in Section 9) expect that the 40 Southland RETA sites, representing 5,460TJ pa of coal, LPG and diesel consumption in 2022, will have switched to low emissions fuel before 2037. The rate this might occur at, 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 5,460TJ of energy consumed by sites in the RETA study will be eliminated through demand reduction projects. Further, installing heat pumps could see significant efficiencies achieved. Finally, some fuel switching projects have already been confirmed. 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.

Figure 6 - Potential impact of fuel switching on fossil fuel usage, 2022-2037. Source: EECA



As 3,341TJ of fuel switching decisions are yet to be made, the magnitude of change in biomass and electricity demand cannot be known with any precision. However, we can say:

- **If all unconfirmed fuel switching decisions choose electricity, this could result in an increase in electricity demand of 790GWh[20], approximately a 12% increase in Southland's electricity demand today.[21]**
- **If all unconfirmed boiler fuel switching decisions choose biomass, this could result in an increase of 3,800TJ, or 520,000t of biomass usage (see Section 7.7).[22] This compares to our estimate that, today, 129,000t of biomass is used for heat at the time of writing, i.e. a ~300% increase in the use of biomass for heat.**

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, and EECA expects that the final outcome in Southland will be a diverse mix of electrification (both heat pumps and boilers) and biomass. These dynamics will be covered more in Section 9.

[20] This includes the 50GWh increase in electricity demand from presumed installation of high temperature heat pumps; the confirmed electric boiler installations, and the replaced fossil fuel consumption (converted into heat at an assumed current efficiency of 78%) is replaced with electrode boilers (at an assumed efficiency of 100%).

[21] Including NZAS consumption at Tiwai. The future of NZAS at Tiwai, which represents 75% of Southland's electricity demand today, is uncertain at this point in time. Alternatively, this process heat impact could be described as a 50% increase in Southland's non-Tiwai electricity demand.

[22] Again, including projects that have already confirmed a switch to biomass.

13 mega-watt (MW) electrode boiler at Open Country, Awarua, Southland, New Zealand

7 Biomass

- The use of woody biomass for bioenergy requires careful emissions and sustainability consideration. Depending on the source, the diversion of wood to bioenergy may change the timing of the release of emissions by a significant period, and/or result in land use change including additional deforestation. While these undesirable consequences should be appropriately managed domestically through New Zealand's policy arrangements, any global consequences of diverting wood away from international markets is not currently visible to domestic decision makers.
- A good sense of the total availability of harvested wood in Southland 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.
- A top-down analysis suggests that an average of around 1,000,000t of wood will be harvested in Southland over the next 15 years. The majority of this will be radiata pine, especially in the short term, but there will be a growing amount of Douglas fir as time progresses. The majority of this wood will be harvested into xport A, K, KI and KIS grade.
- A bottom-up analysis, based on interviews with owners, provides a more conservative view of volumes, especially in the latter part of the period.
- Over half of these forecast volumes are destined for export markets, with the remainder going to domestic timber markets (including the Daiken MDF factory at Mataura).
- As well as forecast harvested volumes, EECA estimates that an additional 205,000t of harvesting residues could be recovered. A little over half this amount is currently being recovered and is destined for bioenergy markets (e.g. firewood), while the rest is not currently utilised.
- Interviews with sawmills suggested that the majority of the processing resides are sold to Daiken's MDF plant. There is less than 4,000t of processing residues (mostly sawdust and bark) which are currently unutilised.
- Overall, it estimated there is around 380,000t (2,740TJ) pa of Southland woody biomass that could be recovered and/or diverted in the near term to a bioenergy market. This includes an assumption that some lower grade export logs could be diverted with little change to the timing of the release of greenhouse gas emissions from this wood. This is sufficient to supply a pragmatic scenario of process heat fuel switching decisions but would not be able to serve a high demand scenario where all RETA sites converted to biomass, without needing the diversion of high sales grade (export A and pruned) logs.

- **Allowing for estimated costs of procurement, chipping, storage and delivery, the potential cost per GJ of the various resources identified may range between:**
  - **$9/GJ - $12/GJ for harvesting and processing residues**
  - **$14/GJ - $18/GJ for diverted export chip and low grade KIS logs**
  - **$21/GJ - $23/GJ for higher export-grade unpruned logs**
  - **$29/GJ for pruned logs**
- **Hence a commercial overlay suggests the diversion of higher-grade logs to meet the high demand scenario may note eventuate.**

7.1. Approach to our analysis of biomass

This section considers the availability and potential cost of wood resources in the Southland 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 500,000t – which would be the demand should all RETA sites elect to switch to biomass for process heat. While we note below that there are other sources which could complement forestry, we do not investigate these in any detail due to their relatively small volumes.

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 Southland, including those sources that are not currently being recovered from, e.g. 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.
- Highlight the existing domestic and international markets for the harvested wood, either for timber products or existing demand for bioenergy (e.g. firewood) that will likely constrain the ability to divert wood to bioenergy for process heat in the near-term.
- Consider what this analysis implies for the potential cost of delivering different types of biomass to process heat users.
- Overlay two scenarios of process heat demand for biomass from RETA fuel switching decisions, to ascertain whether this demand could be met from near-term available sources, noting that the supply of bioenergy will evolve through time.

Thus the results (bullet points 3 & 4 on prevous page) give a plausible view of the medium term availability of Southland biomass for process heat purposes, and the foreseeable economic implications of using these resources (i.e. based on what we know at the time of writing). This has the potential to help users make indicative commercial judgments about the attractiveness of biomass, in the quantities required, relative to other fuel switching alternatives.

Only biomass sources within the Southland region are considered. There are other regions in New Zealand where bioenergy supply potentially exceeds the demand.[23] Conceivably, these resources could be transported to Southland, 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 for 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, biofuels are a potential low-emission alternative to existing oil-derived transport fuels, and the Plan includes an action to implement a sustainable biofuels obligation.[24] This requires further analysis, as EECA does not currently have reliable estimates for the likely local demand for biofuels.[25]

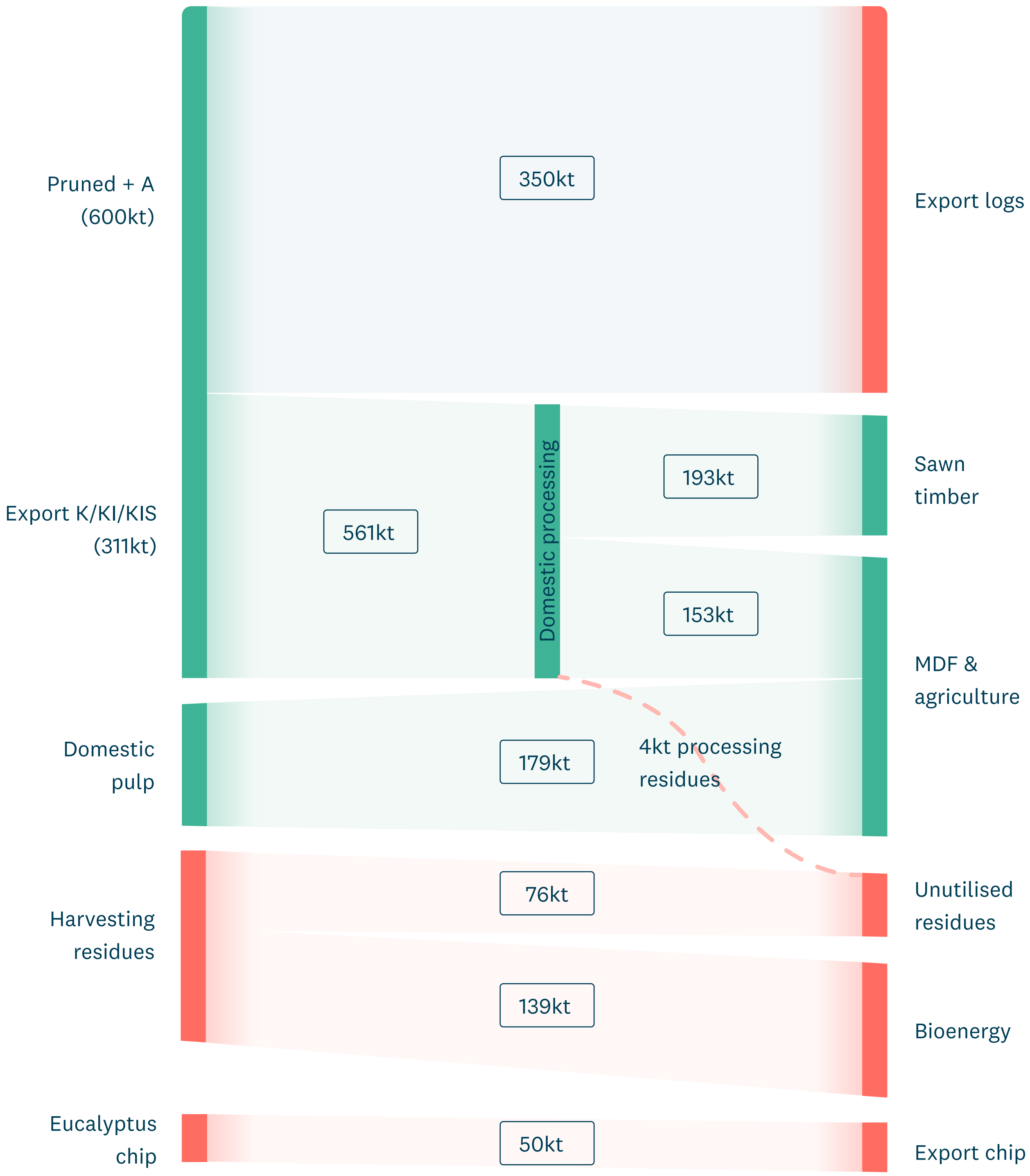
Figure 7 provides an overview of the section's analysis.

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

[24] Ministry for the Environment, (2022), *Aotearoa New Zealand's first emissions reduction plan*, Action 10.3.5, page 190.

[25] An approximate estimate, from internal EECA analysis, suggests that around 1Mt of woody biomass would be needed to completely replace Southland's demand for diesel from heavy trucks with biodiesel. This assumes that Southland's diesel demand is 2.9PJ (derived from AECOM's emissions report for Great South) and conversion estimates derived from the IEA of between 2,400 and 4,000MJ/kg. We have used an average figure of 3,000MJ/kg in deriving our estimate here.

Figure 7 - Flows of Southland's biomass resources 2023-2027 . Source: Ahikā



7.2. Emissions effect of biomass

The use of biomass as a low-emissions alternative to fossil fuels gives rise to some debate when forestry resources are considered. Generally, this debate centres on whether the forestry-based biomass is simply derived from waste products and in-forest residues, or is sourced by diverting timber away from end markets.

- If the biomass is purely sourced from in-forest waste residues, there is no net emissions effect[26] as these by-products would have decomposed anyway in situ; however, that decomposition may have benefits to e.g. soil quality and carbon sequestration.
- If these markets are local, the domestic arrangements for accounting for and surrendering carbon emissions should provide the correct incentives (as they do in New Zealand).
- If the biomass is sourced by diverting away from export markets, New Zealand has no visibility or control over the emissions impact (i.e. the change in timing of when emissions from biomass are released into the atmosphere) or how the international demand "hole" created by that diversion will be met (i.e. whether it will result in felling additional forests elsewhere). Neither does New Zealand have to account for alternative supply under its Emissions Trading Scheme (ETS) arrangements. This means there is a risk that diversion from exports would create an acceleration of the release of emissions from the biomass, or direct/indirect deforestation.
- Biomass could be derived from dedicated new energy crops, but the land use implications of this need to be carefully considered. In any case, even if dedicated new crops were planted today, they would not be available to users until beyond the timeframe of this RETA study (15 years).

The Climate Change Commission stated that "Exotic forestry will also play an important role in providing biomass feedstock for the bioeconomy, allowing biomass to be used as a replacement for fossil fuels", and that their analysis assumes the biomass resource is available from "accessible domestic forestry residue and pulp logs".[27] Other international guidance also focuses on harvesting residues.

Some of these issues with the sustainability of biomass supply chains have been included in the sustainability criteria adopted by the New Zealand Government in 2021 as part of the sustainable biofuels obligation.[28] These criteria apply equally regardless of whether biofuels are cultivated or processed domestically or internationally.

EECA understands that low-grade export logs are primarily used offshore for bioenergy, or for short-term purposes such as pallets or temporary construction materials, which is subsequently burned. While not addressing the question of how their diversion from export is filled by these international customers, these low-grade export logs are considered as having a low impact on global emissions should they be diverted to domestic bioenergy.

Below, we consider two different decarbonisation "pathways" which simulate the fuel switching decisions of RETA process heat sites. These pathways will help us consider whether there is sufficient low-emissions biomass to meet the pathways' demand.

[26] We note that collecting in-forest residues in the near-term is likely to be a source of emissions through the consumption of heavy transport fuels.

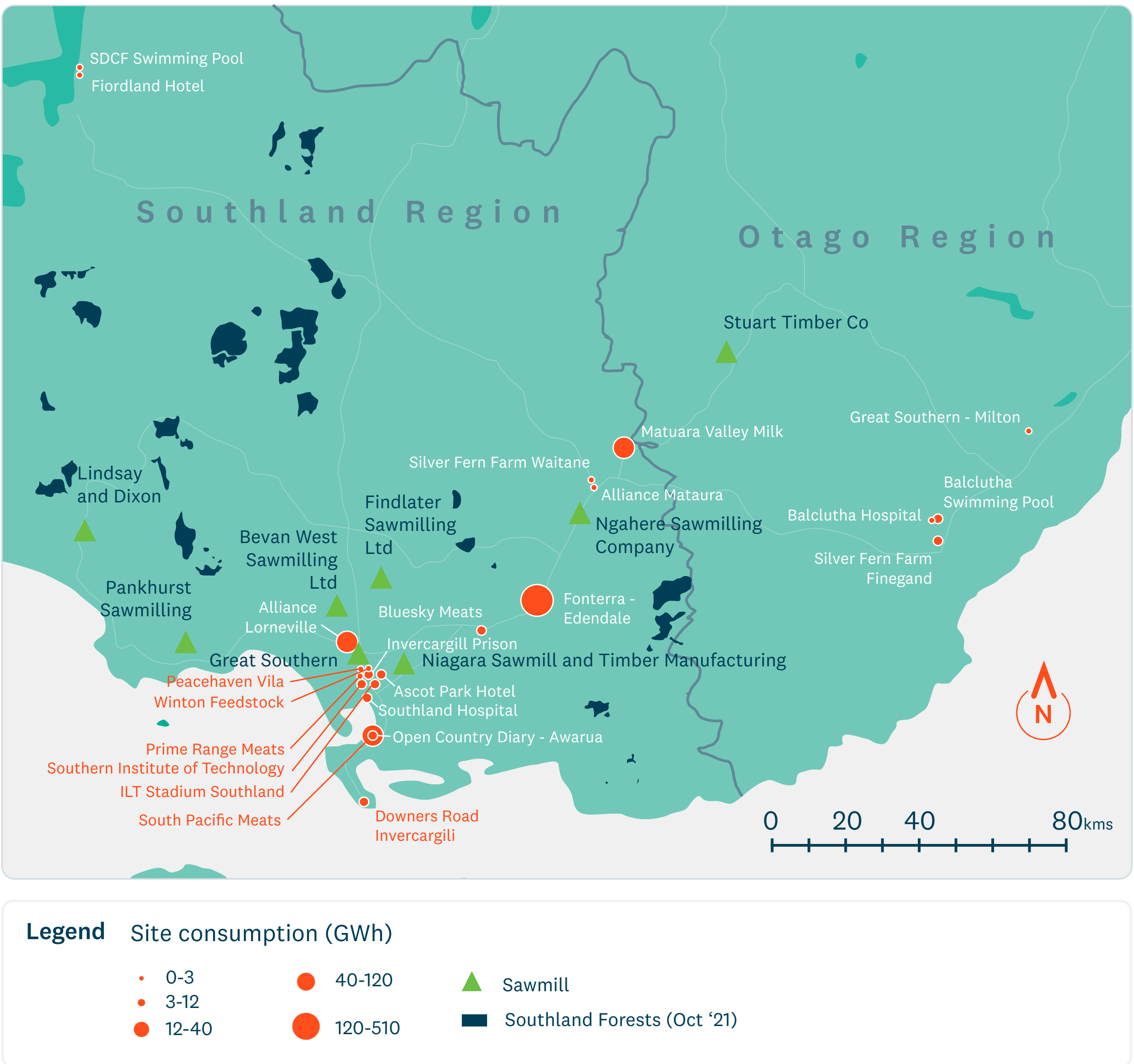
[27] He Pou a Rangi (Climate Change Commission) 2021, *Inaia tonu nei: a low emissions future for Aotearoa*, paragraphs 30 and 70.

[28] https://www.mbie.govt.nz/dmsdocument/21273-the-sustainable-biofuels-obligation-proposals-for-regulations-pdf

7.3. Characteristics of Southland forest resources

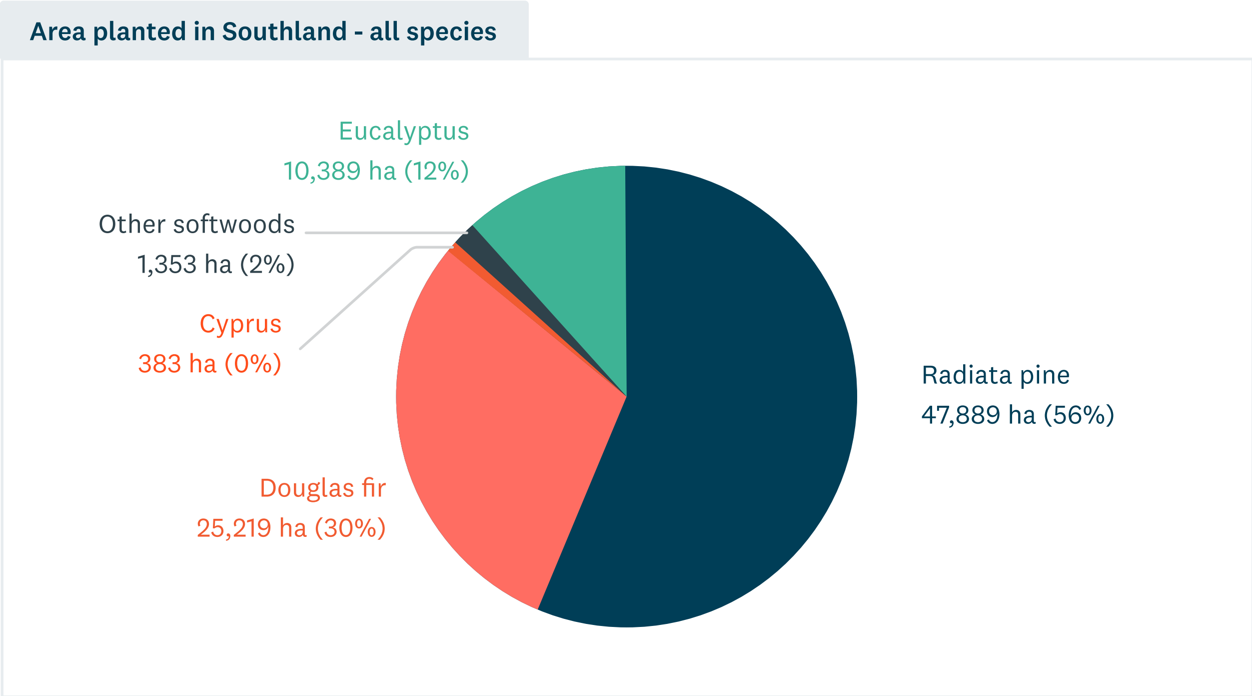
Figure 8 illustrates the key components of the biomass ecosystem in Southland – forests, sawmills and process heat users' sites.

Figure 8 - Location of Southland forests, sawmills and RETA sites



Southland forests consist of three primary species – radiata pine, Douglas fir and eucalyptus. These account for 97% of all forests in the region (Figure 9).

Figure 9 - Area planted in Southland, by species. Source: Ahikā



Ownership of forests

In the combined Southland and Otago estate, large scale owners (>500ha) hold 56% of modelled resources, small scale (<500ha) 44%. In the Southland region, the key estate owners are:

Rayonier Matariki Forests (21,200ha, 25% of Southland estate)

Rayonier Matariki Forests is 100% owned by US-based TRS Holdings. Rayonier have large estates throughout New Zealand including in Otago and Southland. The majority of their Southland estate is located in Western Southland. The estate is mostly comprised of radiata pine and Douglas fir and some minor species.

Southward Export (10,300ha, 12% of Southland estate)

Southwood Export is 100% owned by ITOCHU Pulp and Paper Corporation in Japan. Southwood was established in 1981 to process eucalyptus logs into chip for export to pulp and paper mills in Japan. As well as its own estate, Southwood manages the plantation forest estates of Southland Plantation Forest Company of New Zealand Limited (SPFL) and Kodansha Tree farm New Zealand Limited (KTNZ).

Ernslaw One (8,600ha, 10% of Southland estate)

Ernslaw One is 100% owned by the Oregon Group which is, in turn, owned by the Malaysian based Tiong family. Ernslaw One have the third largest estate with their forest operations in Otago and Southland. In Southland, Ernslaw One estate consists entirely of Douglas fir.

Small Forest Owners (est. 43,315ha, 51% of Southland estate)

Information, at a district scale, on small forest owners (less than 500 ha) is not available but this may be changing as Te Uru Rakau has created a new survey to collect this information. This information is likely to be included in future National Exotic Forest Description (NEFD) reporting. The only information available on small forest owners is at a regional scale. NEFD reports 214 owners across 67,700 ha in Otago and Southland. Ahikā has extrapolated this against the known volumes and estimated 43,315 ha of radiata pine and Douglas fir[29] for the remaining estate in Southland alone, equivalent to half of the total Southland estate.

7.4. Estimating the total volume of woody biomass resource in Southland

Top-down versus bottom-up analysis

The Wood Availability Forecast (WAF) for Otago and Southland[30], produced by the Ministry of Primary Industries, provides an annual series of total recoverable volume of wood available from known forests in the Southland region for dominant species (radiata pine and Douglas fir). As a centralised forecast, this requires a range of assumptions (typically based on recent history) about harvesting intentions, and the breakdown of the total available wood into different sales grade.[31] EECA commissioned an analysis of the WAF from PF Olsen.[32] PF Olsen also provided costs for the various grades of wood that are used in our analysis in Section 7.7.

However, actual harvesting of forests will naturally vary from that forecast depending on market conditions (due to changes in log prices, for example) and other factors specific to the owners of the forests.

"A model can only predict how wood flows may occur subject to assumptions that drive individual forest harvest. In examining the scenarios, it is important to recognise that forests are normally managed in a way that maximises the benefits to the owners, and 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 affects the age structure and maturity of the forests they own. This in turn feeds back into future wood availability."[33]

[29] Ahikā estimated radiata pine has an 14% share of the remaining estate through to 2030, rising to 34% by 2035.

[30] The WAF is only presented at an Otago and Southland level, hence volumes for Southland alone had to be estimated from the WAF charts.

[31] This relied on both factors published from the National Exotic Forest Description (NEFD), as well as PF Olsen's own analysis where the NEFD did not provide the granularity required.

[32] PF Olsen (2022), *Southland Biomass Cost Forecast*, May 2022.

[33] Ahikā, 2022, *Biomass Availability Assessment for the Southland Region*, report prepared for EECA, p10.

The most recent WAF was produced in 2021. In order to assess the degree to which harvesting intentions and expectations of different wood grades had changed since the publication of the WAF, EECA commissioned Ahikā to conduct a bottom up analysis, which was based on extensive interviews with major forest owners[34] about their harvesting intentions and expectations of yields, conducted in 2022. From a practical perspective, these interviews were restricted to the three major owners from Section 7.3. However, it is noted that there is a high degree of confidence in harvesting intentions amongst major forest owners (>500ha), when compared with the smaller scale owners (<500ha).

That said, while the large forest owners' shares of planted areas are significant (radiata pine: 15,390ha, 32%; Douglas fir: 14,400ha, 57%; and eucalyptus: 10,300ha, 100%), it is still only 48% of the total Southland estate. Based on major owners' intentions, estimates were extrapolated to include the remaining estate.

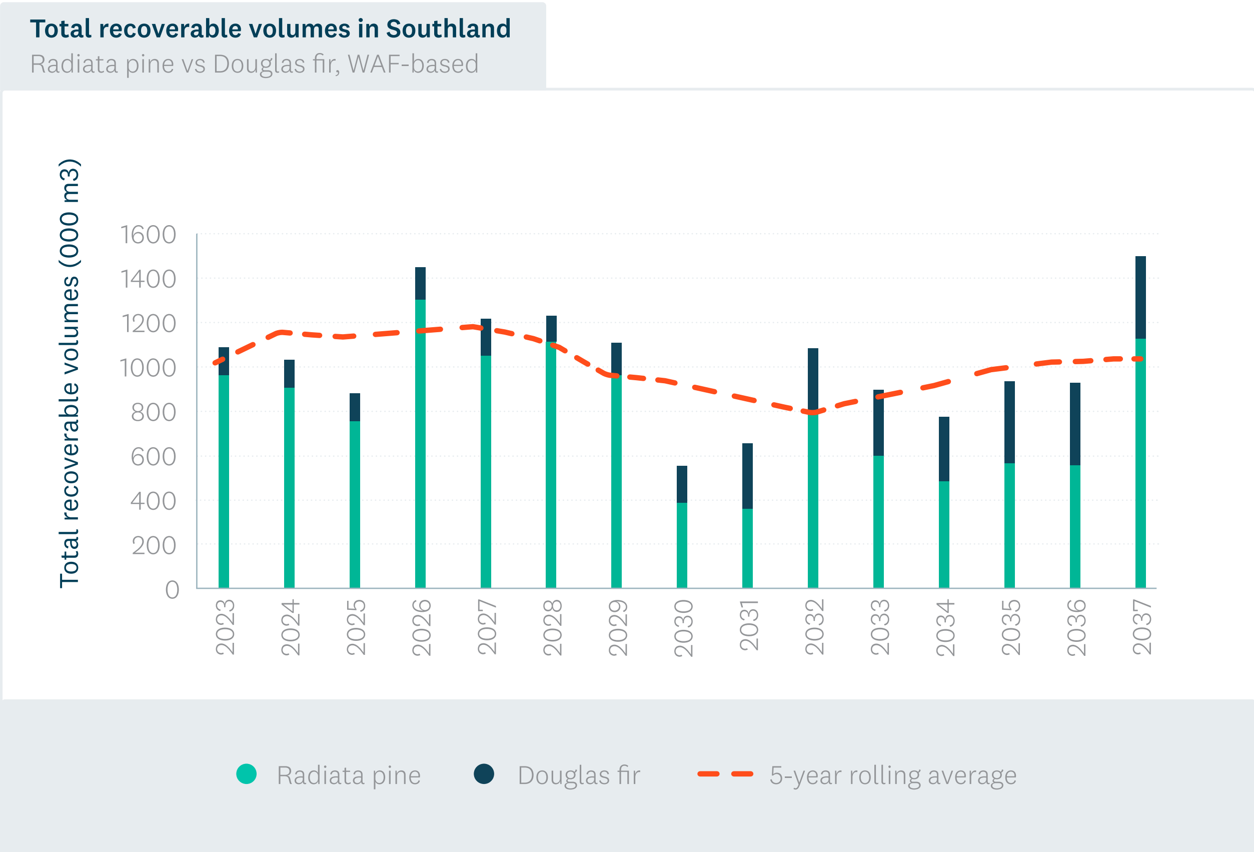
The resulting difference between the WAF-based top-down (denoted "WAF" in the charts that follow) and the interview-based bottom-up (denoted "IV") approaches shows that harvesting intentions do deviate from modelled outcomes, even over a short space of time. Markets for wood are dynamic and forest owners will adapt their plans accordingly. We discuss the materiality of these differences below. In our analysis of the potential cost of using different wood-based sources of bioenergy (Section 7.7), we use the interview based volumes where possible.

[34] As outlined EECA also requested Ahikā conduct interviews with sawmills to obtain a bottom-up assessment of potential processing residues.

Harvesting intentions: top-down WAF-based analysis

Given the age-class distribution of current forests, the WAF predicts the annual total available volumes of the two primary tree species (radiata pine and Douglas fir). In the WAF, a declining trend of radiata volumes over 2030-2040 will be offset somewhat by growing availability of Douglas fir over the same period. Combining the two yields an average annual recoverable volume of around 1,000,000m3 (Figure 10).

Figure 10 - Annual total recoverable volumes, radiata pine and Douglas fir. Source: PF Olsen[35], WAF



[35] These figures were based in the underlying WAF; while the WAF provides graphs that separate Southland from Otago volumes (by species), the numerical figures in the WAF are for the Southland/Otago region aggregated together. Hence PF Olsen had to estimate Southland volumes by species from the charts.

Figure 11 converts these volumes into a breakdown of sales grade (using 5 year averages)

Figure 11 - Total recoverable wood supply in Southland. Source: PF Olsen, WAF

Figure 12 - Total recoverable wood supply in Southland: WAF vs IV-based analysis.

Harvesting intentions: interviews with major forest owners

As discussed above, there is a difference between the WAF-based assessment of available wood by grade, and the current harvesting intentions revealed from interviews with major forest owners (and subsequent extrapolation to the remaining estate of small forest owners).

This difference manifests in terms of:

- The timing of harvest[36]
- The breakdown of logs into grades[37]
- Estimation of harvesting residues, as discussed further below

The material difference between the WAF and interview-derived availability is illustrated in Figure 12. The major forest owner interviews primarily focused on industrial grade and pulp/chip logs, hence we retain the WAF-based estimates of pruned and export A grade logs. The aggregate effect on volumes is, as discussed above, that the WAF forecasts higher volumes of wood being available, particularly towards the back end of the period.

All subsequent analysis in this section uses Ahikā's interview-based analysis, as it captures the current intentions of forest owners. Further, it is also a more conservative view of volumes.

[36] The WAF is based on the age-class distribution of current forests, combined with a set of assumptions about how the forests will be harvested. In particular, the WAF assumes that most Douglas fir forests will be harvested at age 43 (on average). However, over the period 2032-2041, it assumes the average age of harvested Douglas fir is less than 43, for small scale owners. Ahikā's analysis based on interviews assumes that all Douglas fir forests are harvested at age 43. This results in the WAF's assessment of harvested Douglas fir volumes being higher than Ahikā's over that period.

[37] This manifests mainly in the breakdown between Export K/KI/KIS volumes and domestic pulp. As discussed above, a change in export prices for KIS relative to domestic pulp can result in substitution between these categories; higher demand (and thus price) for pulp logs can result in greater recovery; and there can be increased tolerance for the KIS grade, for example, tolerance for more sweep, shorter log length, and smaller diameter log lengths. Further, we understand that export requirements (for example, K/KI grade wood), primarily relating to the quality of log accepted, constrains the way that these logs are harvested. If these logs were destined for domestic bioenergy use, harvesting strategies would change, resulting in forest owners recovering more of what is now left as a unrecovered residue.

Harvesting residues/in-forest recovery

During harvesting, a volume of biomass is left in the forest as offcuts, branches, out-of-specification logs and cording. These volumes are not included in the WAF volumes above, as they are assumed to be unutilised.

Using EECA's *Good Practice Guide*[38], PF Olsen estimated there would be a 10% yield in addition to the total recoverable volumes above from chip and hog roadside residues, and a further 2% yield (hog and chip) cutover residues (left where the felling took place). This would add approximately 130,000-140,000m^3 to the availability above.

Again, this top-down estimate was complemented by a bottom-up analysis[39] which looked at a different categorisation of residues and estimated the potential for Southland's forests based on conversations with major forest owners, as well as researchers. This yielded the following (higher) estimate of harvesting residues, some of which are currently being recovered by forest owners:

- **Billet wood (129,000t pa):** Billet wood is a by-product of harvesting and is typically 1m-3m lengths of offcuts that do not meet specifications. It is currently used as a source of bioenergy (for example, for firewood and boilers at existing wood processing sites). Based on interviews with major forest owners, and extrapolation to the remaining small owner estate, Ahikā estimates that the current billet wood availability is approximately 129,000t per annum, noting this is currently being recovered and has a destination firewood and bioenergy market.

- **Skid site processing (70,000t pa):** A skid site is a platform that is built within a forest for processing logs during harvesting. The "skid" is a receiving site for removing branches and bark, cutting the logs to specification for a market (grading) and storing logs before they are offloaded to trucks. During grading, there is some wastage. The remaining offcuts are discarded in close proximity to the skid. The estimate above is the volume that is not currently being collected and utilised, and is based on an assumed recovery of 70t per ha per annum.[40]

- **Cord recovery (6,500t pa):** Cording is a technique used during harvesting to create roads, working platforms or temporary structures. If an area around the skid site is likely to get wet during harvesting, a cord platform will be built using the low grade portions of the surrounding trees. Sometimes the cord is left in place after operations and in some cases, the contractor must dismantle the structure. This cord wood is relatively easy to collect but can be quite contaminated from sitting on top of soil.

[38] https://www.usewoodfuel.org.nz/documents/resource/EECA-90-production-wood-fuels-from-forest-landings-4-10.pdf

[39] Ahikā (2022).

[40] In 2021, Rayonier estimated recovery from 27 recent skid sites representing 420 ha. The average recovery was 1,115t per skid or 70t per hectare per annum. Source: Ahikā (2022).

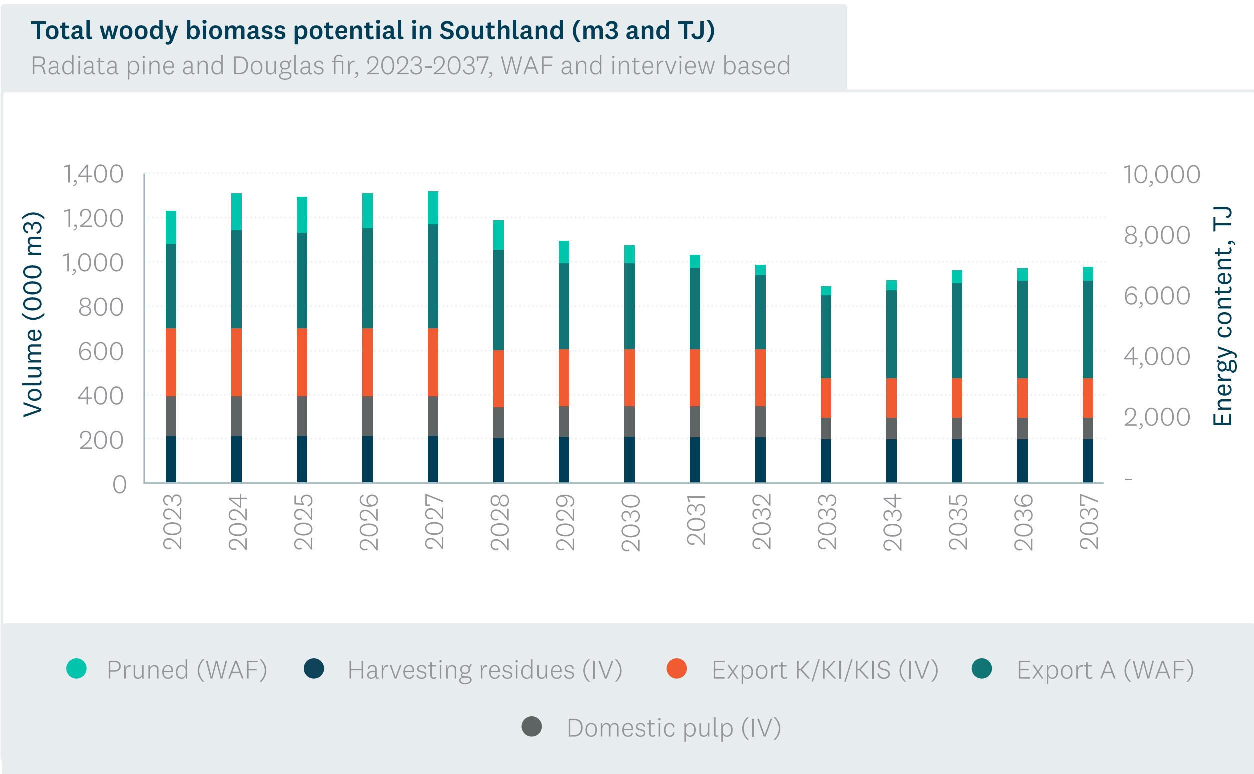
Another volume of bioenergy that is currently unutilised is the in-forest windrow slash from harvesting operations. Slash is the term used to describe the left-over biomass and includes branches, leaf and offcuts and tree ends. Slash varies in size, shape and density. Windrow slash recovery is not simple as the terrain can be difficult, but it is an obvious source of unutilised bioenergy. Some research of in-forest slash recovery has estimated the potential volumes available, and it ranges widely depending on the harvesting operations. Based on an average value of 24t per hectare per annum and extrapolating across the Southland radiata estate, in-forest windrow slash recovery could contribute 42,000t per annum. However, it is more difficult to recover than skid site or cord, hence we have not included it in the availability figures.

The figures for skid sites and cord recovery are based on average recovery rates achieved in a small number of individual trials. These trials suggest individual sites could vary by as much as +/- 30%.[41]

Summary analysis of total available wood in Southland

Combining the analysis in the preceding sections, we can estimate the availability of wood in the Southland region.

Figure 13 - Total woody biomass potential in Southland region. Source: Ahikā, PF Olsen



[41] Ahikā had discussions with Port Blakely about their residue recovery programme. Port Blakely's trial was undertaken on two skid sites which reported 700t at one site, and 1,400t at the other. In 2021, Rayonier estimated recovery from 27 recent skid sites representing 420 ha. The average recovery was 1,115t per skid or 70t per hectare. Since the latter figure seemed more robust (and lay almost exactly between the two Port Blakely figure), it was used to inform the estimate above. Cording was estimated at 110t per site, based on visual inspections. For slash recovery (not included in our final availability assessment), international published trials showed recovery ranging between 19-29t per ha. 24t per ha was used to derive the 42,000t per annum estimate.

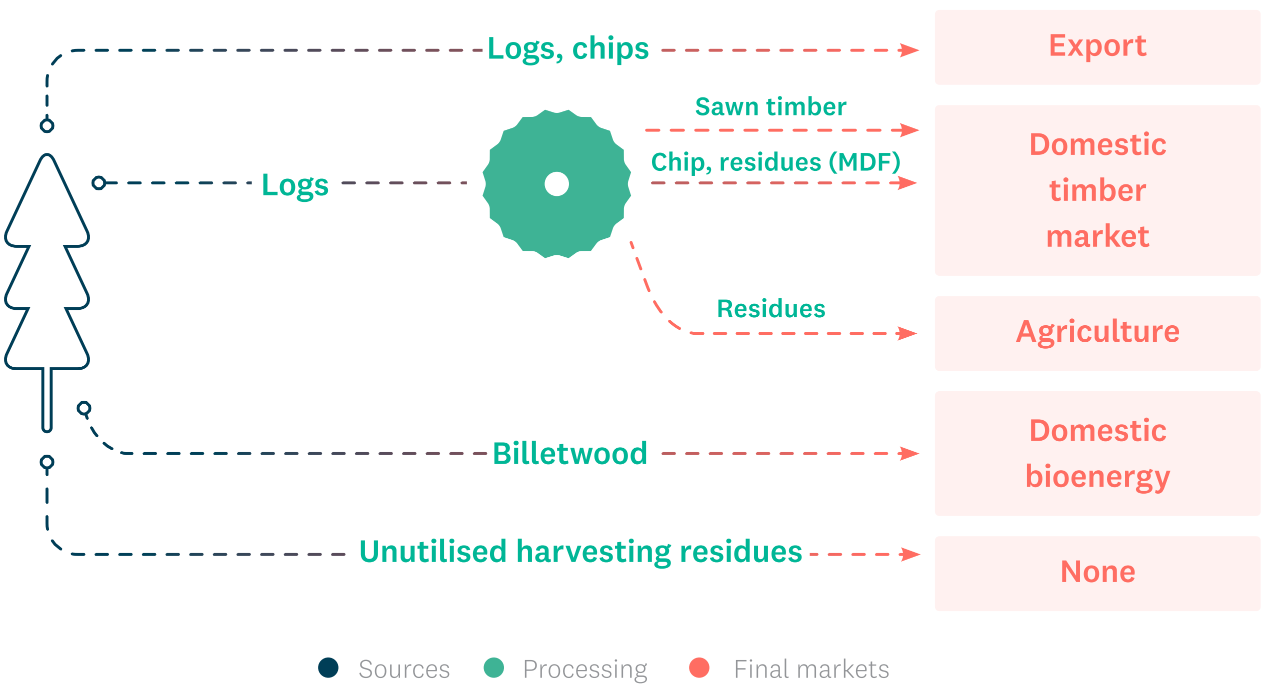
7.5. Current markets for woody biomass

The top down analysis of total volumes from the current estates suggests a theoretical maximum of timber that could be available for bioenergy. However, the majority of forestry resources in Southland have existing markets. These markets include:

- Domestic via e.g. sawmills, where logs are processed into higher value timber products
- International logs or chip exported for processing in other countries
- Existing domestic bioenergy uses (e.g. firewood, or existing boilers)

Having understood the overall availability above, we now consider the volumes that could plausibly be diverted to bioenergy for process heat fuel switching in the near term, i.e. without causing disruption to these existing markets. Ahikā's interviews with major forest owners (estates greater than 500ha) allows us to identify where recoverable volumes are currently contracted to existing markets, and may therefore not be immediately available to the bioenergy market, at least in the short term.

Figure 14 – Overview of destination markets for wood in Southland



Export grade logs and chip

This includes pruned, A grade, industrial grade and pulp/chip logs exported to Asia via Southport. Export log volumes through Southport have increased three-fold since 2012, and have exceeded 600,000t per annum since 2017. Diverting export grade logs away from export markets could increase volumes into the biomass sector without impacting on other domestic markets. However, the export price is the main driver for supply. This can fluctuate, and for pruned and A grade logs, would imply a high price for the bioenergy user.

Some of the industrial and pulp grade is sold into MDF when their domestic supply is constrained.

Eucalyptus was not included in the WAF-based analysis in Section 7.4, as the WAF does not provide data on total recoverable volumes in Southland. However, the interviews yielded one major forest owner who can, at an acceptable price, divert approximately 50,000t per annum of their lower quality (for paper production) eucalyptus chip volume currently destined for export within six months. Eucalyptus species also offer other benefits, for the biomass sector, compared to the main commercial species. firstly, the expected harvest age is shorter at 18 years (radiata pine is 28 years) and the whole tree can be tilized which suggests a greater volume of biomass when harvesting. Further, the density of the species is greater than radiata pine (Hall 2010) by 24% so this will proportionally increase available energy per volume (GJ/m³).

Domestic chip/pulp logs

The medium density fibreboard (MDF) plant in Mataura is the single largest consumer of low-grade domestic chip logs and woodchip in Southland. Millar (2015)[41] estimated that the plant consumes 350,000-390,000t per annum from Otago and Southland. Based on discussions with industry, EECA does not expect this volume to have changed over the last five years. The MDF plant provides a reliable and consistent source for low grade logs and many forest owners make a small margin but see this option as a cost recovery for preparing the forest for the next planting rotation.

Residues from processing at sawmills in Southland

Wood processing sawmills create products for the domestic market, mostly building and farming products like construction products and fence posts. Sawmills purchase logs from the forest companies. When processing a log, almost half of the volume is lost in the process as offcuts and sawdust.[42] The main residues from wood processors[43] are:

- **Woodchip:** Woodchip is created onsite from all viable offcuts and the majority is sold to the MDF plant in Mataura but can also be sold to farmers for animal bedding.
- **Sawdust:** Sawdust is the residue 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.
- **Peelings and bark:** These are the residues created from making round posts (fencing, poles, lamp-post) and are thin and long in shape. The offcuts are from the log ends and are sold as firewood. Any remaining bark is also removed before processing.
- **Shavings:** Shavings are created when dressing the timber which creates a finished product that is smooth and clean. Shavings are usually created after the timber has been dried so it is light and very dry.

Some of the residues, like shavings and sawdust, are also be used as biomass fuel for the sawmills' own boiler energy requirements.

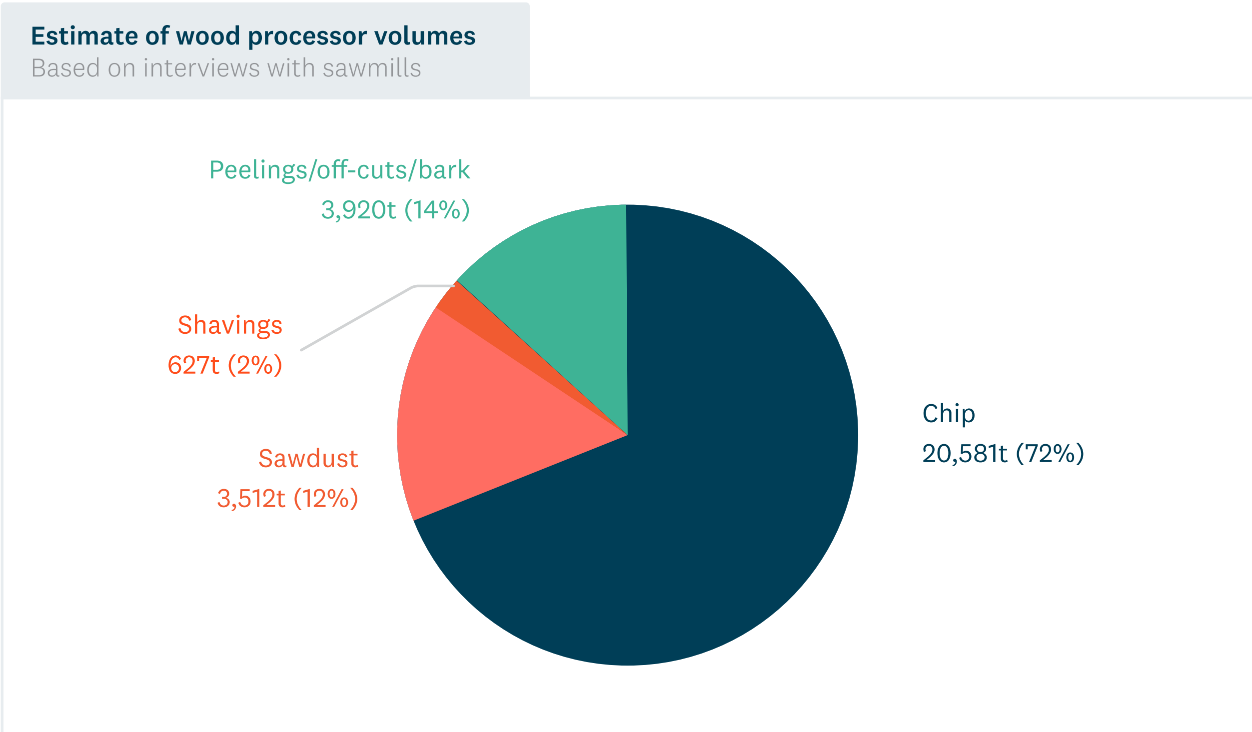
[41] Ahikā Consulting Ltd and Forest Management Ltd (2015), *Southland Wood Residue Supply Assessment*, report for Wood Energy South, Venture Southland and EECA.

[42] Ahikā (2022), Southland Region Bioenergy Availability Assessment.

[43] There are eight wood processors in Southland with the largest being Niagara in Kennington. Other processors include Stuart Timber, Beven West, Lindsay Dixon, Great Southern Group, Findlater Sawmill, Ngahere Sawmill and Pankhurst Sawmill.

Interviews with six of the eight sawmills in Southland were conducted to understand if there were any volumes that could be diverted to biomass. These interviews suggested that there was around 28,000t of residues arising from sawmill operations (Figure 15)[45], however, most of this (~20,000t) is currently sold to the Daiken MDF plant in Mataura. Only small volumes of sawmill residues (~4,000t) do not have existing markets: mostly sawdust and bark. EECA assumes these volumes continue at approximately the same levels indefinitely.

Figure 15 – Processor volumes disclosed from interviews with sawmills. Source: Ahikā



Other wood-based bioenergy options

There are a range of other potential sources of biomass. Many of these are either small volumes or difficult to access and so have not been included in forecast volumes:

- **Minor forest species:** Minor forest species represent more than 2,000 ha of forestry in Southland consisting of species such as macrocarpa, poplar, ash and bishop pine. These would have very limited markets today and would likely become firewood. Bioenergy could provide an attractive income especially if a second rotation energy forest was replanted. Ahikā estimates these species could phrovide 17,000-20,000 tonnes per annum (122TJ – 143TJ).

[45] Note that this figure excludes volumes of residues from Niagara Sawmill, due to commercial sensitivity. Niagara is the largest processor in the region, and hence its processor residue volumes, not included in the 28,000t assessment, will be significant. Ahikā provided an estimate of 115,000t arising from Niagara's activities, based on Millar (2015) that suggested that Niagara's two sawmills had a processing capacity of 380,000t-450,000t per annum.

- **Quick rotation energy forests:** If a forest were being grown as an energy crop, a high density and fast growing species would be preferred. Species like eucalyptus and poplar can provide these advantages and the entire crop could be utilised for energy. Eucalyptus could yield volumes of 160t (1.15TJ) per hectare.[46]

- **Biomass for agricultural uses:** Assessing the volume of biomass woodchip going into the agricultural sector is difficult as many farmers will utilise shelter belts and other small stands for cow pads. Millar (2015) estimated 40,000 tonnes (287TJ) of biomass is going into this sector. Anecdotally, demand from the dairy sector is increasing and being fulfilled by sawmill and wood processors.

- **The wilding conifer estate:** There are over 17,000 hectares of DOC-administered land at 19 sites in the Southland Conservancy affected by wilding conifers. The most extensive area of wilding spread is at Mid Dome in Northern Southland where contorta pine and several other wilding species threaten over 4,000 hectares of DOC-administered land, and a further 13,000 hectares of other land. After assessing the sites for suitability, Ahikā concluded that approximately 50 ha may be suitable for 23,500t (165TJ). This would be a one-off volume, available over the next two to three years, as it is unlikely to be replanted.

7.6. Near-term availability of woody biomass for bioenergy

The interviews clearly indicate that the majority of regional wood resources are already being utilised in other domestic and export markets. However, all interviewees can see the opportunity of the bioenergy sector and in some cases were already being approached directly for supply. EECA expects that, as the bioenergy market develops in scale, some sources of wood may switch from their existing markets to bioenergy, depending on the price.

Therefore, our definition of “near-term availability” of Southland woody biomass that could be utilised for process heat includes:

- Unutilised harvesting residues (average 76,500t, equivalent to 550TJ of energy[47]).
- Unutilised processing residues (4,000t, 28TJ).
- Export chip volumes where the forest owner has indicated diversion availability within the next 6-12 months (50,000t, 360TJ).
- Export low-grade logs (250,000t, 1,800TJ). These are included, as discussed in Section 7.2, as a low emissions source of biomass.

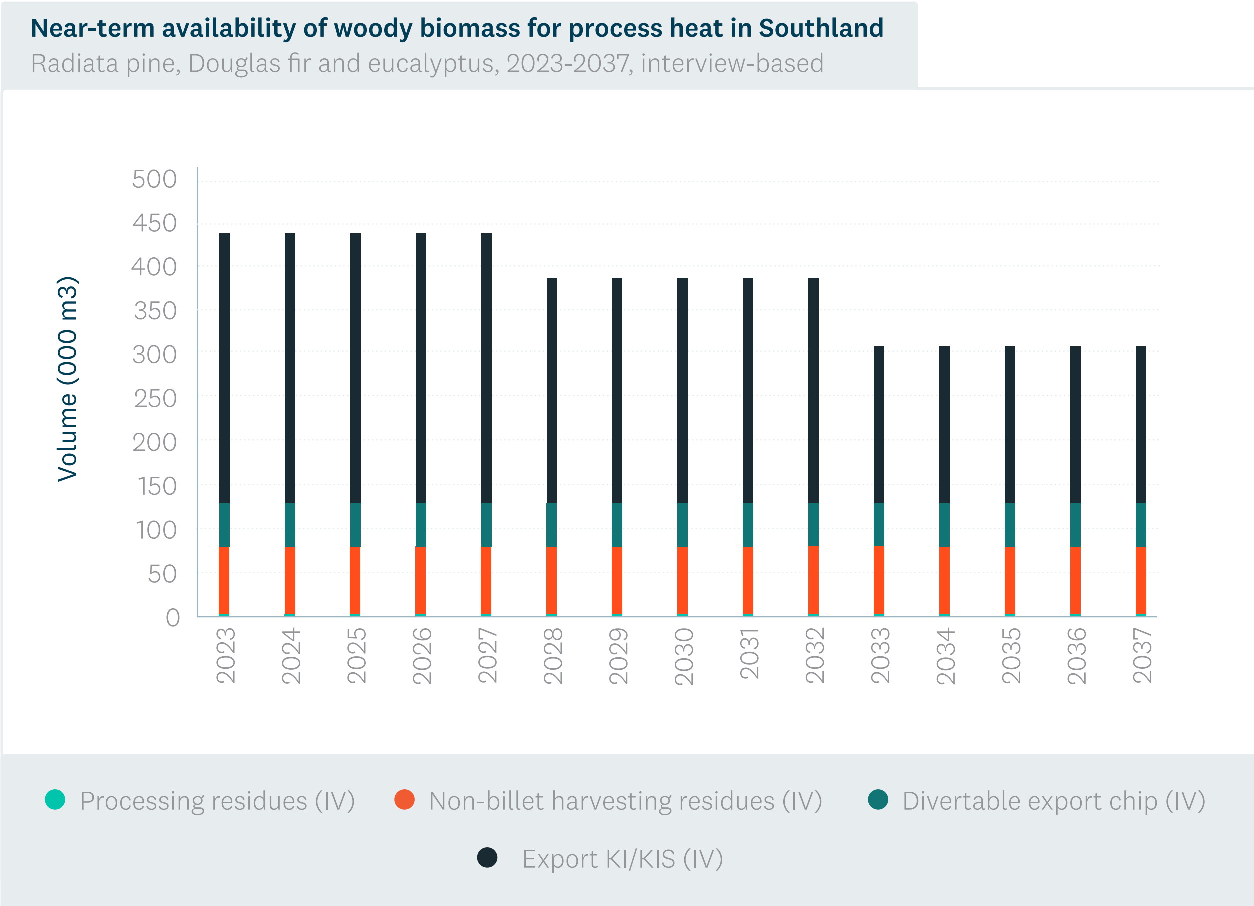
We assume that all domestic chip/pulp log and the majority of processor residues are currently contracted to Daiken’s MDF plant at Mataura.

A total average resource availability has been estimated at 380,500t per annum, equivalent to 2,738TJ of supply. This is illustrated in Figure 16.

[46] Based on mean annual increment of 18m³/ha/year and 520kg/m³ for an 18 year rotation.

[47] 55% moisture content, resulting in NCV of 7.184 GJ/t.

Figure 16 - Volumes that could be utilised as bioenergy in Southland in the near term. Source: Ahikā, PF Olsen



We reinforce that this assessment of "near term availability" for bioenergy is based on what is known at the time of writing, and have maintained the definition throughout a 15-year period. As highlighted through the bottom-up and top-down analyses, harvesting intentions and methods can change in a relatively short space of time, and will be responsive to the relative prices for resources from the various destination markets.

The following sections will discuss the cost associated with these different resources, and what this may mean for the potential demand for biomass from RETA process heat users who may wish to switch to bioenergy as a fuel.

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" to the value of resources in other markets (where these markets existed). Shadow pricing uses e.g. export prices for wood, to imply a price that has to be "matched or beaten" if users are to divert their wood resources away from that market to bioenergy.

The three primary sources of data for this analysis were:

- **Pulp logs, export logs and pruned sawlogs:** PF Olsen analysis of *AgriHQ Forestry Log Price Report* (Southern South Island 3-year average prices to September 2021).
- **Processor residues:** Ahikā cost analysis.
- **In-forest residues:** Estimated in consultation with Scion, University of Canterbury, literature review, and the local knowledge of PF Olsen in Southland.

Cost components

The sources listed above provided a base price for each source of biomass, delivered to a central chipping location. In order to provide an indication of the costs of biomass delivered to a process heat customer's site, two additional cost components must be added:

- The costs of chipping logs and in-forest residues into a form suitable for boiler use,[48] and storage of the chip. An assumption was made that there would be one central location for chipping and storage, and that costs equated to \$15/m3 for chipping and \$6/m^3 for storage.[49]
- Transport costs from the central chipping and storage location to the customer site. Since transport costs will vary with the distance from a single central site to any of the process heat sites, they were assumed to vary between \$11/m^3 (30km) to \$28/m^3 (120km).

Including these costs results in a set of prices for biomass delivered to a biomass customer. Table 2 and Figure 17 show these costs, assuming a 60km distance between a centralised chipping and storage location, and the process heat user's site. This figure is not based on any analysis of the sites, and is purely for illustration purposes.

We also convert these underlying costs (in \$/t biomass) to an 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 2; this will need more detailed consideration by process heat users contemplating conversion to biomass.

[48] Processor residues are assumed to be in a form suitable for use straight away.

[49] Estimated by PF Olsen in consultation with Scion, University of Canterbury, literature and PF Olsen experience.

Table 2 - Sources and costs of biomass resources in Southland. Source: PF Olsen, Ahikā

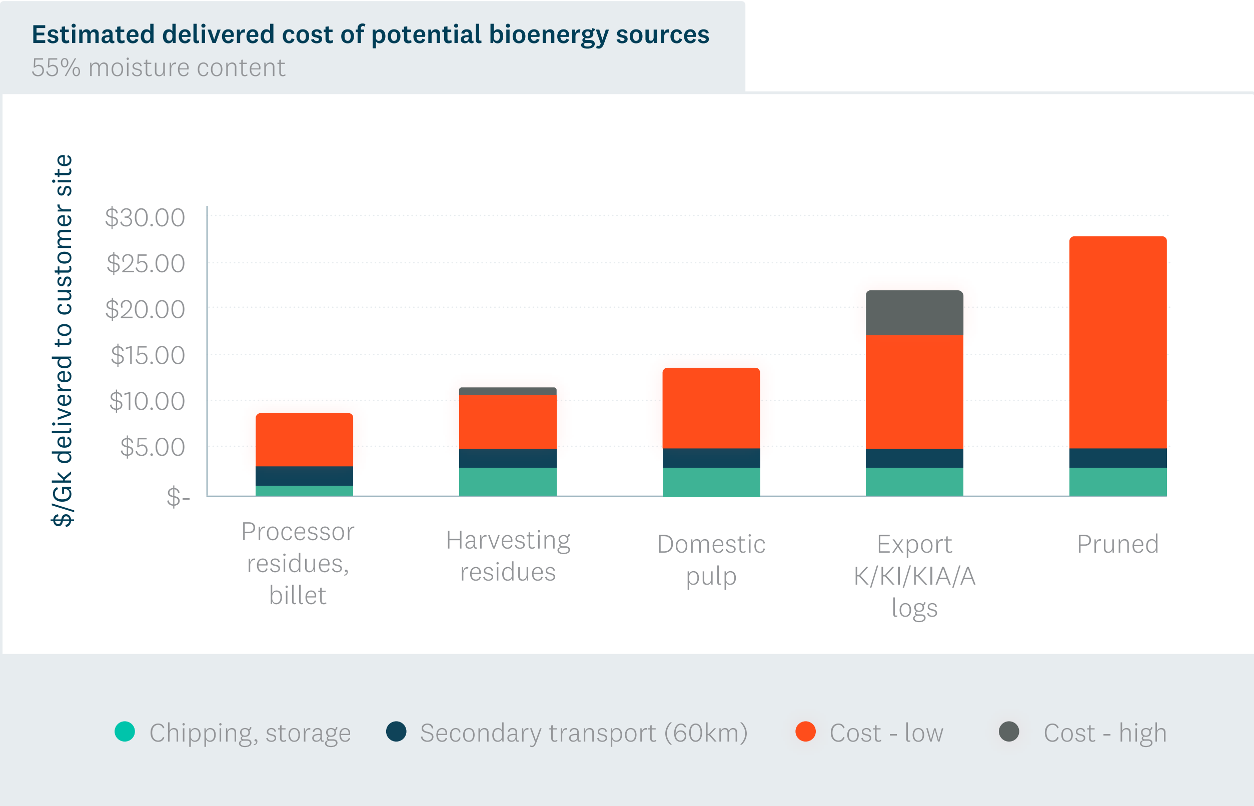
Bioenergy source	Cost of biomass source ($/t)[50]	Chipping and storage ($/t)	Transport to process heat user ($/t)	Total cost delivered to user's site ($/t)	Total cost delivered to user's site ($/GJ)[51]
Processor residues and billetwood	$40	$6[52]	$17	$63	$9
In-forest residues (incl. collection)	$41 - $46	$21	$17	$79 - $84	$11 - $12
Domestic pulp logs and export chip	$62	$21	$17	$100	$14
Export logs (grades KIS, KI, K and A)	$90 - $124	$21	$17	$128 - $162	$18- $23
Pruned sawlogs	$167	$21	$17	$205	$28

[50] Primary transport from the forest or processor site to a centralised location is factored into the delivered log or residue price At Mill Gate (i.e. incurred by the forest owner).

[51] Conversion in energy equivalent assumes a net calorific value of 7.184 MJ/kg (55% moisture content), and 1m^3 = 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 heatpump, where applicable). We expand on this comparison in Section 9.

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

Figure 17 - Estimated delivered cost of potential bioenergy sources. Source: PF Olsen (2022), Ahikā (2022).



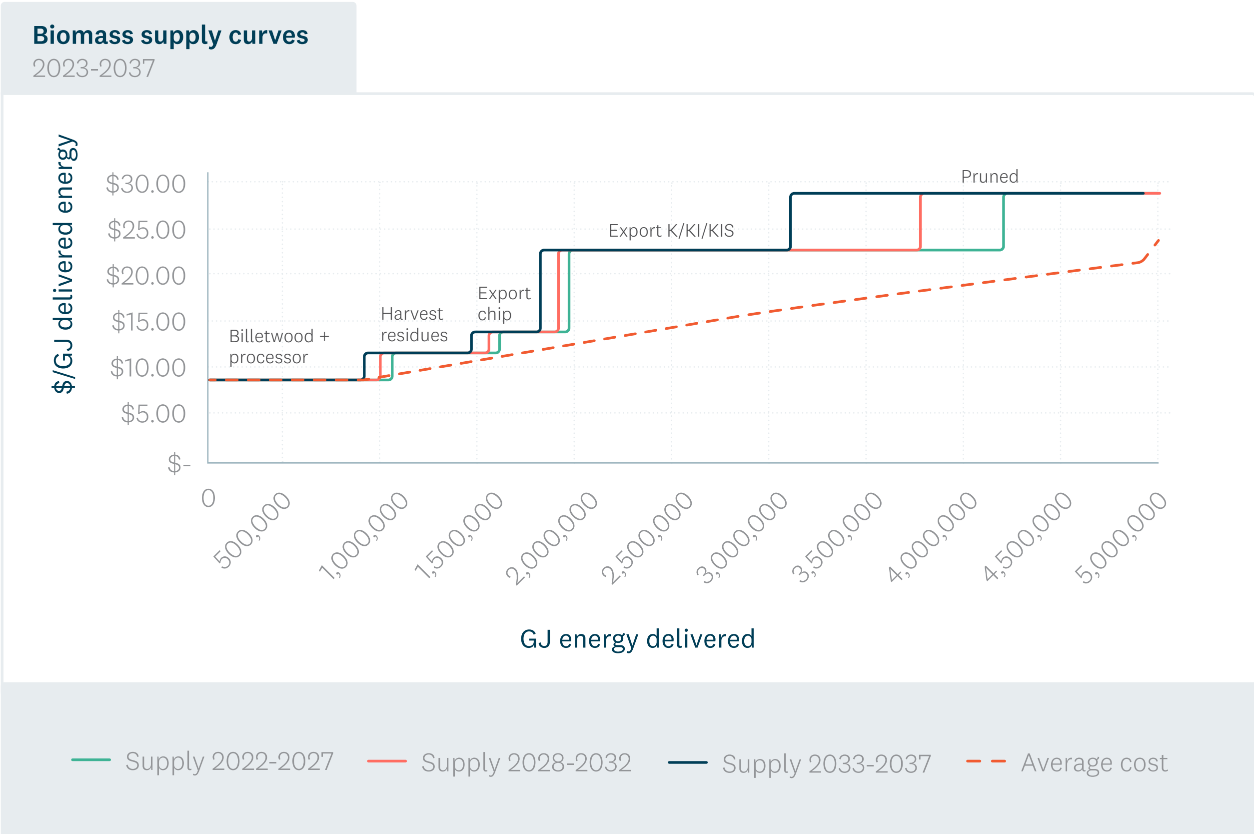
Supply curves

In order to convert these costs into an indicative market supply curve, available volumes of each type of source must be assumed. We use the regional "near term available" resources (from Section 9 above) as the primary sources of interest, with two modifications:

- We include, for reference, billetwood, even though it has a current destination bioenergy market and is not available in the near term. Including it in our bioenergy market assessment allows us to see what the "whole" market for bioenergy in Southland looks like, from a current supply **and** demand perspective. To be consistent, we will also later include the current demand for billetwood (e.g. firewood) as an existing demand, to which the potential new demand from RETA process heat users will be added.
- We include pruned logs as a "last resort" price, should bioenergy demand exceed what is available from the four main sources identified and illustrated in Figure 16.

Since the supply of near-term bioenergy resource availability varies through time, we produce three supply curves, one for each of the five-year periods in Figure 16. This is shown in Figure 18.

Figure 18 - Biomass supply curves through to 2037. Source: PF Olsen



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 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 18 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.

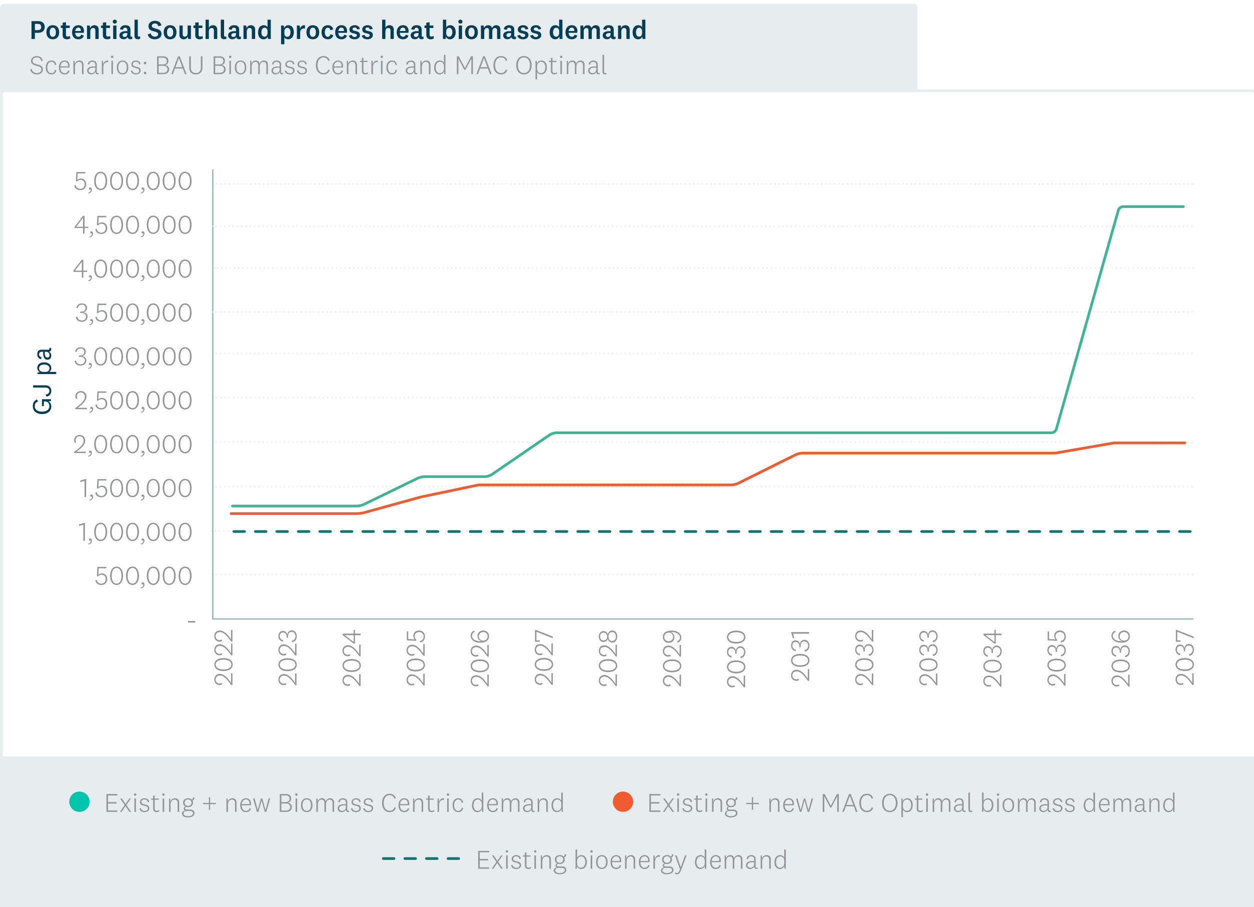
Scenarios of biomass costs to process heat users

With a nascent bioenergy market, there is no price history to draw on to use to calibrate price forecasts. In order to get an indication of what prices may be, we overlay plausible demand scenarios on each of the three supply curves on previous page. 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.

Our demand curves through time (Figure 19) illustrate two scenarios from Section 9:

- **Biomass Centric:** a scenario where biomass is selected as the fuel for every boiler conversion in the RETA study, 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.
- **MAC Optimal:** a scenario where RETA projects choose the fuel switching option with the optimal "marginal abatement cost" (MAC) value. This results in a mix of electrification and biomass switching decisions. MAC values are explained further in Section 9.

Figure 19 – Southland bioenergy demand for process heat, for Biomass Centric and MAC Optimal pathways. Source: EECA



As discussed above, we include billet wood in our supply assessment (~129,000t or 1PJ on average over the period). Since it has an existing bioenergy market, we also include it in the demand curve, i.e. we assume the current consumption of billet as a source of bioenergy continues throughout the 2023-2037 period, and this is not available to new consumers of biomass. The existing billet wood consumption is shown as the dashed line in Figure 19.

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

Figure 20 – Biomass supply and demand, 2023-2027. Source: PF Olsen, EECA

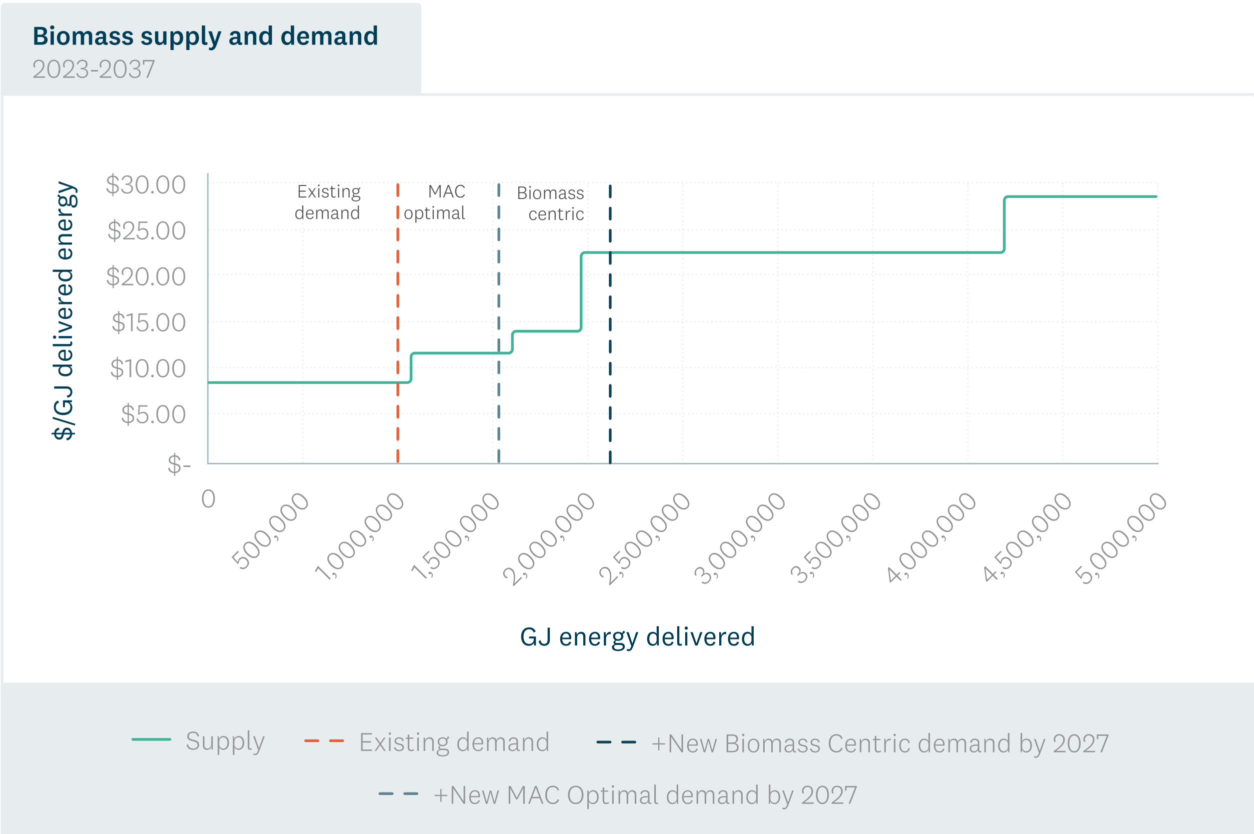


Figure 20 illustrates that, beyond the existing biomass demand, a future aligned with a Biomass Centric scenario will begin to require biomass resources to be diverted from export markets by 2027. In a MAC Optimal scenario, where biomass is only chosen when it is the lowest (modelled) cost, demand in 2027 can be satisfied using processor and (mostly) harvesting residues, at an average cost of ~$10/GJ.

Figure 21 shows that, by 2032, the availability of wood has shrunk and even the MAC Optimal scenario is requiring all of the diverted export eucalyptus chip and the first volumes of export diverted low-grade logs, increasing the average cost of resources to $12/GJ. The Biomass Centric pathway has a slightly higher **average** cost at $12.50/GJ, but is starting to use material volumes of wood at costs >$23/GJ. As discussed above, if process heat users that switched early secured long-term contracts for the lower cost resources, the price faced by those switching in 2032 will be around this level.

Figure 21 – Biomass supply and demand, 2028-2032. Source: PF Olsen, EECA

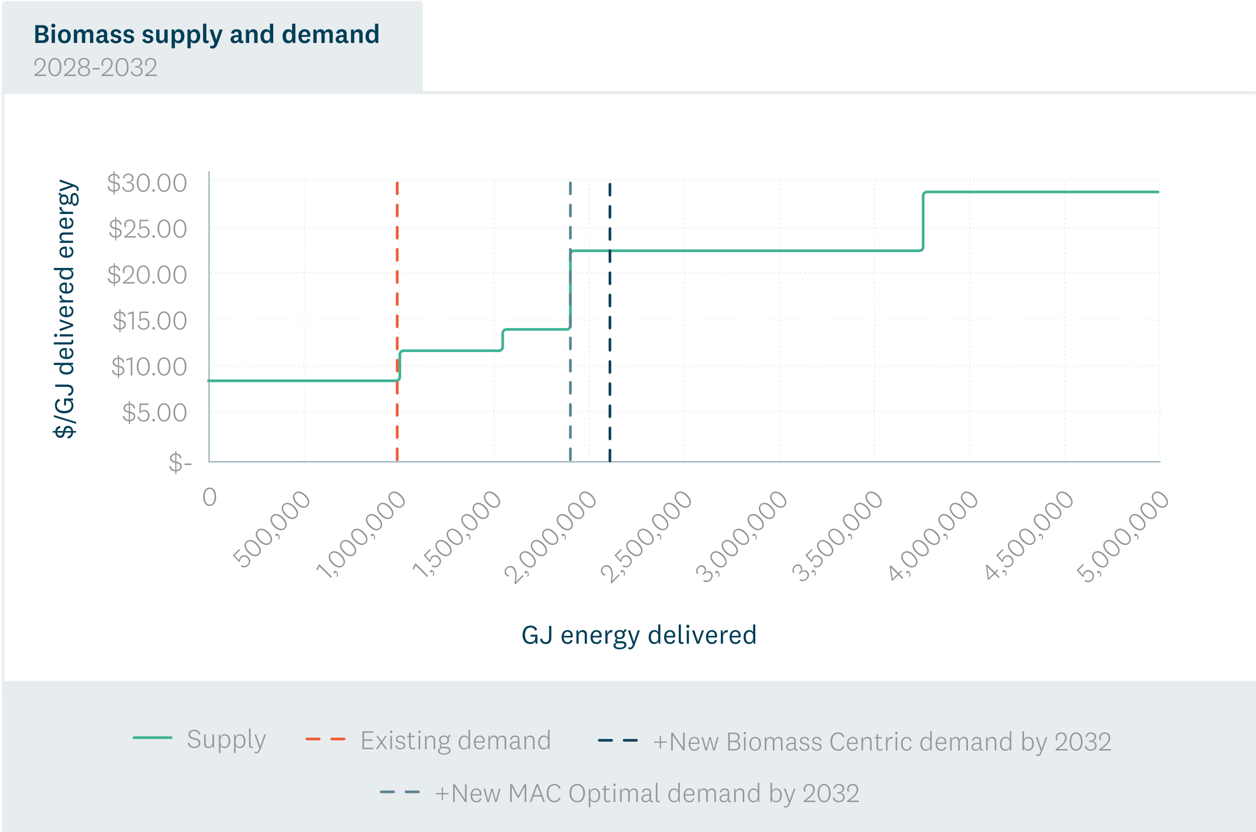
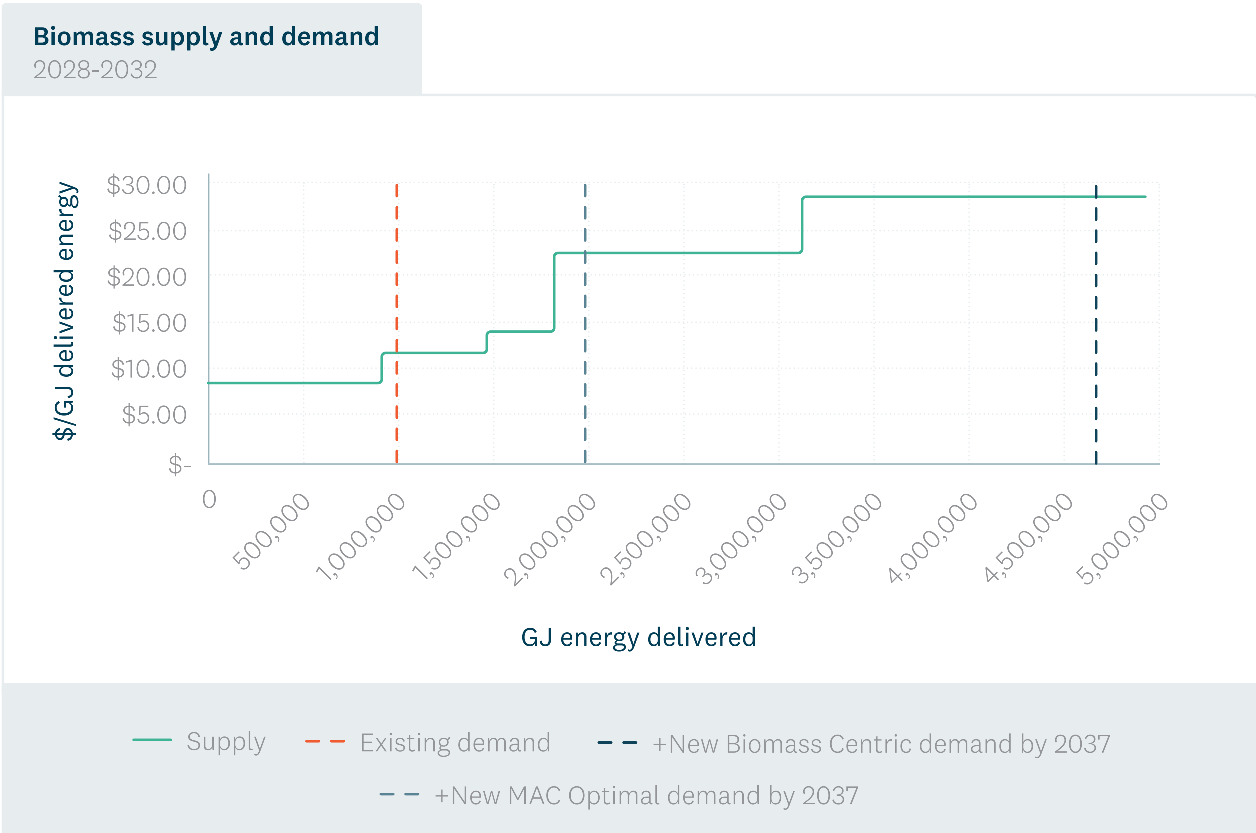


Figure 22 – Biomass supply and demand, 2033-2037. Source: PF Olsen, EECA



As supply reduces further in 2033-37, export logs will be insufficient to supply the significant increase in demand that occurs under the Biomass Centric pathway. Here, a significant number of pruned logs will be required to satisfy demand; the price faced by those process heat users that switch later in the period may challenge the economics of the decision.

Shakespeare Bay - Marlborough Sounds, New Zealand

8 Electricity

Availability of infrastructure and price

- **The availability of electricity to meet the demand from process heat users is largely determined at a national "wholesale" level, and this supply is transported to an individual RETA site through electricity networks – a high voltage network owned by Transpower, and a lower voltage network, owned by "Electricity Distribution Businesses" (EDBs), that connects individual consumers to the boundary of Transpower's grid (known as GXPs).**

- **Hence the primary considerations for a process heat user considering electrification are:**

  - **The current "spare capacity" of Transpower and the EDBs' networks to supply electricity-based process heat conversions.**

  - **The cost of any upgrades required to accommodate the peak electricity demand of process heat user (as well as any other consumers looking to increase electricity demand on that part of the network).**

  - **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).**

  - **The level of connection "security" required by the site, including its ability to tolerate rarely occurring short outages, and/or its 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 retail costs of electricity.**

- **RETA analysis suggests that, for networks, accommodating the new peak electricity demand from the majority of RETA sites is minor in complexity, and the estimated costs of the equipment required to connect these sites is <$1m. These sites place relatively low demands on the network.**

- **However, for sites with higher peak demands, the connections increase in complexity. If the connections do not require upgrades to Transpower's network, indicative costs are between $3m and $16m, while the largest consumers requiring upgrades to both distribution and transmission networks approach $60m.**

- **These costs 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.**

- **The forecast price of electricity (via a retail contract) is expected to rise (in real terms) around 10% between 2027 and 2037 (to ~11c/kWh) under a "central" scenario. However, different scenarios could see real retail prices 2c/kWh higher or lower than that level by 2037.**

This section considers the impact of the electrification of process heat on the electricity system. 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 also 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 power loadings on local electricity networks. While the national wholesale electricity market will invariably ensure there is enough supply to meet demand at every point in time (at a price), transportation (from point of generation to where the customer requires it) 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.

8.1. The emissions impact of electricity

On average over the past 5 years, approximately 18% of our national electricity supply is sourced from fossil fuelled generation (coal, gas and diesel).[53] Furthermore, while geothermal generation is renewable it releases some CO_2 into the atmosphere. On average, every MWh of electricity supplied releases about 100kg of CO_2 into the atmosphere.

These are Scope 2 emissions; however, it is important to be cognisant of the impact of increasing electricity demand in how we account for emissions reductions. Electricity industry expectations are that the amount of electricity provided from renewable sources will increase over the coming years, likely exceeding 95% by 2030.[54] However, this doesn't necessarily mean a significant reduction in the emissions intensity of electricity if geothermal is to remain a dominant part of the generation mix.[55]

[53] MBIE *Energy Quarterly*, https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/electricity-statistics/, accessed September 2022.

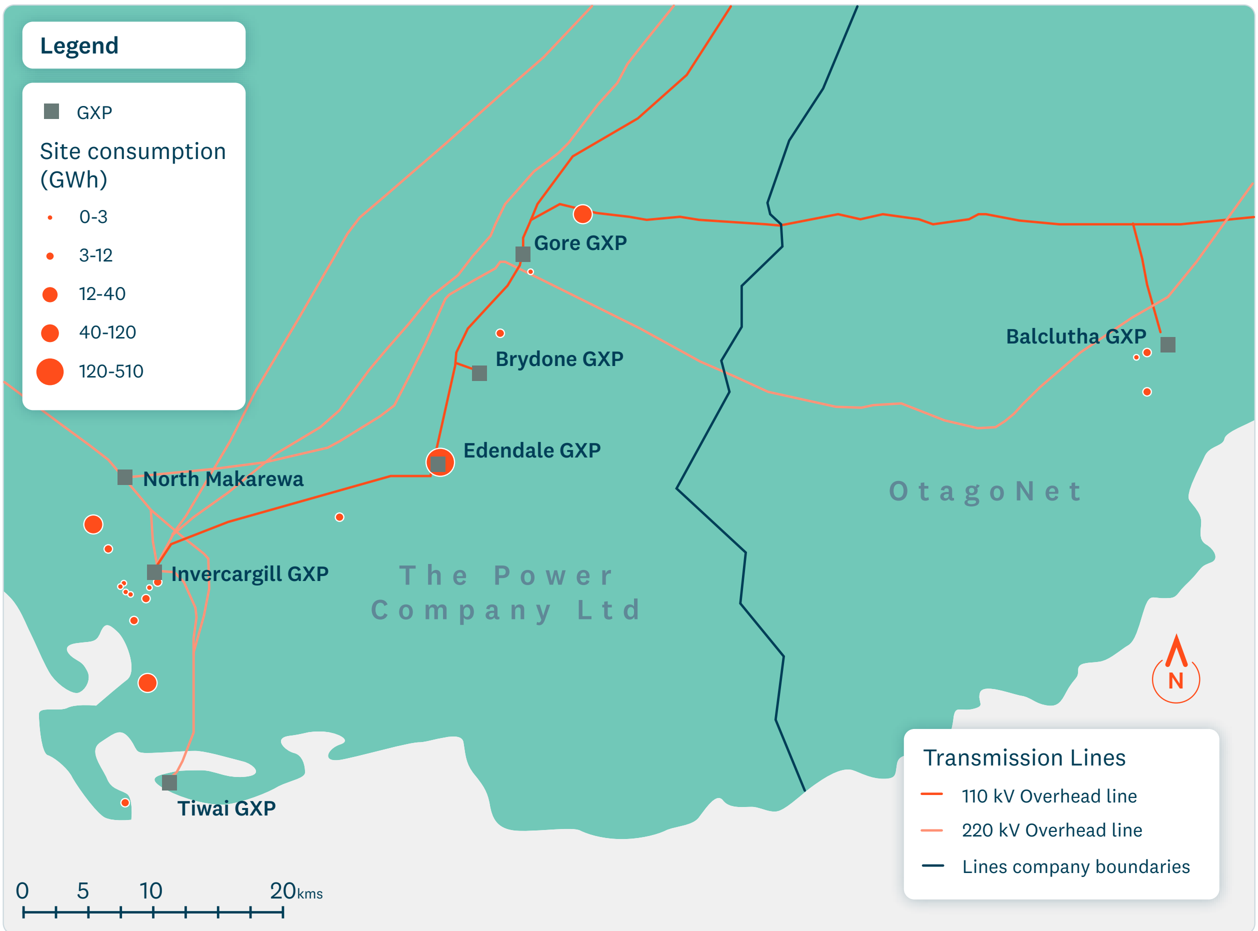
[54] See for example, Climate Change Commission's demonstration pathway; Genesis Energy half-year results presentation 2022.

[55] Geothermal generation does result in modest CO_2 emissions. However, we are aware that current geothermal owners are trialling methods for CO_2 reinjection. See https://www.thinkgeoenergy.com/successful-tests-of-capturing-and-reinjecting-geothermal-co2-nz/

8.2. Characteristics of Southland's electricity supply

The location of the Southland RETA process heat sites relative to Transpower's high voltage network are shown in Figure 23. Electricity distribution businesses (EDBs) provide the network that links "grid exit points" (GXPs) on Transpower's grid to customers.[56] The boundaries of each of the four EDBs in the area of interest are also shown on the map.

Figure 23 - Transpower GXPs and process heat sites



[56] Except very large customers, such as NZAS at Tiwai, who don't need a distribution network and simply connect directly to the national grid.

8.3. Approach to our assessment of electricity

The purpose of this section is to provide an indication of:

- Any capacity issues on either the transmission or distribution networks that might result from the connection of process heat sites.
- The cost of rectifying these capacity issues, allowing sites to connect should they choose to pursue electrification of their process heat demand.
- A forecast for the future retail price of electricity.

Our approach is supported by analyses conducted by Ergo Consultants[57] and EnergyLink[58], and proceeds as follows:

- We summarise an assessment of the **spare capacity at peak** times (see below for further discussion) available on different parts of the transmission and distribution network (lines and substations). This is informed by available network capacity (derived from discussions with EDBs and Transpower, asset management plans and regulatory disclosures), and data on the current (peak[59]) loadings on this capacity.
- We then consider whether the spare capacity on the existing network could accommodate the connection of a site. Where possible, consideration has been given to the extent to which the profile of demand over the year from the site will add to the overall peak demand for electricity and reduce the spare capacity.
- Where capacity is insufficient, a consistent “building block” approach has been used to estimate the costs of capacity upgrades, as well as any other assets required for the site to connect to the network. Where possible, opportunities have been considered for some sites to be flexible in their electricity demand at particular times, so that the need for upgrades are reduced or avoided.
    - Three scenarios of future retail electricity price paths provide an indicative set of forecasts of the cost of buying electricity.

The costs considered in this section (network upgrades and electricity retail purchases) do not include the line charges levied by local distribution companies on consumers to access the wider distribution and transmission network. These charges are in addition to any costs of new network assets required to accommodate the site, and need to be discussed with PowerNet as part of more detailed studies for each site.

[57] Ergo (2022), *Southland Electrical Network: Spare Capacity and Load Conversion Opportunity Report*, June 2022.

[58] EnergyLink (2022), *Regional Electricity Price Forecasts: EECA Regional Energy Transition Accelerator Program*, May 2022.

[59] Electricity demand varies over the day and year. Like most network infrastructure, electricity networks are generally designed to meet the highest level of instantaneous (half-hourly) demand expected. Further, Ergo used peak loadings published as part of regulatory disclosures instead of the 2020 loading data provided by Transpower and PowerNet. Ergo’s view is that the former are typically more conservative than the actual loadings and are therefore more appropriate for this sort of high level, preliminary assessment.

8.4. Costs of securing connection capacity

Connection security levels: N and N-1

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 are "overbuilt" in order to maintain 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:

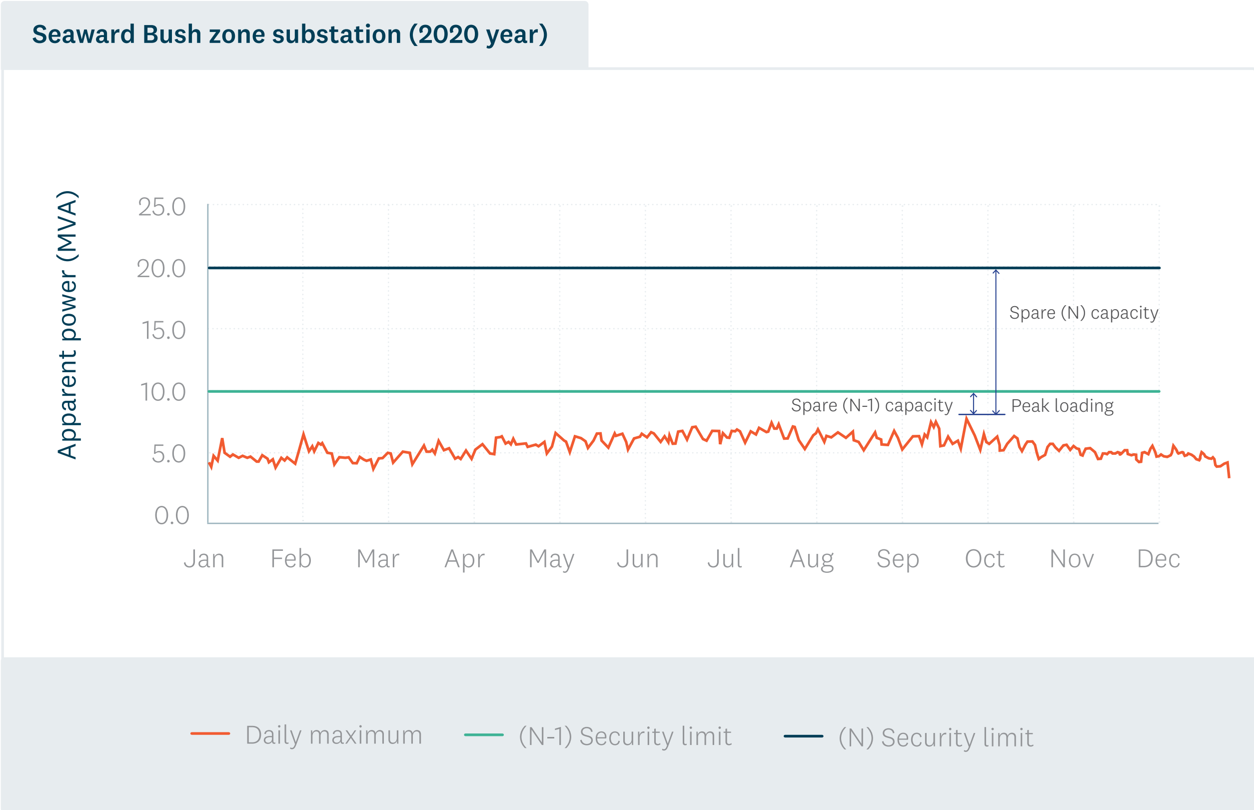
- **N-1 security:** Where N-1 security is present, forecast peak demand can be met and, furthermore, any failure of a single component of the network (e.g. transformer or circuit) will also leave the system in a satisfactory state .
- **N security:** A failure of any single component of the network at forecast peak demand may result in service interruption.

As discussed above, N-1 is generally provided through overbuilding assets. Two identical 50MVA transformers are capable of transmitting 100MVA of demand, but the failure of one of these transformers will (at best) result in the interruption of any demand that exceeds the capacity of the remaining transformer (50MVA). Only if demand remains below 50MVA is N-1 security in place.

Generally N-1 is the standard that applies on the "interconnected" parts of Transpower's high-voltage transmission grid. The scale of bulk power flows makes N-1 generally economic. 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). In the distribution networks, the lower scale, coupled with higher network density, means preserving N-1 to every customer would be exorbitantly expensive. Hence, many parts of the distribution network only experience N security.

Figure 24 illustrates the difference between the available capacity for N and N-1 security for a zone substation.

Figure 24 - Illustration of N and N-1 security capacity at Seaward Bush zone substation. Source: Ergo



The role of demand response and other "non-network alternatives" in providing security

As electricity demand grows, there may be circumstances where security can be maintained more efficiently through transmission and distribution companies managing demand on their networks, rather than investing in new network assets. Both transmission and distribution network owners may consider these solutions when making investment decisions to accommodate new demands on the system. These solutions can include asking consumers to respond by reducing demand for short periods of time (when system conditions require it), or the use of distributed energy resources and non-network alternatives (e.g. batteries). These sorts of responses are likely to reduce the cost of purchasing electricity in the wholesale market, as wholesale electricity prices are likely to be high at the same time as network loadings are high. How these cost reductions are enjoyed by the site will depend on the nature of any arrangement they have with an electricity retailer.

Obtaining more accurate cost estimates

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.[61]

Further, exploring the assumptions below with PowerNet may indicate where opportunities for cost reductions exist. Estimates are conservative. Each individual site should be re-considered when more detail is available.

Specifically, the following assumptions need to be considered when considering the results below:

- As discussed above, the spare capacities of both the GXP and zone substations[62] were based on the **publicly disclosed loading and capacity information**, which has been reviewed by PowerNet.
- Typically, peak demand from an individual site is **assumed to be coincident with peak demand on the network**, for the purposes of assessing the amount of spare capacity each site absorbs. In the absence of intra-day profiles of consumption, this is the most conservative assumption to make. 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.
- We **assume the current site security should be maintained** (unless otherwise stated). For example, if the site currently presently has (N-1) security, infrastructure upgrades are recommended to maintain this. That said, we highlight 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, but enabling the site to provide flexibility (i.e. rapid reduction) in demand in response to a failure on a network[63] could save significant amounts of money where expensive upgrades are required to maintain N-1 security.
- The upgrades and costs provided are for an individual site **in isolation of other process heat sites connecting to 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. For example, there is sufficient substation capacity at the Invercargill GXP to accommodate any of the individual 10 sites that would connect to the local network there. However, if a number of the 10 sites chose to electrify their process heat, a GXP substation upgrade would potentially be required. We consider this further below.

[61] 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

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

[63] 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 down to the N-1 limit.

- Cost estimates **exclude land purchase, easements and consenting**. 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 general 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.
- Cost estimates 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, MV switchboards/cabling and LV switchboards/cables within the respective sites are not included).
- The estimates of the time required to execute the network upgrades 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.

8.5. Assessment of individual connections

Below we present the results of Ergo's analysis of the 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 costs. Many of these connections are relatively low-cost and are only estimated to require 3-6 months to implement (excluding consenting or easements). Some connections may require infrastructure which takes additional time to implement (e.g. 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[64] network. These investments are estimated to be more significant and are estimated to take up to 36 months to implement (again, excluding consenting and easements).
- **Major:** The "as designed" electrical system requires large upgrades at both the transmission and distribution level, likely requiring substantial investment.

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.

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. This theme is returned to in the next section.

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

Table 3 lists the connections that are categorized as “minor” in nature.

Table 3 - Connection costs and lead times for minor complexity connections. Source: Ergo

Site	Transpower GXP	Network	Peak site demand (MW)	Total cost ($m)[65]	Timing
Alliance Mataura	GOR	TPC	4	$0.12	2-4 months
Ascot Park Motels	INV	EIL	1.6	$0.57	3-6 months
Balclutha swimming pool	BAL	OJV	0.6	$0.20	3-4 months
Blue Sky Meats	EDN	TPC	4.1	$3.70	12-18 months
Downers Roading Invercargill	INV	EIL	1.4	$0.40	3-6 months
Fiordland Hotel	NMA	TPC	0.13	$0.08	2-4 months
Great Southern Invercargill	INV	EIL	0.9	$1.08	3-6 months
Great Southern Milton	BAL	OJV	0.9	$0.20	3-4 months
ILT Stadium Southland	INV	EIL	0.9	$0.99	12-18 months
Invercargill Prison	INV	EIL	1.3	$0.40	3-6 months
Kelvin Hotel	INV	EIL	0.4	$0.18	3-6 months
Peacehaven Village	INV	EIL	2.4	$0.71	12-18 months
Prime Range Meats	INV	EIL	1.5	$1.15	12-18 months
SDCF Swimming Pool	NMA	TPC	0.6	$0.20	3-6 months
Silver Fern Farms Waitane	GOR	TPC	1	$0.10	2-4 months
Southern Institute of Technology	INV	EIL	1.9	$0.35	12-18 months
Winton Feedstock	INV	EIL	0.6	$0.26	3-6 months

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

Table 4 lists the connections that are categorised as "moderate"

Table 4 - Connection costs and lead times for moderate complexity connections. Source: Ergo

Site	Transpower GXP	Network	Peak (MW)	Total cost ($m)	Timing - Transpower	Timing - EDB
Alliance Lorneville[66]	NMA	TPC	23	$16.10	12-18 months	12-18 months
Balclutha Hospital	BAL	OJV	5.1	$3.50		18-24 months
Open Country Dairy Awarua[67]	INV	EIL	23.5	$15.80		24-36 months
South Pacific Meats	INV	EIL	4	$2.46		18-24 months
Southland Hospital	INV	EIL	6.1	$3.10		12-18 months

The following observations have been made with respect to the sites:

- The assessment of Balclutha hospital assumes that alone it does not trigger any upgrades to the Balclutha GXP, despite its peak loading (5.1MW) exceeding Ergo's assessment of spare capacity (~3MW) at the GXP. This is because existing demand on the Balclutha GXP peaks in summer/spring, whereas the expected demand from the hospital would peak in winter.
- The assessment of Alliance Lorneville assumes that a minor upgrade to Transpower's North Makarewa substation (replacement of cables and disconnectors, costing $0.5m) will yield enough capacity to accommodate the 23MW peak demand from the site at N-1 security.
- Ergo highlighted that there may be multiple options for the connection of Open Country Dairy – Awarua, including the possibility of taking a lower level of security (N) via a direct connection from the Invercargill GXP. As discussed above, this increases the risk that OCD's supply is interrupted, but would result in a connection cost estimated to be 40% lower at $9.8M.

Table 5 lists the connections that are categorized as "major".

Table 5 - Connection costs and lead times for major complexity connections. Source: Ergo

Site	Transpower GXP	Network	Peak (MW)	Total cost ($m)	Timing - Transpower	Timing - EDB
Fonterra Edendale	EDN	TPC	85	$54.50	36-48 months	36-48 months
Silver Fern Farms Finegand	BAL	OJV	8	$12.65	24-36 months	24-36 months
Mataura Valley Milk	GOR	TPC	15	Investment already committed		

[66 & 67] Following feedback from PowerNet, this investment could be classified as major.

In respect of the major complexity connections:

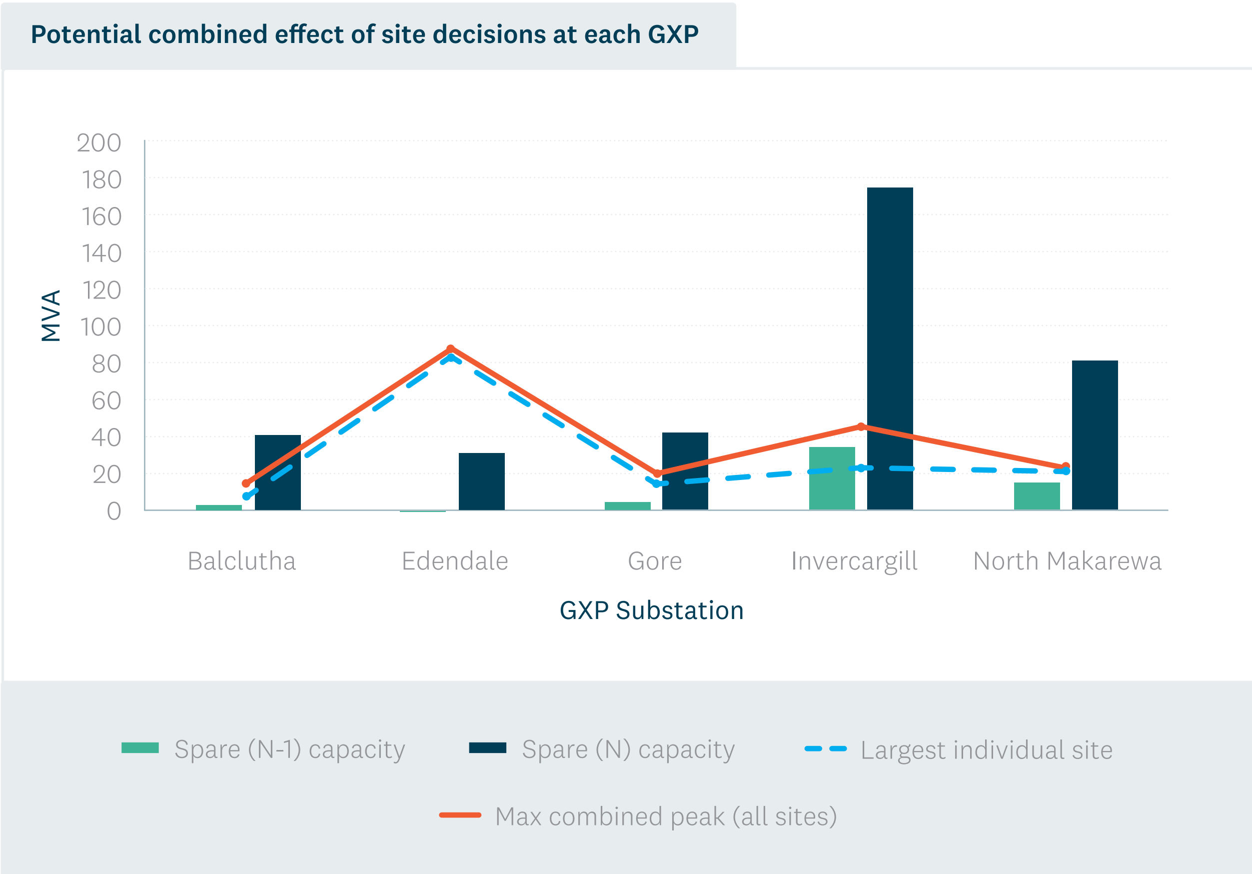
- All require material expenditure on expanding Transpower's substations or lines: Fonterra ($29m, substation and lines), Silver Fern Farms ($7.5m, substation only) and Mataura Valley Milk ($7m, substation only).
- All these connections are estimated to require two to four years to design and execute, not including consents and easements where required.
- There are a number of connection options for Fonterra's site at Edendale depending on the magnitude of demand that is electrified and the security required. These options are presented below.

Option	Existing (MW)	Additional (MW)	Connection security	Estimated capital cost ($m)
Fonterra – Option 1	30	21	N	$9.60
Fonterra – Option 2	30	32	N - 1	$34.10
Fonterra – Option 3	30	97	N	$55.90

8.6. Collective impact on upgrade costs

The above analysis considered each site in isolation from each other. Figure 25 shows a summary by GXP, highlighting the GXPs where the largest site would require an upgrade by itself, and then whether the collective decisions of all sites connecting to the GXP would trigger a GXP upgrade.

Figure 25 – Potential combined effect of site decisions at each GXP. Source: Ergo



In Figure 25 we have taken the most conservative view of new demand from electrification, by assuming that:

- All sites will reach their peak demand at the same point in time that the existing demand at the GXP peaks. Practically speaking, where there is a number of sites, demand diversity is likely to result in the combined peak being lower than this figure.
- It is assumed that none of the sites actively manage their demand to avoid system peaks; again, this is a conservative view of peak demand.

The chart shows that at most GXPs, the collective decisions of all sites at a GXP to electrify would not alter the need (or otherwise) for an upgrade to maintain N-1 security. However, at Invercargill, an increase of peak demand of more than 35MW (which could result from a range of combinations of the 12 sites at the GXP electrifying) an upgrade would be required; yet no individual site would alone cause this investment. This case is outlined in more over page.

Invercargill GXP

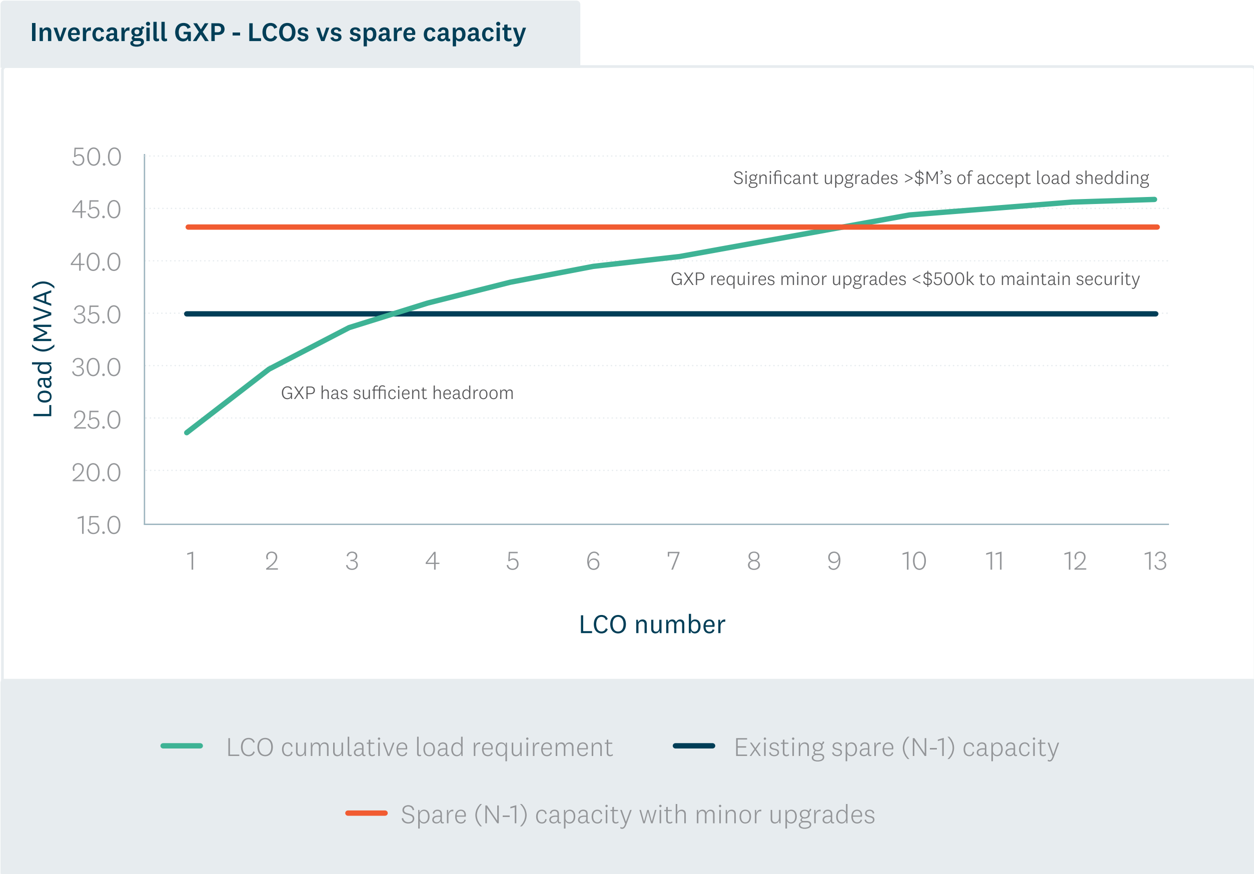
The following 13 sites, if electrified, would have impacts on the demand at Transpower's Invercargill GXP:

- Open Country Dairy Awarau (23.49 MW)
- Southland Hospital (6.1 MW)
- South Pacific Meats (4.0 MW)
- Peacehaven Village (2.4 MW)
- Southern Institute of Technology (1.9MW)
- Ascot Park Hotel (1.6 MW)
- Downers Road Invercargill (1.4MW)
- Invercargill Prison (1.3 MW)
- Prime Range Meats (1.2 MW)
- Great Southern Invercargill (0.9 MW)
- Stadium Southland (0.9 MW)
- Winton Feedstock (0.6 MW)
- Kelvin Hotel (0.4 MW)

The screening analysis concluded that no individual site would require an upgrade to the Invercargill GXP, as there is currently ~30MW of spare N-1 capacity. However, if all sites electrified (Figure 26), it would increase peak demand by up to 46MW (if all demands coincidentally peaked – as discussed earlier, this is a conservative assumption). In fact, Open Country Dairy, South Pacific Meats, and Peacehaven Village would likely collectively trigger an upgrade, even if the remaining 10 sites converted to biomass.

Ergo advised that an initial upgrade to the Invercargill GXP is likely to be relatively inexpensive ($0.6M) as it only requires the replacement of circuit breakers, current transformers and 33kV cables. This would increase the spare capacity to ~43MVA, sufficient for most of the sites identified at Invercargill.

Figure 26 - Cumulative demand (load) requirement and spare capacity for Invercargill RETA sites. Source: Ergo



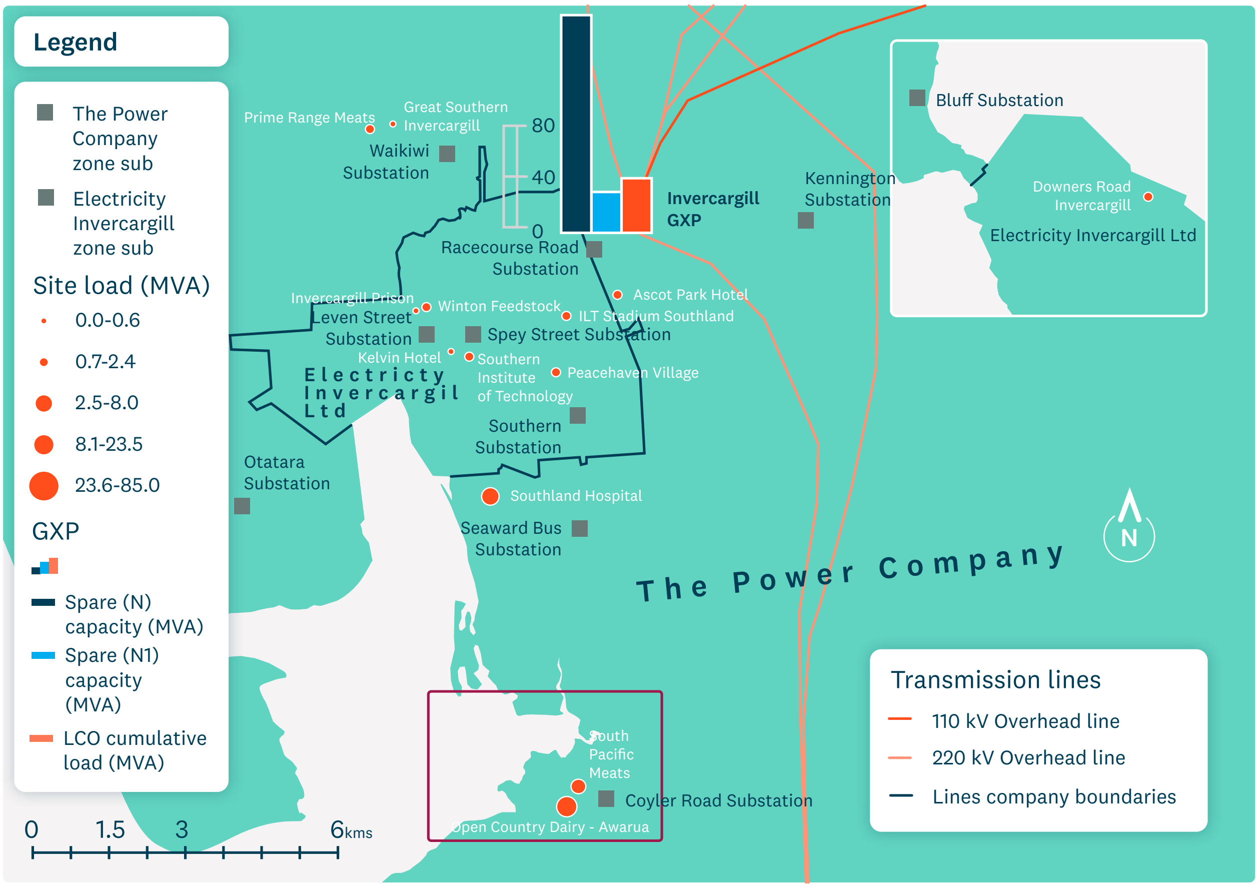
However, if all sites electrified their process heat and had peak demands coincident with existing demand, the resulting network peak demand would increase by 46MW, and would require a more significant upgrade (Figure 26). More detailed analysis is required to determine the likelihood that demand would behave in a way that caused this outcome.

That said, the cost per site may be lower, as network upgrades often experience economies of scale.

Coordination efficiencies – Open Country Dairy and South Pacific Meats

The below is an example of where coordinating between RETA process heat sites could lead to a superior commercial outcome (Figure 27).

Figure 27 - Locations of Open Country Dairy and South Pacific Meats (red box)



The Open County Dairy and South Pacific Meats sites are within 400m of each other near the Colyer Rd zone substation. If both opportunities proceeded, this would result in 27.5MW of additional demand. These sites could be supplied[68] from the Invercargill GXP (no GXP upgrades would be required) with a new zone substation situated closeby, supplying both sites[69].

The estimated $16.8M of this option to supply the two sites is $1.46M less than the combined estimate to supply the sites individually.

The examples raise the question of how the costs associated with a combined upgrade are allocated to the individual sites where an upgrade is triggered by the collective decisions, especially where this may result in economies of scale. Further discussions with PowerNet and Transpower will be required to understand the methodology for cost allocations.

[68] Via a new double circuit 33kV supply.

[69] Assumed to be three double circuit 11kV cables supplying Open Country Dairy and one 11kV single circuit cable supplying South Pacific Meats.

Other electricity demand growth

Ergo's assessment of spare capacity at each point in the network was based on near term estimates of peak demand published by network companies. 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.

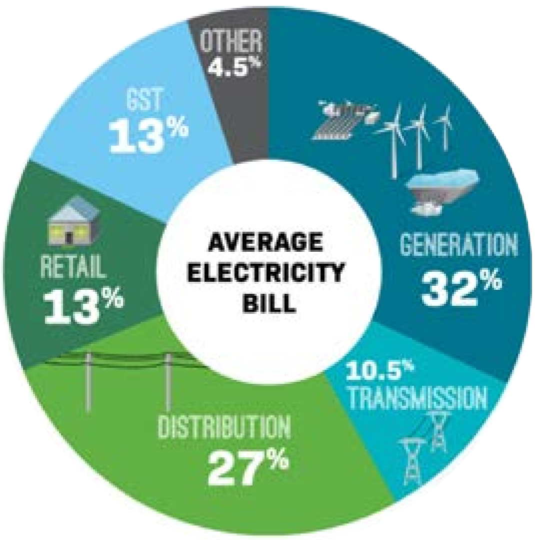
Each individual distribution business will have developed peak demand forecasts over the next 10+ years that account for these factors. EECA understands these forecasts are shared with Transpower, as they develop their peak demand forecasts for each GXP.

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

8.7. Retail electricity prices

Retail electricity prices, that would be faced by the majority of the sites[69], 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 28 - Components of the bill for a residential consumer. Source: Electricity Authority



[70] 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.

However, while all of the components in Figure 28 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.

The components of costs this section focuses on relates to the "generation" and "retail" components. On top of this, process heat sites will also pay:

- Charges for metering and Electricity Authority levies.
- Charges for the use of the **existing** distribution network, except for those large customers who connect directly to one of Transpower's GXPs. The magnitude of these charges depends on each distribution company's "pricing methodology", which they are required to disclose.[71]
- Charges for the use of the **existing** transmission grid, which are passed through by the distribution company.
- Charges for any distribution or transmission upgrades required to accommodate the site. These charges are usually paid by way of a contribution to the capital cost of the upgrades, and may not appear as part of the overall electricity price per se. Again, the capital contributions policies for each of the networks will define this.[72]

Indicative estimates for the total cost of upgrades which underpin (iv) are provided in Section 8.

Given the complexity of the methodologies that determine the charges paid by non-residential consumers, it is difficult to generalise the likely magnitude of charges (i)-(iii) above. It is recommended PowerNet are engaged with for more tailored estimates.

Generation (or "wholesale") prices

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

[71] PowerNet publishes the pricing methodology for each of the three networks relevant to the Southland RETA. They can be found here: https://powernet.co.nz/disclosures/

[72] Also available at https://powernet.co.nz/disclosures/

EECA engaged EnergyLink 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) 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.[73]

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

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.[74] 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.

Thus the retail electricity price 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.

[73] 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 have not included these effects in the scenarios produced for this project.

[74] 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.

Specifically:

- The price is only forecast for the generation and retail ("energy") component[75] of the customer's tariff, i.e. 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 needs to be discussed with the relevant EDB.[76]

- Prices include the effects of high-voltage transmission losses to the nearest GXP in Southland, but do not include distribution network losses to the customer's premises.[77]

- The prices are produced 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 e.g. high wholesale prices by shifting demand.

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 e.g. lower demand, lower fuel costs, or accelerated[78] build of new power stations

- **High price scenario:** Assumptions that would lead to higher electricity prices than the Central Price Scenario, e.g. higher demand, higher fuel costs or more restrained investment in new power stations.

The three scenarios used are outlined in Table 6 below. More detail on these assumptions is available in EnergyLink's report.[79]

[75] 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.

[76] General network pricing tariffs for all types of customers is available on an EDB's website. However, where network investment is required, the impact on total network charges needs to be discussed with the EDB in question.

[77] Network losses depend on where in the EDB's network a customer is situated. The EDB publishes network loss factors for different parts of the network. The pricing provided here should be inflated by the network loss factor for each individual customer.

[78] 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.

[79] EnergyLink (2022), *Regional Electricity Price Forecasts: EECA Regional Energy Transition Accelerator Program*, May 2022.

Table 6 - 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[80]	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[81]	NZD75/t	NZD75/t	NZD75/t
Generation investment behaviour[82]	Neutral	Aggressive	Lagged/Conservative
Generation disinvestment	Huntly Rankines dry year and retired by 2030	Huntly Rankines dry year and retired by 2030 Huntly CCGT retired 2033	Huntly Rankines dry year and retired by 2030 Huntly CCGT retired 2037

EnergyLink also model the "levelised cost of energy" (LCOE) associated with generation investment classes (e.g. wind, solar) into the future.[83] 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.

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

[81] 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.

[82] 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.

[83] "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.

Noting that the Low and High scenarios are not necessarily designed to be the most plausible storylines,[84] 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 assumptions 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.[85]
- EnergyLink applies different inflation assumptions to the various assumptions in the table above, each of which imply different rates of decline from its current level of 6% to a long-term rate of 2%.

Price forecasts

Annual average (nominal) price forecasts are presented below for the period 2026-2048. In real terms, electricity prices remain at or below recent levels indicated by EnergyLink's electricity contract price index until 2032 for the High scenario, and 2037 for the Low and Central scenario. After 2040 the Central and High scenarios see real prices exceeding that observed over the past 20 years, principally because of the impact of electrification of transport and process heat on electricity demand.

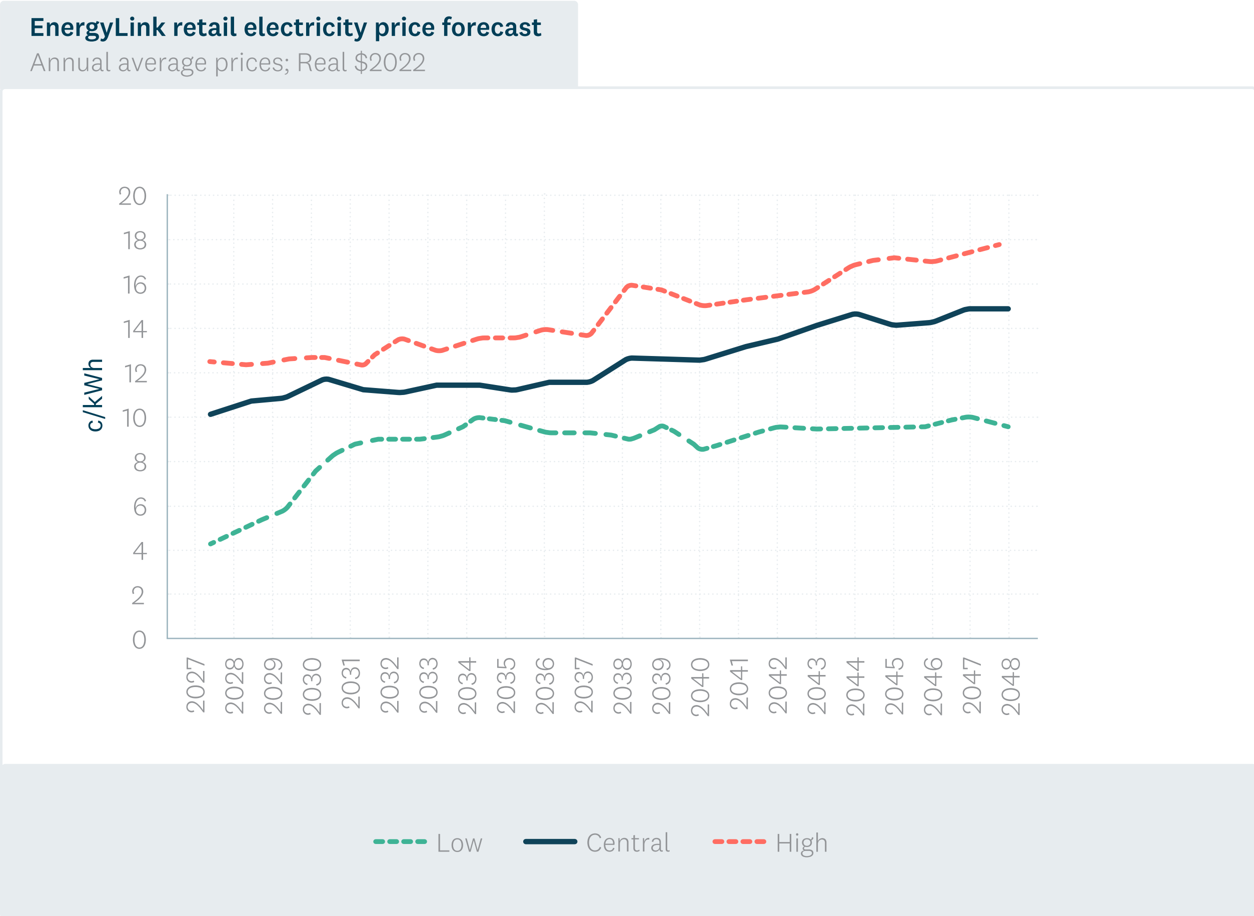
As is shown in Figure 29, the impact of Tiwai's exit (combined with the other assumptions in the Low scenario) significant. While this is a lower end on the range of prices, other forecasts (e.g. Climate Change Commission) show similar impacts from the Tiwai closure, albeit with shorter duration.[86]

[84] 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.

[85] 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.

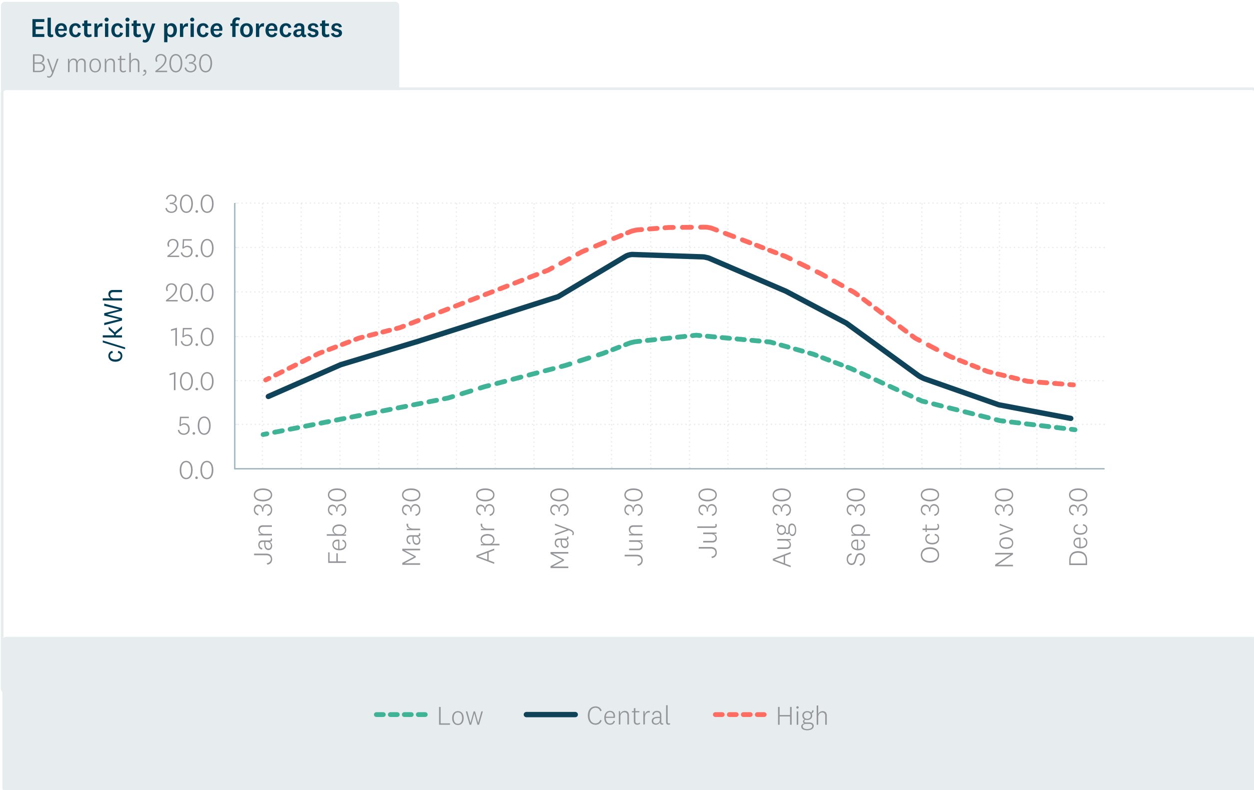
[86] The shorter duration of the price suppression in the CCC's modelling is likely to be due to the fact they did not combine a Tiwai exit with the other price-suppressing variables (e.g. low gas prices, lower decarbonisation demand, lower coal prices) in EnergyLink's modelling.

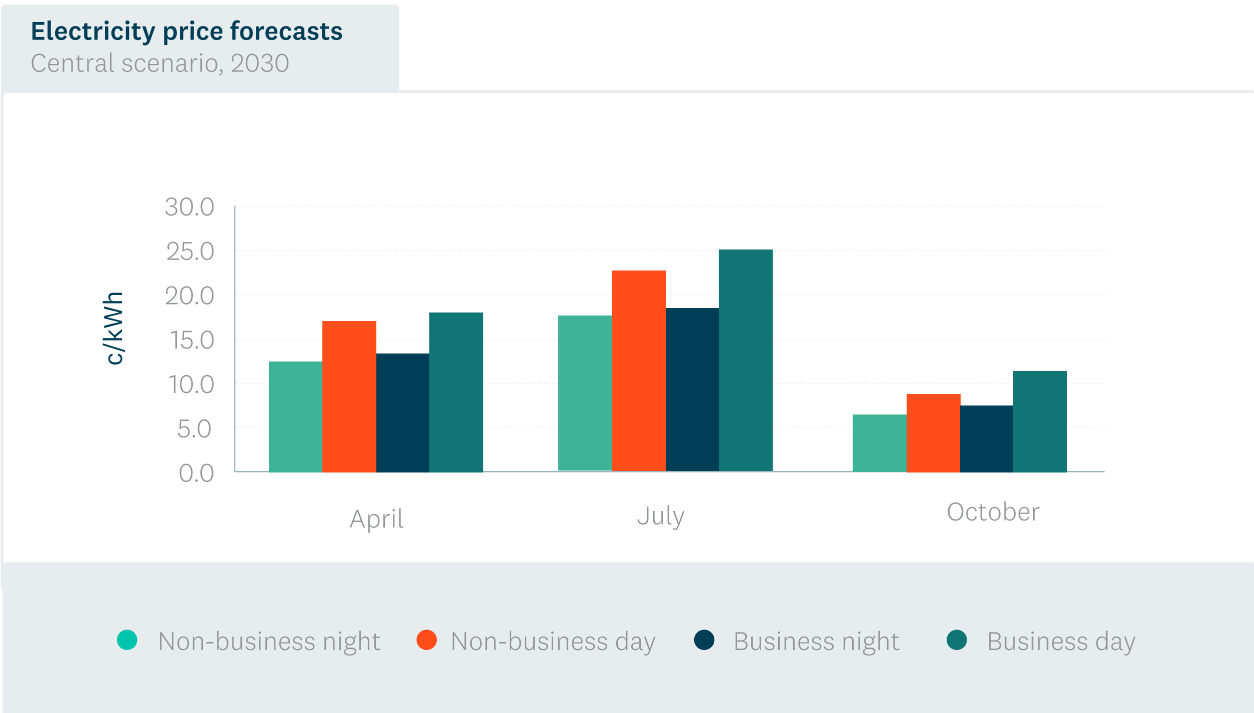
Figure 29 - Forecast of real annual average electricity price for large commercial and industrial demand. Source: EnergyLink



As outlined earlier, the price forecasts are actually produced at a finer resolution than the annual average series in Figure 29. Figure 30 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 30 - Electricity price forecasts (a) by month and (b) by time block in April, July and October 2030. Source: EnergyLink





The shape of electricity prices over the year reflects the expected nature of national winter demand (winter peaking – lighting and heating) coupled with lower winter inflows into alpine lakes. However, this is somewhat inversely correlated with some of the sites considered in this study, particularly dairy, who experience the lowest levels of demand during winter. Hence the volume-weighted price paid for electricity at these sites could be materially different from the annual average prices shown in Figure 29 above.

The variation of prices between night and day illustrate a potential source of cost reduction for process heat users – if electricity demand can be shifted from higher priced periods to lower priced periods. Further, EnergyLink's forecast prices assume that the site is on a typical commercial retail contract, which has prices that are fixed by the retailer for these day/night and weekday/other day structure. More "sculpted" pricing arrangements are available today, where the retailer provides prices for each four-hour block of time over the day. Finally, some retail arrangements would see the true wholesale price of power in each half hour passed through to the site, providing a strong incentive for the site to use any flexibility in its consumption to avoid higher prices. The type of retail arrangement that is best for an individual site needs to consider these opportunities. But we note that, as for the sizing of the network investment discussed in Section 8, any flexibility in the site's demand for electricity can be used to bring down the cost of electricity.

9 Decarbonisation pathways

9. Decarbonisation pathways

The previous sections have highlighted key considerations in any process heat user's decision to switch fuels. These sections have focused on the availability and costs of biomass resources, and the network availability and cost of electricity at their site.

It is now possible to consider how this information can provide insights for the local electricity and biomass "market" relating to the pace and magnitude of demand increases for the two categories of low-emissions fuel.

To do this, indicative decarbonisation pathways for process heat in the region have been prepared to illustrate a range of site decisions about fuel switching. This provides scenarios for how fast emissions could be reduced over time, and determines the quantum and timing of demand for electricity and biomass. This, in turn, informs the degree to which electricity upgrades may be required for process heat decarbonisation, as well as the likely cost of biomass.

9.1. Sources and assumptions

The modelling that sits behind the simulated pathways relies on a vast array of assumptions about how individual RETA process heat sites will work through the process outlined in Section 6.4, and the main relevant factors that will drive their fuel switching decision – boiler sizes, efficiencies, fuels, capital and operating costs to name a few.

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
- GIDI funding applications
- Regional Heat Demand Database
- Online articles

The emissions profiles of all the major sites have been covered off using these sources, covering over 90% of RETA sites. However, for sites where individual ETA data was not available, estimates based on other data available to EECA were made, including:

- Demand reduction opportunities have been estimated to be 10%
- Heat pumps have been estimated to reduce demand by 15% where the split between hot water and steam is not available
- 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

In order 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 costs associated with these decisions are sourced from:

- Capital costs derived from specific individual ETAs where available, or derived from wider ETA data where unavailable.
- Biomass pricing estimates have followed a price path of $15/GJ ($189/t). However, if a significant increase in demand is triggered, the price is increased to $17.50/GJ ($220/t) for that additional volume.[87] This is effectively an average cost of the resources identified in Section 7.7, but incorporates the cost of higher-priced wood pellets where boiler conversions are contemplated.
- A conservative view of electricity upgrade costs have been incorporated as per Section 8.
- Variable electricity costs have used the central pathway from Section 8.7.

However, the following general rules have also been applied to each site, which reflect the decarbonisation decision making process outlined in Figure 5:

- 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[88];
- 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.

[87] These numbers do not match any individual resource illustrated in Section 9, as the approach adopted to create the pathways assumed an average cost of the different types of resources available through time, also allowing for the higher cost of wood pellets (not considered in that section) where conversions of existing boilers are being evaluated. It is a somewhat more complex optimisation to integrate the “stepped” nature of supply illustrated in Section 7.7 with the calculation of MAC values.

[88] 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.

- Based on conversations with industry, including boiler owners, we have assumed that if a site is converting from coal boilers it will change to wood pellets, as retrofitting is more likely possible. If a biomass boiler is purpose built, and large (~>5MW), these conversations have suggested wood chip or hog fuel is the best option.

Calculating Marginal Abatement Costs

For the pathways that involved an optimisation of boiler conversions based on marginal abatement costs (MACs).

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 emissions in New Zealand, as this is implied by the MAC.[89] The MAC value effectively provides an implied carbon price that would make the decision maker financially indifferent between proceeding and not proceeding. If the future expected (discounted) carbon price is higher than the MAC value, the decision maker would proceed with the project. If it was less than the MAC, they would not proceed.

Of course, there is more than one option available (i.e. biomass or electricity), and the MAC also gives a relative ranking of the options expressed in terms of their marginal abatement cost. The lower the MAC, the more financially attractive the option is, for a given expectation of the future carbon price. The ruleset for the MAC-based pathways below select the fuel with the lowest MAC value.

This simulated decision making framework thus presumes that the decision regarding which fuel to switch to is purely about financial factors (which are, in turn, based on the modelled reality of the physical solution). There may be a range of other factors which drive this decision, e.g. confidence in future fuel supply.

The impact of boiler efficiency on the “price of heat”

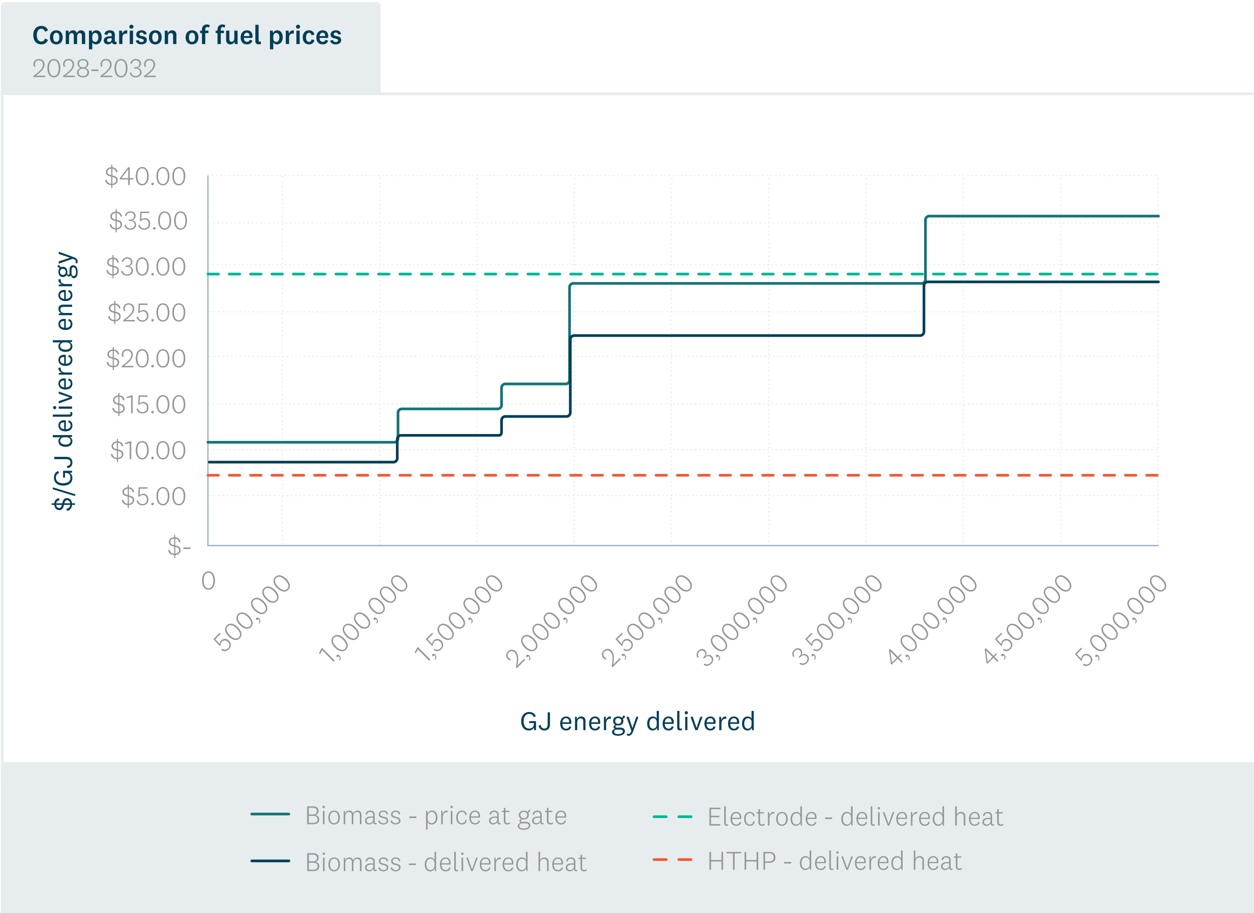
The MAC analysis implicitly trades off all the costs – capital, operating and fuel – to provide a single analysis of the lowest-cost fuel (from an emissions reduction perspective). This (necessarily) incorporates the different efficiencies of the boiler technologies chosen.

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 100% efficiency. On the same basis, heat pumps effectively have efficiencies 400% or higher, due to the coefficient of performance (CoP). The cost per unit of **heat** received by the process is therefore different from the cost per unit of the energy delivered to site.

[89] In the same way that calculating the levelised 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.

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 8.7 (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 taken into account with the MAC calculation). The biomass price does not account for any margin that suppliers may seek on the various bioenergy resources.

Figure 31 - Comparison of the variable costs of biomass and electricity from a delivered heat perspective. Source: PF Olsen, Ahikā, EECA



Resulting MAC values for the optimal fuel

The range of marginal abatement costs for the optimal fuel switching choice, for projects which have not (at the time of writing) committed to a fuel choice[90], are illustrated in Figure 32 below. Despite relatively common assumptions about capital and operating costs, there is a wide variety of MAC values. These reflect 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.

[90] Three sites that had committed to a fuel choice (Alliance Lorneville, Alliance Mataura and Mataura Valley Milk) were included in ERGO's analysis in Section 8 but not in the MAC summaries here.

Figure 32 - Number of conversion projects by range of MAC value. Source: EECA

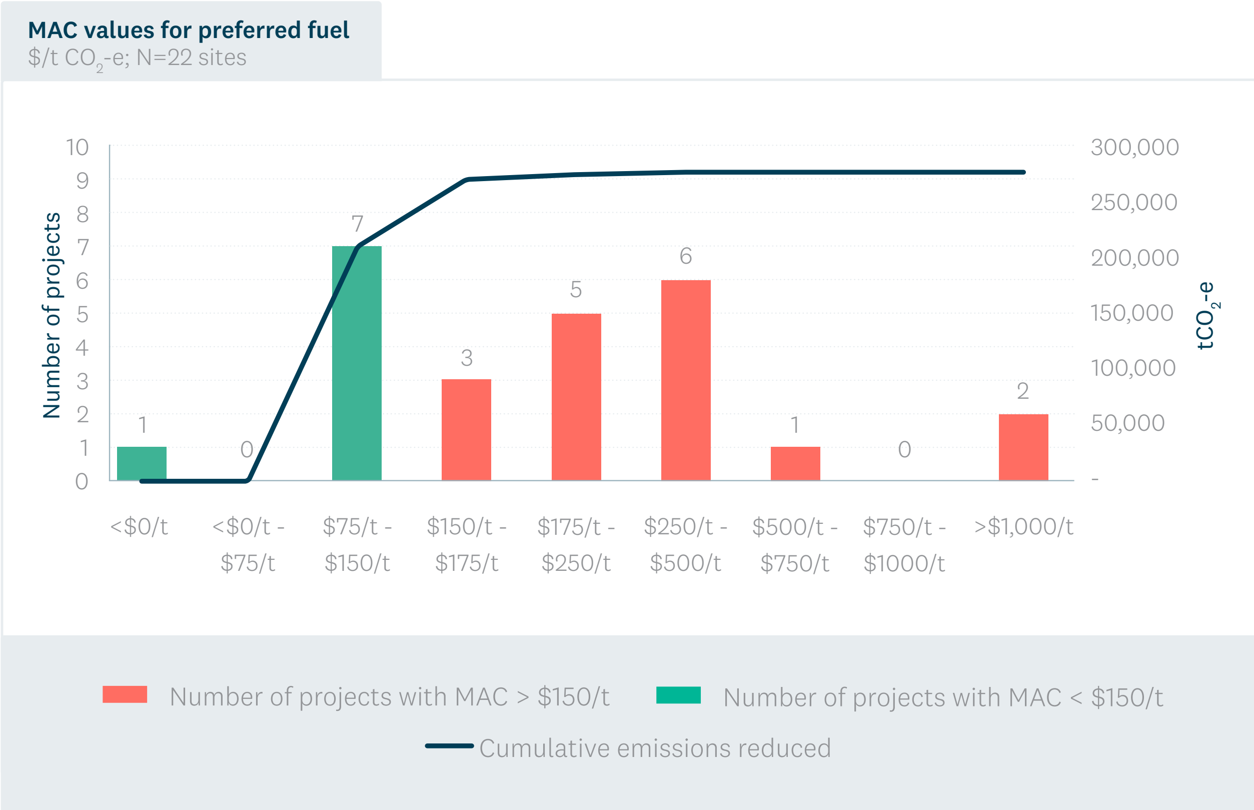
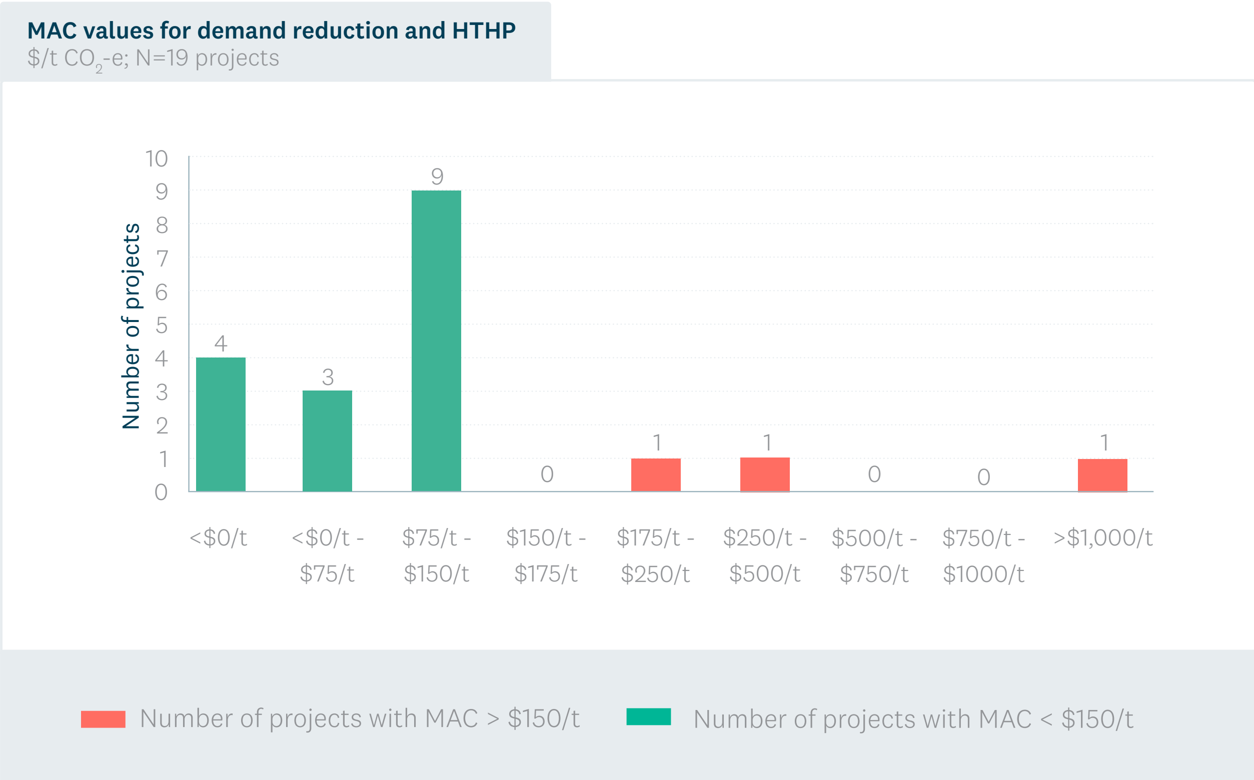


Figure 32 shows - highlighted in green, the projects would have a positive NPV at some point in the period of the RETA study, if ETS prices rose in line with the Climate Change Commissions carbon price projections[91] . The figure also displays the cumulative emissions reduced as the MAC value increases, showing that 75% of the total emissions reduced through these projects can be achieved at carbon prices less than $150/t (which is approximately equal to the Climate Change Commission's estimated carbon price in 2030).

[91] The demonstration path from the CCC's final advice.

Figure 33 illustrates the range of MAC values for demand reduction and high-temperature heat pump (HTHP) projects. As indicated earlier, many of these projects are attractive today - seven (out of 19) would generate a positive NPV at today's carbon prices, and another nine would do so at carbon prices expected by 2030.

Figure 33 - MAC values for demand reduction and HTHP projects. Source: EECA



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.[92]

- Any timing of an electrification project which (individually) appears infeasible because of likely lead times for network upgrades (as outlined in Section 8) was delayed sufficiently to accommodate these.

[92] 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/

The pathways[93] were then developed as follows:

Pathway name	Description
BAU - Biomass-centric	All unconfirmed site fuel switching decisions proceed with biomass at the timing indicated in the organisation's ETA pathway. If not indicated, timing was set at 2036.
BAU - Electricity-centric	All unconfirmed sites 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.
Linear	Each site switches to the fuel with the lowest MAC value for that site; projects ordered and timed to achieve a relatively constant annual level of emissions reduction (within reason).
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 is less than a ten-year rolling average of future carbon prices[94].
MAC Optimal with co-funding	As for Mac Optimal except with MACs recalculated to assume acceleration co-funding from the GIDI fund. GIDI co-funding has been applied to projects in a consistent manner.

Pathway results

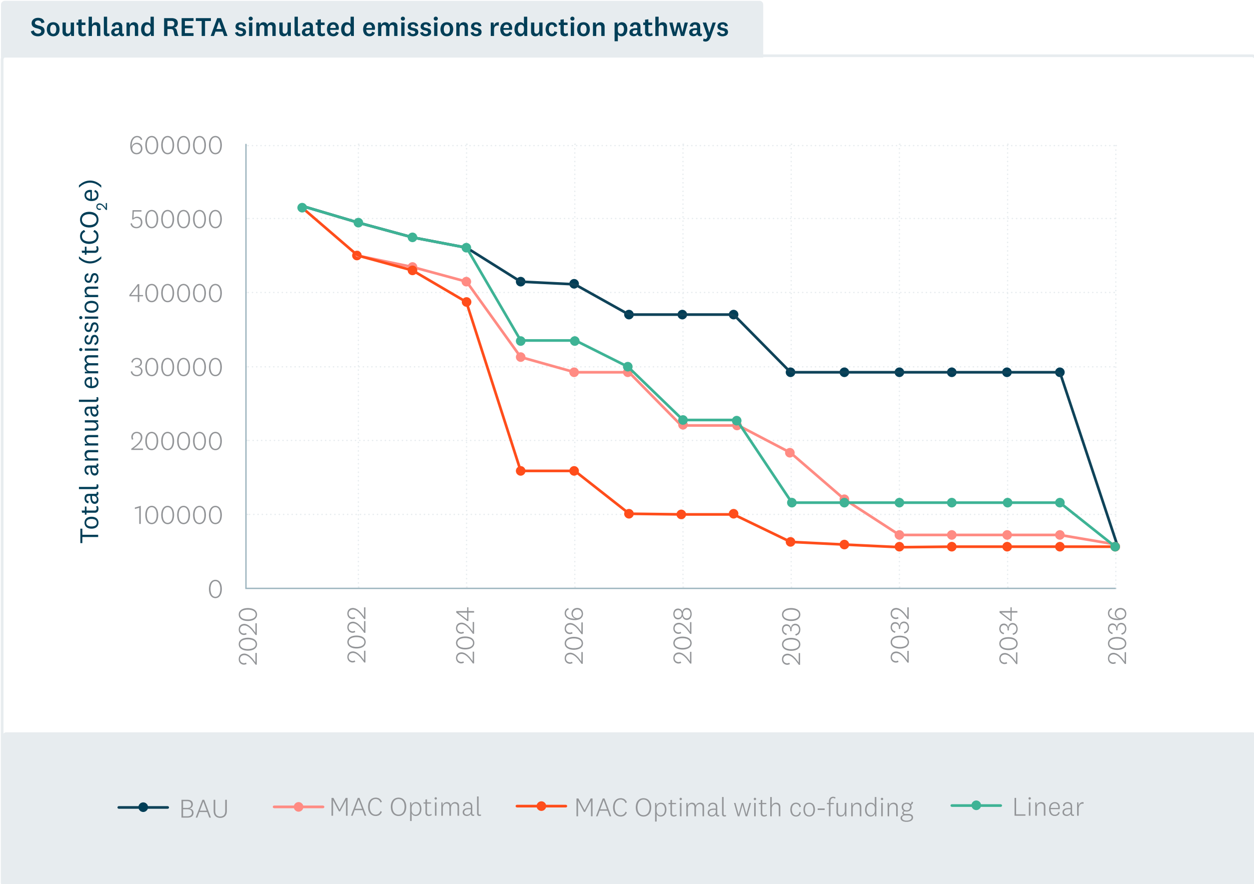
All pathways eliminate nearly 90% of process heat emissions in the region (a reduction of 464kt out of a total 519kt[95]), but at significantly different pace (Figure 34).

[93] In future RETAs, EECA will use the advanced TIMES-NZ energy system model to provide alternative views of pathways.

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

[95] 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. Since the increase in electricity demand is approximately 550GWh, there is ~55t CO_2-e resulting from this increase in electricity demand.

Figure 34 - Emissions reduction trajectories for different simulated pathways. Source: EECA

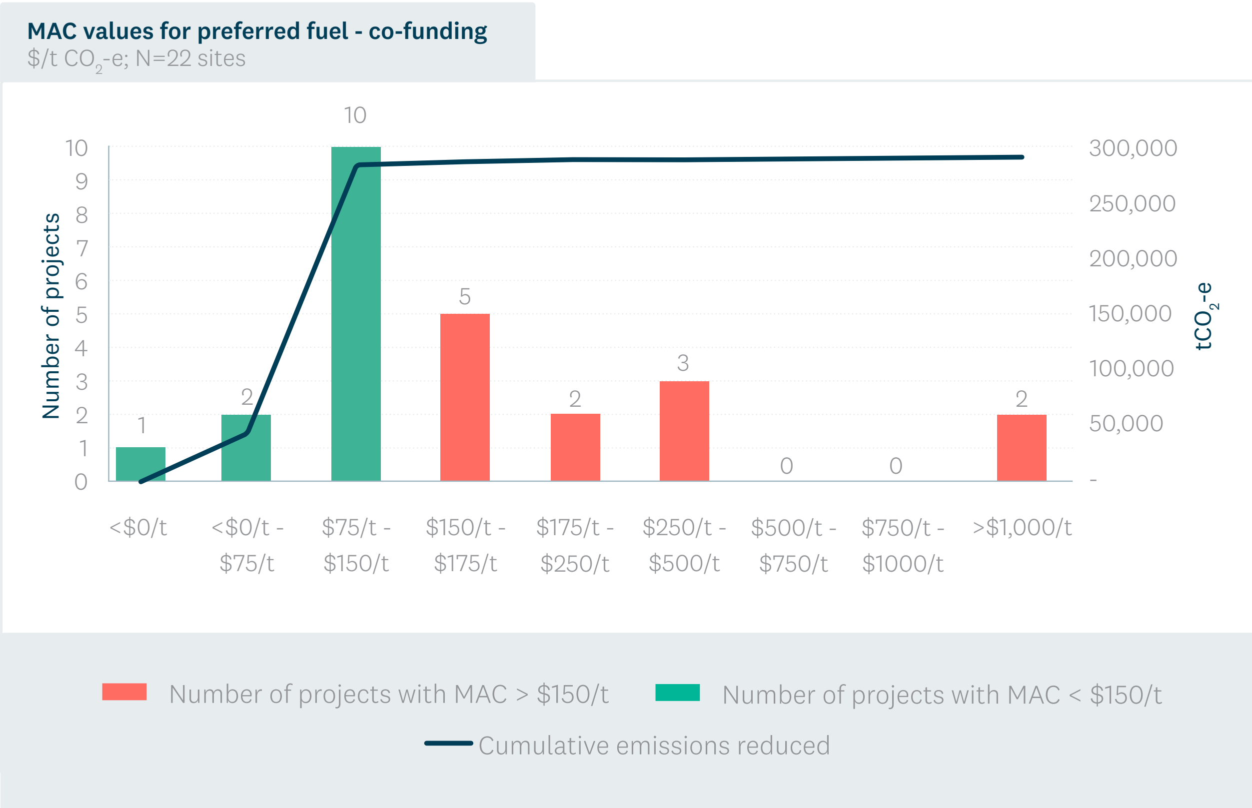


Using the assumed timings in the individual ETAs (or 2036 where unavailable) is the slowest decarbonisation path. Around half the emissions reductions are assumed to occur in 2036.

The MAC Optimal pathway proceeds at a similar smooth pace as the linear approach, with the majority of emissions reductions achieved by 2030.

Acceleration co-funding could effectively double the pace of decarbonisation, with 70% of the decarbonisation decisions made by the end of 2025. The cumulative difference between the BAU approach, and MAC optimal with co-funding, is 2.9m tCO_2-e across the period 2022-2036. The effect of the government's simulated GIDI co-funding on the MACs is illustrated in Figure 35.

Figure 35 - Range of MAC values and cumulative emissions reductions with co-funding. Source: EECA



Acceleration co-funding essentially results in 96% of emissions reductions having a MAC value of less than $150/t (up from 75% with no co-funding).

Both the "MAC Optimal" pathways (with and without acceleration co-funding) see fuel decisions that result in 45% of the energy needs supplied by biomass (with a consumption of 476GWh of delivered energy), and 55% of energy needs supplied by electricity (with 576GWh of delivered energy).

EECA acknowledges that there are a range of factors which determine each organisation's final decision on boiler conversion. The NPV of a project (at the expected carbon price) is only one factor, albeit an important one for owners and shareholders. However, capital constraints, uncertainty about future costs, government funding, and labour market implications are examples of the myriad factors that must be taken into account when deciding when to make a conversion, 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. While EECA has not undertaken a broad sensitivity analysis of the cost inputs (e.g. biomass price, electricity market scenario), Figure 36 below indicates how different (in absolute terms) the electricity versus biomass MAC value was across the 22 sites making fuel switching decisions.

Figure 36 - Box and whisker plot of difference between projects' MAC values for biomass and electricity. Source: EECA

Three outliers were removed (differences of $564/t, $989/t and $6,767/t).

If, for an individual project, the biomass and electricity MAC values were very close, small changes in input assumptions could change the decision. Figure 36 shows that the majority of the modelled fuel switching decisions are quite robust – 10 projects have differences between the biomass and electricity MAC values of over $100/t, and only three projects with differences of 10% or less of the optimal MAC value.

9.3. Pathway implications for fuel usage

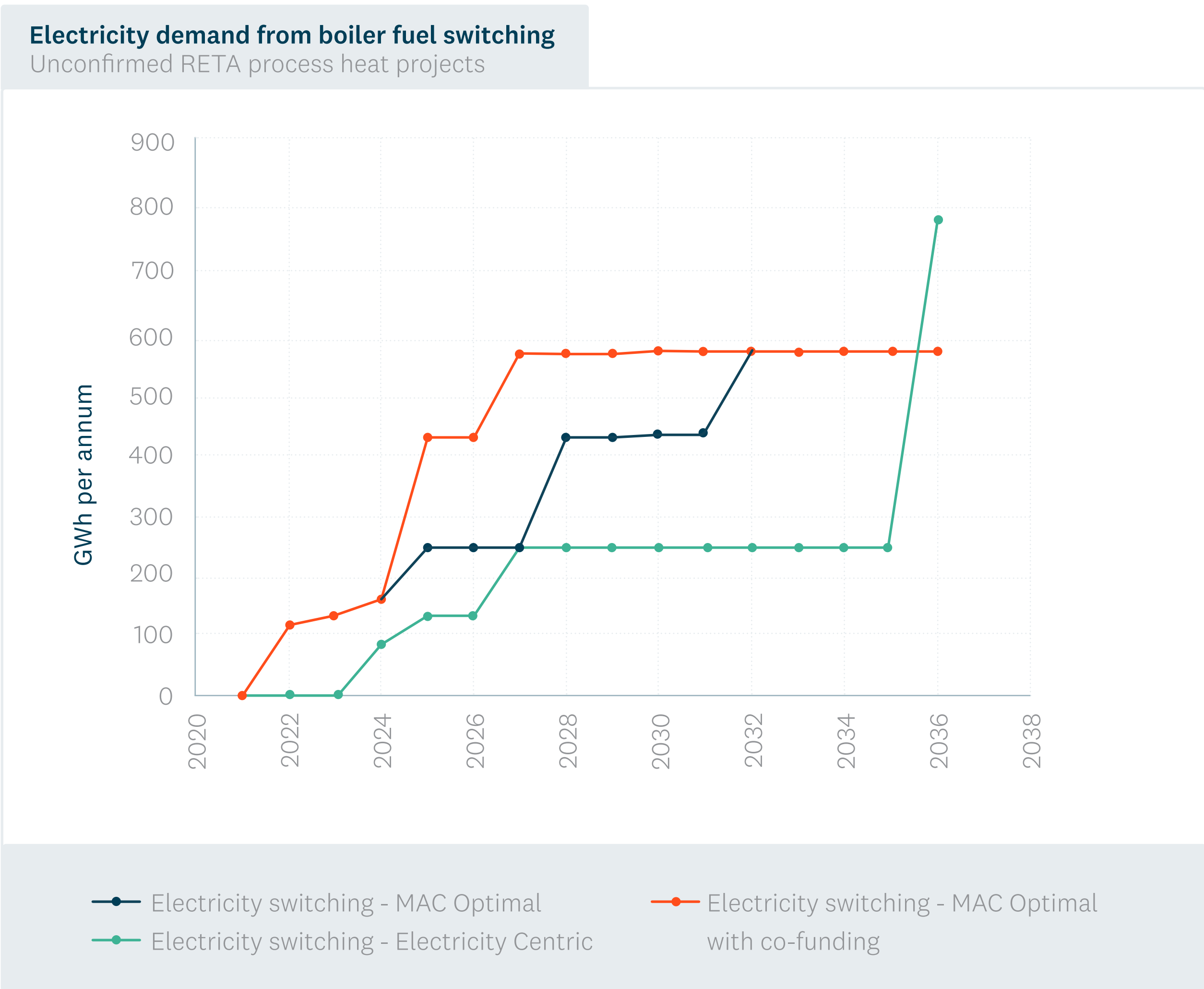
We can now compare the trajectory of demand for biomass and electricity arising from the various pathways. Below we compare the growth in demand in three of the pathways:

- BAU - Biomass Centric and Electricity Centric
- MAC Optimal
- MAC Optimal with acceleration co-funding

Electricity

Figure 37 shows the growth in electricity demand in each of the pathways. Note that this is growth associated only with unconfirmed fuel switching decisions: an additional 100GWh growth arises from confirmed sites, plus ~50GWh from confirmed or modelled use of heat pumps for low temperature heat.

Figure 37 - Growth in electricity demand from fuel switching pathways (unconfirmed RETA sites). Source: EECA



While the BAU Electricity Centric pathway ultimately results in the highest demand growth (790GWh, or 12% growth on current Southland demand[96]), the majority of the growth does not manifest until 2037. In the two optimal pathways, fewer RETA sites switch to electricity, and thus reach a lower level of ultimate demand growth (576GWh, or 8% growth) around 2032. However, with acceleration co-funding, this demand level is reached by 2027, implying an average annualised demand growth rate of 1.7% between now and then, attributed solely to process heat decisions. Demand growth from other decisions (e.g. electric vehicles) would be in addition to that.

Biomass

Figure 38 shows the growth in biomass demand (in TJ per annum) arising from each of the pathways. Again, the Mac Optimal pathways result in approximately half the final demand from the BAU pathway, and the co-funding sees an acceleration of demand growth – approximately 95% of ultimate biomass uptake is achieved by 2025.

Figure 38 – Growth in biomass demand from fuel switching pathways (unconfirmed sites). Source: EECA

[96] Southland demand includes Tiwai consumption.

We can also see that by 2024, the estimated volumes of unutilised harvesting and processor residues, identified in Section 7, will be exhausted. Meeting the remaining demand from fuel switching projects will require diversion of export chip and export low-grade logs to domestic bioenergy, which, while likely to be a low-emissions source, may have global sustainability implications as discussed in Section 7.2.

The rapidity with which the simulated pathways suggest harvesting residues will be taken up motivates a more careful analysis of the true potential here, both in terms of volumes and cost, as well as working closely with forest owners to develop the harvesting methods required.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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 a number of organisations facing the decision of how to convert away from fossil fuelled boilers to renewable fuels – biomass and electricity.

The aim of this report, which is the culmination of the RETA planning stage, 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.

> 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.

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 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.

10.1 Biomass - insights and recommendations

The analysis in this report shows that our estimate of additional processor residues and (mostly) harvesting residues has the potential to supply around a third of the demand for biomass that would eventuate if all fuel switching decisions were in favour of biomass (and assuming no other competing uses for this biomass, e.g. biofuels). Based on the "MAC optimal" pathway from Section 9.2, around three-quarters of the overall demand for biomass in 2027 could be delivered before diversion of export chip or logs was required.

However, by 2037, meeting the demand from the MAC Optimal boiler conversions (considered in this RETA) requires diversion of some volume of Southland's wood destined for export markets to bioenergy needs.

While our pathway analysis suggests that only half of the decarbonisation decisions would rely on biomass (with others choosing electrode boilers) it is still not clear that forestry waste residues would be sufficient to meet the demand that eventuates. The following work is recommended:

- **Given the potential significance of harvesting residues, 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 harvesting residues.** The estimates of how much of these "waste" residues could be recovered, and at what cost, were derived by extrapolating from existing experience and trials across a range of sites in Southland. This work will provide more confidence that this low-emissions form of biomass can be realised for those sites contemplating switching to biomass as a fuel.
- **In tandem, work should be undertaken with forest owners to understand the logistics, space and equipment required for harvesting residues. This could extend to developing local residue "hubs" where smaller forest owners, who may not have the space to let residues dry in their own forests, can transport residues to a drying location. This work should include how these residues can most efficiently be delivered to a chipping and storage location that minimises the overall transport costs to process heat users.**
- **EECA also believes analysis is 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.**
- **An analysis should be commissioned to better inform potential users of biomass for energy of the global emissions and sustainability implications of any diversion of currently exported wood.**

- Broader still, and as highlighted above, it is expected that there will likely be competition for biomass from other sectors – locally, in the form of biofuels for transport decarbonisation, and internationally as other countries seek sources of biomass to replace coal and liquid fuels. **More in-depth analysis of competing uses of biomass for energy at a national and regional level could help future RETA studies understand the significance of these competitive pressures**. It would also help the process heat decisions where transport emissions may factor into decisions about securing biomass supplies.
- Effective markets thrive on information symmetry between suppliers and consumers. The nature of supply and demand for biomass is ever evolving, and it is very difficult for any one participant to obtain the collective view (such as that presented in this report). **Each RETA analysis should be updated in a brief, standardised format every two-three years, to ensure all organisations who support or participate in the decarbonisation of process heat have access to good, evidence based insights.**
- The uncertainty in future costs strongly suggests that securing long-term contracts with biomass suppliers will be key to confidence in making fuel switching (boiler conversion or replacement) decisions. Contracts also serve the purpose of providing certainty to forest owners who may face up-front costs in developing the capability to recover such residues. There are useful analogies to the gas and electricity markets here, which, in different ways, offer purchasers and suppliers a choice between achieving long term supply and price certainty, with the ability to supplement (or sell back) supply at any given time from a "spot" market. **Mechanisms should be investigated and established 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.**
- Conversion to biomass could be technically easier if wood pellets were produced locally. This would increase the availability of pellets. **Wood processors are encouraged to explore the production of pellets locally, based on the likely demand provided in this report.**

10.2 Electricity - insights and recommendations

While electricity has a more established delivery infrastructure, in many situations it is not currently sized to accommodate more significant electrification projects and maintain existing levels of security of supply. If an electrification project requires modest or significant upgrades to existing networks, these can be both costly and have long lead times.

EECA recommends process heat users engage with PowerNet and Transpower (if they aren't already) as soon as possible to obtain a greater understanding of:

- Required network upgrades (especially around the issue of coincident peak demand) and their cost, based on more detailed engineering and power flow studies.

  - Flexibility around the network security required; what that practically means for the sites' operational environment; and integrating that with a wider understanding of the value of demand flexibility (as outlined below).

- 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).
- Use-of-system tariffs and network loss factors relevant to their connection location. As indicated above, this analysis has only considered the cost of new network assets required to accommodate the process heat electrification decisions of the sites. It has not considered the network charges applied by EDBs (and Transpower, via EDBs[97]) for a site's use of the existing network. EECA encourages discussions between Transpower, EDBs and process heat users regarding the quantum of these charges.

At a regional level, EECA sees additional opportunities to improve decarbonisation decision making.

The analysis highlighted situations where more efficiencies could be realised through coordination with other organisations considering electrification.

[97] Except where the site is directly connected to one of Transpower's GXP.

EDBs across the country are reporting record number of requests for connection analyses. This is raising a number of complex problems around how EDBs coordinate requests from different parties, and at different times[98]. The analysis highlighted situations where more efficiencies could be realised through coordination with other organisations considering electrification. **EECA recommends EDBs develop and publish clear processes for how they will handle connection requests, 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)**. Transpower's web-based guide to connection is an excellent example of high-level information which would guide organisations through the process.[99]

EECA believes better and more transparent information could be provided to decarbonising organisations, by EDBs, about important factors in considering electrification. These factors include how connection requests will be handled, 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). Transpower's web-based guide to connection is an excellent example of high-level information which would guide organisations through the process.

EECA's analysis has highlighted some situations where costs could be significantly reduced if process heat users have a comprehensive understanding of:

- The nature of their demand (baseload and varying components).
- How their demand aligns with existing demand patterns on the relevant parts of the network.
- The flexibility in their heat requirements, which may allow them to shift demand, potentially at short notice, in response to system or market conditions.

A future electricity system, with a higher penetration of renewables, will benefit from demand-side responses. 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. It is likely that the retail market will evolve to reward customers who are able to respond dynamically to wholesale charges. 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. These contracts may also reward customers who maintain an alternative "backup" supply of heat that they can switch to during extended periods of low inflows, sunshine and/or wind.

[98] We note an increase in connection requests for new distributed generation connections is highlighting some of the inadequacies of Part 6 of the Electricity Industry Participation Code which governs the connection of distributed generation to distribution networks.

[99] https://www.transpower.co.nz/our-work/getting-you-connected/our-connection-process

Practically speaking, this means that process heat users who are considering electrification should take the following 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) 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 low lake levels). 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 Electricity Authority about important factors in considering electrification and opportunities for use of demand flexibility. These factors include:

- **Network demand and security characteristics:** EDBs need to 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. This requires confidence that EDB forecasts of peak demand (and its timing) are based on the best information to hand about the nature of demand growth, especially given the role of electricity in decarbonising process heat and transport.

- **Future wholesale price behaviour:** Retailers and the Electricity Authority should assist by sharing information about future wholesale price dynamics[100] which, as described above, provide opportunities to reduce the electricity purchase costs faced by retailers (passed on to consumers) and large consumers connected to the national grid. This information can support the design of new process heat delivery systems, including, for example, hot water storage.
- **Retail and network tariffs:** Finally, EDBs and retailers should be ensuring that the tariffs they offer process heat users are incentivising the right behaviour. In some situations, flexibility may only be able to be embedded in the process heat system at the point of design and thus consumers need clear signals that reflect the wholesale and network benefits this flexibility can deliver.

[100] We note that the Electricity Authority's Market Development Advisory Group has conducted extensive modelling of potential wholesale price dynamics under a very high renewable world, including what this means for the provision of demand side flexibility. See https://www.ea.govt.nz/development/advisory-technical-groups/mdag/mdag-price-discovery-project/

10.3 Pathways - insights and recommendations

The pathways provided in this report have their limitations, and EECA intends to enhance these in future RETAs through:

- The incorporation of transport as a decarbonising decision that will compete for electrical network capacity and biomass.
- Conducting sensitivity analysis on key variables (e.g. biomass and electricity price sensitivities) in order to provide process heat users confidence in the robustness of fuel switching decisions.
- Finding alternative ways to consider how “optimal” fuel switching decisions and pathways can be simulated.
- Illuminating the quantum of electricity infrastructure investment that is required under the different pathways.

The pathways also demonstrated how government co-funding could substantially accelerate decarbonisation of Southland’s process heat. **EECA encourages 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.**

10.4 Summary of recommendations

In summary, our recommendations for future work 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 these residues on soil quality, carbon sequestration, the risk of forest fires and what actions may be required to offset this.**
- **An analysis should be commissioned to better inform potential users of biomass for energy of the global emissions and sustainability implications of any diversion of currently exported wood.**
- **More in-depth analysis of competing uses of biomass for energy at a national and regional level could help future RETA studies understand the significance of these competitive pressures.**
- **Each RETA analysis should be updated in a brief, standardised format every two-three years, to ensure all organisations who support or participate in the decarbonisation of process heat have access to good, evidence based insights.**

- **Mechanisms should be investigated and established 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.**

- **Process heat users should engage with PowerNet and Transpower (if they aren't already) as soon as possible to 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, 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 and the Electricity Authority should assist by sharing information about future wholesale price dynamics.**

- **EDBs and retailers should be ensuring that the tariffs they offer process heat users are incentivising the right behaviour.**

- **EECA should expand future RETA studies to include: transport as a decarbonising decision that will compete for electrical network capacity and biomass; sensitivity analysis on key variables; alternative ways to consider how "optimal" fuel switching decisions and pathways can be simulated; and the quantum of electricity infrastructure investment that is required under the different pathways.**

- **Process heat users 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.**

11 Summary

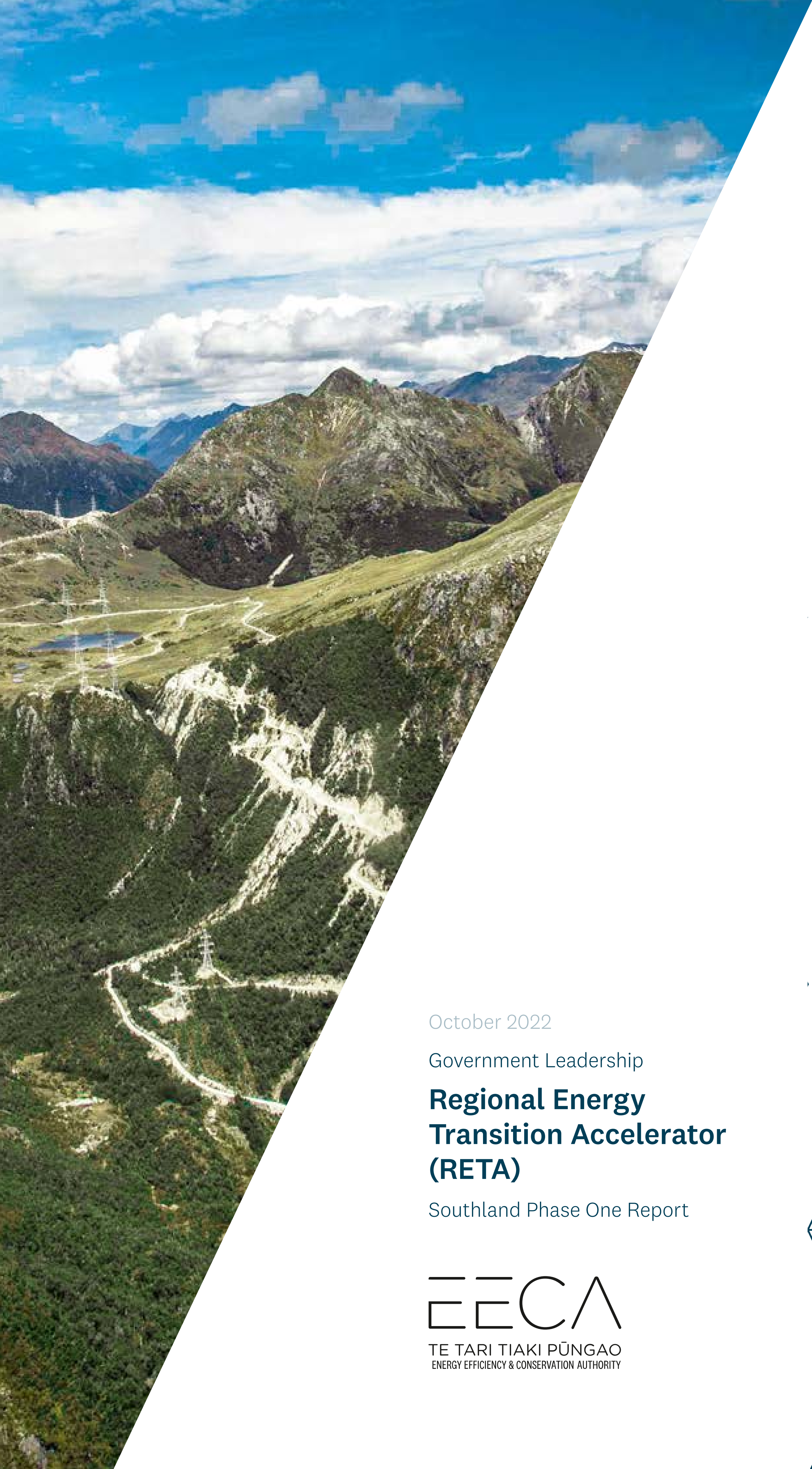
EECA's first-of-a-kind RETA, delivered for Southland, has provided a common set of information to all organisations considering process heat decarbonisation.

The Southland Phase One Report has clearly demonstrated that the collective effect of customers' fuel switching decisions will have significant effects on investment in these regional resource and infrastructure systems. It has improved the transparency of relevant information and knowledge, which improves the effectiveness of the decarbonisation decisions being made. However, as our recommendations show, there is much more to be done.

The recommendations are dominated by a theme of much greater sharing of information; given the magnitude of financial decisions being made, we need to ensure decision makers – on the supply and demand side – have the very best information available to them.

Sharing of information, however, is not a one-off event. The significance of the emissions reduction challenge demands that the many organisations in the region continue to build a collective understanding of each other's objectives, in order to find the best solution to decarbonisation of process heat. Markets (domestic and global) and technology are changing fast, which means that organisations need to commit to working collaboratively in order to respond in the most effective manner to these dynamic conditions.

EECA now turns its RETA focus to the other regions of New Zealand. Much has been learned in this first RETA, and we welcome feedback from all participants and users of this report about improvements we can make that will benefit the rest of the country.



October 2022

Government Leadership

Regional Energy Transition Accelerator (RETA)

Southland Phase One Report

TE TARI TIAKI PŪNGAO
ENERGY EFFICIENCY & CONSERVATION AUTHORITY