MINISTRY OF BUSINESS,
INNOVATION & EMPLOYMENT
HĪKINA WHAKATUTUKI

Renewable Electricity Generation | Process Heat

Discussion Document
Accelerating renewable energy and energy efficiency

December 2019

New Zealand Government

MINISTRY OF BUSINESS,
INNOVATION & EMPLOYMENT
HĪKINA WHAKATUTUKI

Ministry of Business, Innovation and Employment (MBIE)

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ISBN 978-1-98-857067-9

December 2019

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Submissions process

The Ministry of Business, Innovation and Employment (MBIE) seeks written submissions on the issues raised in this document by 5pm on 28 February 2020. Your submission may respond to any or all of these issues. Where possible, please include evidence to support your views, for example, references to independent research, facts and figures, or relevant examples.

Please include your contact details in your submission. You can make your submission:

- By completing the online survey which can be found at: https://www.research.net/r/Accelerating-renewable-energy-and-energy-efficiency
- By sending your submission as a Microsoft Word document to: energymarkets@mbie.govt.nz.

- By mailing your submission to:
  Energy Markets Policy
  Ministry of Business, Innovation and Employment
  PO Box 1473
  Wellington 6140

Please direct any questions that you have in relation to the submissions process to: energymarkets@mbie.govt.nz.

Use and release of information

The information provided in submissions will be used to inform MBIE's policy development process, and will inform advice to Ministers on accelerating renewable energy, and energy efficiency and uptake of renewable fuels in industry. MBIE intends to upload PDF copies of submissions received to its website at www.mbie.govt.nz.

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Minister’s foreword

The world is going through one of the most significant energy transitions in history.

The coming years will see a complete re-wiring of global energy systems in response to the threat of climate change, and the economic and environmental opportunities low emissions energy sources are creating. This transition will be enabled by the increased viability of renewable energy sources, and technologies in areas such as storage and demand management.

This Government has ambitious renewable electricity and climate change goals. Our energy system will be a key component of a future economy that is productive, sustainable and inclusive.

Aotearoa New Zealand is better placed than many countries to transition to a low emissions energy sector. We already generate a high proportion of our electricity from hydro and geothermal sources, with wind energy also growing its share.

However, we face significant challenges in transitioning away from process heat and transport systems fuelled with fossil fuels. We will need to significantly increase the future supply of renewable energy and energy efficiency if we are to achieve energy security, affordability and environmental sustainability.

This discussion paper continues the conversation on how we can accelerate the future development of renewable energy and energy efficiency. The proposals and options in this paper build on and support other key commitments, including our response to the Productivity Commission’s Low Emissions Economy report, and the Interim Climate Change Committee’s Accelerated Electrification report. We intend to take options forward that complement the Zero Carbon legislation and improve the Emissions Trading Scheme.

We want to hear your views on the proposals and options in this paper, or any additional options that you may suggest. We will not develop a preferred package of options until we have heard your feedback, and have a good understanding of the costs and benefits.

Thank you for taking the time to engage on these issues and I look forward to hearing your ideas for how we can transition to a low emissions energy future.

Hon Dr Megan Woods
Minister of Energy and Resources

Executive Summary

The Government has a goal to transform Aotearoa New Zealand's economy into a more productive, sustainable and inclusive economy, that improves the well-being and living standards of all New Zealanders. The Government aims to achieve a net zero carbon economy by 2050, a 2030 emission reduction target under the Paris Agreement, which Government projections show that New Zealand is on track to overshoot by about 200 Mt CO_2-e, and an aspirational goal of 100 per cent renewable electricity by 2035.

The Government recognises the importance of ensuring this transition is just and inclusive today, and for future generations.

To achieve these goals, the Government's Renewable Energy Strategy has a range of work programmes underway. We are bringing two of these together – accelerating renewable electricity and lowering emissions from process heat – in this discussion document. This will provide greater coherence and joined-up thinking on policies to reduce energy-related emissions and ensure we take into account security of supply and affordability impacts for our energy system.

The options and analysis in this discussion paper build on the Productivity Commission's *Low-Emissions Economy* report, the Interim Climate Change Committee's *Accelerated Electrification* report, and the Ministry of Business, Innovation and Employment and the Energy Efficiency and Conservation Authority's technical paper *Process Heat in New Zealand: Opportunities and barriers to lowering emissions.*

The options represent a comprehensive policy package for the energy transition. They are intended to be complementary to the New Zealand Emissions Trading Scheme (NZ-ETS), and work alongside initiatives in the Climate Change, Economic Development, and Research, Science and Innovation portfolios, and the Just Transitions work programme.

We have been working to identify opportunities that can be realised, and barriers that need to be removed, to help achieve our goals and unlock wider benefits for New Zealanders. We have taken a broad view, looking at emission reduction actions that can be taken now, investments required in the medium-term and in preparation for the future:

- ensuring information and market barriers are addressed to accelerate adoption of clean energy technologies that are economically viable now,
- well-targeted complementary measures and regulatory settings that support an effective carbon price, and
- unlocking investments in innovation and infrastructure to reduce the long-term cost of transition, and ensure it is just and inclusive.

Each section of the discussion paper considers options to address specific barriers, as outlined in **Table 1** below.

It is important to note that we are not presenting a preferred package of proposals. The options are all subject to feedback and subsequent decisions by Cabinet. Following consideration of feedback, there are some options that the Government could decide to undertake immediately, and other options could be considered as a next step after initial changes have been implemented. In parallel, the Government is also making changes to the NZ-ETS and is reviewing the resource management system. We seek your feedback on both the *sequencing* and the *optimal package* of policies outlined in the document, taking into account related Government work as it progresses.

Table 1: Overview of this discussion document

Part A **Encouraging energy efficiency and the uptake of renewable fuels in industry**	**Section 1: Addressing information failures** – explains issues relating to information failures and asymmetries that prevent or discourage investment in energy efficiency and the uptake of renewables (such as electrification of process heat), and seeks your views on options.
	Section 2: Developing markets for bioenergy and direct geothermal use – examines barriers to the use of woody biomass and direct geothermal for process heat, and sets out options.
	Section 3: Innovating and building capability – explains issues around technology risk for process heat users, and the lack of viable low carbon solutions for emissions-intensive and highly integrated (EIHI) industries, and seeks your views on options.
	Section 4: Phasing out fossil fuels in process heat – explains issues around long-lived process heat investments and emissions lock-in, and seeks your views on options.
	Section 5: Boosting investment in energy efficiency and renewable energy technologies – explains issues relating to underinvestment in energy efficiency and renewable energy technologies, and seeks your views on whether the Government should further consider them and how they could be addressed.
	Section 6: Cost recovery mechanisms – seeks your views on introducing a levy on consumers of coal to partially recover the cost of implementing any new policies in Part A that may be introduced.
Part B **Accelerating renewable electricity generation and infrastructure**	**Section 7: Enabling renewables uptake under the Resource Management Act 1991** – considers policy options to enable renewable energy development under the Resource Management Act 1991, and seeks your views on options.
	Section 8: Supporting renewable electricity generation investment – considers policy options to accelerate investment in supply- and demand-side renewable electricity generation and energy efficiency, and seeks your views on options.
	Section 9: Facilitating local and community engagement in renewable energy and energy efficiency – considers the barriers to greater uptake of small-scale community energy and seeks your views on potential options for facilitation.
	Section 10: Connecting to the national grid – sets out our understanding of issues relating to transmission connections to supporting growth in renewable electricity and the transition to a low emissions economy, and seeks your views on options.
	Section 11: Local network connections and trading arrangements – summarises regulatory arrangements and work underway to enable connections to, and trading on, the local network, and seeks your views on whether enough is being done.

We look forward to your feedback on the best way New Zealand can achieve a more energy efficient and renewable energy system.

Contents

Introduction

The Government has a goal to transform Aotearoa New Zealand's economy into a more productive, sustainable and inclusive economy, that improves the well-being and living standards of all New Zealanders. The Government recognises the importance of ensuring this transition is just and inclusive today, and for future generations.

To enable a just and inclusive transition to a low emissions economy, the Government has passed the Climate Change Response (Zero Carbon) Amendment Act[1], which includes a target to reduce all greenhouse gases (except biogenic methane) to net zero by 2050.[2] In the interim, New Zealand has made a commitment for its 2030 target under the Paris Agreement to limit emissions to around 600 million tonnes of carbon dioxide equivalent (Mt CO_2-e) over the period 2021 to 2030.

The Government has also set an aspirational goal of 100 per cent renewable electricity by 2035, with five-yearly assessments to ensure that security of supply and affordability of electricity are well-managed.

The Productivity Commission's *Low-Emissions Economy* report, the Interim Climate Change Committee's (ICCC) *Accelerated Electrification* report, and the Ministry of Business, Innovation and Employment (MBIE) and the Energy Efficiency and Conservation Authority's (EECA) technical paper *Process Heat in New Zealand: Opportunities and barriers to lowering emissions* provide a basis for the policy work underway in this paper. The options and analysis in this discussion paper build on and respond to those bodies of work.

Our energy system

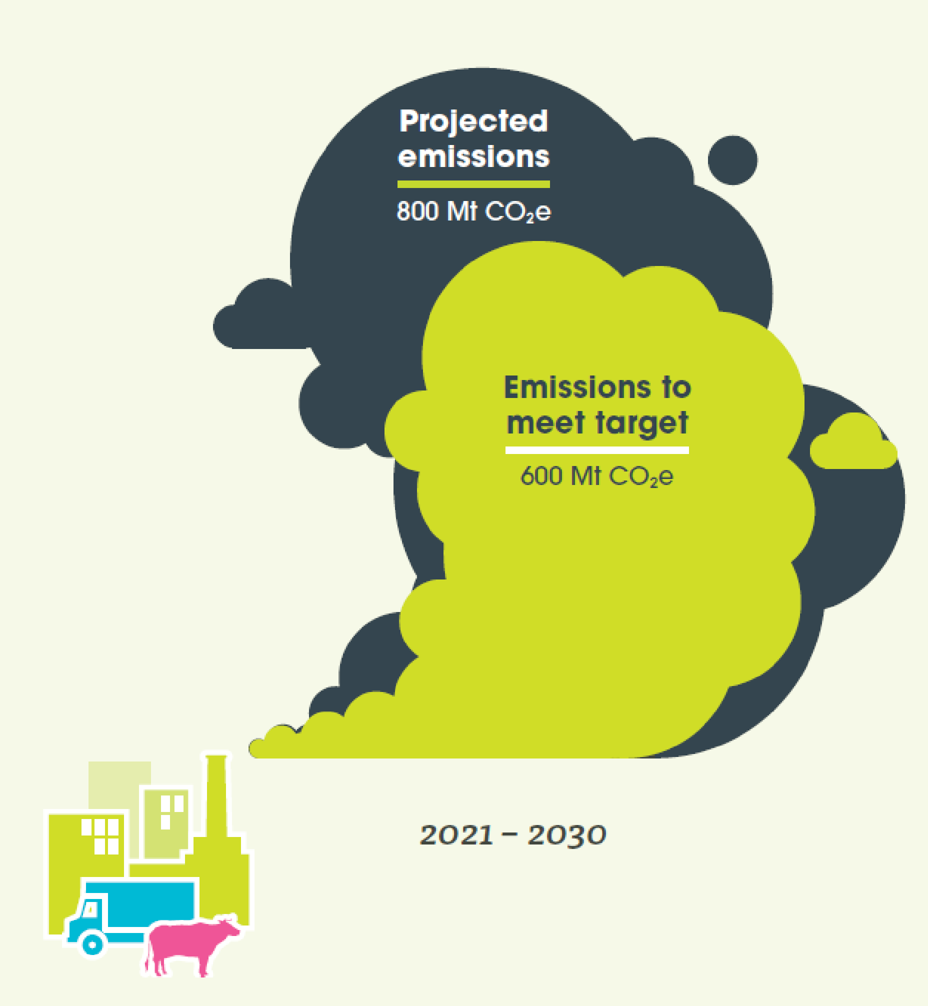
New Zealanders rely on access to affordable and reliable energy to live their day-to-day lives. Energy is a key input into every good and service across our economy. However, while access to affordable and reliable energy remains important, we also need to consider this alongside the need to transition to a low emissions economy.

Energy, including transport, contributes 40 per cent of our total gross emissions, the majority of which are carbon dioxide emissions from fossil fuel use. For example, about 60 per cent of process heat is supplied using fossil fuels, mainly gas and coal, which contributes to 8 per cent of emissions. The vast majority of transport is fuelled by fossil fuels, which contribute 20 per cent of emissions. Electricity generation produces around five per cent of emissions.

The reduction of energy-related carbon emissions is critical to achieving our climate goals. Government projections show New Zealand is on track to overshoot the 2030 target by about 200 Mt CO_2-e, as illustrated in **Figure 1** below. In many cases, alternative technologies already exist to replace fossil fuels.

[1] Referred to throughout this document as the Zero Carbon Legislation.
[2] It also sets a goal to reduce emissions of biogenic methane within the range of 24–47 per cent below 2017 levels by 2050 including to 10 per cent below 2017 levels by 2030.

Figure 1: New Zealand's 2030 emissions gap



Source: Interim Climate Change Committee; Ministry for the Environment

Energy efficiency will be critical to meeting our climate goals and transitioning to a low emissions economy. Energy efficiency gains result in energy savings and support economic prosperity by diverting investment in new energy supplies, including electricity generation or transmission capacity.

Our highly renewable electricity system has a critical role to play in decarbonising the wider energy system. Electrification of transport and process heat can help reduce energy-related emissions. Biomass and geothermal direct heat use also provide key strategic opportunities for reducing energy-related emissions in a cost-effective manner. Hydrogen, as outlined in the Government's hydrogen vision, may also have a role to play in decarbonising activities for which electrification is not a practical option given current technology.[3]

Indicative analysis of the present-day opportunities to reduce emissions in stationary energy[4] suggests a potential to reduce emissions of around 4 Mt CO_2-e per year at current carbon prices, or around 6 Mt CO_2-e per year at a carbon price of $60 per tonne (maximum possible savings).

[3] New Zealand Government (2019). *A Vision for Hydrogen in New Zealand*. MBIE, https://www.mbie.govt.nz/dmsdocument/6798-a-vision-for-hydrogen-in-new-zealand-green-paper

[4] Stationary energy includes all fossil fuels (coal and gas) used in electricity generation and in the direct production of process heat, as well as geothermal energy.

Further detail is provided in Appendix 2, whereby opportunities are ranked by their cost per tonne of emissions, or marginal abatement cost (MAC). Appendix 3 provides a snapshot of location and process heat demand estimates of industrial users.

To realise a more sustainable energy future, without compromising affordability or supply security, we will need to ensure our energy markets and regulatory systems are fit-for-purpose. We will also need to ensure that we are ready to adopt new technologies and new business or cooperative models to assist in the transition to a low emissions economy.

Transitioning to a lower emissions and more energy productive industrial sector brings opportunities for our export industries to capitalise on our renewable advantage, and to build a sustainable, high-value economy.

Meeting our climate change goals

The Zero Carbon Legislation sets up institutional arrangements to help us achieve our emissions reduction goals. It will include the establishment of a new, independent Climate Change Commission that will set emissions budgets as stepping stones toward our long-term target, and will provide expert advice and monitoring to help keep successive governments on track.

The Zero Carbon Legislation also requires the Government to develop and implement policies for emissions reduction in response to emissions budgets. The Government will set an Emissions Reductions Plan that requires sector-specific policies to reduce emissions, including in the energy sector.

The energy transition

The package of policies that will enable the energy transition will affect technologies, natural resources, infrastructure, markets and institutions. There is no 'one-size-fits-all' policy solution suitable for the energy sector as it cuts across the entire economy. We must consider the different ways that energy is used in sectors of the economy and the relevant opportunities available in each case. Regional and geographic differences will influence the use and availablity of low emissions energy sources, including wind, solar, biomass and geothermal. Effective change may require unique transition pathways and different timing and sequencing of changes across different sectors.

The NZ-ETS is a key mechanism to reduce emissions. The NZ-ETS sets a price for each tonne of carbon dioxide (or the relevant equivalent for other greenhouse gases) that is emitted. The Government is making improvements to the NZ-ETS and future decisions on five-yearly emissions budgets will improve forward price certainty for investors.[5]

The Productivity Commission notes that emissions pricing is needed to change behaviour and promote investment. However, complementry measures to the NZ-ETS may be necessary to promote a fair and efficient transition and to maximise opportunities from the transition.

The Productivity Commission and the ICCC note that, in addition to carbon pricing, other regulations and policies may be useful where emissions pricing is not driving change either due to market or government failures, or where there are fairness and distributional considerations.

Technically and economically viable opportunities to reduce energy-related emissions and adopt clean energy technologies exist now. However, businesses and investors currently face a number of barriers that hinder the uptake of clean energy technologies and other cost-effective measures to

[5] Further information available at https://www.mfe.govt.nz/climate-change/proposed-improvements-nz-ets

reduce emissions. Unnecessary regulatory, informational and cost barriers should be removed to unlock least-cost abatement opportunities and encourage rapid uptake of low-emissions technologies.

Complementary regulation and policies can help to address market failures, deploy mitigation technologies and support behavioural change. Additionally, early actions to encourage the supply and use of clean energy technologies will help provide certainty for investors and to manage a transition to ensure that it is just and inclusive.

Delayed action on emissions reduction could require us to make steeper reductions in the future, which could increase the costs of transitioning to a low emissions economy and make it harder to meet our climate goals. If new long-lived emissions-intensive assets are built, there is a risk that these could become stranded assets.

Planning for the future and encouraging early action may require us to consider investments now to reduce the long-term cost of transition. These could include:

1. Up-front investment in energy efficiency
2. Facilitating new infrastructure such as generation, transmission and distribution lines
3. Government leadership and procurement of clean energy technologies
4. Developing emerging markets for alternative fuels such as hydrogen or biomass
5. Research, development, demonstration and diffusion of new clean energy technologies, and
6. Supporting new business, cooperative and community models for energy supply and use.

Co-benefits of the transition to a low emissions economy

There are other benefits to reap from the transition to an energy efficient and low emissions and economy, including:

- Reducing discharges to air from combustion of fossil fuels provides environmental and health benefits
- Raising energy productivity will help businesses to reduce overall costs and exposure to energy price volatility
- Increasing the supply and use of our own energy resources reduces our reliance on imported fuels and reduces exposure to international fuel price volatility, and
- Export industries can capitalise on our plentiful supply of renewable energy and enhance New Zealand's clean green image.

The transition is also likely to diversify the economy – creating space for new industries or services – and help move the economy beyond an economic growth model based on volumetric increase to one that improves productivity, creates more value and lifts the well-being of all New Zealanders.

Renewable Energy Strategy work programme

The Government's Renewable Energy Strategy work[6] programme outlines actions to achieve an affordable, secure and sustainable energy system that provides for New Zealanders' well-being in a low emissions world. Such an energy system will also provide opportunities to grow our economy and exports by driving innovation in clean energy. The work programme focuses on three main outcomes:

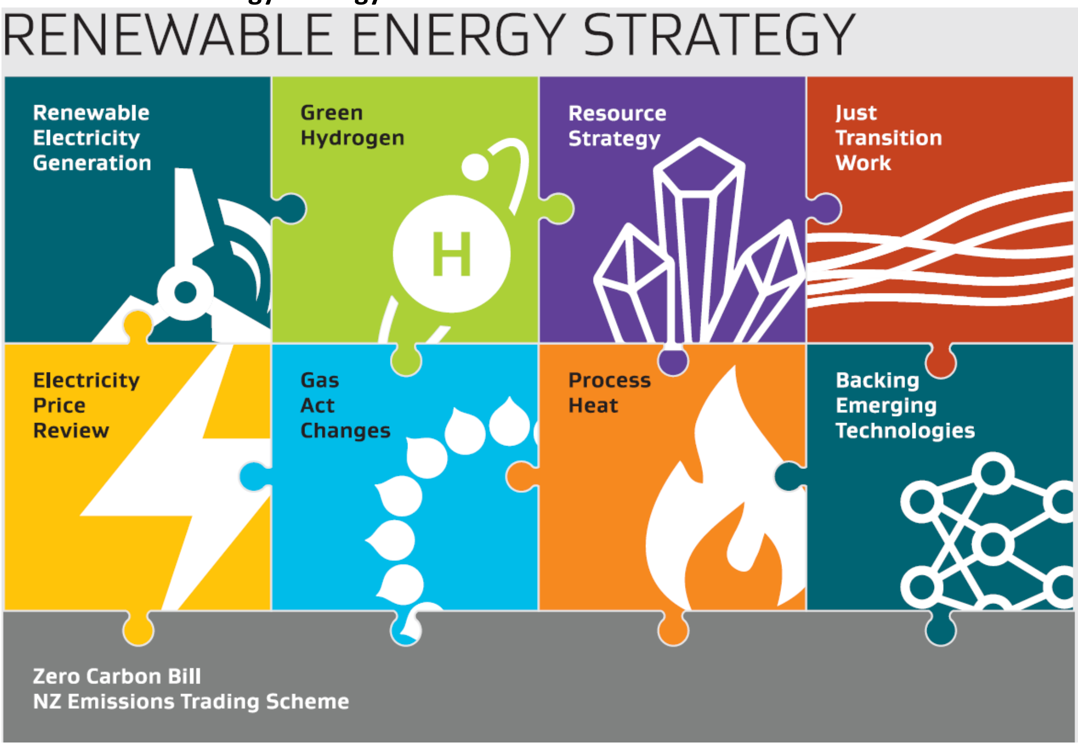
- **An inclusive and consumer focused energy system** – a just and inclusive energy system that puts consumers at the centre, ensuring that consumers pay fair and reasonable prices and share the benefits of an efficient and competitive energy system. This includes providing opportunities for consumers to engage in the energy system, for example as 'prosumers' who both consume and produce their own energy.

- **A system that encourages increased investment in low emissions technologies** – by encouraging, supporting and working with industry to ensure we can capitalise on opportunities for renewable energy, by reducing barriers to new technologies and by setting the right investment signals to avoid lock-in of high emissions technologies.

- **An innovative and modern energy system that creates new opportunities for business and consumers** – preparing for future technologies now to future-proof our energy system. Ensuring our regulatory settings incentivise innovation and uptake of new technologies, and that we create a business environment that encourages innovation to thrive.

Figure 2 illustrates the components of the work programme:

Figure 2: Renewable energy strategy



Source: Ministry of Business, Innovation and Employment (MBIE) 2019

[6] Renewable Energy Strategy work programme, https://www.mbie.govt.nz/dmsdocument/5960-transitioning-to-more-affordable-and-renewable-energy-the-energy-markets-work-programme-proactiverelease-pdf

In addition, the Government is taking a number of actions to take greater leadership in increasing the energy efficiency and the uptake of renewable energy in its own operations. More detail on this has been included in Appendix 1.

We seek your feedback

This discussion paper examines a range of barriers and issues, and seeks feedback on a range of options for two parts of the Renewable Energy Strategy work programme:

- Part A: Encouraging greater energy efficiency and the uptake of renewable fuels in industry (process heat)
- Part B: Accelerating renewable electricity generation and infrastructure (renewable electricity generation)

Out-of-scope issues and related work programmes

This discussion document does not cover the issues and options specific to encouraging renewable energy or improving energy efficiency in the transport sector. For example, it does not discuss issues relating to electric vehicle (EV) charging infrastructure and liquid biofuels for transport.

An EV interagency working group is discussing and working through the different agency interests and perspectives on EV charging, and building a better understand each other's existing work programmes. This working group, co-ordinated by the Ministry of Business, Innovation and Employment (MBIE), is made up representatives from MBIE, the Energy Efficiency and Conservation Authority (EECA), Ministry of Transport, New Zealand Transport Agency, Electricity Authority, Commerce Commission and Worksafe. The working group discusses topics such as generation capacity, transmission and distribution implications for an increased uptake of EVs, public and private light and public heavy vehicle charging infrastructure, safety and new technologies.

The working group monitors any issues associated with EV charging and updates the Minister of Energy and Resources and Associate Minister of Transport as required.

The Ministry of Transport has initiated a project to help inform the Government's strategic approach to reducing greenhouse gas (GHG) emissions from road freight. The project looks specifically at the role alternative fuels (such as electricity, green hydrogen and biofuels) could play in reducing emissions. This work fits within a wider programme of work across the Ministry of Transport to reduce emissions from the transport sector.

The project is focused on heavy trucks involved in road freight because they account for nearly one quarter of all road transport emissions. Road freight is vital to our economy and is predicted to grow substantially over the next 30 years. Reducing emissions from road freight, and long-haul road freight in particular, is also seen as one of the most challenging areas for transport to decarbonise.[7]

[7] See more about this project at https://www.transport.govt.nz/multi-modal/climatechange/green-freight-project/.

Part A: Encouraging energy efficiency and the uptake of renewable fuels in industry

This part has six sections. It seeks your views on options to:

- Address information failures and information asymmetries between industry and other stakeholders (Section 1).
- Develop biomass markets and the direct use of geothermal energy (Section 2).
- Encourage industrial innovation, de-risking technology and building capability (Section 3).
- Phase out fossil fuels in process heat (Section 4).
- Accelerate investment in energy efficiency and renewable energy technologies (Section 5).
- Introduce a levy on consumers of coal to fund administration of industrial energy efficiency and renewable fuel programmes (Section 6).

Opportunities for the Government to support greater energy efficiency in the electricity market are covered in Section 8 of Part B.

Introduction

Why is process heat important?

Process heat refers to thermal energy (heat) used to manufacture products in industry. The industrial sector is an important contributor to the New Zealand economy. Output accounts for around 10 per cent of real GDP and the sector employs around 11 per cent of the labour force. About 60 per cent of process heat is supplied using fossil fuels (mainly gas and coal) and it contributes 8 per cent of New Zealand's emissions.

Changing how the industrial sector uses energy will be a crucial component in our transition to a productive, low emissions economy. The ICCC's analysis shows that it is technically feasible to reduce industrial emissions by 2.6 Mt CO_2-e per year by 2035 through energy efficiency and electrification of low and medium temperature process heat.

Further emission reductions are possible from increasing the energy productivity of the industrial sector, and through further utilisation of biomass and the direct use of geothermal energy.

Early actions in the sector will help provide certainty for investment, and avoid abrupt, high cost transitions later. Raising energy productivity will help businesses reduce energy costs and optimise production processes. It also reduces their exposure to energy and carbon cost volatility, enabling business to more effectively manage risk.

What are the opportunities to reduce emissions from process heat?

The economics of emissions reductions in process heat are complex and can vary widely from site to site. The key factors affecting the choice of energy input are the specific process and temperature requirements, site location and availability of fuel (including transport costs and access to transmission or distribution networks), relative fuel costs, and whether investment is in a new site (greenfield) or an existing site (brownfield).

There are cost-effective, near-term measures to reduce industrial emissions, but complete decarbonisation is challenging. Efforts from industry and government will require pursuing a combination of short, medium-term and longer-term opportunities.

Short term options

In the short term, key opportunities include energy efficiency (such as waste heat recovery and better energy management) deploying heat pumps for water and space heating, using mechanical vapour recompression technology (MVR),[8] and co-firing coal boilers with biomass where biomass is readily available. These opportunities lie in the food manufacturing and government sectors,[9] such as health and education. The food processing sector currently accounts for around 31 per cent of energy emissions in the industrial sector; this is predominantly from dairy and meat processing. Up to 40 per cent of emissions in the food processing sector can be abated cost-effectively at current carbon prices.[10]

There is also an opportunity to make greater use of bioenergy in cement production and wood processing. Cement and wood processing sectors account for six per cent of energy emissions.

Medium term options

In the medium term, it is expected that a rising carbon price will unlock a large number of coal-to-bioenergy and some coal-to-electricity opportunities and could encourage the early retirement of some coal heat plants.

Biomass and electricity may already be cost-competitive with natural gas for some greenfield sites with low temperature heat applications, and depending on future gas and carbon price trends, they could also compete with natural gas for medium temperature applications.

Energy used to produce methanol, urea, refining, aluminium and steel makes up 51 per cent of energy emissions in the industrial sector. Near-complete decarbonisation of these emissions-intensive and highly integrated (EIHI) industries[11] (which have high temperature requirements) has much greater abatement costs and technical challenges. However, new technologies being developed overseas show promise and New Zealand could benefit by staying abreast of these developments.

[8] Mechanical vapour recompression (MVR) is already widely used by New Zealand's dairy sector as it is an extremely efficient way of evaporating water from milk. The opportunity is to deploy more advanced MVR to further increase its use in the dairy industry, and other industries that need to evaporate water.

[9] Appendix 1 outlines the actions the government is taking to reduce emissions.

[10] University of Waikato (2019). *Options to reduce New Zealand's process heat emissions*. Commissioned by MBIE, MfE and EECA, https://www.eeca.govt.nz/resources-and-tools/research-publications-and-resources/business-publications-and-resources/

[11] These industries are also characterised as being single-plant and highly process heat-intensive. For this category, there are typically only limited opportunities to switch to different technologies without re-building the plant. There are, however, operational energy efficiency improvement opportunities within strategic energy management, operations and maintenance practices. The industries with in-built technologies tend to produce globally-traded commodities and are considered at risk of emissions leakage under NZ-ETS.

As well as reducing emissions from existing industrial sites, transitioning to a low-emissions economy might also involve optimising the use of emissions-intensive products, and substituting for lower emission products and materials. As part of its Building System Legislative Reform Programme, MBIE has identified some options to address drivers of risk aversion in the consenting process, which can inhibit innovative (including low-emissions) building products.

Case study: Food processing – electrification and energy efficiency[12]

As Ashburton Meat Processors (AMP) looked to replace its heating and refrigeration systems it also sought to electrify its energy sources to significantly reduce its carbon footprint.

The business worked with Christchurch firm Active Refrigeration to replace its refrigeration and heating systems with a new ammonia based heat pump. The new system provides simultaneous cooling and high temperature heating, offering a significant step-change in efficiency. The switch not only reduced emissions but also generated annual savings of over $200,000. The plant has been able to comfortably provide increased capacity and has reduced overall emissions by 42 per cent.

Why might policies be needed in addition to the Emissions Trading Scheme?

The decarbonisation of our energy system will be critical to achieving our climate change goals. Lowest cost abatement driven by the NZ-ETS may result in a heavy reliance on forestry and the purchasing of overseas ETS units in the short-medium term. The Government has choices about investing in the domestic transition rather than offsetting emissions. This may have additional benefits of economic development, employment and strengthening New Zealand's balance of payments.

As noted above, the NZ-ETS is the key mechanism for reducing energy emissions. The ICCC estimates that switching away from coal to electricity or biomass at scale will become economic with emissions prices in the range of \$60-\$120/t CO_2-e. Switching away from natural gas starts to become economic only above \$120/t CO_2-e.

In many cases, market failures and barriers persist and reduce the effectiveness of the NZ-ETS. These barriers were identified in the Technical Paper *Process Heat in New Zealand: Opportunities and barriers to lowering emissions*[13]. Complementary measures can help to create and deploy mitigation technologies and support behaviour change in industry. In the energy sector, due to the presence of multiple energy efficiency barriers, a package of measures might be needed.

The following sections identify and seek your feedback on options to address each of the key market barriers identified in the Technical Paper. The sections, barriers and options are outlined in **Table 2** below.

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[12] https://www.eecabusiness.govt.nz/resources-and-tools/case-studies/active-refrigeration/

[13] For further information on these barriers, please consult our technical paper: https://www.mbie.govt.nz/dmsdocument/4292-process-heat-in-new-zealand-opportunities-and-barriers-to-lowering-emissions

- Options in Sections 1-3 and 6 are government policy proposals, as there are minimal interdependencies or potential for negative interactions with the NZ-ETS. As such, they could be introduced immediately to support the transition in industry.
- The discussion in Sections 4 and 5 involves measures that have a greater potential to interact with the carbon price. Final government decisions to address the issues raised in these sections need to be considered alongside forthcoming broader government decisions on NZ-ETS settings, the role of complementary measures and the pace and pathways of domestic emissions required to meet the country's emission reduction target. As such, we are seeking feedback and gathering further information from stakeholders on the types of levers that could be used, and level of effort required to meet our emission reduction targets, rather than consulting on preferred options or policy proposals.

Table 2: Barriers and options for encouraging energy efficiency and renewable energy in industry

	Barriers / issue	Option
Section 1	Lack of accurate information on the emissions performance of firms or products. Information gap on the issues, costs, reliability, and process for the electrification of industrial sites. Some entities have poor information about their energy use and emissions.	**1.1** Require large energy users to publish Corporate Energy Transition Plans (including reporting emissions) and conduct energy audits. **1.2** Develop an electrification information package for businesses looking to electrify process heat, and offer co-funded low-emissions heating feasibility studies for EECA's Large Energy User partners. **1.3** Provide benchmarking information for food processing industries.
Section 2	Under-developed supply chains for bioenergy and the availability of bioenergy and geothermal resources regionally.	**2.1** Development of a users' guide on the application of the National Environmental Standards for Air Quality to wood energy.
Section 3	Firms tend to be risk averse to technologies that change or could delay their production process, and process engineers may not be familiar with new technologies.	**3.1** Expand EECA's grants for technology diffusion and capability-building. **3.2** Collaborate with EIHI industry to foster knowledge sharing, develop sectoral low-carbon roadmaps and build capability for the future using a Just Transitions approach.
Section 4	Risk of locking in new long-lived emissions-intensive heat plant. Reluctance to replace legacy fossil fuel facilities before the end of their technical lives (both power plants and industrial facilities).	**4.1** Introduce a ban on new coal-fired boilers for low and medium temperature requirements. **4.2** Require existing coal-fired process heat equipment supplying end-use temperature requirements below 100°C to be phased out by 2030.
Section 5	Competition for capital leading to prioritisation of core business spending and an underinvestment in energy efficiency and renewable energy technologies in the industrial sector.	**5.1** No new options proposed at this time.
Section 6	In order to mobilise private-sector investment and scale up efforts to achieve the Government's process heat outcomes, additional funds will be required to resource implementation of some of the policy proposals.	**6.1** Introduce a levy on consumers of coal to fund process heat activities.

How we are assessing options

In line with the Government's goals for a net zero emissions economy by 2050 and aspirational goal of 100 per cent renewable electricity by 2035 (subject to assessments relating to affordability and security), our high level criteria for assessing options is:

1. **Does the option have an impact on greenhouse gas emissions** (does it reduce emissions in an economically efficient way, is it complementary to the NZ-ETS, how much emissions reduction is expected?)

In addition to these high-level criteria, we have provided a preliminary assessment of the costs and benefits of options (where relevant) against the following sub-criteria:

2. **Wider economic effects** – impact the option has in terms of wider economic costs and benefits, such as:
    - **a. Productivity impacts** – indicating if there is any positive or negative impact on productivity.
    - **b. Distributional impacts –** indicating if any population groups are likely to be disproportionately impacted by the proposal e.g. rural communities, regions, workers, consumers, Māori/iwi, noting that Government will have choices to about how to mitigate these impacts.
    - **c. Innovation and uptake of new technologies –** indicating to what extent the option future-proofs the energy system, and incentivises innovation and uptake of new technologies.
    - d. **Health and environmental benefits and costs, e**.g., warmer homes, air quality, biodiversity
3. **Administrative and compliance costs –** impact the option has in relation to:
    - **e. Administrative costs** – costs to government of delivering option
    - **f. Compliance costs** – whether businesses are likely to face additional costs from options.

Analysis of options addresses these sub-criteria if (and only if) there is a non-negligible impact. For example, where no distributional impacts or effects on innovation have been identified, these sub-criteria are not noted under the option analysis.

However, the costs and benefits of each option have not yet been analysed in detail. One of the objectives of the consultation is to seek feedback from stakeholders on the likely benefits and costs, including the compliance costs on individual businesses affected by an option. Questions at the end of each section are intended to be prompts in this regard.

Section 1: Addressing Information Failures

This section explains the issues relating to information failures and asymmetries and seeks your views on options to:

- Require large energy users to publish Corporate Energy Transition Plans (including reporting emissions annually), and conduct energy audits every four years
- Develop an electrification information package for businesses looking to electrify process heat, and offer co-funded low-emissions heating feasibility studies for EECA's business partners, and
- Provide benchmarking information for food processing industries.

What's the problem?

This section responds to the following recommendations from:

- the Productivity Commission's *Low Emissions Economy* report*:*

  14.2. MBIE and EECA should review targets relating to industrial emissions reductions to determine whether a reduction in excess of that already forecast would be more helpful in driving emissions reductions.

  14.3. MBIE and EECA should review existing initiatives related to information about fuel switching, co-firing, demand reduction and efficiency improvements for process heat, to minimise any information-related barriers to mitigation opportunities.

- the ICCC's *Accelerated Electrification* report:

  3a. Deterring the development of new fossil fuels in process heat.

  3b. Setting a clearly defined timetable to phase out fossil fuels in existing process heat, with coal as the priority.

  3c. Reducing regulatory barriers to electrification.

There is a lack of accurate information available to the public, investors and the Government on the emissions performance of firms or products. This information asymmetry limits the ability to assess appropriate policy responses to meet our climate change and economic objectives in a fair and cost-effective manner.

Some entities have poor information about their energy use and emissions. There can be a lack of visibility of the costs and benefits of energy efficiency and emissions reduction projects by senior managers and directors. Energy is often managed at facility level where energy efficiency opportunities are measured in energy units rather than as sources of emission reductions, cost savings or productivity benefits.

These barriers compound so that investments that reduce energy emissions are undervalued relative to other investment options and are not prioritised.

An analysis of voluntary corporate reporting by the McGuinness Institute since 2017[14], including reporting by Climate Change Leaders' Coalition businesses, has found that there is currently a low level of disclosure of climate-related information, and a lack of clarity of where and how information will be reported in the future, or what guidance or standards might be adopted.

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[14] See July 2018, Working Paper 2018/03, McGuinness Institute, Analysis of Climate Change Reporting in the Public and Private Sectors.

What are the options?

To address these issues, we seek feedback on options to:

- Require large energy users to publish Corporate Energy Transition Plans (including reporting emissions annually) and conduct energy audits every four years;
- Develop an electrification information package for businesses looking to electrify process heat, and offer co-funded electrification feasibility studies for EECA's business partners and;
- Provide benchmarking information for food processing industries.

Corporate energy transition plans

Option 1.1	Require large energy users to publish Corporate Energy Transition Plans (including reporting emissions) and conduct energy audits

Description

This option would introduce a comprehensive procedural requirement for the largest[15] energy using businesses to publicly report energy use and emissions, carry out periodic energy and emissions audits, and publish their plans and strategies to reduce emissions to 2030. The key elements of this option are outlined in Table 3 below.

This option builds on schemes that have been implemented in Australia, the United Kingdom and across Europe.[16] An example of how this could look in New Zealand is outlined in the table below.

Table 3: Proposed requirements for Corporate Energy Transition Plans

Target group	Annual energy spend (purchased) of greater than $2 million per annum
Public reporting	Annual corporate-level energy use and emissions, split out by a range of sources including coal, gas, electricity and transport Energy efficiency actions taken that year Plans to reduce emissions to 2030
Government reporting	Businesses annually report to the Government a defined intensity metric (e.g. specific energy consumption/product emissions intensity), by plant/process. This information will be treated in confidence for statistical and policy purposes
Energy auditing	Mandatory energy auditing every four years with Boards required to review the findings
Compliance	Public information to be included in annual reports or in separate "corporate energy transition plan" on website Energy audits meet the government's guidelines or the company is ISO 50001 certified Boards required to review the energy audits findings and report compliance to a national scheme administrator

[15] We propose that largest is defined as businesses with an annual energy spend of greater than $2 million per annum. We estimate around 200 businesses would fall within scope.
[16] Australia's Energy Efficiency Opportunities (EEO) programme, the UK's Streamlined Carbon and Energy Reporting Scheme (SECR) and the Energy Savings Opportunity Scheme (ESOS), the EU's Energy Efficiency Directive (energy audits) and energy management programmes.

Analysis

Initial analysis of this proposal suggests Corporate Energy Transition Plans may accelerate the adoption of energy saving and emission reducing technologies in response to greater visibility, transparency and accountability on energy use and emissions impact.

We consider the benefits of this option (some of which would be difficult to quantify) include:

- **Businesses**: (large energy users covered by the proposal): Senior management and boards will have better information on the value of energy opportunities available to them. It should generate an increased focus on energy use and emissions. Senior management and boards are required to sign off the reporting.
- **Shareholders and investors**: Improved transparency will provide greater assurance that businesses are actively assessing, managing and disclosing climate-related risks, and taking steps to reduce their exposure to carbon costs where practicable.
- **Government**: It will enable more accurate statistical reporting, evidence-based policy-making, including informing the development of emissions budgets, and assessment of the effectiveness of existing policies.
- **Energy stakeholders:** The plans could outline businesses' plans for electrification of their sites, which would help Transpower and distributors inform the development of transmission and distribution grids and in planning for new connections.
- **The public**: Improved transparency will enhance public confidence that the largest emitting businesses operating in New Zealand are actively taking responsibility for managing their emissions. This could also increase reputational drivers on the targeted entities as improved transparency will more accurately inform public perceptions of climate change action.

The compliance costs of this proposal will vary according to the extent to which individual businesses have already conducted, and have processes in place for, measurement, reporting and energy audit activities. The compliance costs are not expected to be significant for large energy users. Compliance costs would be composed of:

- **One-off costs**: time spent at the outset on understanding requirements of the scheme, time spent determining any structural issues with compliance e.g. legal structure, and any incremental metering and software costs.
- **Ongoing costs**:
    - incremental annual costs of gathering and collating energy consumption data, record keeping
    - reporting for senior officer sign off, boardroom director sign-off and any extra costs of preparing annual reports
    - energy audit cost every four years (internal or external)
    - undertaking internal quality assurance
    - annual notification of compliance
    - external verification or compliance auditing by the regulator.

There will also be costs to government in establishing the scheme, and in monitoring and compliance activities.

This option is currently our preferred means of encouraging emitters to plan a transition to a low emissions economy. While gathering information is compulsory, the proposal increases transparency and enables firms to plan and act according to their specific circumstance.

It is preferred over the following status quo activities:

- Many large energy users already publish, or have made commitment to publish their emissions and plans to transition. There is no intention to encourage business to reduce the level of information they supply. Rather it aims to create a common format and give others (such as the public, value chain businesses and the government) information they need to make more informed decisions.
- EECA co-funds and undertakes energy audits for its Large Energy User clients. However opportunities are likely to remain unidentified as coverage of the largest energy users is not complete, audits are not undertaken on a regular basis, and – depending on the type of audit undertaken – may only cover a small segment of energy use.

Other options we considered but do not favour was to introduce individual components of the CTPs as standalone requirements (annual public emissions reporting only, or four-yearly energy audits only, etc.). Individual elements on their own will help to address discrete information barriers, but are unlikely to be sufficient to unlock energy efficiency opportunities on their own. Individual components would not provide a strategic and corporate prioritisation of energy efficiency, which evidence shows, is best practice.[17]

Related information disclosure requirements

Two other complementary information disclosure requirements have been recently introduced or are underway.

The Government is making changes to make the NZ-ETS18 more transparent to participants and the public through publishing emissions and removals data at the level of individual participants. This will allow for greater understanding of the scheme by the public and allow all participants to have access to the same level of data on which to base their decisions. Some large energy users covered by a Corporate Energy Transition plan option will be NZ-ETS participants. However in the NZ-ETS, most industrial energy users report only their non-energy process emissions. Energy emissions are reported further upstream by producers or importers of fossil fuels rather than users. This does not provide granular information on energy use and emissions at the site, process, and product level.

MBIE and the Ministry for the Environment (MfE) released a discussion document on 31 October 2019 about climate-related financial disclosures.19 Submissions will close on 13 December.

It proposes the introduction of a mandatory (comply-or-explain) disclosure regime for NZX listed issuers, banks, general insurers, asset managers and asset owners. The objective is to move to a position where the effects of climate change on businesses become routinely considered in business and investment decisions.

In the event that a business has emissions reporting requirements under both proposals, the means of compliance would be the same (i.e. annual reports).Under these proposals, entities would be required to disclose information in their annual reports about the risks and opportunities to their businesses that are presented by climate change. The disclosures would need to comply with the recommendations of the Task Force on Climate-related Financial Disclosures (TCFD).20 Non-disclosure would only be permissible on the basis of the entity’s analysed and reported conclusion

[17] IEA (2012). Policy Pathway – Energy Management Programmes for Industry, https://webstore.iea.org/policy-pathway-energy-management-programmes-for-industry

[18] Further information available at https://www.mfe.govt.nz/climate-change/proposed-improvements-nz-ets

[19] *Climate-related Financial Disclosures – Understanding your business risks and opportunities related to climate change*, October 2019, https://www.mbie.govt.nz/have-your-say/climate-related-financial-disclosures/

[20] *Recommendations of the Task Force on Climate-related Financial Disclosures*, June 2017, p.14, https://www.fsb-tcfd.org/wp-content/uploads/2017/06/FINAL-2017-TCFD-Report-11052018.pdf

that they see themselves as not being materially affected by climate change, with an explanation as to why.

The requirements of each proposal are largely targeted at different types of business organisations. The only overlap would appear to be large energy users that are also NZX listed issuers. The only TCFD disclosures that would appear to overlap with the proposals contained in this discussion document relate to:

- Disclosures on Scope 1, Scope 2 and, if appropriate Scope 3 GHG emissions, and the related risks
- The targets used by the organisation to manage climate-related risks and opportunities, and performance against those targets.

Questions

Q1.1	Do you support the proposal in whole or in part to require large energy users to report their emissions and energy use annually publish Corporate Energy Transition Plans and conduct energy audits every four years? Why?
Q1.2	Which parts (set out in Table 3) do you support or not? What public reporting requirements (listed in Table 3) should be disclosed?
Q1.3	In your view, should the covered businesses include transport energy and emissions in these requirements?
Q1.4	**For manufacturers**: what will be the impact on your business to comply with the requirements? Please provide specific cost estimates if possible.
Q1.5	In your view, what would be an appropriate threshold to define 'large energy users'?
Q1.6	Is there any potential for unnecessary duplication under these proposals and the TCFD disclosures proposed in the MBIE-MfE discussion document on Climate-related Financial Disclosures?

Electrification information package and feasibility studies

Option 1.2	Develop an electrification information package for businesses looking to electrify process heat, and offer EECA's business partners co-funded low-emission heating feasibility studies

Description

There were diverse, disparate and sometimes conflicting views from submitters on the Technical Paper *Process Heat in New Zealand: Opportunities and barriers to lower emissions* on the issues, costs and processes relating to electrification.

This option involves a package that could be jointly developed by the Electricity Authority, Transpower, MBIE and EECA to address information-related barriers to electrification. For example, on reliability, resilience, and the process and costs for deploying electrification technologies and on developing new electricity connections. This option addresses in part the ICCC's recommendation to reduce regulatory barriers to electrification (3.c) by providing clear and reliable information on the electrification process. Preliminary information on process heat electrification opportunities is shown in the map in Appendix 5.

This option complements options in section 10 on addressing regulatory barriers to electrification, and could be part of a wider guidance document. The various components of a package are each separable and scalable, and could be offered as a customised service for large sites. They include:

- regularly publishing information on electricity reliability for large sites
- providing information about ways to increase reliability and resilience of electrically- supplied plant and systems; and
- co-funding low-emission heating feasibility studies (including electrification, biomass and demand reduction as appropriate) for EECA's business partners.[21]

Analysis

The primary intended benefit of this option is to provide a reliable and cohesive set of information, and provide clarity and guidance on the electrification process. The information would help identify any hidden costs and reduce transaction costs for businesses exploring options to electrify their process heat, and could enable a wider range of energy users to consider their options for electrifying all or part of their process.

As a new initiative, the Government and Transpower would incur additional administrative costs to resource and develop the information package. The costs could be in the tens or hundreds of thousands of dollars. We have not identified any significant compliance costs associated with this option.

The costs for customised low-emission heating feasibility studies for large sites could be around $50,000 per site. This estimate is based on the costs incurred by EECA for its existing offering feasibility studies which co-funds 40 per cent or up to $50,000 for energy efficiency and renewable energy projects for larger businesses.

Questions

Q1.7	Do you support the proposal to develop an electrification information package? Do you support customised low-emission heating feasibility studies? Would this be of use to your business?
Q1.8	In your view, which of the components should be scaled and/or prioritised? Are there any components other than those identified that could be included in an information package?

[21] EECA has long term collaboration agreements with many of New Zealand's largest energy-using businesses. The list of businesses is available at https://www.eecabusiness.govt.nz/our-partners-and-suppliers/large-energy-user-partnerships/

Benchmarking in food processing

Option 1.3	Provide benchmarking information for food processing industries

Description

Food processing industries[22] usually have a large number of similar sites: for example, there are over 80 dairy processing facilities, over 85 meat processing sites, and over 40 other food processing sites in New Zealand. These groups of sites have similarities in their processes, but a high degree of variation exists between the best and worst performing sites in terms of energy and emissions performance.

Benchmarking would identify sites that are underperforming in energy efficiency and emissions intensity and would compare them to the top performing sites within the sector. This can inform businesses of feasible energy and emissions targets, and the best practice technologies and process designs within the sector.

This proposal involves facilitating and supporting specific food sectors to:

- Develop appropriate energy and emissions performance benchmarks for their processes and/or products. It would be closely aligned with any reporting requirements as part of the proposal to publish Corporate Energy Transition Plans outlined above. The Meat Industry Association[23] supports the option of benchmarking meat sites to support best practice sharing to raise overall energy and emissions performance.
- Convene learning networks to share best practices, identify clean energy projects and learn from energy experts.

Analysis

Benchmarking would identify sites where key opportunities to improve energy efficiency and reduce emissions exist. Analysis by the University of Waikato[24] shows that in the food processing sector, there is significant potential to improve energy management, implement waste heat recovery measures, deploy heat pump technologies, and co-fire coal with biomass to reduce the use of fossil fuels.

Direct costs for benchmarking include measurement and metering of energy and emissions by product or process by site. The cost will vary depending on the data management system requirements, the complexity of the site, and the extent to which a site already has information on their energy use and emissions at the level of detail required. However, the costs are discretionary as the benchmarking proposal is voluntary. If implemented alongside the Corporate Energy Transition Plans, the cost of delivering a benchmarking programme would be significantly reduced.

There are also costs associated with determining appropriate benchmarks, in analysing the performance of each participating site against the benchmark, and in identifying practices that can help to improve performance of the site. These costs would likely be shared between industry and government.

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[22] As opposed to the single plant highly emissions-intensive industries, such as steel.

[23] The meat industry has the potential to reduce emissions in a cost-effective manner due to its low-temperature heat requirements.

[24] University of Waikato (2019). *Options to reduce New Zealand's process heat emissions*. Commissioned by MBIE, MfE and EECA, https://www.eeca.govt.nz/resources-and-tools/research-publications-and-resources/business-publications-and-resources/

Questions

Q1.9	Do you support benchmarking in the food processing sector?
Q1.10	Would benchmarking be suited to, and useful for, other industries, such as wood processing?
Q1.11	Do you believe government should have a role in facilitating this or should it entirely be led by industry?

Summary assessment of options against criteria

	Corporate Transition Plans	Individual CTP components	Electrification information package	Electrification feasibility studies	Benchmarking
To what extent is the barrier addressed?	✓✓✓	✓	✓	✓	✓
Primary benefits – emissions reductions	✓✓✓	✓✓	✓	✓✓	✓
Primary benefits – EE & RE	✓✓✓	✓✓	✓	✓	✓
Wider economic effects	✓✓	✓	✓	✓	✓
Compliance costs	XX	X	-	-	X
Administration costs	X	X	X	XX	X

Key:	Option under active consideration	Option not preferred

Section 2: Developing markets for bioenergy and direct geothermal use

This section examines barriers to the use of woody biomass and direct geothermal for process heat and seeks your feedbacks on our options to:

- Develop a users' guide on application of the National Environmental Standards for Air Quality to wood energy
- Facilitate development of bioenergy markets and industry clusters on a regional basis within Industry Transformation Plans, and
- Support recent initiatives underway to grow the bio-economy and support direct use of geothermal heat.

What's the problem?

This section responds to the Productivity Commission's *Low Emissions Economy* report recommendation:

> 14.3. MBIE and EECA should review existing initiatives related to information about fuel switching, co-firing, demand reduction and efficiency improvements for process heat, to minimise any information-related barriers to mitigation opportunities.
>
> 14.4. EECA and MBIE should consider a wider roll-out of policy initiatives to support the supply and use of biomass.

Location and security of supply

The availability of an energy source is only one of multiple factors that influence the location of a new industrial site. Proximity to primary commodities, labour, transport, and market are key considerations and often take precedence over the specific type or emissions intensity of an energy source. Biomass fuel availability is location-specific. To be economic, biomass users generally need to be located close to the biomass source.

In New Zealand, there are mismatches between woody biomass supply and process heat energy demand at a regional level. The supply of woody biomass residues exceeds the energy demand for process heat in some regions (such as the Bay of Plenty and Gisborne), while it is the opposite in other regions (such as Canterbury). In the Bay of Plenty, the residual biomass supply available could potentially be used to generate about 6.5 PJ of energy per annum, while the demand for fossil fuels (including coal, gas and petroleum) for generating process heat is about 2.6 PJ per annum. More information on biomass supply and process heat energy demand in all regions is shown in the map in Appendix 4.

In addition, while the supply of woody biomass residues may appear to be abundant in some regions, economic trade-offs would need to be made when deciding whether to utilise such residues for process heat. There are alternative uses of these residues, e.g. nutrient recycling for plantation forest (in lieu of the use of fertiliser), and the use of wood chips for cattle and calf beds. The mismatches between regional woody biomass supply and process heat energy demand means that it would not be economical to replace all coal with wood energy for process heat in all regions. While there is some potential for movements of biomass between neighbouring regions to address these mismatches, the economics of such movements depends on the terrain of the biomass source and the infrastructure for accessing the biomass. In the case of the East Coast, its comparative isolation means that the transport costs for moving wood residues to another region are high.

There is potential for densification of wood residues into pellets or briquettes to increase the energy content per cubic metre of wood fuel, thereby making it more economical to transport wood fuels over longer distances. However, there are only some small-scale plants for producing wood pellets or briquettes in New Zealand.

The geographical dependence of wood energy in combination with the under-developed wood fuel supply chain[25] means that wood fuel is yet to be widely used in sectors other than wood processing. Some potential biomass users, particularly those with large energy needs, still have concern about the security of wood fuel supply over the life of their plant (20+ years).

Direct heat from geothermal sources is also limited due to geographical dependence and can only be considered for a new-build industrial plant if the chosen site is located close to a geothermal source. New geothermal direct use opportunities are likely to leverage or "piggyback" on electricity generation projects. A key reason to piggyback on electricity generation is the de-risking and cost reductions of exploring and recovering the resource, since direct use is likely to use only a small proportion of heat compared to electricity generation (e.g. about 5 to 15%).

Industrial clusters

A region tends to develop economic specialisations often based on the region's natural resource endowment. For instance, there is a concentration of wood processing and pulp and paper manufacturing in and around Kawerau to take advantage of the Kaingaroa Forest and geothermal heat.

Regional specialisations create complex ecosystem or clusters of upstream and downstream industries, supporting services including professional and technical services, skills and training, and transport and other infrastructure configured to the needs of the industry. Through moving to lower emitting systems, the industrial clusters making use of wood and geothermal energy could also have other co-benefits, such as better health outcomes because of improved air quality. Industry clusters tend to develop organically, but once established may benefit from a more organised approach to their ongoing growth and development.

In particular, developing a shared heat or combined heat and power (CHP)[26] plant for a cluster of wood processing plants and other heat users (such as hospitals and prisons), may need a more proactive, coordinated and planned approach to their development, due to the multiple supply chain components the industry requires. Significant investment would be required to develop a shared CHP plant. It is estimated that it would cost about $280 million to build a CHP plant with an output of 135 megawatt thermal (MWth) and 15 megawatt electrical (MWe).[27] The case for such an investment would depend on the specific circumstances of the region and facilities concerned.

[25] As outlined in the Technical paper, the reasons for this include concerns over security of fuel supply over the life of their plant; the availability of parties that can contract to supply the required volumes of fuel required over the long term; and fuel suppliers reluctant to make investments in capital investment in the absence of a long-term supply contract.

[26] A combined heat and power plant is one that generates electricity as well as heat. This can allow development in areas that might otherwise have insufficient electricity supply capacity.

[27] Scion (2015) *Assessment of wood processing options for Gisborne: Wood Energy Industrial Symbiosis project - Aim 3 resource convergence opportunities*.

There have already been some relatively small-scale initiatives to establish industrial clusters. For example, EECA, in partnership with Venture Southland, implemented the Wood Energy South project in Southland. (See case study below).

Case Study: Wood Energy South

Between 2014 and 2017, EECA, in partnership with Venture Southland, implemented the Wood Energy South (WES) project to encourage Southland heat users to switch from fossil fuels to woody fuels. This project included credentialing energy specifiers (consulting engineers), subsidising feasibility studies, providing information and case studies on using wood energy, and providing capital grants and Crown loans to aid conversion to using wood energy. The WES project had a $1.5 million budget over three years, and a target of an additional 0.15 PJ of wood energy use.

Key learnings from this project include:

- It takes time to develop projects. Even after a business case has been established it can take several years for heat plant owners to make a final investment decision. (Note: WES supported early work on Danone's $40 million project to build a milk spray drying plant in Balclutha, which will be powered by forest waste. However, its construction is still not yet completed).
- A better understanding of the drivers and decision factors involved in private sector fuel switching would help uptake.
- A promising approach may be to target organisations or areas with large heat demand for fuel-switching to spur the establishment of a fuel supply chain.
- Wood Energy South identified health improvements for children in moving to wood chip boilers, and the life span of the corrugated iron on school buildings was extended with moving from coal to wood chip.

Councils' air quality planning rules applicable to wood energy

Under the Resource Management Act (RMA), councils are responsible for managing discharges to air. The Bioenergy Association has noted that some councils have developed air quality-related planning rules that may be an inadvertent impediment to the use of wood fuels. For example:

- There are concerns that some of the rules in councils' plans do not take into consideration the design of the equipment and its capacity to be operated without compromising acceptable air quality standards. For example, some councils have rules that limit the biomass fuel moisture content of wood fuel, but the Bioenergy Association considers that more sophisticated heat plant can effectively manage emissions from high moisture content wood fuel.
- Some councils' rules applicable to wood energy equipment appear to be based on outdated guidelines. For example, some councils' air quality management plans have chimney heights rules derived from the Third Edition of the 1956 Clean Air Act Memorandum on Chimney Heights, which may no longer be appropriate.

The National Environment Standards for Air Quality (NESAQ) are regulations made under the RMA that aim to minimise the adverse health impacts of air contaminants at the national level by:

- prohibiting activities that discharge significant quantities of contaminants to air, such as burning tyres, bitumen, oil and landfill waste
- setting standards for ambient (outdoor) air quality, and

- setting design standards for wood burners, including emissions and thermal efficiency standards. Note the NESAQ does not prescribe detailed technological specifications of wood energy facilities.

The resource management framework for managing air quality (i.e. RMA and NESAQ) gives councils broad discretion to set rules that are suitable for their local circumstances.

What are the options?

To address the issues, we propose the following options:

- Development of a users' guide on the application of the National Environmental Standards for Air Quality to wood energy
- Facilitate development of bioenergy markets and industry clusters on a regional basis within Industry Transformation Plans, and
- Support recent initiatives underway to grow the bio-economy and support direct use of geothermal heat.

In addition to these proposed options, there is also other work across government to grow the bio-economy, which may increase the availability of wood residue supplies for process heat. For example, EECA has begun to offer bioenergy analyses28 – working with Scion to analyse the regional and site-specific availability of biomass fuel for large process heat users with potential to switch from fossil fuels.

Guidance on RMA consenting for wood energy plants

Option 2.1	Developing users' guide on application of the National Environmental Standards for Air Quality to wood energy

Description

We propose to develop an official users' guide supplementary to the NESAQ. The users' guide will provide councils and businesses with technical guidance on managing the development and operation of wood energy, including information on:

- interpretation of the NESAQ requirements from a wood energy perspective
- development of planning rules that would achieve desirable air quality without creating unnecessary impediment to the use of wood energy
- air quality outcomes of various models of wood boilers, and
- good examples of planning rules suitable for wood energy facilities would be provided in this users' guide.

We expect the proposed users' guide would be jointly developed by MBIE, MfE and EECA, in consultation with key stakeholders, such as councils and wood energy experts. As MfE is currently considering amendments to the NESAQ, we propose that the users' guide be developed after the NESAQ amendments are completed. We seek your feedback on whether a guide would be useful and what it could include.

[28] https://www.eeca.govt.nz/energy-use-in-new-zealand/energy-focus-areas/process-heat/

Analysis
Through addressing unintended regulatory barriers posed by councils' air quality planning rules, the proposed users' guide could potentially make it easier for businesses to obtain resource consents for wood energy facilities, thereby accelerating the uptake of wood energy for process heat. This could also help develop the wood energy market, as growing demand for wood energy encourages more wood fuel suppliers to enter the market.

The Government would incur some costs in developing the users' guide, probably in the order of hundreds of thousands of dollars, depending on its scope and the process for developing it.

Questions

Q2.1	Do you agree that councils have regional air quality rules that are barriers to wood energy? If so, can you point us to examples of those rules in particular councils' plans?
Q2.2	Do you agree that a NESAQ users' guide on the development and operation of the wood energy facilities will help to reduce regulatory barriers to the use of wood energy for process heat?
Q2.3	What do you consider a NESAQ users' guide should cover? Please provide an explanation if possible.
Q2.4	Please describe any other options that you consider would be more effective at reducing regulatory barriers to the use of wood energy for process heat.

Amending the NESAQ

Amendments to the NESAQ are currently being considered. There will be a separate public consultation on any proposed amendments.

Nevertheless, we do not expect that any amendments to the NESAQ will exhaustively set out all the detailed specifications of the technologies that are allowed, as the resource management framework for managing air quality (including the RMA and NESAQ) is intended to give councils broad discretion to set rules for managing emissions of air contaminants, taking into account their local circumstances. Air quality issues are different in different parts of the country due to geographical and climatic differences, and it is important for councils to have the flexibility to respond accordingly.

Questions

Q2.5	In your opinion, what technical rules relating to wood energy would be better addressed through the NESAQ than through the proposed users' guide (option 2.1)?

Facilitating the development of bioenergy markets and industry clusters on a regional basis

The following section seeks your feedback to inform the development of options to support bioenergy markets and industry clusters. At this stage, we are not proposing specific options as there is ongoing work across government to grow the bio-economy. We need further information on the merits of these options before deciding whether additional work is necessary.

Industry Transformation Plans

Securing large-scale, long-term fuel supplies, such as for a shared combined heat-and-power (CHP) plant supplying a cluster of industrial and community energy users, will require long-term agreements with multiple partners, including the resource (forest) owners, contractors and the users. Given the number of parties involved, market facilitation by government may help to open up such agreements between suppliers and buyers.

We are proposing to facilitate development of bioenergy markets and industry clusters on a regional basis, as part of an Industry Transformation Plan (ITP) for the Wood Processing and Forestry sector, taking into account learnings from previous government initiatives, such as the Wood Energy South project (which was discussed earlier).

Through the Government's recently-released Industry Policy: From the Knowledge Wave to the Digital Age – Growing Innovative Industries, MBIE is leading the development of Industry Transformation Plans (ITPs) for four sectors, including the Wood Processing and Forestry sector.29

As part of this ITP, MBIE is proposing to investigate the best approach to working with and supporting the development of industry clusters, as well as developing wood energy markets from both the demand and supply side. This could be achieved through supporting bespoke cluster organisations or through improving the co-ordination of regional economic development efforts.

Initiatives to grow the bio-economy

There are a number of recent initiatives the Government has underway to grow the bio-economy, and these could stimulate bioenergy supplies for process heat.

The Forestry Ministerial Advisory Group30 is preparing advice on the role of New Zealand's forests in the transition to a bio-economy. The Advisory Group is working closely with Te Uru Rākau and MBIE to ensure alignment of research and resources.

Te Uru Rākau is developing a Forest Strategy with a broad view of forests and forestry. 'Forest' includes commercial forestry activities (e.g. growing, harvesting, processing and exporting) along with trees and forests contributing to social, environmental and cultural goals (e.g. permanent carbon forests, indigenous trees, trees in urban and farming landscapes).

[29] ITPs are proposed to set out an agreed vision for the sector and a set of actions that Government and industry will take to drive the transition to this vision. These plans will build on the range of existing sector-based work underway, but will have a strong emphasis on planning for the future, improving cohesion and clarity of overall strategic direction across Government initiatives, working through transitional issues, and understanding the workforce issues and opportunities.

[30] The Forestry Ministerial Advisory Group provides the Minister of Forestry with industry perspective and independent advice on matters agreed between the Minister and the Chair of the Advisory Group.

The Forest Strategy will broadly set out:

- an agreed shared direction for the forest sector for the next 30 years and beyond, that guides government and other participants' investment and effort
- clarity around the opportunities and different roles and responsibilities of forest sector participants
- a more joined up platform from which to grow and develop as a sector; and
- priorities for transformation to enable forest-based industries and activities to contribute to improved social and economic wellbeing for New Zealanders.

The Forest Strategy will include consideration of the role forests can play in transitioning to a low emissions bio-economy. It will also consider the role of direct overseas and government investment in wood processing facilities to improve environmental and climate change outcomes, and the promotion of regional economic growth. This initiative could help to stimulate a range of economic opportunities from forestry and may result in creating greater volumes and availability of wood energy for process heat.

Supporting the use of direct geothermal heat

The New Zealand Geothermal Association (NZGA) has developed the *Geoheat Strategy* and a complementary action plan that seeks to increase the use of direct heat in industry. The strategy outlines the opportunities and the approach to diversify the direct use of geothermal heat to create new businesses, decrease the use of fossil fuels in industry, support regional economic and social development, and carve out a role for New Zealand to promote the use of direct heat and associated technologies internationally.

MBIE continues to support geothermal stakeholders in exploring geothermal opportunities and making business-to-business connections for geothermal direct use. Where relevant and regionally-available, we will work with NZGA and other stakeholders to realise industrial cluster opportunities to also use geothermal heat directly.

Questions

Q2.6	In your view, could the Industry Transformation Plans stimulate sufficient supply and demand for bioenergy to achieve desired outcomes? What other options are worth considering?
Q2.7	Is Government best placed to provide market facilitation in bioenergy markets?
Q2.8	If so, how could Government best facilitate bioenergy markets? Please be as specific as possible, giving examples.
Q2.9	In your view, how can government best support direct use of geothermal heat? What other options are worth considering?

Summary assessment of options against criteria

	Develop user's guide for application of NESAQ to wood energy	Amending NESAQ
To what extent is the barrier addressed?	✓✓	✓
Primary benefits – emissions reductions	✓	✓
Primary benefits – EE & RE	✓	✓
Wider economic effects	Uncertain, as its impacts on consenting would be indirect.	Uncertain, as its impacts on consenting would be indirect.
Reduction in compliance costs	✓	✓
Administration costs	X	X X
Energy trilemma – security and affordability	Uncertain, as its impacts on consenting would be indirect.	Uncertain, as its impacts on consenting would be indirect.

Key:	Option under active consideration	Option not preferred

Section 3: Innovating and building capability

This section explains the issues around technology risk for process heat users, and the lack of viable low carbon solutions for emissions-intensive and highly integrated (EIHI) industries. It seeks your views on options to:

- Expand EECA's grants for technology diffusion and capability-building, and
- Collaborate with EIHI industries to foster knowledge sharing, develop sectoral low-carbon roadmaps and build capability for the future using a Just Transitions approach.[31]

What's the problem?

Technology risk and embryonic markets

This section responds to the Productivity Commission's *Low Emissions Economy* report recommendation:

> 6.3. The Government should investigate and implement any cost-effective institutional models that:
>
> - scan new low-emissions technologies around the world to identify ones with promise for New Zealand but that may need adapting to suit local conditions;
> - help firms to improve their absorptive capacity for external knowledge, including new low-emissions technologies.

Firms tend to be risk averse to technologies that change their production process. This includes energy efficiency and fuel switching technologies. A new process that saves energy but whose effectiveness in producing a safe, quality product is not proven is a risk for a business, particularly low-margin businesses that cannot afford down-time.

In addition, there may be lack of skills and capability, such as systems engineering, process design and installation, to support low emissions technology deployment at the scale needed. New Zealand has an energy efficiency market but it is small relative to the size of the opportunity.

The embryonic market for new and emerging low-emission technologies (for example, high temperature heat pumps), means that firms that are early adopters of the technology face much higher costs than firms that adopt the technology when it is used more widely.

Earlier this year, EECA published information resources including an *International Technology Scan* outlining available commercial technologies to reduce process heat emissions.[32]

Low carbon solutions for emissions-intensive highly-integrated industries

In EIHI industries, such as the manufacturing of steel, cement or methanol, emissions are typically intrinsic to the process with fossil fuels being used as a feedstock. As such, they cannot readily be abated by a change in fuels, only by changes to processes. In addition, some of these processes have high-temperature heat requirements (typically above 500 degrees Celsius) and so would be very expensive to electrify.

[31] A "just transitions" approach is about empowering those impacted by change to drive the solutions.
[32] EECA (2019). Information resources available at https://www.eeca.govt.nz/resources-and-tools/research-publications-and-resources/business-publications-and-resources/

Material decarbonising of these sectors will require long-term decisions to be made around investment in low emissions technologies, as they are developed and commercially proven internationally.

Significant investment and coordinated effort among businesses, governments and researchers will be required to identify or develop such technologies. The European Union and the United States are paying particular attention and investing significant research into decarbonising a wide range of industrial processes over the long term. New Zealand may best benefit by keeping abreast of international developments. Opportunities include innovative industrial production processes (that do not require heat), use of hydrogen as feedstock or fuel, and carbon, capture, utilisation and storage.

What are the options?

Support for demonstration and diffusion not only de-risks low emissions heating technology but helps to train, build and retain new capability for the future and overcome embryonic markets.

We seek feedback on two options:

- Expand EECA's grants for technology diffusion and capability-building
- Collaborate with industry to foster knowledge sharing, develop sectoral low-carbon roadmaps and build capability for the future using a Just Transitions approach.

Technology diffusion and capability-building

Option 3.1	**Expand EECA's grants for technology diffusion and capability-building**

Description

This option involves expanding EECA's grants for innovative technology demonstration, deployment and diffusion, and related activities (such as case studies and learning site visits). This will reduce perceived risk in the marketplace, create enhanced opportunities for training and building clean energy capability, and help overcome embryonic market barriers. This is required to accelerate diffusion of, and help transform the market for, low emissions technologies.

EECA would retain dedicated funding to support innovative projects and first-of-a-kind (in New Zealand) demonstrations under the existing Technology Demonstration criteria[33], while dedicated technology diffusion funding could then be targeted to technologies that have already been successfully demonstrated and for which public co-investment can accelerate diffusion.

To date, the Technology Demonstration Fund is relatively modest (less than $1 million was disbursed last year), and the installation of a particular technology can be funded only once. This constrains the potential for wider industry diffusion, although replication is promoted via dissemination of information (e.g. case studies from successful projects).

Even if other businesses become aware of technologies that have been supported by the Technology Demonstration Fund, its replication potential may still be limited by:

[33] Note EECA's Technology Demonstration programme is available for all energy-using technologies or process improvements that meet funding criteria. It is therefore broader than just low emissions heating.

- The Fund's criteria and quantum of funds available: low emission heat investments tend to require large upfront capital. Under current criteria, co-funding for low emissions heating projects is generally limited to $250,000. This does not make up a substantial enough proportion of the investment for co-funding to be attractive to potential applicants.
- Exposure and hands-on experience of the demonstrated technology is available only to the service provider and business involved in the demonstration. Project consultants that have not been directly involved with the demonstration may retain a bias towards technologies and processes that they see as "tried and true", so tend to replace like-for-like.

The additional support for diffusion and related activities would increase the number of low emissions heat technology deployments to reduce perceived risk for wider market uptake. This could involve one, or a combination, of the following:

- Increasing the amount of funding available, to enable a wider range of technologies to be demonstrated across multiple sectors
- Broadening the objectives to include supporting market transformation and increasing capability of clean energy services
- Funding multiple deployments in different circumstances (e.g. process, scale, or sector) to support diffusion of successful demonstrations, and
- Further knowledge-sharing mechanisms, such as learning networks, site visits and technical guidelines. Knowledge sharing and the dissemination of detailed case studies across industry will be important to effectively de-risk technology for wider deployment.

Analysis

The intended benefits of an expanded programme are:

- De-risking a wider range of technologies in a wider range of applications
- Greater familiarity of and expertise with new technologies in the energy service industry
- Overcoming embryonic markets, and
- Accelerating the rate of market diffusion of de-risked low emission technologies and help overcome the so-called technological "valley of death".[34]

These benefits are intended to support market transformation – i.e. creating lasting change in the market whereby the risks and costs of deploying low emission technologies are reduced, and these technologies are adopted as a matter of standard practice. The longer-term outcomes are that New Zealand businesses are leaders or fast followers of low emission technology deployment, are reaping competitive advantages in international markets and that New Zealand has a carbon neutral and internationally competitive economy.

While the government already supports early-stage science and technology research and development through research and innovation funds, there is currently no government support for diffusion – i.e. the gap between pre-commercialisation and full commercialisation/market transformation. An expanded diffusion and capability-building fund fills a gap in the spectrum of government support for low-emissions technology and innovation.

Due to the co-funding model, both Government and Fund applicants would share the projects' costs. The Fund is scalable to the tens (or even hundreds) of millions of dollars. Under an expanded programme, there would be increased administrative costs for resourcing and implementation.

[34] The gap remaining between pre-commercialisation and full industrial commercialisation of a technology or process.

Questions

Q3.1	Do you agree that de-risking and diffusing commercially viable low-emission technology should be a focus of government support on process heat? Is EECA grant funding to support technology diffusion the best vehicle for this?
Q3.2	**For manufacturers and energy service experts:** would peer learning and on-site technology demonstration visits lead to reducing perceived technology risks? Is there a role for the Government in facilitating this?

Industrial innovation and transitioning to a low-carbon future

Option 3.2	**Collaborate with EIHI industry to foster knowledge sharing, develop sectoral low-carbon roadmaps and build capability for the future using a Just Transitions approach**

Description

This initiative would look to create a partnership between government and EIHI industries on industrial decarbonisation. The partnership would provide a platform for collaboration on emissions reduction and knowledge sharing of existing and emerging technical opportunities. Government could support the platform as a facilitator, and bring in international energy and engineering experts.

This option could assist in achieving EIHI emissions reductions through identifying feasible technological pathways for sectors to decarbonise, and helps spread and smooth overall costs of decarbonisation to enable optimal investment over the longer-term. Collaboration and roadmap co-design could:

- Enable a first-principles investigation of long-term opportunities and challenges of EIHI industries, then help to devise strategies with them to achieve low emissions goals
- Develop a shared understanding of international R&D for "hard-to-abate" industries and identify unique issues for New Zealand R&D efforts
- Effectively address informational asymmetries between industry and government, allowing future interventions to be more effectively targeted, and
- Help ensure an optimal regulatory environment and plan for supporting infrastructure.

Analysis

The intended benefits of this proposal are longer-term and are to support industry to plan and develop their own viable solutions and business models in a low emissions future. As such, the emission reduction benefits will be small in the short-term, but could be significant in the future.

The costs would be shared between industry and government and have not yet been estimated but would involve:

- government and industry staff time and expertise to contribute to the collaborative process
- consultant time to produce background and technical papers, roadmaps, or other publications, and
- resourcing for a secretariat or other coordinating function.

Given the linkage to Industry Transformation Plans (ITPs), this proposal would work in close alignment the ITP process, and leverage (not duplicate) the many existing sector specific initiatives already underway.

Questions

Q3.3	**For EIHI stakeholders**: What are your views on our proposal to collaborate to develop low-carbon roadmaps? Would they assist in identifying feasible technological pathways for decarbonisation?
Q3.4	What are the most important issues that would benefit from a partnership and co-design approach?
Q3.5	What, in your view, is the scale of resourcing required to make this initiative successful?

Other options considered to address capability and skills barriers

In order to specifically address the capability and skills barrier, we considered a standalone industry capability development scheme, which would involve industry training and working with tertiary institutions to develop engineering courses.

However, this option is not preferred for the following reasons:

- Increasing demand for clean energy through other measures may be sufficient and more effective to trigger a market and capability response.
- If not closely integrated into measures to drive demand for clean energy, there is a risk that that the scheme will not address specific process heat user needs. In contrast, the technology demonstration and diffusion option involves applied learning and experience with real-life demonstration plants and EIHI roadmaps would involve close collaboration between industrial users on sector-specific opportunities.
- The Carbon and Energy Professionals New Zealand (formerly Energy Management Association of New Zealand, EMANZ) is already working closely with EECA to expand and boost its training to gear up for low-carbon future, with a focus on industrial process heat and carbon management.

Summary assessment of options against criteria

	Tech demo and diffusion	**EIHI roadmaps**	**Industry capability scheme**
To what extent is the barrier addressed?	✓✓	✓✓	?
Primary benefits – emissions reductions	✓	✓	✓✓
Primary benefits – EE & RE	✓	?	✓✓
Wider economic effects	✓✓✓	✓✓✓	✓
Compliance costs	-	-	-
Admin costs	XX	X	XX

Key:	Option under active consideration	Option not preferred

Section 4: Phasing out fossil fuels in process heat

This section explains the issues around long-lived process heat investments and emissions lock-in, and seeks your views on options to:

- Deter the development of any new coal-fired process heat, through a ban on new coal-fired process heat equipment for low and medium temperature requirements, and
- Require existing coal-fired process heat equipment supplying end-use temperature requirements below 100°C to be phased out by 2030.

What's the problem?

This section responds to the following ICCC recommendations from the *Accelerated Electrification* report:

3a. Deterring the development of any new fossil fuel process heat.

3b. Setting a clearly defined timetable to phase out fossil fuels in existing process heat, with the phase out of coal as a priority.

As highlighted in the ICCC's *Accelerated Electrification* report, if new fossil fuel plant is not deterred, efficiency gains and emission reductions made in existing plants have the potential to be outweighed by the building of new fossil fuel heat plant. There is also a risk that if the carbon price rises faster than a business's expectations, that emissions-intensive assets will become stranded before the end of their economic life.

Industrial energy investment decisions are long-term, involve high capital costs, and are highly dependent on the relative capital and fuel costs of different energy sources. At present, coal is the cheapest form of energy used to supply process heat. It is also the most emissions-intensive. Coal boilers have an economic lifespan of about 25 years, and are often repaired and maintained to be used for much longer periods (some coal boilers have been used for over 40 years). Extending the economic life of a boiler requires less upfront capital than replacing it.

Uncertainty about future carbon prices and policy has contributed to maintaining fossil fuel technologies' on-going attractiveness for investment, and carbon price expectations are often not factored into decision-making because of this uncertainty.

While it is important to maintain policy efforts on ensuring an effective NZ-ETS and carbon price signal, it is possible, for the reasons above, that the price signal alone will not be sufficient to deliver a timely transition that prevents the lock-in of high-emission and long life assets that run the risk of becoming stranded over time.

What are the options?

We seek your feedback on the following options to deter investment in new fossil fuel plants:

- Deter the development of any new coal-fired process heat, through a ban on new coal-fired process heat equipment for low and medium temperature requirements, and/or
- Require existing coal-fired process heat equipment for temperature requirements below 100°C to be phased out by 2030

It is expected that the Corporate Energy Transition Plans option outlined in section 1 would also address, at least in part, the issues outlined in this section. However the following options could be implemented on a faster timeline and would have an immediate impact, lowering the risk of locking in new coal assets. These options also provide more certainty on new coal investment decisions.

Deterring the development of any new fossil fuel process heat

Option 4.1	Introduce a ban on new coal-fired boilers for low and medium temperature requirements

Description

This option would introduce a ban on new coal-fired boilers for low and medium temperature requirements.

The nature of different manufacturing processes defines how the heat can be supplied and used. Temperature requirements can be classified as low, medium or high, as set out below:

- Low: less than 100°C, used for water and space heating
- Medium: between 100 and 300°C, for example drying wood products or milk powder, and
- High: Greater than 300°C, for example making steel.

Analysis

This option would ensure New Zealand avoids building new and additional long-lived and emissions-intensive assets (coal boilers). Preventing investment in new coal plant is considered a priority due to its emissions intensity. A ban is simple to administer, incurs minimal cost on the Government, and could be introduced quickly.

This option has the potential to substitute for a carbon price, and this could suppress the price elsewhere, likely reducing abatement in other areas. Some coal to biomass opportunities exist at current carbon prices, however carbon prices in excess of \$60/t CO_2-e, are required to make widespread coal-to-biomass and some coal-to-electricity projects economic.

It is difficult to assess the impact of a ban as new investments in coal-fired boilers are private industry decisions. Dairy processors Synlait and Fonterra, as well as meat processor, Alliance, have announced their commitments to build no additional coal-fired boilers. As these three companies make up a large portion of the market for low and medium temperature heat, a ban may have a small impact on future emissions abatement, and therefore impose relatively low costs on industry. For low-temperature requirements, cost effective new capacity or capacity expansion can be met through good process design and electrification.

For medium-temperature requirements however, banning the use of coal for capacity expansion has the potential to impose significant costs on industry. This will depend whether or not industry is looking to expand its production capacity in the short term, and whether production of lower emissions goods is a viable option (e.g. a factory making cheese rather than milk power).

New medium temperature coal capacity is most likely be South Island milk powder drying facilities, where coal boilers are typically installed. Dairy production growth is slowing, as productivity improvements are offset by declining herd numbers and changing land use. [35]
However, there may still be dairy processing investments that compete for the existing milk pool, either by new entrants or from the expansion of existing companies.

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[35] MPI (2019). *Situation and outlook for primary industries (SOPI)*, https://www.mpi.govt.nz/news-and-resources/economic-intelligence-unit/situation-and-outlook-for-primary-industries/

If industry is looking to expand its production capacity in the short term, this option may have wider economic impacts. For example, it could deter additional investment in milk drying facilities, especially in the South Island. This is because current drying technologies require steam and there may be insufficient biomass available in some locations to provide this. Supplying steam using direct electricity is relatively expensive.[36] However, this is not likely to impact less emissions-intensive and potentially higher value forms of dairy processing, such as cheese manufacturing.

Other options considered, but not favoured are:

- Allowing exemptions in any ban. Exemptions have the potential to create an "uneven–playing field" and depending on application can be seen as unequitable. Those with greater resource are those likely to be best equipped and successful in being granted an exemption.
- Inclusion of natural gas (and other fossil fuels) in the ban has not been considered because carbon prices in excess of \$120/t CO_2-e are required to make many gas-to-electricity projects economic. Such a broad ban would be a blunt instrument and entail very high cost on industry. It could force higher cost abatement in the sector (and the wider economy) compared to more cost-effective options available today. However, to achieve our net zero carbon 2050 target, it is possible that the phase down of gas in industry will also be required in the future.

A timetable to phase out fossil fuels

Option 4.2	Require existing coal-fired process heat equipment supplying end-use temperature requirements below 100°C to be phased out by 2030.

Description

This option would require process heat users to phase out existing coal assets that are being used to supply end-use requirements below 100°C by 2030.[37] We propose that a government-mandated timetable apply only to coal consumption for temperatures below 100°C due to the higher cost of transitioning existing higher temperature applications and switching away from natural gas.

Analysis

This option would ensure that low cost emission reductions in process heat occur and is intended to overcome potential perverse incentives associated with option 4.1 – whereby existing coal boilers are refurbished and maintained for decades to avoid triggering the definition of "new coal investment".

The compliance costs of this proposal would be different across low-temperature process heat users. These would vary according to:

- The emissions price: fuel switching off coal to supply low temperature heat will be the low hanging fruit for emissions reductions as the emissions price rises. However, it is uncertain whether coal will be phased out by 2030 in response to the emission price. If the phase out of coal for low temperature heat was to occur before 2030 in response to a rising emission price, then compliance costs are minimal. However, if the emissions price does not rise enough, then compliance costs will be higher.
- The age of equipment: having to retire equipment early creates stranded assets. However, we note that many boilers run long past retirement age.

[36] Using electricity directly for steam generation (e.g. in the form of an electric boiler) is still very expensive, needing carbon prices in excess of \$150/t CO_2-e to become cost effective. Using electricity via heat pumps, MVR or heat recovery is much more cost effective compared to making steam directly, achieving 14 times greater emissions reduction per unit of electricity used.

[37] The option for Corporate Energy Transition Plans outlined in Section 1 also addresses the ICCC's recommendation 3 and covers higher temperature applications and other fossil fuels.

- Sector-specific circumstances, such as production process, energy cost as a proportion of revenue, access to capital and profitability, and
- Location and access to alternative fuels including transmission and distribution capacity.

In addition, there is a risk that this option encourages switching from coal to gas when there are viable lower emission alternatives, such as biomass or electricity available. This risk would be mitigated if Corporate Energy Transition Plans for large users are also in place.

As with option 4.1, we also considered, but do not favour, inclusion of other fossil fuels, allowing exemptions, or including higher temperature requirements at this stage.

We have also identified options that could be pursued under the Resource Management Act (RMA), including:

- Exploring options as part of the comprehensive review of the resource management system beginning in 2020, which will consider the role of regulation in supporting climate change mitigation, and ensure alignment with the Climate Change Response (Zero Carbon) Amendment Act. To support the Expert Advisory Group (who will carry out the review), MBIE officials are working with MfE and other agencies to outline key issues and scope options to avoid industrial activities "locking in" high emissions methods for activities that may be consented prior to an effective price signal under the NZ-ETS and to encourage Best Available Techniques (BAT).[38]
- Developing a National Environmental Standard or National Planning Standard for cleaner industrial production requiring councils to take into account New Zealand-specific BAT and/or specifying numerical emissions limits for industrial activities. Any National Environmental Standard would need to be developed in accordance with the process outlined in the RMA.

Questions

Q4.1	Do you agree with the proposal to ban new coal-fired boilers for low and medium temperature requirements?
Q4.2	Do you agree with the proposal to require existing coal-fired process heat equipment for end-use temperature requirements below 100 degrees Celsius to be phased out by 2030? Is this ambitious or is it not doing enough?
Q4.3	**For manufacturers**: referring to each specific proposal, what would be the likely impacts or compliance costs on your business?
Q4.4	Could the Corporate Energy Transition Plans (Option 1.1) help to design a more informed phase out of fossil fuels in process heat? Would a timetabled phase out of fossil fuels in process heat be necessary alongside the Corporate Energy Transition Plans?
Q4.5	In your view, could national direction under the RMA be an effective tool to support clean and low GHG-emitting methods of industrial production? If so, how?

[38] BATs or best practicable options refer to the most effective techniques for preventing or reducing emissions or environmental effects that are technically feasible and economically viable within a sector. BAT does not necessarily prescribe that fossil fuels can or cannot be used for a particular activity. Rather, BAT represents the latest stage of development (state of the art) of processes, of facilities or of methods of operation specific to a business sector that are in operation today, which indicate the practical suitability of a particular measure for limiting discharges, emissions and waste.

Q4.6	In your view, could adoption of best available technologies be introduced via a mechanism other than the RMA?

Summary assessment of options against criteria

	Ban on new coal (low-med temp)	Ban on new coal (low-high temp)	Ban on all new fossil fuels (all temp)	Coal phase-out by 2030 (<100°C)	FF phase-out by 2030 (<100°C)	FF phase-out by 2030 (all temp)
To what extent is the barrier addressed?	✓	✓✓	✓✓✓	✓	✓✓	✓✓✓
Primary benefits – emissions reductions	✓	✓✓	✓✓✓	✓	✓✓	✓✓✓
Primary benefits – EE & RE	✓	✓✓	✓✓	✓	✓✓	✓✓
Wider economic effects	-	X	XX	-	X	XXX
Compliance costs	X	XX	XXX	XX	XXX	XXX
Administration costs	X	X	X	X	X	X

Key:	Option under active consideration	Option not preferred

Section 5: Boosting investment in energy efficiency and renewable energy technologies

This section explains the issues relating to underinvestment in energy efficiency and renewable energy technologies. It seeks your views on whether the Government should be considering these issues and how these issues could be addressed.

This section responds to key barriers identified in the submissions on the Technical Paper *Process Heat in New Zealand: Opportunities and barriers to low emissions.*

What's the problem?

Initial analysis suggests that the total potential for emission reductions from cost effective clean energy projects in industry amounts to an estimated 2 – 3.5 Mt CO_2-e per year (as outlined in Appendix 2).

Energy projects within a business compete internally with other capital investment projects. Even when these projects are privately profitable, they can remain unimplemented as other, more attractive, more easily quantifiable, or essential to core business projects are prioritised. As such, a gap exists between the carbon price that would make a project profitable and the price that would make a project a priority for implementation. This competition for capital is a major barrier to more efficient and renewable use of process heat. In addition, some businesses may have limited access to capital to allow them to implement cost-effective energy projects.

While energy investment results from what might be privately-rational investment behaviour by firms, it can also result in foregone benefits and sub-optimal outcomes for the energy system and emissions reduction efforts. Unless a business has strategic prioritisation of all cost-effective clean energy[39] technologies or has ring-fenced funds for energy technologies, significant economic energy savings and emissions reduction potential may not be realised.

What could be considered to address these issues?

The NZ-ETS and the Corporate Energy Transition Plans (if implemented)[40] are expected to increase investment in energy efficiency and renewable energy technologies. However, barriers of internal competition or access to capital could still persist, which could leave some remaining economic energy efficiency potential unrealised.

We have identified two ways of addressing these barriers, either through regulating clean energy spend or through providing incentives to stimulate investment in clean energy technologies. Both

[39] Clean energy investments includes energy efficiency technologies and technologies that enable fuel switching to low emissions sources such as electricity, biomass, and geothermal. Energy efficiency technologies and the efficiency by which fuel – electricity, coal or gas – can be converted into usable process heat (measured by the Coefficient of Performance (CoP)) can reduce the overall costs of transitioning to a low emissions energy system. For example, lower temperature processes can take advantage of commercial and industrial-scale electric heat pump technology with CoPs of between three and seven (so 3-7 units of useful energy are produced for every unit of electricity). By comparison, using a central gas or coal-fired boiler to produce steam can have a CoP of only 0.5, so only half the energy is used, and half is wasted. Source:

[40] The Corporate Energy Transition Plans option in Section 1 is considered as an important first step to enable the effective design of and support for a range of additional measures.

approaches have the potential to impose high costs on either the Government or industry and could carry significant risk if they are not well designed and targeted.

Due to the nature of these approaches and the scale of investment likely required by the Government and/or industry to achieve our climate change objectives, they need to be carefully considered alongside forthcoming broader government decisions on climate change policy. These decisions include proposals discussed in this paper, changes to the NZ-ETS, discussion on the role of complementary measures to the NZ-ETS, and the pace and pathways of domestic emissions reductions to meet the country's emission targets. As such, we are seeking feedback and gathering further information on the types of levers, rather than consulting on a preferred set of policy proposals.

We are gathering information on the both regulatory and incentive-based levers.

Regulatory approach - regulating clean energy spend

Regulation can be an effective tool in driving investments in energy efficiency and renewable energy technologies. For example, it could be a regulatory requirement that for large energy users all eligible profitable clean energy projects with a payback under a specified number of years are implemented by the business.

In the short term, such regulation could impose significant compliance costs on industry. Increased investment in clean energy projects would potentially be at the expense of investment in other more profitable or urgent core business priorities. The impact on firms is likely to vary depending on their financial position and competing priorities for investment. Firms with limited access to capital and urgent core business spend may struggle to comply with the regulations. To alleviate the upfront investment barriers (compliance costs), regulation could be supported by financial incentives as discussed below.

In addition, the scope would need to exclude projects with significant production risks, so that businesses are not dissuaded from identifying opportunities or forced into unduly risky projects.

In the medium-long term, well designed regulation may not impose excessive compliance costs on industry. Compliance costs could be outweighed by the energy and emissions cost savings that result from the increased energy investment. Regulation could result in greater energy savings and emissions abatement than delivered by the NZ-ETS alone.

At this stage, we would not recommend regulation to drive investment in clean energy is developed. Changes to the NZ-ETS, and other options discussed in this paper should be considered as first steps to drive changes in industrial energy use.

Non-regulatory approach - incentives for specified low emissions heat technologies

This section seeks your feedback on the potential use of incentives that the Government could utilise to support industry in the transition to a low emissions economy. More detailed analysis is required to determine the necessity of and the type of incentives, timing of implementation, the technologies that should be eligible, and the impact on emissions.

Poorly targeted support for low emission energy technologies may have negative interactions with the carbon price by encouraging higher cost abatement. The NZ-ETS reforms will lead to a cap and trade scheme, whereby the total volume of emissions is capped in advance and the price is allowed to vary. If support accelerates the deployment of low emission technologies in industry, in turn reducing emissions, this could suppress the NZ-ETS price by reducing demand for NZ-ETS units by those benefitting from incentives. To avoid potential negative interactions with the NZ-ETS, incentives will need to be well designed and targeted.

Incentives would likely impose high costs on the Government and have the potential to subsidise expenditure that may occur anyway. Without additional incentives however, it may take some time for the NZ-ETS price to rise to levels sufficient to drive significant change and have a material impact on emissions reductions in the industrial sector. The internal competition for capital may persist as a significant barrier if clean energy investments are not prioritised.

At this stage, we would not recommend that incentives to drive investment in clean energy are developed. Changes to the NZ-ETS, and other options discussed in this paper should be considered as first steps to drive changes in industrial energy use.

Questions

Q5.1	Do you agree that complementary measures to the NZ-ETS should be considered to accelerate the uptake of cost-effective clean energy projects?
Q5.2	If so, do you favour regulation, financial incentives or both? Why?
Q5.3	In your view what is a bigger barrier to investment in clean energy technologies, internal competition for capital or access to capital?
Q5.4	If you favour financial support, what sort of incentives could be considered? What are the benefits, costs and the risks of these incentives?
Q5.5	What measures other than those identified above could be effective at accelerating investment in clean energy technologies?

Section 6: Cost recovery mechanisms

This section seeks your views on introducing a levy on consumers of coal to partially recover the cost of implementing any new policies in Part A that may be introduced.

Option 6.1	Introduce a levy on consumers of coal to fund process heat activities

Description

In order to mobilise private-sector investment and scale up efforts to achieve the Government's process heat outcomes, additional funds will be required to resource implementation of some of the policy proposals in Part A of this paper that are agreed by the government.

One option for funding policy proposals is through cost recovery mechanisms. We seek your feedback on introducing a levy on consumers of coal to fund EECA's process heat programmes.

Analysis

Introducing a levy on consumers of coal would provide an even treatment of levies for relevant specified activities of EECA, or could help to fund other implementation activities relevant to any proposals in this Section.

Funds are currently levied on:

- petroleum or engine fuel, to recover the cost of fuel monitoring and specified activities of EECA
- natural gas, to recover the cost of safety, monitoring and specified activities of EECA, and
- electricity, to recover the costs of the Electricity Authority, and specified activities of EECA.

These are based on consumption and sales of these energy sources. There is no equivalent coal levy. Under the Energy Resources Levy Act, the existing levy is only on coal extracted at open-cast mines, not on coal consumed in New Zealand. [41]

Determining the levy rate and the proposed activities to be funded will need to be made once in-principle policy decision have been made. However, the approach will likely be the same as for existing levies where EECA (or another agency) must describe the fuel types it is intending to levy for that year and demonstrate a logical link between its specific programmes and the levy.[42]

Table 4 below provides information on the current levies on petrol, gas and electricity to recover EECA costs, the quantum of revenue they raise for EECA.

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[41] As outlined in the *Discussion Paper: Options for expanding the purpose of existing energy levies*, the existing levy is only on coal extracted at open-cast mines, not on coal consumed in New Zealand , so an expansion would not sufficiently meet the design principles and criteria that apply to using the levy for energy efficiency and emission reduction purposes. https://www.mbie.govt.nz/dmsdocument/2883-options-for-expanding-the-purpose-of-existing-energy-levies-pdf

[42] Available at https://www.mbie.govt.nz/dmsdocument/206-egi-cabinet-paper-levy-policy-decisions-final-sept-2016-redacted-pdf

Table 4: Current energy levies for EECA purposes

Levy (in 2019/20)[43]	Levy for EECA purposes	
	Levy rate	**Amount levied ($ million)**
Petroleum or Engine Fuel Monitoring (PEFM) levy	0.1 cents per litre	7.5
Electricity industry levy	12 cents per MWh	5.2
Gas Safety, Monitoring and Energy Efficiency (GSMEE)	1.4 cents per GJ	1.1

The Energy Resources Levy Act 1976 imposes a levy on the production of open-cast coal and natural gas produced from discoveries made before 1 January 1986. Revenue is paid into a Consolidated Fund. The levy rate is specified in legislation at rate of $2 per tonne on coal (other than South Island lignite), and $1.50 per tonne on South Island lignite. Approximately 50 per cent of coal extracted in New Zealand is exported as it is high-grade coal.

Coal users would face increased costs because of the levy. However, they are expected to benefit from the services the levy will fund. For example, coal users who pay the levy could receive co-funding from a low emissions heating feasibility study to switch off coal, trial a new technology under an expanded Technology Demonstration Fund, or benefit from a tax credit to adopt an energy efficient technology. While the total amount levied would depend on the specific activities to be funded, an initial estimate is in the order to $2 to $4 million. Levy funding would likely complement Crown funding, and any unused funds would be returned to levy payers.

The status quo would be to resource the adoption and implementation of policy proposals from general Crown revenue and existing energy levies. Another option would be to use the proceeds from the auctioning of emissions units.

Questions

Q6.1	What is your view on whether cost recovery mechanisms should be adopted to fund policy proposals in Part A of this document?
Q6.2	What are the advantages and disadvantages of introducing a levy on consumers of coal to fund process heat activities?

[43] Levy rates https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/low-emissions-economy/energy-efficiency-in-new-zealand/energy-levies/

Part B: Accelerating renewable electricity generation and infrastructure

This part has five sections. It seeks your views on a number of proposals to address opportunities and barriers to accelerate investment in renewable energy infrastructure. Specifically:

- Enabling renewables uptake under the Resource Management Act 1991 (Section 7).
- Supporting renewable electricity generation investment, and developing demand response markets and energy efficiency resources in the electricity system (Section 8).
- Supporting development of community and small scale generation (Section 9).
- Ensuring timely and optimal investment in transmission infrastructure to get electricity to where it is needed (Section 10).
- Enabling connections to, and trading on, the local network (Section 11).

Introduction

Renewable energy was 40 per cent of our total energy supply in 2018. The majority of renewable energy is renewable electricity. In 2018, 84 per cent of electricity was generated from renewable resources, mostly hydropower, geothermal and wind.[44]

This Government has set an aspirational goal of 100 per cent renewable electricity by 2035, with five-yearly assessments to ensure that security of supply and affordability of electricity are well-managed.

Our electricity system is expected to reach somewhere between 90 to 95 per cent renewable electricity by 2035 under most 'business as usual' modelling scenarios. Modelling in the ICCC's report *Accelerated Electrification* showed that under 'business as usual' we could reach 93 per cent renewable electricity by 2035.[45]

Our highly renewable electricity system is well-placed to assist in achieving broader decarbonisation goals across the economy. The ICCC recommended prioritising the electrification of transport and process heat ahead of moving to 100 per cent renewable electricity, as achieving the last few per cent of renewable electricity could be costly.

This section of the discussion paper looks at options that increase the deployment of renewable electricity, as well as the opportunities and barriers to electrification for industry and transport. It also considers the role that distributed energy resources and smart, emerging technologies could play in the energy transition. Removing barriers and enabling greater demand-side participation and energy efficiency has significant potential to reduce emissions and optimise our energy system.

[44] See: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-publications-and-technical-papers/energy-in-new-zealand/

[45] The ICCC's modelling assumed that new generation (including consented but as yet unbuilt wind generation) would be able to be built under New Zealand's resource management system, and that the current process to reform New Zealand's Emissions Trading Scheme (ETS) proceeds (represented by an assumption that the emissions price rises to $50/t CO_2e).

The transport and process heat sectors make up 20 per cent (16 Mt CO2-e) and 8 per cent (7 Mt CO2-e of total emissions), respectively. Electrifying transport and process heat can reduce energy-related emissions across the economy. The ICCC estimated that 'accelerated electrification' of transport and process heat could achieve net savings of 5.4 Mt CO2-e annually. For transport (5.7 TWh), this is the equivalent of replacing 2.2 million fossil-fuelled vehicles with EVs by 2035, and for process heat (5.5 TWh), it is the equivalent of switching about one-third of fossil fuels used for food manufacturing to electricity and replacing fossil fuel heating with heat pumps for activities like water and space heating.

The ICCC's analysis shows that electricity demand could increase by about 11.2 terawatt-hours (TWh) by 2035 if we focus on accelerating the electrification of transport and process heat, as well as encouraging energy efficiency improvements and battery and demand response uptake. To reach the energy-related emissions reductions estimated in the ICCC's analysis, at least 5,500 megawatts (MW) of new generation would need to be built by 2035 (along with significant deployment of batteries and demand response).

Wind, geothermal and solar

Wind and geothermal electricity generation currently offer the most competitive investment options for large-scale developments. New Zealand has some of the best wind resources globally. Further, wind turbine manufacturers are continuously improving the performance of turbines and reducing costs. Improvements in wind turbine performance can imply an increase in blade tip height and width. We have seen wind turbine size (and efficiency) increase substantially over the last decade. This can make it more difficult for wind farm developers to obtain a resource consent that accommodates modern, high-performing turbine technology.

Solar energy has begun to play an increasingly important role in New Zealand, but has not reached the levels of deployment seen in some countries, such as Australia. It has a significant potential to grow its contribution to our energy mix, given that many parts of New Zealand have equivalent, if not greater, sunshine-hours than some European countries that have promoted solar uptake through subsidies. Grid-scale solar is reaching cost-competitive levels compared to other new generation options. Rooftop solar is already a good fit for some businesses where they can align peak generation with peak demand, or for households in rural areas.

Supply- and demand-side renewables

Accelerating renewable electricity generation investment has a strong interdependency with encouraging changes in industrial energy use. The electrification of industrial sites could be a major driver of increased electricity demand while reducing industrial energy emissions. Our electricity system will need to deliver increased renewable generation capacity both affordably and securely to ensure electrification of transport and industry can deliver emissions reductions. Hence, Part B of this paper focuses on increasing renewable energy supply, following Part A, which focuses on the use and demand for renewable energy in process heat, including through electrification.

Barriers and opportunities

The NZ-ETS may encourage some fuel switching to electricity, which could in turn encourage new renewables build. However, this Part looks at a range of areas to examine potential non-price barriers to this increased investment and what options may have the most potential to address these barriers.

Each section below discusses the specific problems it is examining, and then outlines a range of options that could address these barriers or issues. **Table 5** below summarises the different options considered in each subsection of this part.

Table 5: Barriers and opportunities for renewable electricity generation and infrastructure

	Section	Options
Section 7	**Enabling development of renewable electricity generation under the Resource Management Act 1991**	**7.1** Amend the NPSREG to provide stronger direction on the national importance of renewables **7.2** Scope National Environmental Standards or National Planning Standards specific to renewable energy **7.3** Other options including: • Pre-approval of new renewable developments: Planning approaches including relatively permissive consenting rules in defined areas • Pre-approval of new renewable developments: Crown acquiring consents for transfer to developers • Pre-approval of new renewable developments: new statutory allocation process • Amending NPSET and NESETA
Section 8	**Supporting renewable electricity generation investment**	**8.1** Introduce a Power Purchase Agreement (PPA) Platform **8.2** Encourage greater demand-side participation and develop the demand response market **8.3** Deploy energy efficiency resources via retailer/distributer obligations **8.4** Develop offshore wind assets **8.5** Introduce renewable electricity certification and portfolio standards **8.6** Phase down thermal baseload and place in strategic reserve **8.7** Other options including: • Government-sponsored storage facility for firming hedge products • State-owned enterprise for renewables investments • Co-ordinated procurement of new generation (single-market buyer) • Tax incentives for renewable electricity generation • Provision of subsidies via auction (one-off or in rounds i.e. biennially)
Section 9	**Local and community energy engagement**	**9.1** Ensuring a clear and consistent government position on community energy issues, aligned across different policies and work programmes **9.2** Government supports development of a small number of community energy pilot projects, through options including financial support, 'handholding' and facilitating of projects, or assisting with regulatory approvals and access to land

	Section	Options
Section 10	**Connecting to the national grid**	**10.1** Encourage Transpower to include the economic benefits of climate change mitigation in applications for Commerce Commission approval of projects expected to cost over $20m **10.2** Put in place additional mechanisms for, or encourage, Transpower, first movers and subsequent customers to agree to alternative forms of cost sharing arrangements by contract **10.3** Shift some of the cost and risk allocation for new and upgraded connections from the first mover through mechanisms within the Commerce Commission's regulatory scope, with the Crown accepting some of the financial risk. Two identified ways to achieve this are: **10.3.1** Optimise asset valuations under the Commerce Commission's regime in circumstances where demand is lower than originally anticipated because expected (subsequent) customers do not eventuate **10.3.2** Provide for Transpower to build larger capacity connection asset or a configuration that allows for growth, but only recover full costs once asset is fully utilised, with the Crown covering risk of revenue shortfall. **10.4** Provide independent geospatial data on potential generation and electrification sites (e.g. wind speeds for sites, information on relative economics and feasibility of investment locations given available transmission capacity) **10.5** Extend the data and information provided in MBIE's EDGS and increase the frequency of publication, and potentially recover the cost through the existing levy on electricity industry participants. **10.6** Produce a user's guide on the current regulations and approval processes relating to getting an upgraded or new connections to the grid **10.7** Provide a "map" or database of potential renewable generation and demand sources, location and potential size (e.g. wind, geothermal, milk plant). **10.8** Introduce measures to enable coordination regarding the placement of wind farms to ensure they are more likely to be better distributed around the country
Section 11	**Local network connections and trading arrangements**	No new options are proposed at this time.

How we are assessing options

In line with the Government's goals for a net zero emissions economy by 2050 and aspirational goal of 100 per cent renewable electricity by 2035 (subject to assessments relating to affordability and security), our high level criteria for assessing options is:

1. **Does the option have an impact on greenhouse gas emissions** (does it reduce emissions in a least-cost way, is it more efficient than emission reductions in other sectors, is it complementary to the NZ-ETS, how much emissions reduction is expected?)
2. **Does the option reduce barriers to investment in future renewable energy generation or energy efficiency?**

In addition to these high-level criteria, we have provided a preliminary assessment of the costs and benefits of options (where relevant) against the following sub-criteria:

3. **Wider economic effects** – impact the option has in terms of wider economic costs and benefits, such as:
    a. **Productivity impacts** – indicating if there is any impact on productivity.
    b. **Distributional impacts –** indicating if any population groups are likely to be disproportionately impacted by the proposal e.g. rural communities, regions, workers, consumers, Māori/iwi.
    c. **Innovation and uptake of new technologies –** indicating to what extent the option future-proofs the energy system, and incentivises innovation and uptake of new technologies.
    d. **Health and environmental benefits and costs** e.g., warmer homes, air quality, biodiversity
4. **Administrative and compliance costs –** impact the option has in relation to:
    a. **Administrative costs** – costs to government of delivering option
    b. **Compliance costs** – whether businesses are likely to face additional costs from options.
5. Impacts on other parts of the **energy trilemma**, in addition to sustainability:
    a. **Energy affordability** – impact the option has on electricity or energy prices/affordability for different population groups and communities.
    b. **Security of supply –** impact the option has on security of supply.

Analysis of options addresses these sub-criteria if (and only if) there is a non-negligible impact. For example, where no distributional impacts or effects on innovation have been identified, these sub-criteria are not noted under the option analysis.

However, the costs and benefits of each option have not yet been analysed in detail. One of the objectives of the consultation is to seek feedback from stakeholders on the likely benefits and costs, including the compliance costs on individual businesses affected by an option. Questions at the end of each section are intended to be prompts in this regard.

Section 7: Enabling development of renewable energy under the Resource Management Act 1991

This chapter considers policy options to enable renewable energy development under the Resource Management Act 1991 (RMA). We seek your views on the following key options:

- Amending the National Policy Statement for Renewable Electricity Generation (NPSREG) to provide stronger direction on the national importance of renewables
- Scoping National Environmental Standards or National Planning Standards specific to renewable energy (note: we propose to prioritise amending the NPSREG while proceeding with this scoping work.)
- Other options including spatial planning, pre-approval of new renewable energy developments, and amending other RMA national direction instruments.

This chapter also notes a wider range of options that could enable renewable development, including the comprehensive review of the resource management system.

This chapter does not discuss the options relating to facilitating cleaner industrial production (such as switching from coal-fired boilers to wood chip boilers) under the RMA framework. Those options are discussed in sections 2 and 4.

Background

New Zealand will need to build a significant amount of new renewable generation to meet future electricity demand and our climate change goals. Any new projects that might affect the environment, ranging from construction of wind farms and hydro dams to installations of boilers, will require resource consent under the RMA.

Some resource consents for existing renewable energy facilities are also due to be re-consented in the near future (e.g. the Waitaki hydro generation scheme in 2025). Technological advancements also mean that some consented, but unbuilt, renewable energy projects may seek to have their resource consents amended or re-consented in order to use the latest technology, rather than the technology available at the time the consent was granted (for example, larger wind turbines).

Central government has issued a number of national direction instruments under the RMA to give local government direction on environmental issues. Councils must have regard to these national direction instruments when making decisions on resource consents. For plans and regional policy statements, councils must give effect to national policy statements, and amend their plans to remove any duplication or conflict with national environmental standards (NES).

The national direction instrument most relevant to renewable energy development is the National Policy Statement for Renewable Electricity Generation 2011 (NPSREG), which sets out an objective and policies to enable the sustainable management of renewable electricity generation (REG) under the RMA.

The other national direction instruments most relevant to renewable energy development include:

a. The National Policy Statement for Electricity Transmission 2008 (NPSET).

b. National Environmental Standards for Electricity Transmission Activities 2009 (NPSETA).

c. The National Policy Statement for Freshwater Management 2014 (amended 2017) (NPSFM) (relevant to hydro generation).

d. The New Zealand Coastal Policy Statement 2010 (NZCPS) (particularly relevant to renewable energy projects in coastal areas).

e. National Environmental Standards for Air Quality 2004 (NESAQ) (relevant to the development of wood energy facilities).

f. The National Planning Standards 2019 (these standards require plans to use the noise measurement methods and symbols set out in the New Zealand Standard on wind farm noise[46]).

RMA-related proposals subject to separate public consultations

Comprehensive review of the resource management system

There are a range of RMA-related policy proposals that are being developed or consulted on separately. They may have implications for renewable energy development, but are not included in this discussion document. These proposals include:

- A comprehensive review of the resource management system, focusing on the RMA ;
- The Essential Freshwater package, which includes proposals to amend the NPSFM; and
- A proposed National Policy Statement for Indigenous Biodiversity (NPSIB), which includes provisions for managing adverse effects on significant natural areas and could have implications for development of energy resources sites and mining proposals.

What's the problem?

This section responds to the following recommendations from:

- the Productivity Commission's *Low Emissions Economy* report:

  13.3 The Government should give priority to revising both the NPS-REG and the NPS-ET to ensure that local authorities give sufficient weight to the role that renewable electricity generation and upgrades to the transmission network and distribution grid will play in New Zealand's transition to a low-emissions economy. This will likely require making the language of the NPS-REG and the NPS-ET more directive, and to be more explicit about how the benefits of renewable electricity generation should be recognised and given effect in regional and territorial authority planning instruments.

  13.4 The Government should issue a new National Environmental Standard for Renewable Electricity Generation that sets out the conditions under which renewable energy activities are either permitted, controlled, restricted discretionary or non-complying activities under the Resource Management Act 1991. This should be drafted to increase the speed, and lower the cost and uncertainty for obtaining resource consents for a significant proportion of renewable electricity generation projects that have only minor environmental and social impacts.

- the ICCC's *Accelerated Electrification* report:

  4a The Government should ensure the value of existing hydro generation to New Zealand's climate change objectives is given sufficient weight when decisions about freshwater are

[46] NZS 6808:2010 Acoustics – Wind farm noise.

made, including by strengthening and clarifying national direction on making trade-offs between hydro generation and freshwater objectives across National Policy Statements.

5a The Government should provide for the development of wind generation and its associated transmission and distribution infrastructure at scale by revising the National Policy Statement for Renewable Electricity Generation to resolve issues relating to lapsing and varying consents, and re-powering existing wind farms.

5b The Government should develop National Environmental Standards to enable timely consenting of wind generation, both large and small, and transmission and distribution infrastructure. This should include proactively identifying which types of landscapes are likely to be particularly suitable for wind infrastructure.

Resource consents are a crucial part of the resource management system. The consent process helps ensure the environmental effects of a renewable energy proposal (which often are significant) are appropriately managed. The resource consent process also needs to reconcile the national benefits of renewable energy projects with the local impacts.

A number of concerns have been expressed around consenting processes under the RMA. These are summarised in the reports of the Productivity Commission (2018) and ICCC (2019).

The Productivity Commission's (the Commission) 2018 report on a Low-Emissions Economy noted that obtaining resource consents under the RMA may slow further expansion of New Zealand's renewable energy development. The Commission found that the language of the NPSREG was not sufficiently directive to give weight to the central role for renewable energy generation in a transition to a low-emissions economy.

The Commission also noted uncertainty for hydro generators over water allocation decisions[47], and that decisions on resource consents for transmission/distribution grid investment can be time consuming and costly.

The ICCC's 2019 report on *Accelerated Electrification* noted the policy uncertainty between different national instruments (e.g. weighing the value for hydro generation in hydro schemes versus freshwater management goals). The ICCC also noted challenges to consenting renewable energy generation and recommended a streamlining of consenting and re-consenting processes – including constraining the ability to decline applications for wind generation due to landscape or visual considerations.

The case study below illustrates that it can still be challenging to obtain resource consents for renewable energy projects, despite the introduction of the NPSREG.

[47] Note that this uncertainty for hydro generators could potentially be reduced by the *Essential Freshwater* package, which includes proposals to amend the NPSFM.

Case study: Blueskin wind generation proposal

Blueskin Energy Ltd pursued establishment of a community-scale wind generation project in Blueskin Bay near Dunedin between 2009 and 2017. BEL started the feasibility and planning process in 2009, and BEL lodged the original resource consent application for the project in 2015 to construct and operate three wind turbines. The Dunedin City Council declined the original application on the grounds of adverse amenity impacts particularly from one turbine. In preparation for mediation prior to the Environment Court hearing, BEL revised its proposal to just constructing and operating a single 3MW turbine. The Environment Court ultimately declined consent on the basis of the turbine's adverse visual amenity effects in 2017.

The NPSREG was considered in this case. The Environment Court interpreted Policy A of the NPSREG, which provides that "decision-makers shall recognise and provide for the national significance of renewable electricity generation activities…", as requiring the court to have regard to the NPSREG's objective and policies and weigh them appropriately. The Environment Court considered that Policy A does not necessarily provide for a REG activity by a grant of consent in the absence of any matters of national importance stated in section 6 of the RMA. [48]

What are the options?

We are seeking your feedback on stronger national direction under the RMA on the importance of renewable energy, through revisions to the NPS-REG and potential development of complementary NES or National Planning Standards. These options relate to recommendations 13.3 and 13.4 of the Productivity Commission's *Low Emissions Economy* report[49], and recommendations 4a, 5a and 5b of the ICCC's *Accelerated Electrification* report[50].

Revising the NPSREG (proposal 7.1) is a priority of the Renewable Energy Strategy work programme.

This discussion paper also seeks feedback on other potential options – including an enhanced role for spatial planning, or changes to other national direction instruments.

Amend the National Policy Statement for Renewable Electricity Generation

Proposal 7.1	**Amend the National Policy Statement for Renewable Electricity Generation, including potential expansion of its scope to cover a broader range of renewable energy activities**

Description

The NPSREG acknowledges the national significance of renewable electricity generation (REG) in the RMA framework, and aims to promote a more consistent national approach to RMA decision-making for REG projects.

[48] *Blueskin Energy Ltd v Dunedin City Council* [2017] NZEnvC 150.
[49] The Productivity Commission's recommendations are shown in Annex Two.
[50] The ICCC's recommendations are shown in Annex One.

To date, the NPSREG does not appear to have had a significant impact on the time and cost of the consenting process for REG projects. An evaluation[51] of the effectiveness of the NPS-REG completed in 2016 found that:

- NPSREG had not noticeably improved the consistency of planning provisions across councils.
- The NPSREG did not appear to have had any significant effect on the time, complexity or cost of consenting for REG projects.
- One of the particular concerns raised, by generation investors in particular, is that the language of the NPSREG is not directive enough and, consequently, does not have a binding effect. When the NPSREG is weighed alongside other instruments in RMA decision-making, it receives a lower priority than the RMA instruments that are more directive (such the NPSFM).

We are beginning work to identify policy options to amend the NPSREG to provide councils with clearer direction on how to provide for renewable energy projects in RMA instruments such as district/regional plans and regional policy statements. This could help provide more certainty for the consenting process for REG projects.

Details of any proposed amendments to the NPSREG will need to be developed further and are subject to further consultation. We consider that, at a high level, the NPSREG could be amended to provide clearer direction on some or all of the following matters:

a. How to consider the national benefits of renewable energy generation when making decisions on renewable energy consent applications;

b. How to locate and plan strategically for renewable energy resources — for example, the amended NPSREG could set out policies and/or directives that would require councils to:

    i. Identify potential areas for renewable energy resources in their planning framework (e.g. existing and potential wind and solar farm sites and geothermal sites);

    ii. Develop specific strategies or policies for renewable energy development; and/or

    iii. Identify areas where facilities for certain types of renewable energy (e.g. wind energy) definitely should not be developed (for purposes such as aviation and conservation);

c. The relationship of the NPSREG to freshwater management decisions (note: Policy E2 of the NPSREG relates to hydroelectricity resources and the preamble of the NPSREG states that "This national policy statement does not apply to the allocation and prioritisation of freshwater".);

d. Facilitating upgrades of new and existing renewable energy facilities;

e. Facilitating renewal of lapsing consents for renewable energy projects that would require updated technical specifications, which would allow the latest, most efficient technologies to be deployed;

f. Facilitating renewal of existing consents for existing renewable energy facilities;

g. Catering for the need to develop transmission and distribution networks for connection to REG facilities, e.g. clarifying the linkage between the NPSREG and the NPSET and NESETA by

[51] MfE and MBIE (2016). *Report of the Outcome Evaluation of the National Policy Statement for Renewable Electricity Generation*. Retrieved from https://www.mfe.govt.nz/publications/rma/report-of-outcome-evaluation-of-national-policy-statement-renewable-electricity

setting out more specific policies for such networks in the NPSREG and cross-referencing the NPSET and NESETA;

h. Enabling or facilitating development of small-scale renewable energy facilities; and

i. Acknowledging community benefits or local and social impacts of renewable energy projects.

Another potential amendment that could be explored is whether the scope of the NPSREG should be expanded to cover not only REG but also all other types of renewable energy, e.g. wood energy, liquid biofuels, green hydrogen and waste-to-energy.

This would acknowledge the role the other types of renewable energy play in New Zealand's transition towards a net zero emissions economy. The challenge, however, would be how to capture a potentially broad and changing range of activities, with highly varied scales and environmental effects. More discussion on the consenting barriers to wood energy has been discussed in Section 2.

Analysis

If the amended NPSREG in practice reduces the cost and uncertainty of investment in renewable generation, these changes could contribute to the facilitation of renewable energy by:

- Improving consistency in planning and consenting decisions on renewable energy facilities and activities;
- Enabling more weight to be given to renewable energy in these decisions; and
- Encouraging councils to plan strategically for renewable energy development.

The impact of this option will depend on the aggregate impact of multiple developments, and is subject to many factors outside of the RMA process. The impact of the amended NPSREG in terms of reducing consenting costs and uncertainty would depend on how directive the revised NPSREG would be, how the revised NPSREG would interact with other national direction instruments, and how councils implement it.

An amended NPSREG would also provide stronger direction on how to weigh renewable energy generation against potentially competing values under the RMA (e.g. amenity or biodiversity values). Its impact on potentially competing values will depend on the details of the NPSREG amendments, which are yet to be developed.

There will be costs for councils to implement the NPSREG through revising relevant planning instruments. The precise costs will depend on how large the changes are, and where councils are in their planning cycle (for example, whether they are already in the process of reviewing relevant plans, or need to do a standalone change).

With the NPSREG providing for more directive policies, and a number of other national direction instruments in development, there is a risk of clashing priorities between different instruments. The wording of the NPSREG amendments will need to be carefully drafted in consultation with other agencies which have developed, or are developing, RMA national direction instruments.

Questions

Q7.1	Do you consider that the current NPSREG gives sufficient weight and direction to the importance of renewable energy?
Q7.2	What changes to the NPSREG would facilitate future development of renewable energy? In particular, what policies could be introduced or amended to provide sufficient direction to councils regarding the matters listed in points a-i mentioned on page 59 of the discussion document?
Q7.3	How should the NPSREG address the balancing of local environmental effects and the national benefits of renewable energy development in RMA decisions?
Q7.4	What are your views on the interaction and relative priority of the NPSREG with other existing or pending national direction instruments?
Q7.5	Do you have any suggestions for how changes to the NPSREG could help achieve the right balance between renewable energy development and environmental outcomes?
Q7.6	What objectives or policies could be included in the NPSREG regarding councils' role in locating and planning strategically for renewable energy resources?
Q7.7	Can you identify any particular consenting barriers to development of other types of renewable energy than REG, such as green hydrogen, bioenergy and waste-to-energy facilities? Can any specific policies be included in a national policy statement to address these barriers?
Q7.8	What specific policies could be included in the NPSREG for small-scale renewable energy projects?
Q7.9	The NPSREG currently does not provide any definition or threshold for "small and community-scale renewable electricity generation activities". Do you have any view on the definition or threshold for these activities?
Q7.10	What specific policies could be included to facilitate re-consenting consented but unbuilt wind farms, where consent variations are needed to allow the use of the latest technology?
Q7.11	Are there any downsides or risks to amending the NPSREG?

Scope National Environmental Standards or National Planning Standards specific to renewable energy

Proposal 7.2	**Option A: Scope National Environmental Standards for Renewable Energy Facilities and Activities** **Option B: Scope additional renewable-energy-related content for inclusion in the National Planning Standards**

Description

National Environmental Standards (NES) are regulations made under the RMA and:

- Set out technical standards, methods or requirements relating to matters under the RMA.
- Provide consistent rules across the country by setting planning requirements for certain specified activities.

NES can have a significant direct impact on resource consent processes. At this time, we are proposing to prioritise amendments to the NPSREG, while proceeding with background work on complementary National Environmental Standards for Renewable Energy Facilities and Activities (NESREFA).

The details of potential NESREFA are yet to be developed, but could potentially cover some or all of the following:

a. Standardising the consent process for re-consenting and repowering (upgrading) existing renewable energy generation facilities;
b. Standardising the consent process for re-consenting consented but unbuilt renewable energy generation facilities, where the existing consent is due to expire and/or consent variations are needed to allow the use of the latest technology;
c. Prescribing standards for shadow flicker from wind turbines (Note: We will consider through the policy development process whether it might be better to include these standards in the National Planning Standards);
d. Standardising the consent process for small-scale renewable energy projects;
e. Standardising the consent process for new renewable energy generation proposals;
f. Standardising the consent process for adaptive management practices for geothermal electricity generation, such as drilling activities associated with adjusting the location of pipelines and operational plant; and/or
g. Setting out the consenting framework for high voltage lines that are connected to REG facilities but are not part of the National Grid. (Note: High voltage lines that are not part of the National Grid are not covered by the existing NPSET and NESETA).

As we scope the standards and rules that could be covered by NESREFA, we will assess whether NESREFA or the National Planning Standards would be more appropriate for prescribing standards and rules to drive changes in the planning and resource consent processes.

Under the RMA, National Planning Standards can specify different elements of council plans and policy statements, including objectives, policies, methods (including rules), other provisions, structure and form, and requirements that relate to electronic accessibility and functionality. The first set of National Planning Standards, which were introduced earlier in 2019, focus on providing nationally consistent structure, format, definitions, noise and vibration metrics and electronic functionality and accessibility, rather than setting out objectives and policies. More specifically, National Planning Standards prescribe the use of standard measurement methods and symbols for plan rules that manage wind turbine noise, but there is scope to include more renewable energy content in National Planning Standards in the future.

Analysis

NESREFA could significantly and directly reduce the costs and uncertainty in the consenting process for renewable energy facilities and activities through standardising the consenting process. NESREFA could clearly identify the activity status of different renewable projects – for example which activities would be permitted activities[52] under the RMA, or would require a resource consent.[53] This would give strong and consistent direction on the required level of consideration under the RMA for

[52] Under the RMA, permitted activities do not require a resource consent.
[53] Under the RMA, activities that need a resource consent are classified as controlled, restricted discretionary, discretionary and non-complying. Councils have to grant a resource consent for a controlled activity (with a couple of exceptions) but can refuse to grant a resource consent for a restricted discretionary, discretionary or non-complying activity.

specific activities. The positive impact on the consenting process could be particularly noticeable for wind farm projects and small-scale renewable energy projects if the NESREFA sets out a favourable consenting framework for these types of projects. This would support increased supply of renewable energy, and support reduction of greenhouse gas emissions.

The impact of NESREFA on values other than renewable energy (such as amenity or biodiversity values) would depend on the details of the NESREFA amendments, which are yet to be developed.

The implementation costs of a proposed NESREFA could be lower than those for implementing an amended NPSREG. The reason is that NESREFA provisions can set specific consenting rules, while the NPSREG cannot. The specific consenting rules would eliminate the need to interpret NESREFA provisions plan-by-plan.

It is likely to be more complex to develop NESREFA than to amend NPSREG because national environmental standards tend to more detailed and technical in nature than national policy statements.

Because of the relative complexity, the administrative cost to the Government for developing the NESREFA could be significantly higher than that for amending the NPSREG, and it could potentially also take longer to develop NESREFA than to amend NPSREG. Based on past experience, it could take between two and five years to develop. A technical expert panel with representatives from various sectors (such as the electricity and planning sectors) may need to be set up to develop NESREFA.

The benefits, costs and risks associated with developing the NESREFA (option A) also apply to developing additional renewable energy content for the National Planning Standards (option B).

Questions

Q7.12	Do you think National Environmental Standards (NES) would be an effective and appropriate tool to accelerate the development of new renewables and streamline re-consenting? What are the pros and cons?
Q7.13	What do you see as the relative merits and priorities of changes to the NPSREG compared with work on NES?
Q7.14	What are the downsides and risks to developing NES?
Q7.15	What renewables activities (including both REG activities and other types of renewable energy) would best be suited to NES? For example: • What technical issues could best be dealt with under a standardised national approach? • Would it be practical for NES to set different types of activity status for activities with certain effects, for consenting or re-consenting? For example, are there any aspects of renewable activities that would have low environmental effects and would be suitable for having the status of permitted or controlled activities under the RMA?
Q7.16	Do you have any suggestions for what rules or standards could be included in NES or National Planning Standards to help achieve the right balance between renewable energy development and environmental outcomes?
Q7.17	Would National Planning Standards or any other RMA tools be more suitable for providing councils with national direction on renewables than the NPSREG or NES?

Other options for feedback

We seek your feedback on the following options that we have considered, but at this stage we do not recommend be developed further. We need further information on the merits of these options before deciding whether further work is warranted.

Spatial planning

Spatial planning is a form of strategic planning. It is broad and long-term in its focus and integrates social, evidence-based economic, environmental and cultural dimensions across a defined (usually large-scale) area. It can be used as a tool to integrate policy and practice across land use regulation, infrastructure planning and investment through different levels of government (national, regional, territorial) and sometimes legislation (for example, aligning land-use planning and transport infrastructure investment in urban centres).

Spatial planning is strategic and high-level; it is not prescriptive land use planning (designations, zones or rules), or structure or area plans (these identify land use at a more detailed level). Internationally, there are some examples of spatial planning for future renewables development.[54]

Currently, there is no consistent framework for spatial planning in New Zealand. The application of spatial planning in New Zealand has, at times, been ad-hoc and disconnected from other types of planning. For example, it has generally not been developed in a partnership with central government, even though collective central government decisions (e.g. on transport infrastructure, education and health facilities and public housing) can have a significant impact on the growth of a place or region. Auckland Council is the only local authority that is legally required to prepare a spatial plan; however, spatial planning has been undertaken on a voluntary basis in other places (e.g. SmartGrowth in the Bay of Plenty and Future Proof in the Waikato).

Spatial planning is one of the five pillars of the Urban Growth Agenda. The pillar is initially focussed on Auckland and the Auckland-Hamilton corridor, with the aim of building stronger partnerships with local government as a means of developing integrated spatial planning.

This discussion document does not propose the creation of new statutory spatial planning tools in relation to energy, as a new legislative framework for spatial planning is best considered as part of the comprehensive review of the resource management system (RM system review), which is planned for 2020.

However, we are interested in views on whether a stronger spatial planning approach could be taken under the status quo. This would involve government agencies, local government, and energy sector organisations collaborating, and working with iwi and communities, to plan for the future strategic mix of activities and values in an area.

This could, for example, involve looking at potential renewable energy sites in relation to transmission links, future energy demand areas, and biodiversity and landscape values. In the "Connecting to the national grid" section (section 10) of this discussion document, we discuss the options for addressing the gaps in publicly available and independent information on these potential sites, and a lack of information sharing between companies. Filling this information gap and facilitating information sharing through actions such as options identified in the "Connecting to the national grid" section (section 10) could help inform identification in RMA plans of areas suitable for renewables, and help align future planning across transmission, distribution and generation stakeholders.

[54] For example, in South Australia, the State-wide Wind Farm Development Plan Amendment explicitly envisages wind farms in all rural type zones in the state.

A stronger spatial planning approach can also potentially be used to facilitate development of bioenergy markets and industry clusters. This could involve identifying the optimal location of industry clusters that could make use of wood energy and the associated infrastructure, based on the economics of transporting woody biomass to different areas. Central government can explore that with local government when undertaking the initiatives mentioned in section 2, such as the development of the Forest Strategy and the Industry Transformation Plan for the Wood Processing and Forestry sector.

Questions

Q7.18	Are there opportunities for non-statutory spatial planning techniques to help identify suitable areas for renewables development (or no go areas)?

Pre-approval of new renewables developments

We have also considered options around the 'pre-approval' of renewables activities. This, in general, refers to measures that would give a high degree of certainty to an operator that they could obtain the required regulatory approvals (in the form of resource consents in the case of the existing RMA framework). Such measures could streamline the regulatory approval process, thereby improving business certainty and reducing compliance costs for consenting. They could help attract further investment into renewables, especially from parties (e.g. community groups or overseas investors) which may struggle to navigate the RMA system.

Pre-approval option A: Planning approaches including relatively permissive consenting rules for renewables in defined areas

As mentioned above in the section on spatial planning, planning for suitable renewables sites, or 'no go' zones, can give increased certainty for resource consent applications. It is possible for districts and regions to have quite permissive rules for consenting of renewables in defined areas through rules on activity status, depending on the environmental effects of the activities concerned.

Pre-approval option B: Crown acquiring consents for transfer to developers

A more direct option would be for the Government (or another development-focused agency) to obtain resource consents for an 'envelope' of activities and effects that could then be transferred to another party for implementation. The resource consents would need conditions sufficiently flexible to cope with future technological developments, and the specific requirements of the end user.

This option would have significant cost and resourcing implications for the Government, which would effectively need to set up a new development arm (which could be established within an existing government agency or as a separate entity), to undertake extensive consultation with potential operators and local communities to undertake feasibility assessments, and to prepare resource consent applications for the renewable energy sites concerned.

To some extent, the options identified in the "Connecting to the national grid" section (section 10) to fill the information gap could facilitate the necessary feasibility assessments.

The advantage of this option is that it would provide a means to directly allocate regulatory approvals to new investors, or small-scale community operators. On the other hand, this option would potentially 'crowd out' non-government operators with interest in the site. Also, the effectiveness of this option could be limited by the risks that a large proportion of the potential renewable energy sites are already under the control of existing operators, and that operators may not be interested in the resource consents obtained by the Crown because they prefer developing the sites they already control.

Pre-approval option C: New statutory allocation process
A pre-consenting option outside the RMA framework would be for central government to identify appropriate renewable sites and set up a new statutory process for allocating these sites for use and development.

However, this option would require creating a new statutory regime, which could compete with and confuse the existing RMA framework and comprehensive RM system review. There would be high compliance and administration costs in the setup and operation of a new statutory regime. It also appears disproportionate to the size of the problem, given that there currently are a number of consented, but yet-undeveloped, renewable energy sites.

The effectiveness of this option could also be limited by the risk that most of the potential renewable energy sites are already owned by operators or other landowners.

Questions

Q7.19	Do you have any comments on potential options for pre-approval of renewable developments?

Amend other RMA national direction instruments

We have considered the options of amending the National Policy Statement on Electricity Transmission (NPSET) and the National Environmental Standards for Electricity Transmission Activities (NESETA) to improve consistency in the RMA decisions on electricity network connections to renewable electricity generation.

For example, some stakeholders have suggested the NPSET could be more specific for re-conductoring activities, enabling changes to the National Grid, while the NESETA could better reflect current routine maintenance practices with minor environmental impacts, particularly in urban areas.[55]

At this time, we intend to prioritise work on a revised NPSREG/potential NESREFA, as we consider this will have the greatest impact on development of new REG. However, we would appreciate feedback on the relative merits of amending these instruments, and what changes you would suggest.

Questions

Q7.20	Are the current NPSET and NESETA fit-for-purpose to enable accelerated development of renewable energy? Why?
Q7.21	What changes (if any) would you suggest for the NPSET and NESETA to accelerate the development of renewable energy?
Q7.22	Can you suggest any other options (statutory or non-statutory) that would help accelerate the future development of renewable energy?

[55] MfE and MBIE (2019). *Evaluation of the effectiveness of the National Policy Statement on Electricity Transmission and National Environmental Standards for Electricity Transmission Activities*. Retrieved from https://www.mfe.govt.nz/publications/rma/evaluation-of-effectiveness-of-national-policy-statement-electricity-transmission.

Summary assessment of options against criteria

	Amend NPSREG (impacts on consenting and energy prices would be indirect.)	**Scoping NES or National Planning Standards specific to renewable energy**	**Pre-approval of new renewable developments – planning approaches including relatively permissive consenting rules in defined areas**	**Pre-approval of new renewable developments – Crown acquiring consents for transfer to developers** (assuming that resource consents are sought by central government but are granted in line with existing councils' rules)	**Pre-approval of new renewable developments – new statutory allocation process**	**Amending NPSET and NESETA**
To what extent is the barrier addressed?	✓✓	✓✓✓	✓✓✓	✓ Effectiveness could be limited by the risk that most potential renewable energy sites are already owned by operators or other landowners	✓	✓
Primary benefits – emissions reductions	✓	✓	✓	✓	✓	✓
Primary benefits – EE & RE	✓	✓	✓	✓	✓	✓
Wider economic effects	Uncertain	✓	Uncertain	Uncertain	Uncertain	✓
Reduction in compliance costs	✓✓	✓✓✓	✓✓✓	✓✓✓	Uncertain – it depends on design of new process	✓✓✓
Administration costs	X	X X	X X	X X X	X X X	X X
Energy trilemma – security and affordability	Uncertain	✓	✓✓	Uncertain	Uncertain	✓

Key:	Proposal under active consideration	Option not preferred

Section 8: Supporting renewable electricity generation investment

This chapter considers policy options to accelerate investment in supply- and demand-side renewable electricity generation and energy efficiency. We seek your views on the following:

a. Introduce a Power Purchase Agreement (PPA) Platform

b. Encourage greater demand-side participation and develop the demand response market

c. Deploy energy efficiency resources via retailer/distributor obligations

d. Developing offshore wind assets

e. Introduce renewable electricity certification and portfolio standards

f. Phase down thermal baseload and place in strategic reserve

Options a-d have potential to accelerate investment in future renewable energy generation or energy efficiency. Options e-f also have this potential but would involve substantial government intervention and carry significant risks. However, these options have been analysed in-depth to seek your feedback on their potential effectiveness and design details before determining whether further investigation is warranted.

This chapter also notes other options that could support investment in renewable electricity generation and includes them for your feedback, however we are not recommending further investigation of these options at this stage.

What's the problem?

Electricity does not currently compare well with other fuel options on a cost per gigajoule (GJ) basis. The cost per gigajoule of delivered electricity can be three to five times more expensive than for natural gas or coal at current emissions prices. However, Transpower notes in its recent report "the commercial reality is more complex, as the inherent efficiency of electricity means less energy (fuel) is required."[56]

For low temperature processes, electric heat pumps can deliver three to seven units of heat energy for every unit of electricity consumed. This inherent efficiency implies electricity is already a competitive fuel option for some low temperature applications. For some medium or high temperature processes, such as drying milk powder, reducing the delivered electricity price for end-users compared to fossil fuels could improve the competitiveness of electricity.

Current and potential electricity users may opt for a fixed-price, short-term contract with a supplier, or purchase directly from the wholesale electricity market at variable spot prices.[57] However, electricity spot prices are typically too high (on average), or carry too much volatility risk to encourage significant levels of process heat electrification, particularly for medium or high temperature applications.[58]

[56] See: https://www.transpower.co.nz/resources/taking-climate-heat-out-process-heat

[57] The electricity market uses spot electricity prices for each trading period to schedule available generation so that the lowest-cost generation is dispatched first. A spot price is the half-hour price of wholesale market electricity. The spot price is determined for each point of connection on the national grid.

[58] The annual demand-weighted average wholesale electricity price was $113 per megawatt-hour (MWh) in 2018; $81/MWh in 2017; $58/MWh in 2016; $71/MWh in 2015; $80/MWh in 2014, according to data from the

Further, investors that are assessing new renewable electricity generation opportunities look for sustained high spot prices to justify investment. High average spot prices are sought upfront to cover the risk that average spot prices fall during the project's operational lifetime. Investment decisions are based on long-run expectations regarding prices.

This leads to a gap between the electricity price that would incentivise accelerated electrification of process heat (demand-side) and the electricity price that would incentivise accelerated deployment of renewable electricity generation (supply-side). It is possible that this gap will persist even as emissions prices rise, since the emissions price affects both direct use of fossil fuels in process heat applications and remaining fossil fuel-fired electricity generation.

What are the options?

This section considers policy options that could work alongside the Emissions Trading Scheme to support renewable electricity generation (and energy efficiency) investment. The aim is to provide investors with greater certainty regarding future electricity demand growth and help to manage wholesale power price exposure (also referred to as merchant power price risk). Further discussion of the specific barriers and opportunities are discussed under each policy option.

Power Purchase Agreement (PPA) Platform

Option 8.1	Introduce a Power Purchase Agreement (PPA) Platform

Description

This option seeks to accelerate investment in renewable electricity generation by matching additional supply to new sources of demand from process heat electrification.[59]

Long-term, fixed-price contracts (e.g. around 10-20 years) can help close the price gap described above, manage risks and match new sources of electricity demand with new renewable supply to reduce fossil fuel use across the economy. These are referred to as power purchase agreements (PPA).[60]

This option explores whether there is a role for government to play in increasing access to PPAs for new electrification projects, particularly for small to medium businesses, state-sector or iwi and community groups.[61] For these energy users, in-house know-how, such as the legal expertise required to negotiate long-term deals, and other resources, are limited. There could be a role for government to provide information resources, facilitate match-making and/or assume some of the burden of merchant power price risk, via a Power Purchase Agreement (PPA) 'Platform'. The Platform can also serve to aggregate small loads to achieve the scale required to match with a new source of renewable electricity supply.

Electricity Authority. Prices vary significantly by year, season, month, day and half-hour based on weather, hydrology and a myriad of other factors.

[59] International precedent: Business Renewables Centre Australia (seed funding provided by the Australia Renewable Energy Agency – ARENA).

[60] In the case of intermittent generation, like wind and solar farms, contracts will specify a fixed price for each unit of electricity that is generated (rather than for a fixed volume).

[61] Typically these users are smaller than members of the Major Electricity Users Group (MEUG). MEUG is also referred below.

Members of the Major Electricity Users Group (MEUG) are currently considering PPAs to help bring forward the construction of existing, consented renewable energy projects. Their proposal does not involve electrifying new loads nor increasing current demand for electricity. (See case study below).

This policy option targets new loads and new renewable projects. Increasing access to PPAs may encourage electrification and new renewable electricity generation to reduce fossil fuel use across the economy and lift the share of renewables in our primary energy use.

Case study: Major Electricity User's Group (MEUG) investigating power purchase agreements

Currently, the Major Electricity Users' Group (MEUG) is working with at least five of its members - Refining NZ, New Zealand Steel, Fonterra, Oji Fibre Solutions and Pan Pac Forest Products - to explore PPAs for a portion of their combined existing load to bring forward consented renewable generation and encourage new entrants into the generation market.[62] They have commissioned a study into their initiative due out in February or March 2020.[63] Members will then make any decisions about if and how to proceed to market.

Several possible variations on a PPA Platform are plausible and we seek your feedback:

Option A Contract matching service. This option would provide seed funding via a tender to a private entity for the setup and initial operation of a contract matching service – the Platform. The Platform could provide information resources, a network of energy buyers and project developers, inexpensive training and advice on PPA requirements. This option would address information barriers or lack of legal and contracting expertise.

Option B State sector-led. The Platform could specifically target state sector entities for electrification, aggregating off-takers like councils, and hospitals alongside corporate entities, like the Melbourne Renewable Energy Project. (See case study below).This option could be coordinated within a State Sector Decarbonisation programme and administered alongside Government Procurement's All-of-Government contract for electricity. (See Appendix One).

Option C Government guaranteed contracts. Government could also guarantee / underwrite PPAs to help lower the contract strike price. This serves to de-risk electrification projects.[64] This option could be targeted at small businesses and community or iwi-owned projects with significant local co-benefits, such as improving self-sufficiency and grid resilience, and reducing electricity bills. It may also support regional economic development.

Option D Clearing house. The Platform would both buy and sell PPAs, acting as a contract clearing house under this option. It aggregates and matches supply and demand, without requiring 1-to-1 contract matching, hedging any residual exposure to electricity prices. This would only be made accessible to new loads and new renewable electricity generation projects. A sub-option to consider is a rolling contract structure offering a mini-perm[65] or borrowing base[66] type facility over a defined forward period.[67]

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[62] Ballance is not a member of MEUG, but has also recently joined the project.
[63] See: http://www.meug.co.nz/node/1025 Also: https://www.energynews.co.nz/news-story/electricity-generation/44322/big-users-mull-plan-hasten-renewable-projects
[64] Infratec, a solar developer, has modelled electricity costs and shown that government-backed PPAs for 25 years could reduce the levelised cost of a grid-scale solar project to $80/MWh and $50/MWh for wind.
[65] "Perm" alludes to traditional permanent financing, which the borrower in this case has not yet been able to secure. Mini-perm financing is something a developer would use until a project has been completed and can therefore start producing income. In other words, a developer will use this type of financing prior to being able

Government guarantees cover the risk of Platform insolvency.

Note that it is not always necessary to sign a PPA for the entirety of a project's output in order to secure debt or equity finance. A hybrid contract could cover a portion of supply (e.g. 50MW of a new 100MW wind farm). Forward hedging could be used to cover the remaining generation.[68] The PPA terms could stipulate an obligation to hedge some of the remaining generation. That is, the financier may require the project owner to purchase exchange-traded or over-the-counter electricity futures for additional generation.[69]

Case study: Melbourne Renewable Energy Project (MREP)

Under this project, fourteen members of a buying group combined their purchasing power to support the construction of the 80 MW windfarm at Crowlands, near Ararat, owned and operated by Pacific Hydro. This is the first time in Australia that a group of local governments, cultural institutions, universities and corporations collectively purchased renewable energy from a newly built facility. The new windfarm in regional Victoria began supplying energy to power town halls, bank branches, universities and street lights across Melbourne. The Melbourne Council is now powered by 100 per cent renewable energy.[70]

Analysis

Benefits

PPAs provide a steady and certain stream of income for new generation projects.[71] A PPA reduces the project risk so investors may accept a contract price at a discount to average spot prices. This provides the off-taker with a steady, certain and competitive price and secures their electricity supply over the long term. PPAs can also attract a different class of investor, such as pension funds or other institutional investors, looking for less risk, steady returns, portfolio diversity and reduced exposure to emissions prices.

The Platform, in any form, may have the added benefit of encouraging more existing electricity market players to participate in long-term contract-making (for new loads and generation). This may also increase competition for generation investment, as well as supporting new and independent renewable developers.

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to access long-term or permanent financing solutions. Mini-perm financing might also be used as a vehicle to acquire investment properties. This type of financing is usually payable in three to five years.

[66] A borrowing base is the amount of money that a lender is willing to loan a company, based on the value of the collateral the company pledges. The borrowing base is typically determined by a method known as "margining," in which the lender determines a discount factor, which is then multiplied by the value of the collateral in question. The resulting numerical figure represents the amount of money a lender will loan out to the company.

[67] A Platform that acts as a clearing house (option D) could be a company set up by the government, as an SOE or schedule 4 company, or a private entity chosen by tender. Each would have different funding and governance implications.

[68] See: https://about.bnef.com/blog/big-oil-utilities-seen-covering-risks-wind-solar-qa/

[69] New Zealand electricity futures are financial instruments traded on the Australian Stock Exchange on most business days. Current prices are public information available at: https://www.asxenergy.com.au/futures_nz. Futures contracts are also offered by brokerage firms. The latter is referred to as over-the-counter trading.

[70] See more: http://www.melbourne.vic.gov.au/business/sustainable-business/mrep/Pages/melbourne-renewable-energy-project.aspx

[71] The contract price may be inflation-indexed.

Costs and risks

Both options C and D above involve financial risk and fiscal impact for government, particularly if technology costs decline faster than envisioned over the duration of the contract lifetime. This implies that the Government wears the cost of emissions abatement, but co-benefits accrue for off-takers (such as small businesses and/or community projects) that would otherwise struggle to access PPAs, electrify processes or build local renewables supply.

Care would be needed in setting a level of government financial support if these sub-options are considered so as to not materially raise or influence the earnings of investors, as the objective is to assist demand-side electrification (or support community renewable energy projects). Care would also need to be taken to ensure that there is no risk that the government crowds out private investment in similar initiatives.

Options C and D are preferred over Option A where government only takes on a facilitation role as, by assuming financial risk, the government could increase the accessibility of PPAs and lower contract prices for renewable electricity supply for small firms or communities. The Platform could aggregate portfolios of 10-15 smaller buyers that may have higher borrowing costs and otherwise struggle to access PPAs. This would increase the complexity of PPAs, but also diversify risks for the Platform.

For Option A, deals would be struck on commercial terms with participants assuming the costs and benefits. For these commercial deals, the cost of additional emissions abatement is negligible.

Option B is targeted at the State sector, so may have the value of demonstrating how PPAs can work and what's possible for replication by small businesses. Option B should be compared against other policy options to decarbonise the State sector and the marginal cost of abatement for these options. (See Appendix One).

Another issue is variable output, which applies to wind and solar farms. There may be a mismatch between demand and generation profiles – a risk that would have to be managed by the PPA platform or counter-parties. This would need to be managed with portfolio aggregation and/or hedging.

Further, if average spot prices move significantly, either upwards or downwards, then one of the parties to the contract may wish to seek a price reset. Renegotiation/reset clauses could be considered in some cases to mitigate this risk, but would still need to maintain a high level of investment certainty for both parties. These types of details could be standardised and brokered by the Platform to reduce the burden of negotiations.

The Platform's operational life and mandate could be time-limited to catalyse the first 'wave' of PPAs and de-risk early electrification projects to reduce fossil fuel use. Or it could be set up to operate permanently.

All options above may entail new legislation and set up costs, which would have a fiscal impact, to implement the Platform. An administrative entity would need to be empowered to run the Platform. These costs would accrue to the Government unless they can be recovered from Platform users.

Questions

Q8.1	Do you agree there is a role for government to provide information, facilitate match-making and/or assume some financial risk for PPAs?
Q8.2	Would support for PPAs effectively encourage electrification and new renewable generation investment?
Q8.3	How could any potential mismatch between generation and demand profiles be managed by the Platform and/or counterparties?
Q8.4	What are your views and preferences in relation to different options A to D above?
Q8.5	For **manufacturers**: what delivered electricity price do you require to electrify some or all of your process heat requirements? And, is a long-term electricity contract an attractive proposition if it delivers more affordable electricity?
Q8.6	For **investors / developers:** what contract length and price do you require to make a return on an investment in new renewable electricity generation capacity? And, is a long-term electricity contract an attractive proposition if it delivers a predictable stream of revenues and a reasonable return on investment?

Demand-side participation and demand response

Option 8.2	**Encourage greater demand-side participation and develop the demand response market**

Description

This option seeks feedback on ways to accelerate and prioritise the development of the demand response (DR) market in New Zealand to better optimise asset use across the electricity system and encourage the uptake of emerging technologies, like batteries and micro-grids. It asks whether there is a role for government in developing a national DR market/s that runs alongside the wholesale electricity and ancillary services market. DR markets remunerate participants (such as commercial entities with adjustable air-conditioning load or households with EVs or batteries to charge) for reducing their demand, especially during peak periods, and/or shifting it into a different time period.

There are a few demand response initiatives in New Zealand, but we have not yet fully realised the potential of demand-side participation.[72] Existing initiatives include:

- Transpower's DR pilot programme to help manage the national grid. Participants include supermarkets, wastewater treatment plants and hospitals. Such a programme could be scaled up, or re-designed as appropriate, to provide a more robust national market mechanism.
- Residential consumers, if enabled by retailers, can make use of smart phone apps connected to smart meter data to monitor and manage their power use, and show where savings can be made.

[72] According to the American Council for an Energy-Efficient Economy, demand response programs in the United States shaved an average of 4 per cent off peak demand, with a range of 0-24 per cent, in 2015.

- Technologies like New Zealand's pioneering ripple control temporarily shut off hot water cylinders to save energy when supply is constrained.[73] Most distribution companies around the country use this technology within their local network.
- Demand response aggregator Enel X remunerates commercial customers for demand response services by participating in electricity ancillary services markets.[74]
- The dispatchable demand arrangements that operate as part of the New Zealand electricity market allow larger consumers to set prices at which they would prefer not to draw power, and receive demand instructions to this effect.
- The Energy Efficiency and Conservation Authority is also investigating the case for certain electrical appliances to be demand response capable in New Zealand.[75]

This policy option envisages the penetration of internet-enabled energy-producing and consuming assets increasing rapidly (e.g. 'smart'/Internet-of-Things technology), which may be remotely or automatically controlled. Smart assets including household, commercial and industrial appliances, like EVs, boilers, batteries, can help optimise system-wide asset use.[76] There may be mandatory requirements for some entities, such as large electricity users, or EV chargers and other home, business or industrial appliances to enable internet-connectivity and participate in the DR market, or share data. DR markets can be expected to evolve alongside the roll of smart infrastructure, such as sensors, two-way communications technology, artificial intelligence and software to manage electricity supply and demand.

This policy option could also potentially involve setting up a centralised distribution system operator (DSO) to work with Transpower and other DR market participants. Progressing this possibility would likely require changes to the Electricity Industry Act 2010, the Electricity Industry Participation Code 2010 (the Code), or new regulations. [77]

A number of barriers and opportunities to the development of the DR market exist in the policy settings for transmission and distribution networks. There are also a number of existing, relevant work programmes underway. These barriers, opportunities and work programmes are examined in Section 10 and 11, and would need to be resolved as a pre-requisite to enabling greater local and national demand-side participation for consumers and businesses, as well as improving local and national grid management.

This chapter looks at the implications of enabling greater demand-side participation and a national DR market platform for investment and business models, and asks what priority should be given to developing demand response services.

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[73] See: https://www.transpower.co.nz/keeping-you-connected/demand-response/demand-response-journey-so-far

[74] See: https://www.enelx.com/au/en

[75] See more about this project: https://www.eeca.govt.nz/standards-ratings-and-labels/equipment-energy-efficiency-programme/products-under-the-e3-programme/measures-under-consideration/smart-appliances/

[76] EV uptake is also expected to increase with some residences opting for smart chargers (or smart metering) to manage the timing and rate of battery charging. See the smart appliances consultation underway at the Energy Efficiency and Conservation Authority: https://www.eeca.govt.nz/standards-ratings-and-labels/equipment-energy-efficiency-programme/products-under-the-e3-programme/measures-under-consideration/smart-appliances/

[77] The Code sets out the duties and responsibilities that apply to industry participants and the Electricity Authority.

Analysis

Benefits

Exploiting latent flexible demand will help to manage the grid and the intermittency of weather-dependent renewables, like wind and solar, and reduce emissions across the energy sector by optimising electricity asset use. In addition, distributed energy resources, like solar, household batteries and EVs, will be able to make a greater contribution to our renewable electricity supply if a robust DR market exists to remunerate or monetise demand-shifting or reduction, and support investment.

DR markets can encourage the development and expansion of emerging business models, such as virtual power plants and DR aggregators. A virtual power plant (VPP) is an internet-based distributed power plant that aggregates the capacities of distributed energy resources, trading or selling power on the electricity market.[78] Similarly, DR aggregators identify and aggregate latent flexible demand, and seek remuneration for reducing demand via DR market mechanisms. Businesses may combine the elements of VPPs and DR aggregators, generating income from multiple revenue streams across both electricity (spot, reserve, futures) and DR markets.

Large demand-side participants, such as electrified process heat users or EV-charging providers, may also participate in DR markets (i.e. directly or working with DR aggregators) if the income stream is steady, predictable and sufficient. This income may improve the economics of new heat plant investment or encourage fuel-switching for existing heat plants.

Finally, demand-side participation also provides end-users with a means to participate in their own energy production and consumption. This can empower consumers, communities, iwi and businesses to contribute to our climate goals, whilst improving their own energy self-sufficiency and overall system resilience. Small-scale generation and energy self-sufficiency have been identified as important interests by communities, iwi and hapū.

Costs and risks

There is significant regulatory complexity involved in developing the DR market. This may require new legislation and/or regulations. It may involve setting up a Distribution System Operator (DSO) at some stage. Or it might entail a reprioritisation of the Electricity Authority's existing work programme. (The EA's Innovation and Participation Advisory Group (IPAG) already has a work programme to address network access issues that hinder the uptake of distributed energy resources.) The EA has a key role to play in on-going design and implementation of the DR market for New Zealand.

The consideration of this option should however be weighed against other policy priorities since DR markets alone will not deliver significant growth in renewables nor encourage demand-side electrification at scale. Therefore this policy option is likely to be considered as part of a package alongside other options.

[78] For an example see this trial project in the Wairarapa: https://karitpower.com/news/first-nz-karit-virtual-power-plant-launched/

Questions

Q8.7	Do you consider the development of the demand response (DR) market to be a priority for the energy sector?
Q8.8	Do you think that DR could help to manage existing or potential electricity sector issues?
Q8.9	What are they key features of demand response markets? For instance, which features would enable load reduction or asset use optimisation across the energy system, or the uptake of distributed energy resources?
Q8.10	What types of demand response services should be enabled as a priority? Which services make sense for New Zealand?

Energy efficiency obligations

Option 8.3	**Deploy energy efficiency resources via retailer/distributor obligations**

Description

Energy efficiency gains result in energy savings for households and businesses, and support productivity by deferring investment in new infrastructure, including electricity generation or transmission or distribution capacity. Promoting energy efficiency also has the potential to reduce demand peaks, support the national and local grid, and make better use of our existing asset base.

This option would place an obligation on electricity retailers and/or distributors to deploy energy efficient technologies across their customer and/or asset base. For instance, a retailer might provide low-cost insulation for customers to reduce winter demand. Or a distributor could invest in insulation ahead of distribution line upgrades in urban areas.[79] These requirements could ultimately be serviced by third-party entities, such as an Energy Services Company (ESCO), which have delivered substantial energy savings and emissions reduction in other jurisdictions, including the United States. (See case study below).[80]

This policy option would complement existing Minimum Energy Performance standards enabled under the Energy Efficiency and Conservation Act. These standards remove the worst-performing products from the market, like washers, dryers or lighting products. Also, product labelling encourages consumers to select and purchase efficient products at point of sale, by providing standardised information on energy performance.

Efficiency improvements under these existing Minimum Energy Performance (and product labelling) standards (MEPS) occur in line with equipment turnover, rather than replacing existing inefficient equipment through dedicated outreach and incentives. By definition, MEPS regulate the minimum performance of products and do not reflect higher or best-in-class performing products in the market. Relative performance efficiency varies by product class.

Retailer/distributor obligations to deploy energy efficiency resources aim to accelerate replacement of inefficient products with new products that may go beyond MEPS, as well as assist consumers

[79] Obligations could complement existing programmes like Warmer Kiwi Homes programme. See: https://www.energywise.govt.nz/funding-and-support/funding-for-heaters-and-insulation/warmer-kiwi-homes/

[80] Both private and public ESCOs have been shown to deliver significant benefits in overseas jurisdictions. See: https://database.aceee.org/state/energy-savings-performance

with the higher upfront cost of efficient equipment where it costs less than energy supply or defers infrastructure investment.

This policy option would also build on existing dedicated outreach programmes like EECA's Warmer Kiwi Homes grants or contestable funding for business energy efficiency improvements. Often energy efficiency improvements compete for capital and, whilst the payback period is short, still represent an upfront investment that customers or businesses cannot afford or choose to put off. This policy option introduces a requirement for retailers/distributers to invest to reduce energy costs and emissions. The cost would be passed on to customers incrementally, rather than representing a larger upfront cost.

The benefits and costs of energy efficiency obligations would depend on the specific design of the obligations scheme. For instance, an authorised government agency might create a list of approved energy efficiency measures that meet the obligation. These measures might target certain consumer groups, as is the case in other jurisdictions.[81] Further, the approved measures might be implemented by a list of government approved ESCOs.

This option would require a monitoring agency, which could involve expanding the role of an existing agency, and new regulations. It could also be enacted alongside Renewable Portfolio Standards (see policy option below).

Case study: Energy efficiency programmes in the United States

In the United States, energy efficiency programmes are regarded as an important system resource, covering both electricity and gas markets. States can finance energy improvements through Energy Savings Performance Contracts (ESPCs), which allow the state to enter into a performance-based agreement with an energy service company (ESCO).[82] The contract allows the state to pay the company for its services with money saved by installing energy efficiency measures. The American Council for an Energy-Efficient Economy estimated that in 2015, energy efficiency programmes delivered by ESCOs contributed savings of over 5 per cent to retail electricity sales in the United States. Energy efficiency programmes can also contribute to reducing peak electricity demand. For every percentage reduction in electricity sales, energy efficiency programmes shaved 0.66 per cent off peak demand for that utility.[83]

Analysis

We have identified broad benefits and costs of energy efficiency obligations below, but the specific costs and benefits would depend on the specific design features of any scheme.

Benefits

Incentivising greater energy efficiency could help reduce system costs through deferring or reducing the amount of new generation, transmission and distribution capacity. It can also reduce the peaks in New Zealand's existing electricity daily and seasonal demand profile. A recent study by EECA demonstrated the savings from the widespread uptake of modern technologies like Light Emitting Diode (LED) lamps, heat pumps, energy efficient water heating and electric motors could provide the equivalent of 4,000 gigawatt hours of extra energy, before any new renewable electricity generation

[81] See: http://www.europarl.europa.eu/RegData/etudes/STUD/2016/595339/IPOL_STU(2016)595339_EN.pdf
[82] See: https://database.aceee.org/state/energy-savings-performance
[83] This measure is median not average.

capacity would be required.[84] This is roughly equivalent to half the amount of energy generated from thermal power stations in an average year.

Costs and risks

Before proceeding with this option, the Government would need to review relevant legislation and regulations to identify and examine the effectiveness of existing provisions encouraging energy companies to invest in customer energy efficiency measures – and this could be part of a review of institutional arrangements.

Energy efficient investments can and do occur when these make sense from a network and system efficiency point of view. Encouraging energy efficiency when these prerequisites are not present may increase system costs, which may in turn be passed on to the consumer. There is a risk of unintended consequences when trying to pursue too many objectives in what is already a complex business and regulatory decision making environment.

However, we have also heard that energy efficiency investment does not occur even when it makes sense from a system efficiency point of view due to information barriers, lack of access to capital and other potential market barriers. Therefore, there is also a risk that we lock-in high-cost, low efficiency infrastructure investments if we fail to incentivise and realise the potential of energy efficiency across the economy.

There would also be a considerable cost to Government to enact new regulations and fund an administrative and monitoring agency.

Questions

Q8.11	Would energy efficiency obligations effectively deliver increased investment in energy efficient technologies across the economy? Is there an alternative policy option that could deliver on this aim more effectively?
Q8.12	If progressed, what types of energy efficiency measures and technologies should be considered in order to meet retailer/distributor obligations? Should these be targeted at certain consumer groups?
Q8.13	Do you support the proposal to require electricity retailers and/or distributors to meet energy efficiency targets? Which entities would most effectively achieve energy savings?
Q8.14	Could you or your organisation provide guidance on the likely compliance costs of this policy?

[84] See: https://www.eeca.govt.nz/news-and-events/media-releases/energy-efficiency-key-action-to-meet-renewable-energy-goals/

Developing offshore wind assets

Option 8.4	Investigate regulatory and economic requirements to develop offshore wind assets in New Zealand

Description

Offshore wind installations have the potential to provide significant new renewable electricity generation capacity in the future. While the levelised costs of offshore wind are still substantially higher than onshore wind, this is changing rapidly internationally. Already, there is considerable investment in offshore wind internationally, including very large projects in Europe and China, with new markets emerging in the United States, Taiwan and Japan.[85] An exploration licence was also recently granted to an Australia-based project. (See case study below).

Offshore wind is attractive as it locates significant electricity generation capacity in one place, potentially close to large load centres. Also, being at sea, offshore wind is less visible and less audible – key objections raised with regards to onshore wind farms in some communities.[86]

A 2019 study of New Zealand's offshore wind resource identified at least 7 GW of potential capacity from fixed foundation wind turbines in South Taranaki alone, with the potential for additional capacity from floating turbines, and in other locations.[87] If there is sufficient demand for this resource to be developed, it would be possible for offshore wind to make a contribution to our future energy mix.

Case study: Star of the South 2.2 GW project under investigation in Australia

In March 2019, the Australian Government granted the Star of the South project an exploration licence, allowing the project team to carry out a range of marine site investigations for a potential 2.2GW offshore wind farm off the coast of Gippsland, Victoria.[88] These investigations will assess local wind, seabed and environmental conditions and will help to confirm if the project can viably be built. A decision to construct the project will be made at a later stage, subject to Australian and Victorian Government approvals. This licence was granted by the Prime Minister under constitutional powers, and does not give any rights to construct or operate an offshore wind farm.

The Minister for Energy and Emissions Reductions, the Hon. Angus Taylor MP has also been asked to undertake work to develop a regulatory framework to establish offshore wind projects in Australian waters. The Department of the Environment and Energy is leading this work together with the Department of Industry, Innovation and Science, and the National Offshore Petroleum Safety and Environmental Management Authority having provided recommendations about how a regulatory framework may look. This taskforce will be engaging with Australian state and territory governments as part of consultation on the proposed regulatory framework over coming months.

[85] The IEA notes that "these markets face permitting and grid connection challenges however, and cost remain relatively high. Innovation is needed to reduce the costs of installation processes and foundation design". See: https://www.iea.org/tcep/power/renewables/offshorewind/

[86] Offshore wind turbines are significantly larger than onshore wind turbines – 9 MW is common today with 12 MW turbines in development.

[87] C.A. Ishwar; I.G. Mason (2019), Offshore Wind for New Zealand, Proceedings of the EEA Conference and Exhibition, 25-27 June 2019, Auckland, NZ

[88] See: http://www.environment.gov.au/climate-change/government/renewable-energy/proposal-conduct-offshore-wind-farm-activities and http://www.starofthesouth.com.au/

Analysis

We note that New Zealand's existing grid-connected electricity generation is currently sized at just over 9 GW. Offshore wind projects generally require scale of 1GW or greater in order to be economic, given the significant infrastructure required. In some cases however, projects may be economically feasible at smaller capacities. An offshore wind farm of 1GW would be surplus to New Zealand's existing demand for electricity in the near to medium-term, however it could meet growth in demand in the long-term as we transition to a low emissions economy (i.e. electrification of transport and process heat, or replace retiring thermal power generation assets). Nevertheless, it may remain more economical to develop wind assets onshore or deploy other renewable energy or energy efficient technologies.

New sources of demand could include large industrial users, such as a hydrogen electrolysis facility. A large industrial user that could contract to off-take the electricity generated by a new offshore wind farm at a fixed price for a duration of 20 years or more would help to underwrite development – for both counterparties. The economic viability of hydrogen electrolysis is highly sensitive to electricity costs. A long-term contract price could help reduce the price to an economic level for hydrogen production by electrolysis and provide long-term certainty regarding input costs. It would also provide on-going revenue certainty for potential offshore wind farm investors.

Both hydrogen production by electrolysis and offshore wind are technologies within scope of the Transition Pathway for the Taranaki 2050 vision and could be investigated by the National New Energy Development Centre (NNEDC) in the region.

Taranaki may be an appropriate region for locating an offshore wind farm as it transitions away from fossil fuel production. Research conducted by the University of Canterbury found that "offshore South Taranaki has an exceptional wind resource, and that there is approximately 1065 square kilometres of suitable area for fixed foundation wind turbines. Additional suitable space for floating turbines was also identified."[89]

New analysis by the International Energy Agency (IEA) also suggests there may be useable sites (near shore and shallow waters) near Golden Bay, in the Canterbury Bight, off the coast near Bluff, in both North and South Taranaki waters, in the Hauraki Gulf and near Poverty Bay.[90]

We have heard suggested that petroleum platforms in the Taranaki basin could be repurposed for offshore wind installations. We have also heard that it could be logistically challenging to "convert" existing petroleum platforms to platforms for electrical switch-gear to support offshore wind development. It may be more efficient and safer to remove all or part of the petroleum platform and then install specially designed platforms for offshore wind developments. Additional infrastructure including offshore substations, a potentially a high-voltage direct current link to the shore and special purpose ships will be involved in developing and maintaining offshore wind electricity generation sites.

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89 C.A. Ishwar; I.G. Mason (2019), Offshore Wind for New Zealand, Proceedings of the EEA Conference and Exhibition, 25-27 June 2019, Auckland, NZ

90 The IEA states that its report, Offshore Wind Outlook 2019, published 25 October 2019, is the most comprehensive global study to date, combining technology and market developments with newly commissioned geospatial analysis. This analysis suggests that constructing offshore windfarms across useable sites worldwide, which are no more than 60 kilometres off the coast and in waters no more than 60 metres deep, could generate 36, 000 terawatt hours (TWh) of renewable electricity annually. This exceeds current annual global demand of 23, 000 TWh. Whilst, offshore wind is only 0.3 per cent of current global power generation, its potential is vast and could grow 15-fold to emerge as a US $1 trillion industry in the next 20 years. For the report, as well as a visual map and information on the methodology see: https://www.iea.org/offshorewind2019/Geospatialanalysis/.

Further investigation needed
For an offshore wind market to develop in New Zealand's future, further work regarding the necessary regulatory framework, environmental impacts and economic feasibility of offshore wind, needs to be conducted first. It would also be necessary to carry out environmental impact assessments for marine consents. Further, we may need to conduct geotechnical surveys to understand more about the seabed (this may include seismic surveying) and engage widely with communities and stakeholders.

Developing offshore wind assets would likely require new regulations, including the introduction of an allocation system for auctioning or tendering a lease for use of the seabed, water column, and airspace above the water, and permitting for an electricity company to operate assets beyond 12 nautical miles (nm). There may be a need to extend the application of Electricity Industry Act to New Zealand's exclusive economic zone. Offshore wind farms, beyond 12 nm, will be subject to approval under the Exclusive Economic Zone and Continental Shelf (Environmental Effects) Act (EEZ Act). We will need to consider whether the EEZ Act adequately considers the effects of such activities on the environment and existing interests.

Offshore wind generation in New Zealand's territorial waters (out to 12 nautical miles) would be subject to approval under the Resource Management Act. No developments on the scale of a large offshore wind farm have ever been developed in New Zealand waters, and we would need to consider how wind generation fits within the provisions of regional coastal plans and national direction instruments – particularly the New Zealand Coastal Policy Statement. We also would need to consider the intersection with other marine laws – such as fisheries and marine mammals protection legislation. The interaction with Te Tiriti o Waitangi (in particular Article 2) and the Marine and Coastal Area Act will also need to be assessed.

Further, there are additional barriers to investment given the significant installation costs and ongoing maintenance costs, due to the large scale of the installations and the difficulty of access to installations at sea (often in unfavourable weather and ocean conditions). Specialist equipment and expertise would also needed to be mobilised from demand centres in the North Sea (Europe) or other centres of offshore wind development, such as those emerging in Asia. The availability of these specialist resources is influenced by demand in the larger northern hemisphere markets, and there may be delays in accessing the equipment.

Questions

Q8.15	Do you consider the development of an offshore wind market to be a priority for the energy sector?
Q8.16	What do you perceive to be the major benefits and costs or risks to developing offshore wind assets in New Zealand?

Other options for feedback

The following two options are considered for feedback, however, at this stage we need further information on the merits of them before determining whether any further work is warranted. Due to the nature of these options – i.e. the scale of investment by government and/or impacts on industry – they need to be carefully considered alongside other government decisions on Emissions Trading Scheme settings, the role of complementary measures and the pace and pathways of domestic emissions to meet the country's emission reduction targets.

Renewable electricity certificates and portfolio standards

Option 8.5	Renewable electricity certificates and portfolio standards

Description

Renewable Portfolio Standards (RPS) create a requirement for retailers and/or large electricity users (buyers) to procure (or produce) a given quota of renewable electricity. The quota is ratcheted up annually which requires investment in new renewable projects to meet the higher portfolio requirements. This supports the development of new renewable electricity generation to displace existing thermal generation.

Buyers demonstrate that they have met their quota by purchasing Renewable Electricity Certificates (RECs).[91] RECs are allocated for each megawatt-hour of electricity generated from eligible projects, tallied on an annual basis. The certificates can be traded providing a financial benefit for firms that procure (or produce) above the quota. The RECs reward renewable electricity generation. This complements the emissions price which penalises fossil fuel generation. In setting up a certification scheme, the government could go to tender to select an appropriate entity to run the scheme.

Case study: New Zealand energy certification for Garage Project beer

A nascent certification scheme that is run as a private business already exists in New Zealand – the New Zealand Energy Certificate System (NZECS).[92] NZECS adheres to international certification standards.[93] This was created to respond to requests from a number of generators to meet the demands of customers looking to procure 100 per cent renewable electricity. Recently, Meridian Energy launched a pilot project with NZECS. Meridian partnered with Wellington beer brewery, Garage Project, to match the generation from the local Brooklyn wind turbine to the brewery's annual electricity needs. A new beer, the Turbine™ Pale Ale, was launched after the agreement was finalised.[94]

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[91] International precedent: Renewable Portfolio Standards/Renewable Energy Certificates in the United States; Guarantees-of-Origin (GO) schemes in the European Union member states. For more information see: https://www.aib-net.org/

[92] See: https://www.certifiedenergy.co.nz/

[93] GHG protocol, ISO 14064-1:2018

[94] See: https://www.brewbetter.co.nz/

Case study: Ecotricity electricity retailer's carbonzero certification

Ecotricity is an independent retailer with 100 per cent renewable electricity certification on an annualised life-cycle basis.[95] It purchases from specific wind, hydro and solar generation sites and measures all lifecycle greenhouse gases associated with those sites, offsetting with emissions units purchased from native forestry sources resulting in their carbonzero product certification. In addition, Ecotricity's organisational emissions are carbonzero certified.

The carbonzero organisation and product certification programmes are delivered by Toitū Envirocare.[96] The carbonzero programme is a voluntary scheme which provides accredited certification of the emissions footprint of an organisation or product. It covers emissions from electricity, vehicles, air travel, freight and office waste. The certification adopts international best practice and is in compliance with United Nations recognised and accepted Product Category Rules for the measurement of lifecycle emissions from renewable energy.

Analysis

To be effective in lifting current levels of renewable electricity supply and boosting investment, the certification scheme would require high participation rates. This is why, internationally, schemes are generally compulsory for certain entities, such as retailers and large electricity users. Voluntary schemes do not have the same scale and efficacy. They are unlikely to support significant investment in new renewable projects. Rather voluntary schemes aim to meet the needs of businesses seeking to achieve their own sustainability goals. (See case studies above).

Compulsory participation has resulted in large users signing PPAs or even taking an equity stake in new renewable projects to secure a supply of RECs and meet portfolio requirements in overseas jurisdictions, including the United States. (See case study below). The PPA or an equity contribution can improve the economics of a proposed project and make it bankable.[97]

Compulsory international schemes tend to define eligibility criteria based on when an asset was built to encourage investment in new renewable electricity generation. For example, in Australia, assets are accredited above a 1997 baseline. This includes renewable electricity generation facilities built after 1997 or facilities upgraded/retrofitted after 1997, for the portion of increased generation, such that efficiency gains are eligible.[98] Retailers and/or large users may also have the option to invest in energy efficiency to meet their portfolio standard as well. (See option 8.3 above on energy efficiency obligations).

Eligibility criteria may also be applied to technology types. For instance, geothermal could be excluded on the basis that it generates emissions (though this varies significantly by site). Or it may be included if emissions-free technology is adopted by the geothermal industry.

[95] See: https://ecotricity.co.nz/

[96] See: https://www.enviro-mark.com/what-we-offer/carbon-management

[97] This is sometimes referred to as 'additionality', which implies the project would not have gone ahead otherwise.

[98]See: http://www.cleanenergyregulator.gov.au/About/Accountability-and-reporting/administrative-reports/The-Renewable-Energy-Target-2012-Administrative-Report/The-Renewable-Energy-Target-explained

Case study: Google's renewable power purchase programme

In 2009, Google's data centre energy team began to study power purchase agreements (PPAs): large-scale, long-term contracts to buy renewable energy in volumes that would meet the needs of its business.[99] Google entered its first PPA in 2010, with a 20-year agreement to purchase 114 MW of power from a wind project in Iowa. It has since signed more than 20 PPAs across the United States, Europe, and South America totalling more than 2.6 GW of renewable energy. Google's commitment to off-take renewable electricity generation from these new projects made them bankable. Google meets its renewable portfolio standards in the United States by signing PPAs and purchasing renewable energy certificates (RECs), but the company has also gone beyond regulatory requirements and can now claim to be powered by 100 per cent renewable electricity (since 2017).

Benefits

This policy option could lift the economic value of new renewable electricity generation projects to accelerate investment. The value of RECs may encourage new investment directly as project developers expect to receive additional income from selling RECs, while energy users may seek a PPA or develop their own renewable generation project to meet RPS requirements as the quota is ratcheted up. This would be the key benefit of a renewable certification scheme.

There is also growing local demand for green or certified renewable products. Further, international firms with New Zealand-based operations could use RECs to meet their global corporate sustainability targets. Exporters, such as potential green hydrogen producers, may also see a competitive advantageous in global markets from government-backed certification that their product is derived from 100 per cent renewable electricity. Renewable electricity generators are able to track and trace their generation, and sell RECs to customers under the scheme. This promotes supply chain transparency and provides reputational benefits for participants. However, the scale of such demand in New Zealand is unclear at this point, given the already high proportion of renewable generation in the electricity system.

Costs and risks

The scheme will entail significant set up costs, as well as on-going administrative and compliance costs. For a mandatory scheme, these costs are likely to be high. The Government would also need to enact new legislation and/or regulations to implement the scheme.

Further, a government agency or authorised entity would need to be set up to administer the scheme. This could be an existing agency, but it would require an increase in funding and resourcing to support their expanded responsibilities. This funding and resourcing would be on-going, not a once-off. Certificate scheme participants will also need skilled staff to manage the buying and selling of certificates, and ensure compliance with the quota – an on-going expense. There is also the added expense of the certificates themselves for those entities that must meet RPS requirements, which would be large if RECs are to support increased investment in new renewable electricity generation. Retailers and/or large users may pass these added costs on to consumers.

A government-sanctioned certification scheme may also affect existing businesses that provide certification services. The government could crowd these entities out of the market given the mandatory nature of RPS requirements.

A number of risks are associated with setting a RPS quota too low or too high. Setting of a quota would need to be done carefully to avoid negative interactions with the NZ-ETS price by encouraging higher cost abatement. If it is too low then it will fail to encourage increased investment in renewable electricity generation and procurement. If too high then this could increase electricity

[99] See: https://sustainability.google/projects/ppa/

system costs excessively, which may be passed on to consumers. Additionally, if set too high, additional abatement in this area could suppress the NZ-ETS price by reducing demand for emissions reductions through the NZ-ETS elsewhere. Eligibility criteria that encompass existing assets could also lead to economic windfalls and advantages for existing electricity market participants. Also, it has the potential to introduce market distortions. Such a scheme would need to be designed carefully to ensure that it incentivises new generation build, does not unnecessarily disadvantage existing renewable generators and other market participants, and avoids or minimises market distortions.

Questions

Q8.17	This policy option involves a high level of intervention and risk. Would another policy option better achieve our goals to encourage renewable energy generation investment? Or, could this policy option be re-designed to better achieve our goals?
Q8.18	Should the Government introduce RPS requirements? If yes, at what level should a RPS quota be set to incentivise additional renewable electricity generation investment?
Q8.19	Should RPS requirements apply to all retailers and/or major electricity users? What would be an appropriate threshold for the inclusion of major electricity users (i.e. annual consumption above a certain GWh threshold)?
Q8.20	Would a government backed certification scheme support your corporate strategy and export credentials?
Q8.21	What types of renewable projects should be eligible for renewable electricity certificates?
Q8.22	If this policy option is progressed, should retailers and major electricity users be permitted to invest in energy efficient technology investments to meet their renewable portfolio standards? (See option 8.3 above on energy efficiency obligations).
Q8.23	Could you or your organisation provide guidance on the likely administrative and compliance costs of this policy?

Phase down thermal baseload and place in strategic reserve

Option 8.6	Phase down baseload thermal generation and place in strategic reserve

Description

Low emissions renewable energy technology could replace much of New Zealand's existing thermal (fossil fuel) baseload electricity generation today. However, thermal asset owners have little incentive to reduce generation and retire baseload before the end of its technical life. Whilst fuel, emissions and other operational costs, as well as maintenance costs, remain less than revenues gained via the wholesale electricity market, these assets are likely to keep generating and their retirement to be delayed. At present, there are no firm commitments from thermal operators to close remaining fossil-fuel electricity generation assets in New Zealand.

These assets contribute to ensuring security of supply, especially during dry spells when hydro generation is reduced. Also, thermal power plants often still generate even when hydrological conditions are good or electricity demand is reduced (i.e. during the summer). These "hydro-firming" operations contribute to conserving the energy stored in hydro lakes. Renewable electricity generation technologies, such as solar and wind farms, could however play a greater role in hydro-firming and replace thermal baseload (not peaking capacity).

The ICCC's modelling assumes[100] that thermal baseload power plants will retire or convert to peaking plant by 2035 under a business-as-usual (BAU) scenario without intervention. The BAU scenario reaches 93 per cent renewables. (See case studies below).

As there are no firm commitments to retire thermal baseload, replacement by renewables could happen slowly without intervention. We seek your feedback on an option where thermal baseload operations are regulated and restricted to accelerate this replacement in a managed way.

Note that this option only applies to baseload assets that use fossil fuels, not peaking facilities.

Case study: Huntly Power Station

In 2018, Genesis Energy announced plans to halt coal use at its Huntly power station by 2025 under normal market conditions, with an intent to cease coal fired generation by 2030. Genesis re-iterated this in a submission to the Ministry for the Environment on the Zero Carbon Bill stating: "We are now focused on working with the sector to address the broader market dependence on coal and meet our intention to exit coal-fired generation altogether by 2030 at the latest." Previous announcements in 2015 signalled the intent to permanently withdraw the remaining two 250 MW Rankine coal and gas fired units at Huntly unless market conditions changed significantly. There are additional gas only units at the Huntly site of 403MW and 51 MW capacity. Currently, there are no firm commitments to close any of the fossil fuel-fired electricity generation facilities at Huntly.

[100] Based on company announcements and publicly available information

Case study: Taranaki Combined Cycle Gas Turbine

Baseload thermal operators have tentative, voluntary phase down plans at present. Contact Energy, which owns and operates a 377MW Combined Cycle Gas Turbine in Taranaki (TCC), has stated in the media that it may reduce its thermal operations in coming years, and consider its closure in favour of geothermal investment if conditions warrant.[101]

This policy option could include a strategic reserve mechanism working alongside the phase down. This would retain thermal baseload in a ring-fenced reserve that could be used in emergencies, when there is a risk of energy shortages.

A strategic reserve is intended to be decommissioned as more renewable generation is constructed and technologies that support the management of variable renewable supply are deployed (such as batteries or demand response).[102] This transition period could endure for five years, for example.

A strategic reserve mechanism involves regulating when ring-fenced thermal baseload facilities could offer into the wholesale electricity market. The trigger could be a high price or when lake levels reach a given level (i.e. the 4 per cent risk curve).[103]

Under the temporary strategic reserve mechanism to manage the phase out of thermal baseload, asset owners are remunerated for maintaining an operational facility, but the facility very rarely generates electricity – if at all.

This approach has been adopted in Belgium where a strategic emergency reserve is maintained and remunerated outside normal market operations to manage security of supply.[104] Germany has a similar strategic reserve for 2 GW of supply that is intended to keep older legacy plants (coal and nuclear) operational to support grid emergencies while more renewable electricity generation is commissioned. Note that both Belgium and Germany have interconnections that enable electricity to be imported from neighbouring countries, whereas our market operates in isolation with around six weeks of storage in our national hydro lakes.

Analysis

The potential strategic reserve mechanism outlined above is a variant on a capacity market, but designed to maintain and manage security of supply during a transitional phase as thermal baseload is replaced by renewable energy supplies.

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[101] See: https://www.energynews.co.nz/news-story/geothermal/43052/contact-announces-30m-drilling-programme-ahead-tauhara-decision
Also: https://www.energynews.co.nz/news-story/geothermal/43983/gas-prices-new-geothermal-may-seal-tccs-fate-contact

[102] There are two different concerns with regards to ensuring security of electricity supply. The first is to ensure there is sufficient capacity available. That is, enough operational power plants available to generate and meet demand at any given moment in time. Having sufficient capacity is most important when demand is highest, for example on cold evenings in winter. The second concern is to ensure there is sufficient energy available in the system. That is, whether there is enough fuel – such as water, gas or coal – to run available power plants and generate electricity over a given period of time. Capacity is effectively measured in megawatts (MW) whilst energy can be measured in megawatt-hours (MWh).

[103] The ICCC provided related commentary on this in *Accelerated Electrification*, page 50: "100% renewable electricity would not be achieved in any of the 'hydrological years' unless natural gas were restricted to be used only in dry/calm years (and forbidden during times of peak demand). However, defining under what weather conditions this dry/calm year restriction would kick in would be extremely challenging (and potentially operationally infeasible)."

[104] See: https://www.elia.be/en/products-and-services/Strategic-Reserve

Other capacity market mechanisms can be designed to ensure security of supply over the long term by providing payments for existing capacity to remain open or to incentivise investment in new generation that is schedulable, like thermal facilities or batteries (in contrast to variable renewables like solar and wind). This type of permanent capacity market mechanism would need to be carefully designed to support the energy transition and avoid the construction of new thermal facilities that may increase emissions. The temporary strategic reserve mechanism seeks to manage the phase out of existing, legacy thermal assets, rather than providing payments to avoid their closure.

The need for a comprehensive capacity market to ensure security of supply may shift with time as technologies evolve and the contribution of variable renewables increases. We believe that existing hydro generation has the capacity to manage the variability of technologies, like wind and solar, at present. In the future we may have very high levels of variable renewables making a much greater contribution to our electricity mix and there may be a need to provide payments to ensure fixed back-up capacity remains available for when the wind stops blowing or the sun stops shining. This back-up may not be thermal facilities. Flexible technologies with lower emissions (e.g. batteries and demand response programs) may be more affordable and capable of delivering this firm capacity in the future as technology develops.

We note the recommendations of the International Energy Agency's review of New Zealand's energy policies in 2017 which suggested that a capacity market may need to be reconsidered in the future.[105]

We also note the Electricity Authority's comments on the current market's ability to deliver firm capacity:

> "For over 20 years the spot market has operated effectively in providing signals for efficient generation investment.... This has been supported in more recent years by well-functioning hedge and futures markets that provide parties with the means to enter into forward contracts … without the prescription of a formal capacity mechanism that can be readily gamed." [106]

Benefits

This policy aims to mitigate greenhouse gas emissions related to fossil fuel-fired electricity generation before 2035 by bringing forward investment in renewables to replace baseload thermal assets. This policy option would bring forward this replacement and realise the benefits of increasing renewables supply in the near-term.

In addition to reducing electricity-related emissions, renewables offer the lowest cost form of baseload generation (on an annualised basis).[107] They do not face risks such as exposure to global fossil fuel prices or potential fuel supply chain constraints. Wind and solar facilities have no fuel needs, so these risks are eliminated. They are also less expensive to build, repair and maintain than

[105] The IEA cites the example of Sweden where Svenska Kraftnat, the Swedish transmission systems operator, can procure up to 2 GW of reserve via auctions for winter periods. See: https://www.iea.org/publications/freepublications/publication/EnergyPoliciesofIEACountriesNewZealand2017.pdf

[106] See page 390 of the Productivity Commission's 2018 *Low-emissions economy* report.

[107] The lowest cost option for new build electricity generation in New Zealand is wind or geothermal. Industry experts have shared that these technologies are competing to deliver a levelised-cost-of-electricity (LCOE) in a band of roughly $50 to $70 per megawatt-hour (MWh). LCOE is a proxy for the wholesale power price required to deliver an acceptable return on investment. However, every project is different and details are commercially sensitive.

thermal power plants. Wind and solar do however have intermittency issues that need to be managed.

Costs and risks

Removing thermal generation early or entirely may pose an unacceptable risk to dry year security, absent other technological developments. However, this option would retain thermal peaking generation.

This option is similar to the reserve scheme operated by the Electricity Commission (the Electricity Authority's predecessor) until 2008, when the Government owned the Whirinaki Power Station. The Whirinaki scheme was disestablished in 2009 as it was found that market participants anticipated and planned for the Whirinaki Power Station's contribution.

Designing an appropriate trigger is complex as it directly influences electricity trading behaviour. Another key complexity with regards to this policy option also involves defining 'baseload' appropriately. For example, whether the strategic reserve should be used during dry winters when lake levels are low, or to conserve water in the hydro lakes ahead of winter or as peaking capacity for morning/evening demand peaks on a fairly regular basis. Given these complexities, it is expected that on-going compliance and administrative costs for the scheme would be high.

Further, this option would entail new legislation and/or regulations. Implementing the strategic reserve and regulating thermal phase out would have considerable set up costs for Government.

This option may also lead to higher cost emissions abatement (by targeting fossil fuel-fired electricity generation) relative to what abatement could be achieved by the Emissions Trading Scheme could have achieved elsewhere in the New Zealand economy. Replacing depreciated baseload thermal (before the end of its technical life) may temporarily raise system costs and lead to an increase in wholesale electricity prices in the next few years. However, thermal assets are already expensive to run given fuel and maintenance costs, so it is likely that average wholesale prices will fall again as more low-cost renewables come online.

We seek your feedback on the best way to meet resource adequacy whilst reducing emissions in the electricity sector, and the need for and possible design of a strategic reserve mechanism or other capacity market mechanisms.

Questions

Q8.24	This policy option involves a high level of intervention and risk. Do you think that another policy option could better achieve our goals to encourage renewable energy generation investment? Or, could this policy option be re-designed to better achieve our goals?
Q8.25	Do you support the managed phase down of baseload thermal electricity generation?
Q8.26	Would a strategic reserve mechanism adequately address supply security and reduce emissions affordably during a transition to higher levels of renewable electricity generation?
Q8.27	Under what market conditions should thermal baseload held in a strategic reserve be used? For example, would you support requiring thermal baseload assets to operate as peaking plants or during dry winters?
Q8.28	What is the best way to meet resource adequacy needs as we transition away from fossil-fueled electricity generation and towards a system dominated by renewables?

Q8.29	Should a permanent capacity market which also includes peaking generation be considered?

Summary assessment of options against criteria

	PPA platform	Develop demand response market	Energy efficiency obligations	Develop offshore wind assets	Renewable certificates & portfolio standards	Phase down thermal baseload & strategic reserve
To what extent is the barrier addressed?	✓✓✓	✓	✓	✓✓	✓✓	✓✓
Primary benefits – emissions reductions	✓✓✓	✓	✓✓	✓✓	✓✓	✓✓
Primary benefits – EE & RE	✓✓✓	✓✓✓	✓✓	✓✓	✓✓✓	✓✓
Wider economic effects	✓✓	✓✓✓	✓✓	✓	✓	XX
Compliance and admin costs	XXX	XX	XX	XXX	XXX	XXX
Energy trilemma – security and affordability	✓	✓	✓	✓	XX	XX
Community participation*	✓	✓	-	-	-	-

Key:	Option under active consideration	Option not preferred

*Note: Community participation in energy consumption and production may be promoted by policy options 8.1 and 8.2 – see analysis under each option.

Other options considered

We have also considered the following options. They have been included to demonstrate our wide-ranging assessment of possible policy options and to respond to early feedback we have heard from stakeholders. We are not recommending them for further investigation but we welcome any views you may have on them.

Government-sponsored storage facility for firming hedge products

Access to a subsidised firming hedge product would support independent and small-scale investment in variable renewables. If designed and appropriately located new storage assets (e.g. batteries) could also improve grid stability and help manage existing transmission or distribution bottlenecks.

Our assessment of this policy option is that it creates a risk that government investment in technologies like batteries may crowd out private investment. This option could also lead to complaints of unfair treatment as a subsidised firming product is only offered to a subset of market participants.

State-owned enterprise for renewables investments
This option involves setting up a new state-owned enterprise (SOE), which would invest in new wind farms or other renewable energy projects. It may sign PPAs with off-takers (existing or new 'electrified' loads from the process heat or transport sector), or undertake the investments itself. This entity could potentially target new market entrants such as community- or iwi-owned projects, or independent developers. It could also offer concessional financing terms (Crown loans) for projects that have significant co-benefits (i.e. enable greater energy self-sufficiency for communities, iwi and hapū.)

Our assessment of this policy option is that it entails high costs to set up and some risks. If the SOE undertakes its own investments as opposed to contracting though PPAs there is a risk that its inexperience in the market may lead to inefficient investment. There is also the risk that it will crowd out private investment as it will undercut them with lower state-subsidised costs.

Co-ordinated procurement of new generation (single-market buyer)
Under this option the Government would control new generation investment by contracting via auctions for new generation and/or issuing licenses for new generation. This option has been considered in prior reviews of the electricity market. The general conclusion of those prior reviews is that this option entails both pros and cons. On one hand it may provide investors with greater certainty with regards to future supply needs, and potentially through explicit control of capacity could set a level that improves security of supply and maximises renewable investment. In addition, depending on the price setting mechanism used, the single buyer could also result in lower prices for consumers benefit.

Under the current market structure there is diversity of views regarding future supply needs. The assessed risk with this option is that with a single investment decision maker , there is a risk of over- or under-shooting supply needs, which could negatively impact security of supply and energy affordability under this option. These considerations also apply to co-ordinated state procurement of renewables via auction.

Previously this initiative has not advanced, because the expected transaction costs, the higher risk associated with loss of diversity of investment and the long lead time required for restructuring the market was thought to exceed the potential gains that might accrue from the adoption of this policy. Solutions probably could be identified to reduce or negate some of these risks, but overall our assessment remains that this proposal is not warranted.

Tax incentives for renewable electricity generation
Tax incentives could incentivise renewables investment (including PPAs), as this lowers the cost of electricity sourced from new renewable electricity projects compared to other sources. In the United States, some forms of renewable generation can receive a Production Tax Credit (PTC) that has improved the economics of wind farm and other renewables investments.

Our assessment is that other policy options can incentivise investment in renewables without introducing distortions to the tax system that could create a perception of unfairness and lead to possible unforeseen consequences. The cost to the tax payer via lost tax revenue was also considered a downside of this policy option.

Provision of subsidies via auction (one-off or in rounds i.e. biennially)
Renewables auctions are a market-based mechanism for awarding subsidies, such as feed-in tariffs (FiTs)[108] or contracts-for-difference (CfDs)[109] to new renewable energy projects. Subsidies like FiTs

[108] Feed-in tariff subsidies are long-term contracts offering a fixed fee or tariff for each megawatt hour generated by an eligible renewable electricity supplier. The amount paid depends on the technology, i.e. solar

and CfDs provide a predictable stream of revenues for renewable generators and/or a floor price for each unit of generation (MWh) sold which reduces the cost of financing and encourages investment.

Auctions reduce risk of subsidies leading to a situation of over-subsidising or oversupply. The final value of the subsidy is determined in the auction process and the most competitive bidders receive the minimum incentive required to proceed with an investment. If the amount of capacity awarded via auction is capped (in megawatt terms) then this will limit uptake and the pace of renewables deployment. This policy option is prevalent in other jurisdictions that tend to have a high proportion of fossil fuel baseload supply (such as the EU member states).

Our assessment is that provision of subsidies for renewables, which are widely considered to be the lowest cost option for new generation capacity, would be unnecessary for these commercially competitive technologies as well as costly for the taxpayer. It could however be possible to restrict eligibility to small-scale or community-owned projects to support energy self-sufficiency for communities and iwi, and consumers' participation in their own energy production and consumption.

Questions

Q8.30	Do you have any views regarding the above options to encourage renewable electricity generation investment that we considered, but are not proposing to investigate further?

would have a higher FiT than wind as the capital investment required for a new wind farm is currently less than for solar in New Zealand (per megawatt of installed capacity).

[109] Contracts-for-difference subsidies are long-term contracts offering a "top-up" on the wholesale power price whenever it is below a contract level. The generator would pay back the additional revenue when wholesale power price is above this level.

Section 9: Facilitating local and community engagement in renewable energy and energy efficiency

This section considers the barriers to greater uptake of small-scale community energy projects and potential options to facilitate community energy, including:

- a clear government position on community energy
- support for community energy pilot projects.

Background

Renewable energy investment in New Zealand has been largely led by established utilities, with little involvement of local and community organisations. However, there is a growing interest in local and community energy projects. This comes from a desire from many New Zealanders to engage locally in the transition to a low emissions economy, a resurgence of interest in contemporary papakāinga on whenua Māori, and a growing interest in regional development and local resilience.

Community energy projects need to be carefully designed to suit market arrangements and New Zealand's emissions profile. This means community energy projects in New Zealand are likely to look different from first generation community energy projects in Europe and North America, for example.

We have defined community energy as any renewable energy activity that is managed in an open and participative way, and has local and collective benefits and outcomes. Community energy includes both communities of place (defined by the places people live, such as a neighbourhood or region), and communities of interest (defined by a shared interest, such as a sports club or national co-operative).

Community energy can involve a wide range of activities, including heat and power generation, demand side management, storage, clean transport and energy efficiency.

Benefits and costs of community energy projects

This section sets out the potential benefits and costs of community energy projects. Many of the benefits are based on overseas experience. We would expect it to take time for New Zealand projects to scale up to the benefits seen offshore.

Economic impacts

Large-scale community projects are likely to procure locally and spend a higher proportion of revenues locally, generating multiplier effects in income and employment. Local and community energy has been used to test novel applications or functional integration of commercially available technology, to drive technological learning and support nascent clean technology industries to scale. These local benefits support a just and inclusive energy transition to a low-emissions economy.

In the longer term, participation of a wide variety of new entrants in the electricity market could increase competition and may lead to lower overall wholesale prices in the electricity market.

However, the potential downside of investment in community energy is the low economies of scale in comparison to larger projects. There is precedent overseas for large community projects delivering energy at lowest cost, but they have largely been joint ventures.

There also can be a tension between people and groups seeking to minimise their energy costs at a local level, versus the need to operate energy markets at a national level for the lowest aggregate cost. For example, persons generating a large proportion of their own power will expect lower power bills, but also will expect energy on demand from national networks at times (which is more efficiently generated at large scale).

Social impacts

Community energy can provide a platform for individuals to engage with complex problems and build positive relationships, contributing to social wellbeing. Projects can build local capacity for consumer-facing pilot projects on a wide range of energy issues, including energy efficiency, smart appliances, and EV uptake and utilisation.

In remote areas on low voltage networks, islands, or locations that have ample low-cost wood fuel supply, community energy can improve energy access and energy affordability, with associated health benefits. Generation methods such as small-scale solar and wind can be combined with batteries to operate independent micro-grids to supply isolated communities with emissions-free electricity.

Community organisations working on the basis of trusted relationships can enhance participation, energy savings outcomes and energy literacy. Projects can also facilitate knowledge and skill development across a range of areas and result in organisations replicating and scaling projects. Community energy also facilitates trust and improved reputation of energy utilities, and support for government climate change and renewable energy policy.

A risk is that inclusive management with input from the wider community can generate trust and local buy-in, but can also slow decision-making and increase development time and cost, in comparison to commercial decision makers. There also is a risk of a lack of capability for ongoing maintenance and operation of energy systems.

Environmental impacts

Internationally, community energy has accelerated investment in clean technology. It can contribute to lowering emissions by providing additional renewable electricity capacity, short-term flexibility and ancillary services, and reducing peak loads, and provide renewable dispatchable alternatives to gas.

However, as discussed above, the likely small scale of community energy projects (in the near term) means they are a less cost-effective means of decarbonising the national energy system, in comparison to utility-scale projects.

Distribution networks and security of supply

Community energy can contribute to local energy supply resilience and network stability. In some cases, a local or distributed generation project may offer an alternative to new transmission or distribution build, thereby reducing the system cost of delivered electricity. In cases where community energy projects are able to use waste heat locally, such as biomass or geothermal based 'combined heat and power', system efficiency increases substantially.

The flipside is potentially unfair distribution of benefits and costs. For example, the burden of whole energy system costs fall disproportionately on consumers who do not have the capacity to engage in community energy schemes (e.g. they could pay a higher proportion of the fixed costs of network connections).

Case study: Blueskin Energy Network and P2P

Blueskin Energy Network (BEN) is a solar sharing venture started by the Blueskin Resilient Communities Trust (BRCT) in 2017, run in collaboration with P2P (emhTrade), who provide the retail service and trading algorithm. It operates across the Powernet network area in Otago. Since the project has gone online in April 2018, over 60 households have joined the project in order to buy local solar power below retail rates, or sell their solar power above wholesale price at half hourly intervals.

A smart phone app (PowerPal) connects remotely to smart meters enabling monitoring of power usage, provides tips, gift and monetary incentives to use (or not use) power at certain times of the day, allowing users to participate in optimising grid function. The biggest challenge in getting the project up and running has been the lack of start-up funding.

BRCT's longstanding community presence and experience in energy efficiency and wind, as well as its work with the University of Otago on energy innovation, the partnership with emhTrade, and the simplicity of the system have all been key to the project's success to date. BEN is also exploring data sharing and collaboration with PowerNet on network charging rates and battery storage.

Questions

Q9.1	Should New Zealand be encouraging greater development of community energy projects?
Q9.2	What types of community energy project are most relevant in the New Zealand context?
Q9.3	What are the key benefits and downsides/risks of a focus on community energy?

What's the problem?

Electricity market arrangements

There are a number of perceived barriers to community energy from current electricity market arrangements. Many of these issues are discussed in Section 11 of this discussion paper, and relate to more general issues with distributed (not just community) generation. As noted in section 11, many of these issues are subject to current work from the Electricity Authority. **Table 6** below sets out the key issues, and relevant projects.

Table 6: Key issues for community energy projects and related work underway

Issue	Electricity Authority work programme
Ensuring electricity distributors have the necessary incentives, data and know-how to identify and promote distributed energy solutions and engage with community actors.	The EA is currently considering the need for more data to be published about opportunities to provide alternative solutions to network issues as part of the Open Networks programme.
Concerns independent power generators have in some instances faced high risk and poor terms and conditions in securing power purchase contracts/agreements in the market.	The EA has an active project on its work programme to improve hedge markets.
Concerns that current network charges for distributed generation do not accurately reflect the costs incurred by networks. Inconsistent terms and conditions for distributed generation to connect to the network, and the need to recognise the range of (ancillary, capacity, demand response) services it can deliver to the network.	The Open Networks project will overcome barriers to greater uptake of distributed energy resources at both the consumer and network services level. The EA is monitoring and supporting distributors' efforts to make network charges more cost-reflective, consistent with distribution pricing principles the EA released this year.
Difficulties for consumers to grant access to consumption data with (non-retail) third parties, or to be serviced by peer-to-peer and retail service providers simultaneously.	The Additional Consumer Choice of Electricity Services (ACCES) project – decisions are expected in late 2019 on rules to better facilitate third party access to consumption data and enable simultaneous service providers.

Coordination of policy across government

Central and local government agencies can sometimes take different positions on, for example, the costs and benefits of solar energy, or the added value of community energy. This partly reflects the competing priorities of different agencies and work programmes, plus the fact that community energy is a relatively small and emerging part of New Zealand's energy sector.

Small scale of community energy advocates, and lack of networking effects

The community and distributed energy sector is largely comprised of small organisations, who have expressed concern they have insufficient capacity to engage in government consultations and make their voice heard. There is currently a lack of 'sector identity' and a unified voice – plus low networking and knowledge sharing across operational community energy projects. This also means a lack of data and evaluation to identify local impacts and successes to justify community-based approaches, and inform decisions about how to support replication.

At the project level, the small scale of operators often results in a lack of local capacity and resources to identify viable projects and bring them to financial close. Constraints can include:

a. Land, often due to a reliance on a single site for development.

b. Seed finance to fund the first high risk project stages, especially for new organisations with small cash reserves.

c. Capital finance, because of a lack of precedent and legitimacy of projects amongst commercial lenders.

d. In some cases, a shortage of legal, technical and financial expertise, or having "no idea where to start".

Resource Management Act barriers
Community energy practitioners have raised concerns around disproportionate and inconsistently applied resource consenting procedures. There is also a perception that the local benefits of community energy are not weighed appropriately alongside the negative impacts of a proposal. Resource Management Act barriers are discussed more generally in Section 7 of this discussion paper.

Questions

Q9.4	Have we accurately identified the barriers to community energy proposals? Are there other barriers to community energy not stated here?
Q9.5	Which barriers do you consider most significant?
Q9.6	Are the barriers noted above in relation to electricity market arrangements adequately covered by the scope of existing work across the Electricity Authority and electricity distributors?

What are the options?

We seek your feedback on a range of options to support future development of community energy proposal.

A clear government position on community energy

Option 9.1	**Ensuring a clear and consistent government position on community energy issues, aligned across different policies and work programmes.**

Description
Government could develop a coordinated position on community energy. This would nest into any wider government energy strategy and energy emissions targets, and consider synergies and trade-offs with other programmes. For example, we would not want to invest heavily in a community energy generation project without having first considered more cost-effective energy efficiency measures.

This position could set out strategies and direction for how the sector can overcome key challenges, covering matters such as electricity market arrangements, distribution networks, the ability of local government to invest and facilitate projects, and resource management issues.

Government could also explore whether existing sources of government finance and support for social enterprise, regional development, technology innovation and diffusion are aligned to vet and support credible community energy projects, in a way that recognises the wider co-benefits.

Community energy proposals could also benefit from some of the proposals in Section 8 (investment) of this discussion paper. For example, a power purchase agreement platform could potentially help de-risk small local generation projects.

Government can also play a networking and information sharing role to facilitate learning and inspire replication of community energy proposals, for example by means of an online information hub to help connect community groups and share best practice.[110]

Finally, government could work to foster a shared ownership culture in the renewable energy industry, for example by producing guidance on principles, business models and community engagement processes for shared ownership.

Analysis
The benefits of an aligned position on community energy depend on the downstream implementation actions. A greater focus on community energy would contribute indirectly to goals for 100 per cent renewable electricity generation and decarbonisation but have minimal impacts at the national scale in the short term. It is likely, however, that community energy proposals – and distributed generation and storage more broadly – will have increasing impacts over time.

Enabling market access and addressing regulatory barriers

Option 9.2	We do not propose any new initiatives in addition to existing work programmes

Description
Improvement to market arrangements for community energy would generate scope for wider uptake and replication of projects and more diverse community energy models.

Section 11 of this discussion paper notes the current work programmes across Transpower, the EA and electricity distributors looking at changes to network charging and connection to the network to better enable distributed small-scale connections. As such, no further proposals are suggested here, though we seek your feedback on the degree to which this work would support development of community energy proposals.

Government support for pilot projects

Option 9.3	Government supports development of a small number of community energy pilot projects

Description
The government could support and resource a number of pilot projects to 'learn by doing', set precedents for success, and build an evidence base that supports the case for community energy.

[110] Local Energy Scotland is an example of a one-stop-shop for community energy, where practitioners can go to for information, tenders, funding and networking.

Pilot projects could help reveal barriers to community energy projects, and explore the business models, practices, market design and regulation required for replication and scaling. This will inform any subsequent programmes to assist the development of community energy proposals.

Analysis

The key direct benefits of pilot projects would be:

- direct end user benefits – e.g. lower power bills, warmer homes and associated health impacts
- potential improvement to resilience of energy supply (depending on the location and proposal)
- social capital benefits – new networks, relationships and collaborations fostered around local energy and environmental action.

The key costs of this proposal are the direct costs to government for investment and assistance. The costs are highly scalable, based on the size of the support package. Because these projects are small in scale, there would not be a substantive short-term effect on national-scale energy supply or climate goals. However, they could provide proof of concept for how community-based solutions, and distributed supply solutions in general, might be scaled up in the future.

Summary assessment of options against criteria

Community energy is still nascent in New Zealand, which makes it difficult to assess options against the criteria at this stage (i.e. we would not expect any short-term impacts around greenhouse gas emissions). The benefits of individual projects will fall to a small number of households or community organisations.

The key potential benefits lie more around the potential future scaled-up impact that might follow from pilots. For example, lessons learned about the best means to deploy small scale distributed generation could inform policies around distribution network regulation, or the most cost effective technologies to provide energy and resilience in remote communities.

Pilot and demonstration projects are used internationally by governments (such as the USA, Japan and many European) to catalyse the early adoption of new technologies and social programs. In particular, they have been extensively used to help overcome innovation uncertainties in renewable energy for electricity supply systems.

If we proceed with support for pilot projects, a monitoring and evaluation strategy will be required to assess the impacts, and look at how the national-scale benefits could be scaled up over time.

Questions

Q9.7	What do you see as the pros and cons of a clear government position on community energy, and government support for pilot community energy projects?
Q9.8	Any there any other options you can suggest that would support further development of community energy initiatives?

Section 10: Connecting to the national grid

This section sets out our understanding of issues relating to transmission connections to support growth in renewable electricity and the transition to a low emissions economy.

It seeks your views on options to address:

- the first mover disadvantage
- gaps in publicly available and independent information, and
- a lack of information sharing for coordinated investment.

What is the problem?

We are moving into a period of more customer-driven transmission investment, with increased renewable generation and process heat demand connecting to the grid. The challenge is to enable this while managing opposing risks of under or over-investing in the national grid.

Additionally, there are long lead times for major new and upgraded transmission assets relative to lead times for new generation or demand. Issues with cost allocation and risk associated with new transmission lines may slow or hold up the deployment and uptake of renewable electricity generation, risking delays in decarbonisation. There are also coordination challenges where investments involve multiple parties.

Recent modelling by the ICCC[111] indicates that about 10 to 15 transmission upgrades could be needed by 2035 to support decarbonisation. The upgrades common across all the scenarios modelled include a few known "pinch points" and a small number where new generation is built in parts of the grid with limited transmission capacity.[112]

Enabling new connections

Traditionally, investment in new and upgraded transmission lines has been driven by steady or predictable growth in electricity demand (e.g. new lines to Auckland), and has been part of system wide investment in interconnection assets with a relatively low risk of stranding or underutilisation.

In anticipation of more renewable generation and electrification, Transpower recently commenced a complementary project called "**Enabling New Connections**" to consider what it (and the industry) needs to do to enable the new connections required. It will consider how the system and market could evolve over the coming decades, barriers to connection, information needs and process, and potential constraints in terms of people capability and capacity.

In addition, new assets would be needed to connect new generation and process heat plants to the grid. Transpower's recently commenced project "Enabling new connections" (refer text box) seeks to understand how it and others can meet this challenge.

[111] New generation included in this modelling is based on details of consented and otherwise potential new projects that are publicly available, although in scenarios with the largest number of wind farms, some are moved to reduce correlations in output/manage intermittency.

[112] The modelling also indicates an upgrade to the HVDC link is needed under the 'accelerated electrification' scenario, and possibly under the 'business as usual' and '100% renewable electricity' scenarios.

The ICCC heard that regulatory hurdles relating to the connection of boilers to transmission and distribution networks can play a significant role in fuel switching decisions. Further:

> *"If uncertainty and regulatory hurdles result in new investments in fossil fuel technologies instead, this would lock New Zealand into high-emissions technology for decades to come and would make it much more challenging to meet New Zealand's emissions reductions targets. Policy change is needed."*[113]

Understanding how the costs of transmission assets are recovered and who bears the risk of underutilisation helps with understanding the issues with investing in transmission assets to connect to the grid.

The Commerce Commission determines how much revenue Transpower can recover each year from assets in its regulated asset base (RAB). The Transmission Pricing Methodology (TPM) determines how charges are calculated for RAB assets and who pays for them. The EA's guidelines for the development of the TPM are being reviewed.[114] For assets outside of the RAB, cost recovery arrangements are established in contracts with Transpower.

The three types of transmission asset (interconnection, connection, or HVDC asset) and cost recovery mechanisms are described below.

Connection assets

The challenges addressed in this consultation are most relevant to connection assets, which are typically dedicated to one customer such as a generator or grid-connected large user. Any costs Transpower incurs ahead of a decision to build a new connection asset are an upfront cost to the customer seeking to connect. Once established, the costs of connection assets (capital and operating) are paid for by connected parties.

Charges for connection assets are either determined under the TPM or in a contract with Transpower. Under the current TPM, the ongoing charge for each connection asset is calculated based on average depreciation of all the connection assets in the RAB.

In its recent consultation on transmission pricing, the EA proposed largely retaining this aspect of the TPM as it considers it provides parties with incentives to take connection costs into account in their own investment activity and operations, and to seek the connection option (or an alternative to connection) that most cost-effectively meets their needs.

Connection assets come with a higher risk of becoming stranded assets, for example if the dedicated customer shuts down. There is also the issue of 'first mover disadvantage', where the first customer (generator or large user) incurs the full costs on a larger asset and bears the risk of subsequent customers not eventuating (this is described more below).

Interconnection assets

Interconnection assets form the core part of the grid[115] and generally sit in the RAB. Interconnection charges cover the (shared and common service) costs, which currently are shared between all *demand* customers connected to the system.[116] This means that there is little incentive for

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[113] Page 90, *Accelerated Electrification*, ICCC

[114] The current TPM is considered to encourage inefficient use of and investment in the transmission grid. The proposed changes to TPM guidelines aim to better align the charges transmission users pay for new investments with the costs of those investments.

[115] They are "looped" assets, where the line loops through the service area and returns to the original point

[116] This is called the Regional Coincident Peak Demand (RCPD) charge and recovers both capital and operating costs over the lifetime of the asset (e.g. 30 to 40 years). It is a "postage stamp" type charge, where connected

information sharing between parties, and for participation in the process, and scrutiny of, Transpower's proposals to invest in interconnection assets.

In its recent consultation, the EA proposed that the costs of interconnection assets are instead allocated based on how customers benefit from them. This will create an incentive for customers to participate in the approval process as they will pay a larger portion of the cost of a new investment they benefit from (instead of simply paying a small share of all costs).

HVDC assets

HVDC assets link the South and North Islands and are currently paid for by South Island generators. The EA has proposed that the HVDC charge be replaced with benefits-based and residual charges. This may create a more favourable investment climate for South Island based renewable generation investments, depending on how any new charges compare to the current HVDC charge. The issues outlined below are not relevant to HVDC assets, so they are not discussed further.

Grid investments

Transpower is a State Owned Enterprise (SOE) and is required to operate as a commercial business.[117] Because it has a regulated income, it generally avoids taking undue risk with grid investments, preferring certainty that its costs will be recoverable. However, there is some latitude in the level of risk Transpower and its shareholder (the Crown) is willing to accept. A higher level of risk may be acceptable in the context of the need to transition to a low emissions economy.

There are two ways that investments in the grid can occur – either by approval from the Commerce Commission, or through a contract between Transpower and one or more counterparties.[118]

Investments in the Regulated Asset Base (RAB)

Investments approved by the Commerce Commission become part of Transpower's RAB. Transpower can continue to recover the cost of assets in its RAB under the TPM even if they become stranded or are underutilised. While this takes an element of risk away from Transpower, it is a cost to all connected customers, which is ultimately passed on to electricity consumers.

Investments in transmission that are expected to cost over $20 million must be individually approved by the Commerce Commission using criteria set out in Transpower's 'Capital Expenditure Input Methodology' (Capex IM).[119] The Commerce Commission must consider MBIE's Electricity Demand and Generation Scenarios (EDGS) in the approval process.

An investment needed for the deployment and/or uptake of renewables may not get approval if there is too much uncertainty (risk) regarding its utilisation (and therefore its costs and benefits).

Transpower pays for investments that are expected to cost less than $20 million from a fungible envelope of 'base expenditure' that is approved by the Commerce Commission.[120] This does not

customers pay the same rate ($109 in 2019/20) per kW it contributes to the top 100 peak demand periods in the region in the previous year) no matter where they are in the country.

[117] Under the State-Owned Enterprises Act 1986.

[118] The counterparty does not need to be a transmission customer.

[119] *Transpower Capital Expenditure Input Methodology Determination 2012,* made under Part 4 of the Commerce Act 1986.

[120] Base expenditure is set for each five year regulatory period. Transpower can apply to have the limit increased for certain asset replacement and for refurbishment projects over $20 million, and it has the freedom to reallocate/reprioritise spending on any project within the overall funding envelope.

fully de-risk Transpower from overspending as there are efficiency incentives in place for cost management.[121]

Contracted assets

New and upgraded transmission assets[122] commissioned under a contract do not require Commerce Commission approval and sit outside of Transpower's RAB. Cost sharing arrangements will be set out in the contract. Such contracts are a potential option for new large users or large generators requiring a connection or significant upgrade, but have sometimes proved difficult to arrange when they involve multiple parties.

There can still be issues with cost allocation when assets outside of the RAB, and with who bears the risk of stranded or underutilised assets – connected customers under contract (generators, distributors, and directly connected large users), or Transpower (as a cost of business that is passed on to all connected customers).

A business considering new generation or electrification may be deterred from investing if it faces (or perceives it will face) too much risk about the future cost recovery of the associated transmission asset. For example, it could anticipate that its share of the cost will reduce over time if others connect to the asset in the future, but there is always a risk that subsequent customers do not eventuate leaving the asset underutilised. A business that decides to invest is incentivised to have the asset sized to its needs, not to a capacity that could serve future and uncertain demand.[123]

Transpower has indicated that a common 'sticking point' in negotiations is that the budgets and project plans it provides for new connections are indicative[124] and the costs are uncapped. This is because Transpower seeks to avoid the risk of the new connection costing more than it can recover (construction cost over-runs cannot be recovered through TPM charges).[125]

In terms of delivery timeframes, Transpower's reluctance to bind itself reflects delays that can be caused by third-parties due to factors such as the need to acquire land or easements, resource consents and procure equipment. Issues with obtaining resource consents are covered in section 7 of this document: *Enabling renewables uptake under the Resource Management Act 1991.*

Investment timing and commitments of each party inevitably vary, not least due to factors set out above. In addition, devising an equitable cost sharing arrangement between counterparties can be difficult.

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[121] The extent to which Transpower fully recovers the actual spend depends on the extent to which there are cost over-runs for individual projects over $20m, or for the base capex allowance as a whole.

[122] Typically for connection assets, but could be for interconnection assets if there is a willing counterparty or parties.

[123] Note that an asset may initially appear to be 'over-capacity' but could be optimal over the lifetime of the investment, and the first mover may benefit from capacity larger than its own needs, particularly relative to an alternative of not being connected at all. It is therefore not always clear cut whether the first mover should not be expected to make a contribution to the temporary 'over-capacity'.

[124] With rare exceptions.

[125] Under the Capex IM, all assets funded through contracts must go into the RAB at a value of zero.

The first mover disadvantage

What is the problem?

Under the current arrangements, the first party to a new connection covers the full cost of the asset (albeit spread out across the lifetime of the asset) until another party connects and pays its share going forward. This can:

- lead to suboptimal transmission infrastructure investments, which favour existing infrastructure over new infrastructure, or
- disincentivise investment in higher capacity connections by the initial developer (generator or large user) due to the risk of being the only connected customer, paying for capacity and overbuild that it does not need or utilise.

The barriers associated with new investment could also be creating a possible bias towards incremental generation growth in regions already well-served by transmission facilities, even if there are more economic generation options in other regions.

Ideally, to take advantage of economies of scale, new transmission assets should be sized to serve the potential supply and demand growth in a region. Under current arrangements connection assets are more likely to be sized for the first mover, or possibly not even eventuate. Sizing for the first mover may also lead to consenting issues for subsequent parties connecting if a line needs to be incrementally changed to accommodate extra capacity.

For example, there are multiple potential wind generation sites in the Wairarapa with a combined capacity of up to one gigawatt, but the region does not have a transmission connection that could support these. No developer has committed to a project in this area, though in the past several potential developers spent considerable time and resource trying to negotiate an amicable cost sharing arrangement. In the absence of such an agreement, the first mover faces a higher per-unit cost on new generation due to the initial transmission investment, potentially for years to come until other wind farms are progressively developed and especially if a large connection is built.[126]

Such barriers could affect the future development of sufficient renewable electricity generation to support the transition to a low emissions energy sector, and potentially limit more effective regional development.

What are the options?

Three options are being considered for adjusting the cost and risk allocation for new and upgraded connections that could address the issues outlined above. The first two options seek to improve investment decisions while balancing the need to align risks with the benefit arising from the new assets. The third option would lessen the incentives to overbuild the transmission grid and could increase electricity costs, so is the least preferred option.

Some of the options may require the Commerce Commission to consult on potential amendments to Transpower's Capex IM, or other input methodologies that apply.

Other options were identified, including establishing a special purpose Crown company, mechanisms to reserve capacity, and reducing asset values under the TPM. However, these are not proposed for further consideration due to: the perceived risk of unintended consequences (high relative to the size of the problem), potential issues with competition law, and in some cases potential incompatibility with consultation underway on the guidelines for the TPM.

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[126] Further discussion of this example is in the Productivity Commission's low emissions economy report, August 2018 (page 396 on).

Option 10.1	Encourage Transpower to include the economic benefits of climate change mitigation in applications for Commerce Commission approval of projects expected to cost over $20m. This would be through the inclusion of the (avoided) emissions price cost incurred by consumers calculated on a consistent basis. Guidance or direction about the emissions price and trajectory would be needed to support this option.

This option would apply to transmission investments over $20 million that need to pass the 'market benefit test' set out in Transpower's Capex IM. This is a test developed and applied by the Commerce Commission. It is designed to ensure there is a robust business case to make the proposed investment based on future needs, and it is intended to avoid the risk of building significant infrastructure in places where there will be limited demand.

The market benefit test can already include the economic benefits of climate change mitigation.[127] Transpower's current practice is to include the emissions cost incurred by generators through applying a forecast emissions (ETS) price as a cost to carbon-emitting generators in its applications. A more holistic approach could be taken to include the benefits of consequential emissions reductions elsewhere, such as through increased electrification and reduced fossil-fuel use.

Fully quantifying the economic benefit of any avoided ETS costs[128] in applications could bring forward investments in transmission assets that enable new generation or electrification.[129] This may negate the need for first movers (and other parties) to establish a connection asset through negotiation. It also shifts cost and utilisation risk from the first mover to Transpower. Once built , the first mover will face higher (per unit) connection charges under the TPM, but it will not face the upfront cost, not bear the risk of underutilisation, as it would under a contracted asset.

Ensuring that the economic benefits of climate change mitigation are routinely included would support the business case for investment in new renewable electricity transmission infrastructure. Options to achieve this range from the Government providing direction (e.g. in an Owner's Letter of Expectation), through to mandating how Transpower should account for emissions goals. For consistency, implementing this option would require government direction or guidance about the emissions price and trajectory that should be assumed in the analysis (e.g. which future emissions price path should be used).

Depending on the proposal, including avoided ETS costs could increase the benefits enough to result in it passing the market benefits test. It may not capture the full externality cost of emissions, but will to the extent that the policy settings for the NZ-ETS allocate the cost of emissions to electricity market participants. As noted earlier, the NZ-ETS settings are currently under review.

Depending on how the costs are allocated, in some cases Transpower may not recoup all of the revenue it requires from a particular asset, and any shortfall would be met by electricity consumers (or the Crown, as per option 10.3 below).

[127] Through the inclusion of avoided emissions costs to the extent that they are (or are expected to be) internal to the electricity market), as per the Schedule D, clause D4(1)(j)(ii) of Transpower's capital expenditure input methodology determination (as at 1 June 2018).
[128] This would require working out how to include reduced fuel burn from thermal generation and/or electrification
[129] Note that the market benefits test will consider lifecycle net benefits and expected demand to connect over the lifetime of the investment, so connection projects serving multiple parties might pass the investment test without the need for ETS benefits to be taken into account, particularly if those benefits are not material to the investment choice.

Option 10.2	Put in place additional mechanisms to support or encourage, Transpower, first movers and subsequent customers to agree to alternative forms of cost sharing arrangements by contract.

This option draws on the ability for Transpower and connecting parties to undertake commercial negotiation to agree how the cost and risk of a new connection is shared between them, and potentially other parties in future. It is most suited to connection assets with only one or two counterparties.[130]

This can already happen if subsequent customers agree (by contract) to contribute to the charges the first mover (now incumbent) is paying under its contract with Transpower. However, as there is currently no obligation on parties that subsequently connect to contribute, there is little incentive for them to agree to a cost sharing arrangement.

One option is to introduce a new charge through the Code (or TPM) for customers that subsequently connect to a contracted asset that they have not contributed to the funding of. The charge could provide a rebate to charges already paid by the first mover or off-set the amount recoverable from all customers on the connection.

Other options

- introducing a requirement (e.g. in the Code) that a second or subsequent customer cannot connect unless it enters into a cost sharing arrangement with the first mover, or make some sort of contribution to the cost of the asset to date. For this to work effectively, it may require a fall-back mediation process to be established to facilitate agreements.
- transferring contracted connection assets that end up serving more than one party to the RAB with annual payments rebated to the first mover.

Note that the cost to the customer of investments under contracted arrangements can be higher than the cost of investments that end up in Transpower's RAB due to customer credit risk.[131]

Option 10.3	Shift some of the cost and risk allocation for new and upgraded connections from the first mover through mechanisms within the Commerce Commission's regulatory scope, with the Crown accepting some of the financial risk. Two identified ways to achieve this are[132]:
	10.3.1 Optimise asset valuations under the Commerce Commission's regime in circumstances where demand is lower than originally anticipated because expected (subsequent) customers do not eventuate.
	10.3.2 Provide for Transpower to build larger capacity connection asset or a configuration that allows for growth, but only recover full costs once asset is fully utilised, with the Crown covering risk of revenue shortfall.

[130] Interconnection assets can be established by contract (instead of through the Grid Investment Test), but this is unlikely due to their high value and the many parties that are involved.
[131] The credit risk is created as charges under a contract are only enforceable against the counterparties to the contract, so if a party defaults, Transpower cannot recover the cost from any other party. By comparison, if a customer defaults on paying its TPM charges on assets in the RAB, Transpower can recover the under-payment from other customers in subsequent years. The extent to which this increases the cost depends on how the risk-adjusted returns in contract compare to the cost of capital applied to the RAB, and it is possible that the costs to individual customers could be lower under contracted arrangements.
[132] Both would require the current input methodologies that apply to Transpower to be amended.

This option aims to provide Transpower more flexibility in how the costs of assets are recovered over time, and allow it to shift more of the financial risk away from connection customers (ultimately to the Crown and therefore taxpayers).

It is difficult to assess the relative merits of this option. There is limited evidence both about the magnitude of the first mover problem and the potential effectiveness of the likely significant shift in cost and risk allocation that would be involved. This is therefore not a preferred option further consideration, but included for feedback to gather information and evidence to inform an assessment.

Under option 10.3.1, Transpower's assets could be partially written off, have their lifetimes extended, or there could be changes made to depreciation rates or methodologies. Transpower would then recover lower transmission charges (and therefore lower revenue) from the connecting customer in respect of the connection asset.

Under option 10.3.2, Transpower would get approval to build a connection asset that then becomes part of its RAB (rather than build it under contract). It could then opt to build the asset to a higher capacity, but not put the increased value of that asset into its RAB. While the asset would sit in its balance sheet, it would gradually appraise its potential value each year based on the likelihood of it being fully utilised.

Under either option, any shortfall in Transpower's revenue that results would need to be covered by the Crown through either accepting a lower return, or through a loan mechanism with the potential for it to be written off.[133] For example, the Crown could provide Transpower a loan for specific transmission assets that could be paid back as more customers connect. This is illustrated in the diagram below that sets out the types of asset and how they could be funded.

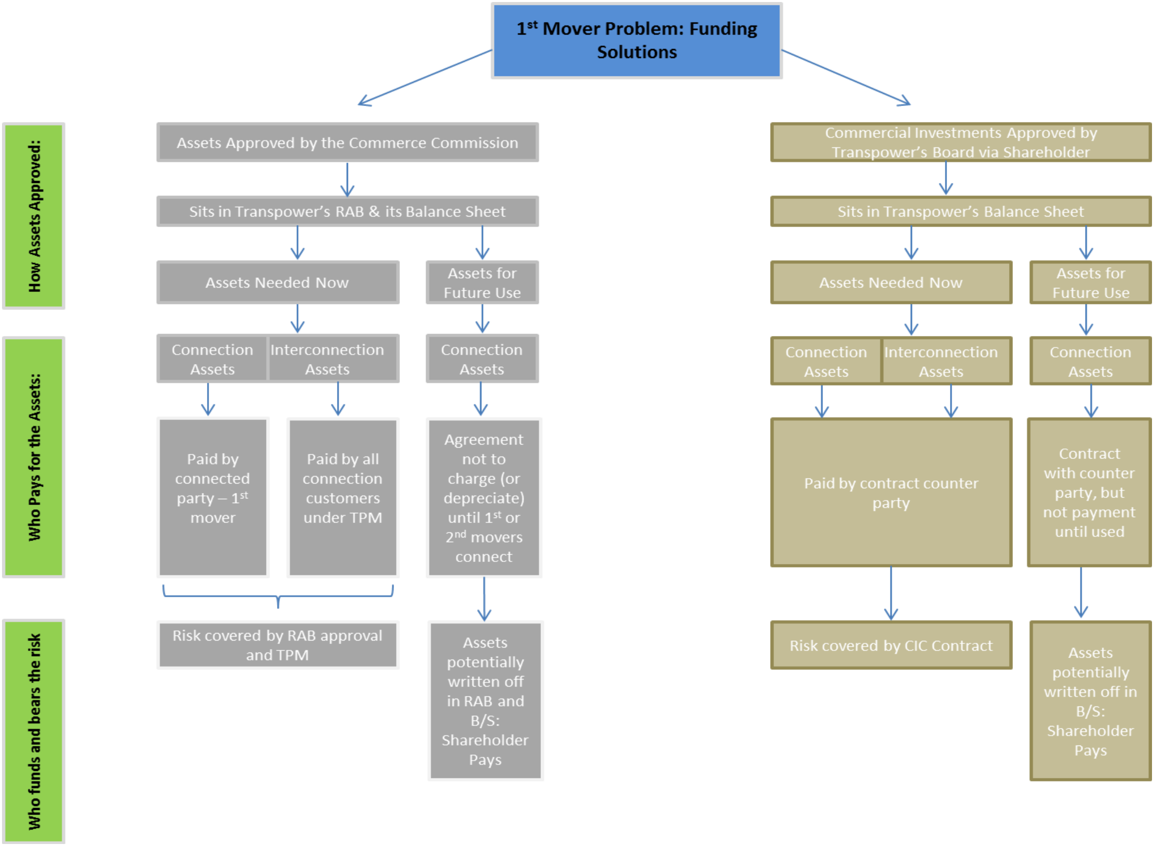
These options would lessen the incentives on Transpower to not overbuild transmission assets and (all else being equal) could increase electricity costs.

Questions

Q10.1	Which option or combination of options proposed, if any, would be most likely to address the first mover disadvantage?
Q10.2	What do you see as the disadvantages or risks with these options to address the first mover disadvantage?
Q10.3	Would introducing a requirement, or new charge, for subsequent customers to contribute to costs already incurred by the first mover create any perverse incentives?
Q10.4	Are there any additional options that should be considered?

[133] As it would reduce Transpower's dividends (as it impacts on its operating balance before gains and losses (OBEGAL)).

Figure 3: First mover problem funding



Source: Ministry of Business, Innovation and Employment

Gaps in publicly available and independent information

What is the problem?

There is limited public information and access to independent data on where new generation is likely to be built, or where large demand is likely to be added. In addition, there are various agencies, regulations and approval processes that can be complex to navigate, especially for a non-electricity business (e.g. a process heat user). As a result, investors and Transpower can lack sufficient or key information for robust and timely decision making.

There is an inherent tension in the provision of information regarding potential investments in generation. Developers will undertake significant investment in data before making investment decisions and see benefit in holding intellectual property (IP) on their new generation options. On the other hand, Transpower requires good information to undertake proactive investment in planning, and independent data sources could add credibility to its investment decision making.

Current public information sources include:

- the EA's existing database on potential or planned generation (based on public information)
- MBIE's and the ICCC's modelling results that show new generation options
- Transpower's planning documents, developer / investor public statements, and
- process heat users' public statements, and stated emissions reduction plans.

Many of these sources are not systematic and only have a limited shelf life. There is a potential role for government to provide more independent public data to fill these information gaps with the aim of:

- Aiding proactive transmission investment, opening up new areas to generation investment and electrification, and better aligning construction timing
- Providing some certainty to investors regarding the availability of transmission capacity, and
- Building understanding of the process for upgrades and new connections to the grid.

What are the options?

There are a range of options to improve information for generation and electrification investors, some of which are set out below for feedback. The options are presented at a high level in order to seek feedback on whether they merit further investigation.

Options involving the mandatory provision of public information were considered, but are not proposed due to the commercial sensitivity of the information involved (it would need to be quite detailed to provide any value).

The option presented in section one of this document regarding Corporate Energy Transition Plans partly addresses issues of information gaps, and could be considered as complementary to the options presented below.

Option 10.4	Provide independent geospatial data on potential generation and electrification sites (e.g. wind speeds for sites, information on relative economics and feasibility of investment locations given available transmission capacity).

Independent information could include wind data on speed for sites, but also information on the feasibility and economics of construction, and consenting issues. The cost of providing this information would depend on its scope and form.

This option would benefit local authorities developing regional and district plans as it could help inform identification in RMA plans of areas suitable for renewables, and help align future planning across transmission, distribution and generation stakeholders. The option would also benefit new investors to a region or area, by providing preliminary information on suitable options that would help their high level scoping assessment before they engaged in more detailed and potentially costly study.

However, it may be that the provision of aggregated consistent wind data for different locations[134] is the only feasible option due to the issue of IP rights of developers who have already developed the relevant information of a potential generation site themselves.

Providing this information to a wider group would undermine any competitive advantage that the earlier developer had obtained, unless they had already secured access and consents to the site. In addition the rapid nature at which generation technology is developing could mean that information could quickly become outdated, requiring frequent reassessment. This would considerably increase costs for the agency undertaking the work.

[134] Detailed indicative wind speed data is freely and/or cheaply available from global models/national datasets, but it requires some manipulation and compilation which may be a barrier for some users

Option 10.5	Extend the data and information provided in MBIE's EDGS and increase the frequency of publication, and potentially recover the cost through the existing levy on electricity industry participants.

The most systematic and regular source of public and independent information on potential demand and generation investment is MBIE's EDGS[135], which have an explicit role in the investment test the Commerce Commission must use in approving Transpower's major capital projects.

In the last decade, the EDGS have been prepared in 2012, 2016 and 2019, and have presented a range of scenarios for growth in demand and capacity at a national level. In future, the EDGS, or something similar, could be updated more frequently, and could include more granular information, such as presenting information at a regional level. The value of more frequent updates to EDGS would be to provide more up to date independent information on a range of potential electricity supply and demand scenarios.

EGDS scenarios are designed to reflect alternative futures that could arise under certain circumstances. None of the scenarios in EDGS are optimised to forecast the 'optimal' future, in the manner that a historical 'central planner' would produce. Hence, consideration would be needed over which scenario(s) should be forecast, if this option was implemented.

The cost of producing the EDGS is currently recovered from tax-payers, but provisions exist for it to be recovered from electricity industry participants through a levy.[136] A shift to levy funding would be based on the principle that those who generate the need for, or potentially benefit from, activities should be contributing towards the costs of the activity. In this case, Transpower and its customers benefit from the provision of independent information to assist with investment planning.

Implementation of levy funding would require annual consultation on the amount of funding, approval by the Minister of Energy and Resources, and, if agreed, recovery of that funding from Transpower. The cost would then be passed on to transmission customers, and ultimately electricity consumers.

Option 10.6	Produce a user's guide on the current regulations and approval processes relating to getting an upgraded or new connection to the grid.

The regulatory processes for new and upgraded transmission and distribution assets are necessary and important, but can create complexity and a barrier for those contemplating electrification, or the connection of generation, particularly if it is small scale.

The purpose of a guide would be to help parties considering new generation or demand to navigate the regulatory and approval process for connecting to the grid. This could assist established investors as well as community groups or other entities considering investing in small-scale generation, and customers considering electrification (including heavy electric vehicles and charging infrastructure, for example).

[135] Available at: www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-modelling/electricity-demand-and-generation-scenarios/

[136] Under the Electricity Industry (Levy on Industry Participants) Regulations 2010, specifically, under regulation 4(1), which states "the costs incurred by the Crown in relation to developing and publishing regional electricity supply and demand forecasts and scenarios, and related information and analysis, for the purpose of assisting investment planning by industry participants".

This guide could set out the regulatory requirements and processes that need to be followed, and the steps, dependencies, and timelines involved. It could include who parties need to talk to and when, and the kinds of things that need to be taken into account along the way. It would be a simple guide to what is (or a least seems to be) a complicated process. Over time, a guide could be extended to include information on getting an upgraded or new distribution line.

There would be some up-front cost involved in producing the guide, and then an ongoing cost to maintain it when any regulatory or process changes are made. Where the costs fall would depend on which agency or entity prepares it, for example, taxpayers would fund it if a central government department produced it.

Questions

Q10.5	Do you think that there is a role for government to provide more independent public data? Why or why not?
Q10.6	Is there a role for Government to provide independent geospatial data (e.g. wind speeds for sites) to assist with information gaps?
Q10.7	Should MBIE's EDGS be updated more frequently? How often?
Q10.8	Should MBIE's EDGS be more granular, for example, providing information at a regional level?
Q10.9	Should the costs to the Crown of preparing EDGS be recovered from Transpower, and therefore all electricity consumers (rather than tax-payers)?
Q10.10	Would you find a users' guide helpful? What information would you like to see in such a guide? Who would be best placed to produce a guide?

Lack of information sharing for coordinated investment

What is the problem?
While provision of public information could go some way to improve decision making, enhanced information sharing between relevant parties could result in more coordinated investment. There may be information that is more suited to sharing between interested parties, rather than making it publicly available. Better information sharing could also help with better aligning the lead times of new or upgraded transmission assets and the development of new generation or demand.

Areas where there is a potential lack of information sharing between potential investors in generation, large users looking to electrify, and Transpower include:

- information on where there might be spare grid capacity
- information on when potential developers (including of heavy electric vehicle infrastructure) or process heat users in the same area are likely to invest.

This has implications for decision making, and particularly for coordination of decisions between the multiple parties involved. It can have timing implications, and also exacerbates the risks associated with the first mover disadvantage.

There is an interrelationship with the TPM in terms of the incentives it does (or doesn't) create for information sharing and participation in the process/scrutiny of transmission investment proposals. For example, because the current interconnection charge spreads the cost of investment across all customers, those that will benefit most have a strong incentive to engage in the approval process and support it since they will only end up paying only a fraction of its cost. Conversely, it creates a weak incentive for engagement and scrutiny for those that don't benefit as they too only pay a fraction of its cost. The EA's proposed changes to the TPM may resolve some of this concern.

Better information sharing would also help Transpower (as the grid-owner) avoid constraints on the system. Given our open access arrangements, changes could be made to further enable:

- better and more timely decision making
- coordination between renewable generation investors / developers, including with Transpower, and
- coordination between large users looking to electrify and Transpower.

What are the options?

Your views are sought on two interrelated options below, and on what other options could be considered.

Option 10.7	Provide a database of potential renewable generation and demand sources, location and potential size (e.g. wind, geothermal, milk plant).

This option would draw on existing data and information to compile a database on potential new generation and demand that would be updated regularly and proactively.

The Electricity Authority already publishes a database of proposed new generation based on publicly available information, including the status of the proposal in terms of the consenting process and the likely commissioning date. This option would extend this information to include potential new sources of demand, and potentially available capacity on the national grid.

If progressed, this option could include more detailed information that could be shared between interested parties, but equally could include only information that could be published.

It could be voluntary or involve introducing mechanisms to improve coordination of transmission and generation lead times, e.g. requiring developers to talk to Transpower earlier about plans, or the provision of better data on future generation supply to Transpower.

An option could also be to present this in map form to inform decisions by potential investors in generation, large users looking to electrify, and Transpower. Variations also include updating and building on the Regional Renewable Energy Resource Assessments undertaken by EECA about 10 years ago, which were made publicly available, or publishing information compiled from market observers that could be commented on.

This option may be costly to administer, and prove difficult to implement as it could potentially require disclosure of investment plans that parties may not want to disclose (to maintain their competitive advantage). The simple disclosure that another party (even if anonymous) is considering an option at a location could be information that generators want to protect. This risk could be reduced by ring fencing information provision to an entity (such as Transpower).

There is also an open question about who would be best to develop and maintain this database, and how it would be funded. Your views are sought on these matters, in addition to your views on its potential design and value.

Option 10.8	Introduce measures to enable coordination regarding the placement of wind farms to ensure they are more likely to be better distributed around the country.

This option addresses the risk of negative consequences if too many wind farms are built too close together. This risk arises because there is a strong correlation between the output of wind farms located in the same region due to weather patterns. It could be an issue if new wind farms are located close together and/or close to existing wind farms. While the wholesale electricity price provides a signal about transmission constraints at hundreds of locations around the country, it also reflects other factors that affect supply and demand for electricity at any one time (such as outages).

The ICCC's analysis showed that a significant amount of new generation is likely to be wind given its cost, the availability of quality sites, and its relatively low impact on the biophysical environment (and easy reversibility). The ICCC's modelling involved spreading future wind farms across the country to reduce the correlations and manage intermittency[137].

This option could be an extension of option 10.7, drawing on either existing public data, or independent wind site data potentially provided under option 10.4 above. Alternatively, it could just involve potential investors providing data relating to wind sites to an entity (such as Transpower) who could advise on locational risks and constraints. This could be voluntary or mandated, and could include Transpower having different arrangements for information sharing between parts of its business.

Similar to the option above, this option may be costly to administer, and prove difficult to implement as it could potentially require disclosure of investment plans that generators may not want to disclose (to maintain their competitive advantage).

The cost of this option, and risks with information provision, need to be assessed against the potential benefit of avoiding additional electricity system costs relating to managing intermittent wind generation, and the benefit of lower emissions generation.

Questions

Q10.11	Do you think that there is a role for government in improving information sharing between parties to enable more coordinated investment? Why or why not?
Q10.12	Is there value in the provision of a database (and/or map) of potential renewable generation and new demand, including location and potential size? If so, who would be best to develop and maintain this? And how should it be funded?
Q10.13	Should measures be introduced to enable coordination regarding the placement of new wind farms?
Q10.14	Are there other information sharing options that could help address investment coordination issues?

[137] For more information, see ICCC Modelling, Wind and Solar Profiles, Final Report, April 2019, available at: https://www.iccc.mfe.govt.nz/assets/PDF_Library/48da95e31a/FINAL-Culy-ICCC-modelling-Wind-and-Solar-Profiles.pdf

Summary assessment of options against criteria

	First mover disadvantage				Information gaps			Lack of information sharing	
	Shift cost and risk allocation from the first mover – optimise asset valuations	**Shift cost and risk allocation from the first mover – delay cost recovery**	**Include benefits of mitigation in Transpower's major capital applications**	**Mechanisms for alternative forms of cost sharing arrangements**	**Provide independent geospatial data on potential sites**	**EDGS: extend data and increase frequency**	**Produce a user's guide on regulations and approval processes for connecting**	**Map of potential renewable generation and demand sources**	**Coordination measures to distribute wind farms**
To what extent is the barrier addressed?	✓	✓	✓	✓	✓✓✓	✓	✓✓	✓✓	✓
Primary benefits – emissions reductions	It is difficult to quantify how these measures might impact emissions, so no attempt is made to compare the relative contribution each option could make								
Primary benefits – EE & RE	✓	✓	✓	✓	✓✓	✓	✓✓	✓✓	✓
Wider economic effects	–	–	✓	–	✓	✓	✓	✓	✓
Compliance costs	–	–	–	–	–	–	–	X	X
Administration costs	X	X	–	X	XX	–	X	XX	X
Energy trilemma – security and affordability	X	X	*It is difficult to quantify how these measures might impact on security and affordability, so no attempt is made to compare them*						

Key:	Option under active consideration	Option not preferred

Section 11: Local network connections and trading arrangements

This section seeks your views on whether enough is being done to enable connections to, and trading on, the local network. It summarises regulatory arrangements and work underway to address:

- barriers to connecting to the local network
- issues with the arrangements for trading on the local network, and
- issues with pricing and cost allocation for network connections and services.

Barriers relating to consenting distribution lines are discussed in section 7 of this document.

New generation and large potential electricity users (such as process heat sites) can connect to a local distribution network instead of the transmission grid, making use of existing or upgraded capacity. Generation connected to the local network is called distributed generation.

The ICCC and the Electricity Price Review (EPR) both evaluated barriers to connecting new generation or process heat loads to the distribution network. The ICCC noted increased opportunities for investment in new distributed generation, and facilitating greater community involvement. It recommended that any regulatory barriers relating to electrification of process heat, and distributed and off-grid renewable generation are identified and addressed.

Distributed generation can play an important role in maintaining system security and reliability, and potentially provide a lower-cost alternative to investing in transmission or distribution networks directly. As a Distributed Energy Resource (DER), it can also reduce electricity losses, and provide incremental increases in supply that are more aligned to local growth in demand. Other DER includes rooftop solar, battery storage, and demand response. Distributors can enable DER by providing a neutral platform to providers to facilitate two way power flows.

More broadly, the ICCC recognised the role distributors (and retailers) have in providing the right price signals to consumers who want to be more actively engaged in demand response, and the need for pricing reform to enable this. This includes ensuring that consumers have access to data and can offer services to the network, such as battery storage. Consumers and new service providers also need to be able to access and trade on the local network to actively engage in the electricity market.

Related conclusions reached by the EPR are that current distribution pricing does not reflect the cost of distributing electricity and prevents consumers from benefiting fully from emerging technologies, and that powers to regulate access to the network are ambiguous.

The EA has a programme of work underway relating to the development and use of evolving technologies and business models, and recently commenced an Open Networks project to identify and develop ways to provide for the uptake of new technology on distribution networks.[138] The Open Networks project will help to overcome barriers to greater uptake of distributed energy resources at both the consumer and network services level. The EA is also monitoring and supporting distributors' efforts to make network charges more cost-reflective, consistent with distribution pricing principles it released earlier this year.

[138] www.ea.govt.nz/development/work-programme/evolving-tech-business/open-networks/development/

The industry association that represents distributors, the Electricity Network Association (ENA), recently prepared a "Network Transformation Roadmap" (ENA Roadmap) to guide boards and senior management in setting their strategies and planning for the future.[139] The ENA Roadmap focuses on new technologies, rather than traditional aspects of electricity distribution, and emphasises the new activities and functions distributors will need to undertake.

Summary of regulatory arrangements

There are 29 businesses that plan, build and maintain the local networks that distribute electricity. The EA regulates the connection of distributed generation through the Code, including the process for connection and default terms and conditions. It also sets pricing principles for distributors to apply when determining connection charges, and distribution pricing principles to guide how distributors allocate their costs between consumers.

Investments in distribution assets are subject to regulation by the Commerce Commission that is designed to ensure that they have incentives to innovate, invest, and meet customers' quality demands, but are also limited in their ability to earn excessive profits. Seventeen distributors[140] are under price-quality regulation[141], and all 29 are subject to its information disclosure rules.[142]

Information disclosure provides transparency about how distributors are performing, and a check that regulation is working. Relevant disclosures are set out in the text box below. Broadly, they require distributors to plan for a changing environment, including for emerging technologies, and to be transparent about how they price their services.

Relevant disclosures: Commerce Act information disclosure requirements

Asset Management Plans (AMP) – Communicate asset investment and maintenance plans, and provide information on how the distributor intends to manage its assets to meet consumer demands in the future. Plans must include:

- Examples of how asset management strategies respond to a changing environment "….due to a variety of factors including demand growth that needs to be funded in a different way to encourage connection, or a change in customer demand patterns for example, due to the uptake of emerging technology like electric vehicles".
- How the distributor has effectively gathered customer input about network enhancements and developments.

Pricing methodologies – each distributor prepares and uses one to determine the prices it will charge customers connected to its network. A distributor's pricing methodology must set out:

- How it has decided to recover its revenue from different groups of consumers
- Its approach to setting prices in non-standard contracts and for distributed generation
- Its policy or methodology for determining when it will charge a capital contribution towards a new line, and what the charges will be.
- How its pricing methodology is consistent with the EA's pricing principles, including for its capital contributions policy.

These existing requirements provide a platform for better coordination as potential investors (and to a certain extent consumers generally) work with distributors to connect new generation, electrify

[139] http://www.electricity.org.nz/news-and-events/news/transformation-roadmap-to-be-launched-in-april/

[140] The other 12 are consumer-owned and exempt as Parliament has decided that their consumers have enough input into how the business is run.

[141] Price-quality regulation limits the revenue distributors can earn or the maximum average prices they can charge, and requires them to deliver services at a quality that consumers would expect.

[142] https://comcom.govt.nz/__data/assets/pdf_file/0025/78703/Electricity-distribution-information-disclosure-determination-2012-consolidated-3-April-2018.pdf

and/or participate in the electricity market. This includes groups and agencies looking to invest in community energy projects. Distributors may increasingly need to invest in the management of their networks as energy flows become more complex and dynamic (for example. increased network congestion as a result of more distributed generation).

Overview 11.1	The existing regulatory framework provides a platform for better coordination between investors (and to a certain extent consumers generally), distributors and other interested parties to connect new generation, electrify and/or participate in the electricity market. There is a significant amount of activity already underway to improve on the existing arrangements, so no particular option has been identified. Some of the options set out in the transmission section could be extended to include distribution, and these are noted below. This section does not have any specific recommendations on reducing distribution barriers, instead we seek information on your experiences, and on whether there are any gaps not addressed by current and planned future work outlined below in relation to the three areas identified.

Barriers to connecting to the local network

Distributors face the challenge of not over or under investing, and will make investment decisions in the context of their existing asset base, expectations about the future, and the regulatory environment that they face.

Network investment has historically been driven by peak demand and providing resiliency. This is expected to change with more distributed energy resources and digital control, and there are opportunities for better utilisation of the network.

Distributors face challenges to their capacity and capability to evolve networks to cope with the effects of emerging technologies. Technology changes will require distributors to be more proactive, better understand their networks, and to adapt to meet the needs of existing and new customers. Changing technology provides new opportunities but also creates increased risk if the wrong technology investment decisions are made. Sufficient adaptability and flexibility in the regulatory environment is also necessary if networks are to respond to changing technologies and consumer patterns.

Developing networks efficiently that are agile and adaptable to future technological and societal change requires greater adaptability and coordination between the multiple parties involved (large users, providers of DER, distributors, Transpower, and other potential customers). They will need to coordinate, share information and at times adopt a shared planning approach. Achieving these goals may require increased flexibility on behalf of regulators to facilitate and coordinate the most efficient network approach.

Process heat

Part A of this discussion paper explores options to reduce emissions from industrial heat processes, including electrification. Full or partial electrification of process heat may require an upgraded or new distribution connection, rather than a grid connection. However, the capacity needed at a site may change over time as it works through the process of electrification.

This means that investments may be made in the distribution network that then become physically stranded as the needs of the plant change, for example, reaching full electrification that requires a direct connection to the grid. Conversely, an upgrade or new connection may be sized for one customer, which then needs to be upgraded for another (large demand) customer connecting to the same line. This creates risk and costs for the parties involved, and a coordinated approach is needed.

In previous discussions with distributors, it has also been noted that it was important for customers to engage early with them to ensure connections could be planned and delivered in a timely fashion, and that consumers tended to engage relatively late in the process.

Some options for improved coordination of information are outlined in section 10. It may be possible to extend some of those options to cover distribution at a later stage, should those options go ahead.

Distributed generation

Current wind farms are often distributed generation, and in the future more wind can be expected to connect to local networks (rather than the grid). Significant growth in solar PV, both at a household and a commercial level is also expected. This means there tends to be more certainty about the needs of a generator looking to connect to the local network rather than the grid, whether it is a small solar PV installation or a relatively large wind farm (about 45 per cent of New Zealand's current wind capacity is distributed generation).

In some network areas, there may only be a limited amount of capacity available, and if it is allocated on a first-come-first-served basis, this may not lead to the most efficient outcome. Technical standards for connections also vary between local networks, creating uncertainty about requirements.

Current work on these issues

The EA has a work programme underway to shift distributors to an "equal access" model on their network. This means having networks that anyone can connect and use any equipment they want to buy or sell electricity services. "Anyone" can range from a large investor wanting to connect and sell generation, through to a person wanting to trade electricity from their solar PV installation, and anyone in between. This model also promotes the development of new business models and service providers.

In addition, the industry-led ENA Roadmap is based on an "open network" framework concept that supports the equal access model. The associated programme of actions includes items such as enabling third party DER, demand response for network support, and working with regulators on the challenges of multiple users of demand response.

This roadmap also contains a programme to standardise technical arrangements so that there is a consistent method of connection of equipment (distributed energy resources or appliances) within and across local networks, which complies with approved standards. This should provide more certainty to both distributors and connecting parties about the requirements that need to be met, and how to meet them. Lastly, it contains a programme to build and adapt capability within distribution businesses.

Recommendations from the EPR review include that the EA should be given more powers to regulate network access, and that it should continue to prioritise work that supports innovation in the electricity sector, for example, its work on equal access to the network.

The Commerce Commission is also working to foster improvements in distributors' asset management and planning capability, and recently released a decision on price quality paths relevant to greater electrification. More detail on this is set out in the text box below.

Enabling decarbonisation through price-quality regulation

The Commerce Commission's recent default price-quality path decision includes a number of features relevant to encouraging innovation by electricity distributors in a way that contributes to the Government's objective of decarbonisation through greater electrification:

- an allowance for innovative projects
- equalising for operating expenditure and capital expenditure to incentivise no-wire alternatives like demand management where it is more cost effective
- a shift to a revenue cap (from a price cap), allowing more freedom to adjust pricing structures to support demand side management and the adoption of new technologies, such as electric vehicles
- provision to "re-open" a price path to allow for the costs of large distributed generation and large unforeseen industrial connections and, such as due to the electrification of process heat.

Issues with the arrangements for trading on the local network

Enabling businesses, new service providers and consumers to actively engage in the electricity market (if they want to) should promote more demand management and demand response. Both can contribute to reducing peak demand and help manage intermittency.

Current work on this issue

The EA has consulted on introducing a default distributor agreement (DDA)[143] that includes provisions for agreements between distributors and 'traders', who offer products and services such as providing network support through aggregated household batteries. This is in recognition that the electricity industry is rapidly changing in response to innovation and new business models.

A default agreement will make it easier for service providers to contract to use a network and provide services to a distributor. It also helps reduce access barriers, promote the deployment and uptake of new technologies, and enables them to compete in the market for network support services.

It is also important that the regulatory framework supports distributors to innovate, and enables alternatives to poles and wires. Recent decisions following the EPR include that the Commerce Commission's price-quality regulation should be implemented in a way that encourages innovation among distributors.

A related issue is that distributors providing DER could unduly lessen competition in the emerging DER market. Decisions from the EPR include the development of more nimble regulation to enable more DER, while ensuring that consumers can fully benefit from it.

The ENA Roadmap open network framework and "consumer insights" programme are relevant here – the latter is about understanding consumer motivations and behaviours to determine the impact on DER deployment and consumption patterns, and new load requirements on the network. This should promote a move to more active planning and delivery of distribution services.

[143] Primarily for agreements between distributors and retailers for access to the network, and submissions closed on 15 October 2019.

Issues with pricing and cost allocation for network connections and services

How the costs of new network connections are allocated, and the way that distributors price their services, has implications for potential investors in new distributed generation (in terms of both the decision to invest and its ongoing viability). The viability of distributed generation will also be impacted by any payments that a distributor is required to make to its owner (see case study regarding avoided cost of transmission below).

Distribution prices also have implications for consumers investing in technology to generate and store electricity, especially if they are to be rewarded for engaging in the electricity market.

For small distributed generation installations such as household solar PV, the retailer's charges and buy back rates are more relevant. The price a household pays a retailer for the electricity it purchases, and the price the household receives for any electricity it sells back to the grid will include transmission and distribution charges. Retailers decide how to bundle and pass on these charges, which is partly why retailers have a role in providing the right price signals to consumers.[144]

Transpower has noted[145] that 'most end-users today face pricing structures that over-stimulate self-production, under-stimulate efforts to moderate peak usage, and overly deter electrification, so ensuring 'suitably' cost-reflective pricing structures is key given their influence on investment and operational decisions.'

At the same time, it will be important for future investments that distributed generation can receive reward for any benefit it provides to the local network, and that there is certainty about revenue streams.

Case study: Avoided cost of transmission (ACOT) payments

The Code currently requires distributors to make ACOT payments to distributed generators that existed before December 2016, and that cause a reduction in transmission costs. This arrangement is the result of reforms in 2016 and further refinements are expected if changes are made to the TPM guidelines.

It has been argued that the current ACOT arrangements and the potential for further unilateral changes have affected the viability of existing distributed generation, and potential investments. The counter argument is that the previous ACOT arrangements were over-stimulating investment in distributed generation that did not reduce grid costs, but did shift costs onto others, raising electricity prices for consumers in other parts of the country.

Current work on this issue

The EA develops and publishes principles that distributors must apply when pricing their distribution services. Revised principles and a monitoring framework recently published by the EA are encouraging distributors to transition to more efficient distribution pricing. The principles state:

> "*…Reform is needed because the scope for poor outcomes from inefficient price signals is growing. This is a result of technologies, such as electric vehicles, solar panels and battery storage, becoming more available and affordable.*"

[144] The other reason is that retailers need to manage their wholesale price risk, so should have incentives to encourage load shifting and conservation at times when wholesale prices are elevated (i.e. at peak and at times of shortage).
[145] Page 7 of submission to the Productivity Commission's *Low Emissions Economy*.

Without pricing reform, the EA expects poor outcomes resulting from overinvestment by consumers in technologies to avoid network charges, which shifts costs onto other consumers, results in unnecessary network investments, and exposes distributors to commercial risks (for example, stranded assets).

The EA recently released a practice guide to distribution pricing[146] to help distributors interpret and apply the principles, and disclosures against the newly revised principles are due in early 2020. It also asked distributors to publish roadmaps to show how they will move to more efficient pricing.

Distributors are working to different timetables, which creates uncertainty in terms of future distribution pricing. The EA's overview of all the roadmaps notes that "….in general, most distributors[147] intend to complete preparatory work and develop plans (including consultation) over 2017-2019, with the implementation and monitoring of the reform occurring from 2019 onwards."

Distributors themselves face uncertainty until transmission pricing reform is completed, and decisions are made on the EPR recommendation to phase out low fixed charges, both of which are likely to affect distribution pricing. The EA is progressing work to reform transmission and distribution pricing.

Under the current regulated terms, distributors can only charge distributed generation no more than the incremental cost for connection and distribution services. Following consultation in 2016, the EA decided[148] not to proceed with a proposal to remove this 'price ceiling', but may revisit this once decisions are made about the TPM and distributors have made progress with setting cost-reflective charges. The price ceiling protects owners of distributed generation from distributors using their monopoly power to overcharge them. The EA had proposed to remove the price ceiling because in their view it may be providing distributed generators with an artificial competitive advantage over grid-connected generators and also over other technologies, such as solar panels, batteries and other modes of demand response.

The ENA Roadmap is also relevant to this issue, particularly the programme relating to distribution pricing.[149] This recognises that cost reflective pricing is essential as it "…communicates the cost of using the distribution service for energy delivery to and from prosumers[150], and of the need for capacity for network support".

Questions

Q11.1	Have you experienced, or are you aware of, significant barriers to connecting? Are there any that will not be addressed by current work programmes outlined above?

[146] Distribution Pricing: Practice Note, August 2019, available at: www.ea.govt.nz/development/work-programme/pricing-cost-allocation/distribution-pricing-review/development/distribution-pricing-practice-note-and-scorecards/

[147] Six distributors did not provide information on timing, but those that did intend to implement new prices before 2023.

[148] www.ea.govt.nz/development/work-programme/pricing-cost-allocation/review-of-part-6-distributed-generation-pricing-principles/development/authority-decision-on-the-review-of-dgpps-and-acot/

[149] The "Cost Reflective Pricing and Regulation" programme with the objective: "enable the open network framework through ensuring the development of appropriate incentives to coordinate DERs for network and system support, and to avoid congestion".

[150] A person that both consumers and produces a product, in this case, electricity.

Q11.2	Should the section 10 option to produce a users' guide extend to the process for getting an upgraded or new distribution line? Are there other section 10 information options that could be extended to include information about local networks and distributed generation?
Q11.3	Do the work programmes outlined above cover all issues to ensure the settings for connecting to and trading on the local network are fit for purpose into the future? Are there things that should be prioritised, or sped up?
Q11.4	What changes, if any, to the current arrangements would ensure distribution networks are fit for purpose into the future?

Appendix 1: State sector leadership

The government is taking a number of actions to take greater leadership in adopting greater energy efficiency and renewable energy in its own operations.

Government procurement

The Government has committed to reducing energy use across its property portfolio. Accordingly, the 4th edition Government Procurement Rules was released on 4 June 2019 and has a priority outcome for government procurement to contribute to the transition to a low carbon economy, in the areas of vehicle fleets, heat and waste. Rule 20, which came into effect on 1 October 2019, directs Government agencies to support the Government's objective of low emissions and waste in Government contracts, and requires agencies to:

- procure low-emitting heat systems when these systems come up for replacement
- support the procurement of low emissions vehicles to work towards the Government's goal of its vehicle fleet, where practicable, becoming emissions free by 2025/26
- reduce waste from the procurement of office supplies.

Government property

Government is the largest tenant of office space in New Zealand and has about 1.2 million square metres of office space across the country. We are progressing work to measure and improve the energy efficiency of Government buildings, both leased and owned using the National Australia Built Environment Rating System New Zealand (NABERSNZ) rating system[151], with a target rating of four stars.

EECA supports large public sector energy users

EECA supports large public sector energy users and emitters in its Large Energy User programme, supporting district health boards with a range of tools, and providing guidance to government agencies looking to measure and report their emissions.

The Government is currently investigating a joined-up programme to minimise any duplication of efforts, appropriately resource procurement requirements, and provide centralised funding and implementation support to assist agencies to act faster whilst also reducing administration burden.

[151] NABERSNZ is a system for rating the energy efficiency of office buildings https://www.nabersnz.govt.nz/

Case study: Northland hospitals[152]

The Northland District Health Board (DHB) runs hospitals that have historically used fossil fuel-fired central boiler systems to provide heat and hot water. Over the past five years the DHB has been progressively converting these to electric heat pumps – saving money and reducing emissions. Kawakawa hospital was the first at which modern, efficient heat pumps replaced boilers. The project was so successful that it was quickly replicated at Kaitaia and Dargaville Hospitals.

The $700,000 investment in making the switch across all three hospitals was funded through a loan from EECA and generated target cost savings of $300,000 per annum. This represents a compelling investment case: including a two-year capital pay-back period and the ongoing annual savings able to be redirected into core health services. Kaitaia and Dargaville Hospitals provide a clear example of the value of the change.

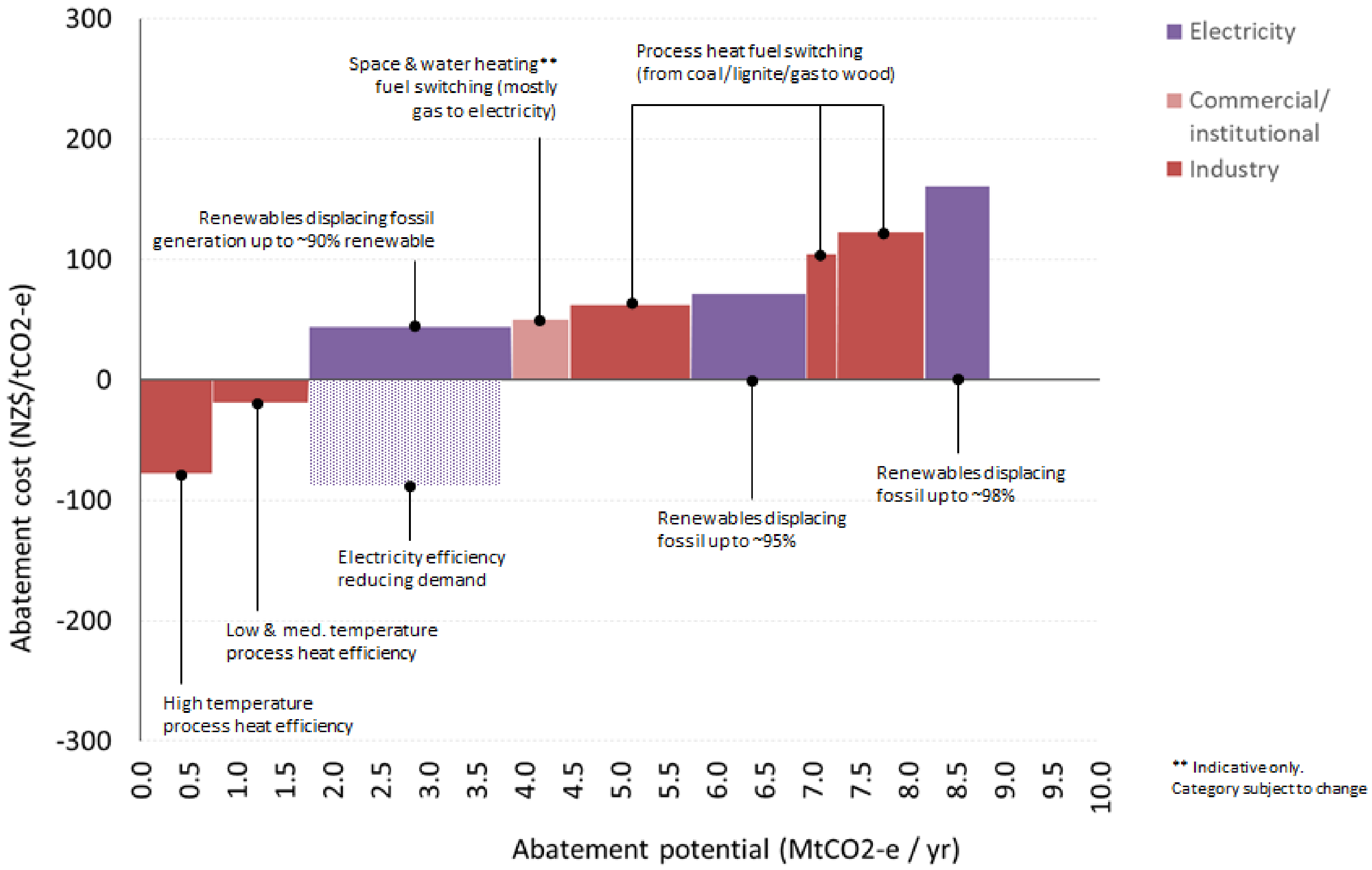
Each hospital's central boiler was run on diesel (burning a combined 127,000 litres of diesel per annum) while the new electric heat pump system is 3.5 times more efficient and enables superior levels of control. For example, the heat pump-based system enables separate control of hot water and heating, enabling individual buildings to be managed based on occupancy. This makes a huge difference as only one ward is used day and night and historically the whole system had to be run on the diesel system. This is a typical example of the dual focus on electrification and efficiency – using less energy from cleaner sources to generate savings.

Overall, the DHB has cited "clear financial benefits" and "reducing our carbon footprint" as the core reasons behind the change.

[152] Northland Hospitals – sourced from Northland District Health Board. www.northlanddhb.org.nz/assets/about/Carbon-Footprint-to-2018.pdf

Appendix 2: Stationary energy opportunities to reduce emissions

Indicative Stationary Energy MACC: present day prices and maximum abatement potential
Uncertainties not shown. Numbers provisional and subject to change.

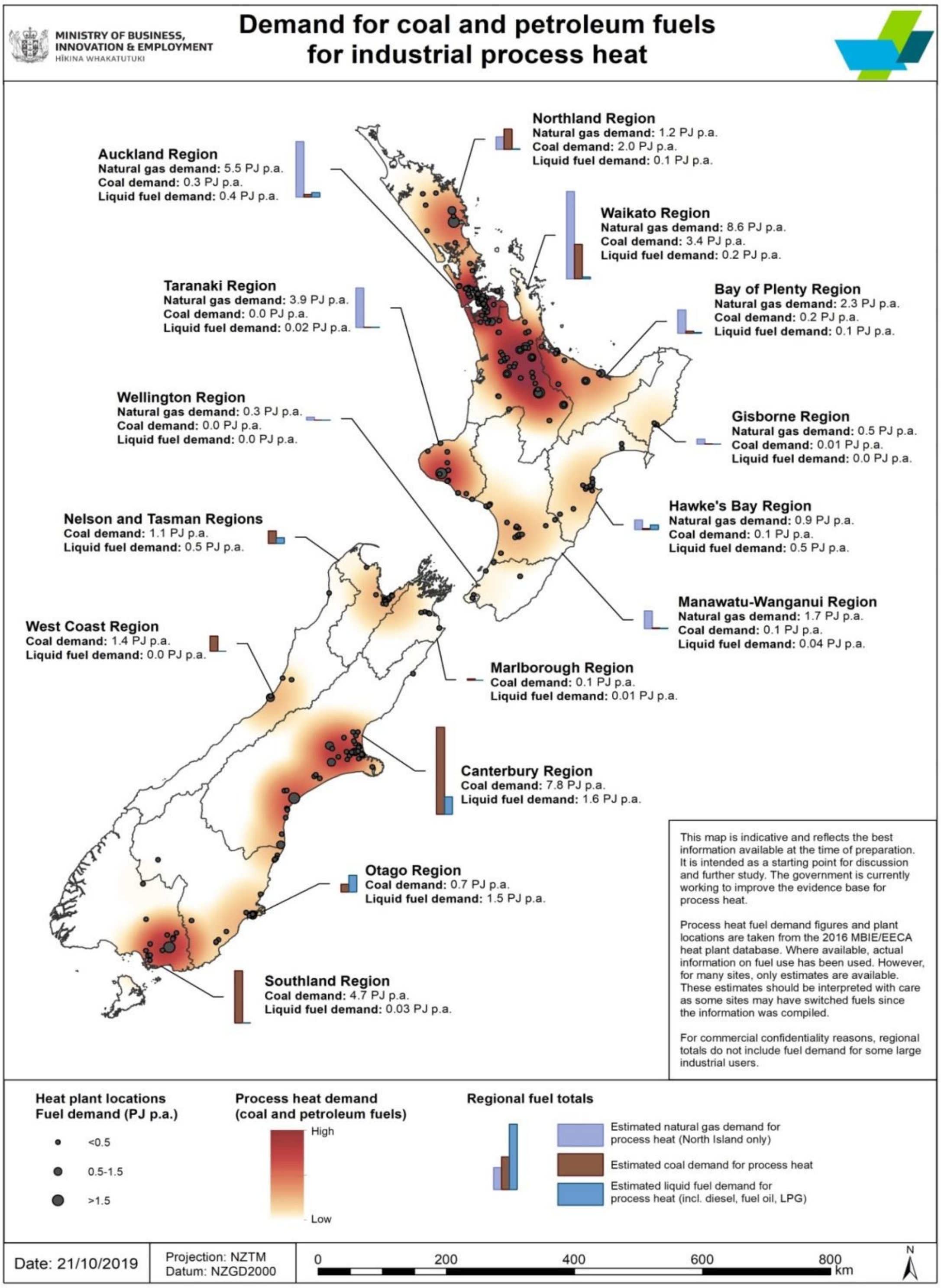


Source: Ministry for the Environment (unpublished 2019) *Draft Marginal Abatement Cost Curves Analysis - Stage 1 report: MACCs tool documentation and initial results*.

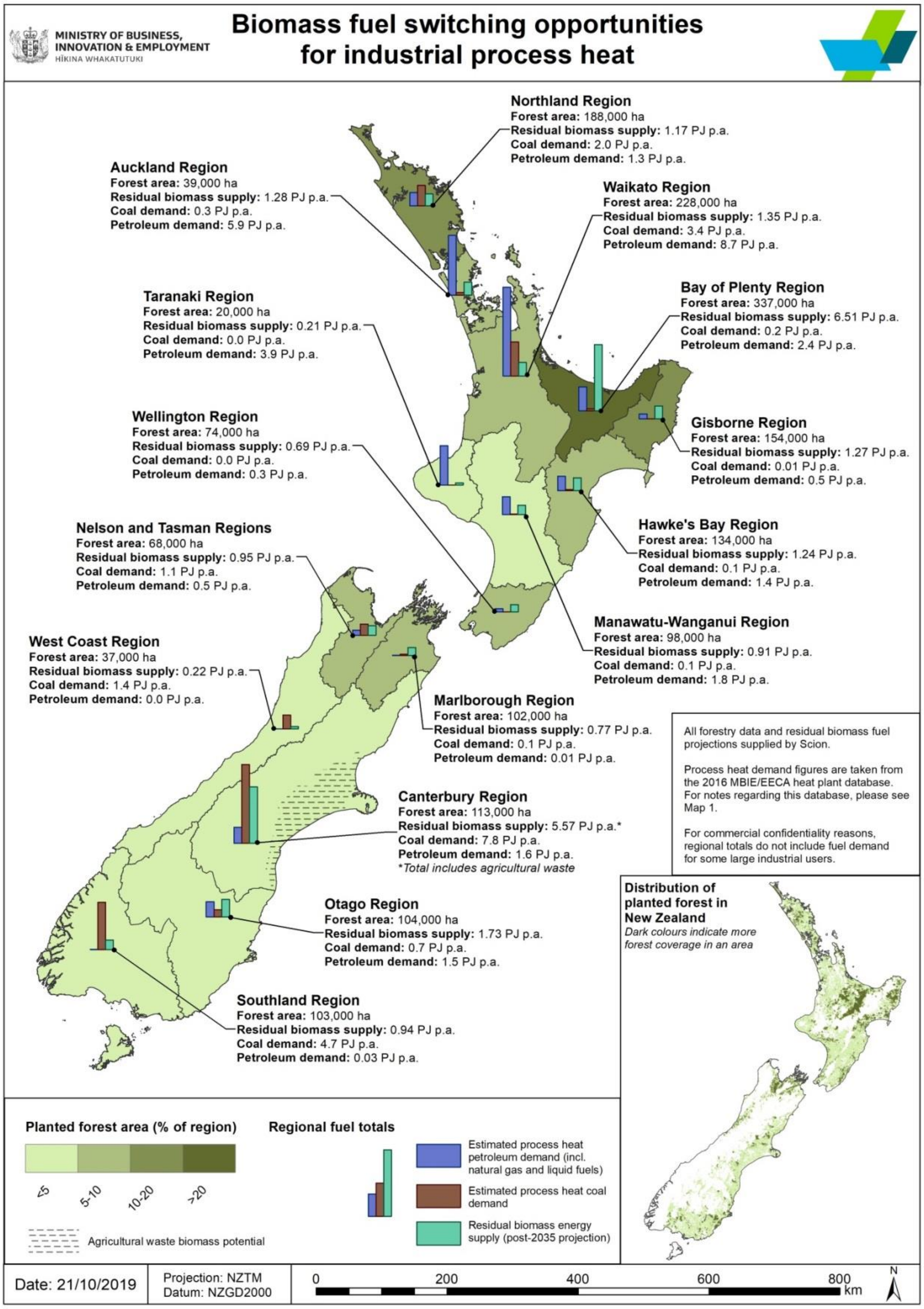
Notes

- Opportunities are ranked by their cost per tonne of emissions, or marginal abatement cost (MAC), where the height of the bar represents the options' cost per tonne, and the width of the bar represents the total possible emissions savings. The figure above shows an indicative present day potential for stationary energy (electricity and process heat). The abatement potential here is the maximum possible savings.
- Provisional results from MfE's MACCs tool supplemented by additional information sources.
- The blocks show the weighted average MAC for the option identified. There is often significant variation within a block.
- 'High temperature process heat efficiency' covers negative cost opportunities identified by Martin Atkins, mostly in refining, steel and methanol production.
- 'Low & med. temperature process heat efficiency' covers heat recovery and process electrification (e.g. MVR) opportunities identified by Martin Atkins in food processing.
- 'Renewables displacing fossil generation' covers the building of new renewable plant (indicatively wind) to displace existing fossil generation (e.g. CCGT). This has been shown in three blocks to reach specified levels of renewable generation.
- 'Electricity efficiency reducing demand' reflects the potential identified in EECA's *Energy Efficiency First* report to replace up to around 4,000 GWh through cost-saving electricity efficiency opportunities such as LED lighting and heat pumps.
- 'Space & water heating fuel switching' covers replacing existing fossil heating systems (mostly gas) in commercial and institutional buildings with electricity or biomass. **Note the costs of this are still being investigated so the average $50/tonne assumption used here is only indicative**.
- 'Process heat fuel switching' covers opportunities to switch from coal, lignite and gas to woody biomass in the food and wood processing sectors. The alternative of switching to electricity is not shown, but our analysis indicates the MAC could be 2-3 times as high as for biomass. Results will be highly site-specific.
- Higher cost options in heavy industry sectors (such as hydrogen or CCS) are not shown.

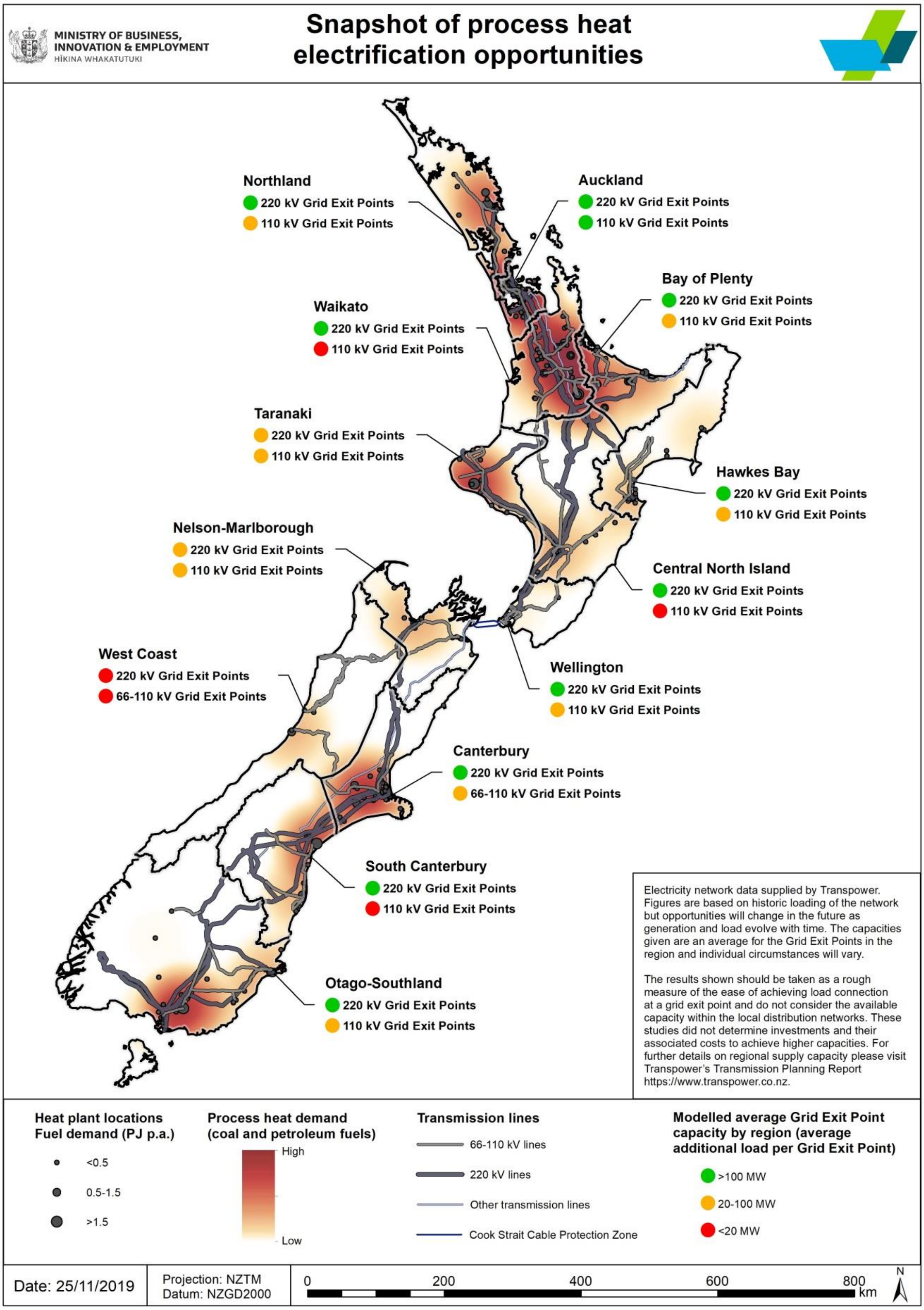
Appendix 3: Process heat demand map



Appendix 4: Biomass fuel switching map



Appendix 5: Process heat electrification opportunities



Appendix 6: ICCC Accelerated Electrification recommendations

The ICCC report 'Accelerated Electrification' and Government response to the report were released on 16 July 2019. The Governement response noted a number of areas where the ICCC recommendations have been welcomed, but specific recommendations are to be consulted through work programmes including accelerating renewable electricity generation and decarbonising process heat. This document contains a number of options that relate to recommendations of the ICCC relevant to accelerating renewable electricity generation and decarbonising process heat as follows:

Recommendation	**Government response**	**Where covered in this document**
Strongly encourage the phase out of fossil fuels in process heat by: 3 a. Deterring the development of any new fossil fuel process heat.	Government welcomes the overarching recommendation of the ICCC to encourage the phase out of fossil fuels in process heat. The Government has work underway on process heat and will be consulting later in 2019 on options to encourage energy efficiency in industrial sector use of energy and to decarbonise process heat through uptake of renewable fuels (e.g. electrification and biofuels).	Option 4.1: introduce a ban on new coal fired boilers
3 b. Setting a clearly defined timetable to phase out fossil fuels in existing process heat, with the phase out of coal as a priority.		Option 1.1: require large energy users to publish Corporate Energy Transition Plans Option 4.2: require existing coal-fired process heat equipment supplying end-use temperature requirements below 100°C to be phased out by 2030.
3 c. Reducing regulatory barriers relating to electrification		Options in Section 10 and 11
Provide for the development of wind generation and its associated transmission and distribution infrastructure at scale by: 5 a. Revising the National Policy Statement for Renewable Electricity Generation to resolve issues relating to lapsing and varying consents, and re-powering existing wind farms.	Government has directed the Ministry of Business, Innovation and Employment to identify workable policy options to revise the National Policy Statement on Renewable Electricity Generation to be more directive, and also to consider the development of a National Environmental Standard on renewable electricity	Options in Section 7
5 b. Developing National Environmental Standards to enable timely consenting of wind generation, both large		

and small, and transmission and distribution infrastructure.		
6 a. Regulators be required to take the objective of reducing emissions into account through mechanisms such as Government Policy Statements.		This is under consideration as part of the Government's response to the Electricity Price Review recommendations
6 b. The regulatory system: • Facilitates timely investment in the transmission network that optimises the development of new lines with the building of new power generation. • Contains clear processes for approving, consenting and constructing new or upgraded electricity lines for process heat and electric vehicle infrastructure. • Enables distributors and retailers to innovate and adapt to increasing levels of consumer-based technology. • Enables consumers to get the right pricing signals to engage in demand response and make best use of new technologies.	Government welcomes these recommendations and notes that recommendations align with the policy Ministers are developing on improving renewable electricity levels. Government will be consulting later in 2019 on options to reduce barriers to accelerating renewables deployment.	Options in Section 7 Options in Section 10 Options in Section 11
6 c. Barriers to distributed and off-grid renewable generation are identified and addressed, and ways to ensure communities can participate are considered.		Options in Section 9

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