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.

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[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 CO2e).

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

<table>
<tr><td>Q7.12</td><td>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?</td></tr>
<tr><td>Q7.13</td><td>What do you see as the relative merits and priorities of changes to the NPSREG compared with work on NES?</td></tr>
<tr><td>Q7.14</td><td>What are the downsides and risks to developing NES?</td></tr>
<tr><td>Q7.15</td><td>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?</td></tr>
<tr><td>Q7.16</td><td>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?</td></tr>
<tr><td>Q7.17</td><td>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?</td></tr>
</table>

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

[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.

renewables, and help align future planning across transmission, distribution and generation stakeholders.

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

[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.

mini-perm[65] or borrowing base[66] type facility over a defined forward period.[67] 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

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[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 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.

also increase competition for generation investment, as well as supporting new and independent renewable developers.

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.

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[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]

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

[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/

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

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

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.

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.

[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

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

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 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

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[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 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?

[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 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

[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

[126] Further discussion of this example is in the Productivity Commission's low emissions economy report, August 2018 (page 396 on).

size of the problem), potential issues with competition law, and in some cases potential incompatibility with consultation underway on the guidelines for the TPM.

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.

[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.

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).

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.

[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.

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.

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.

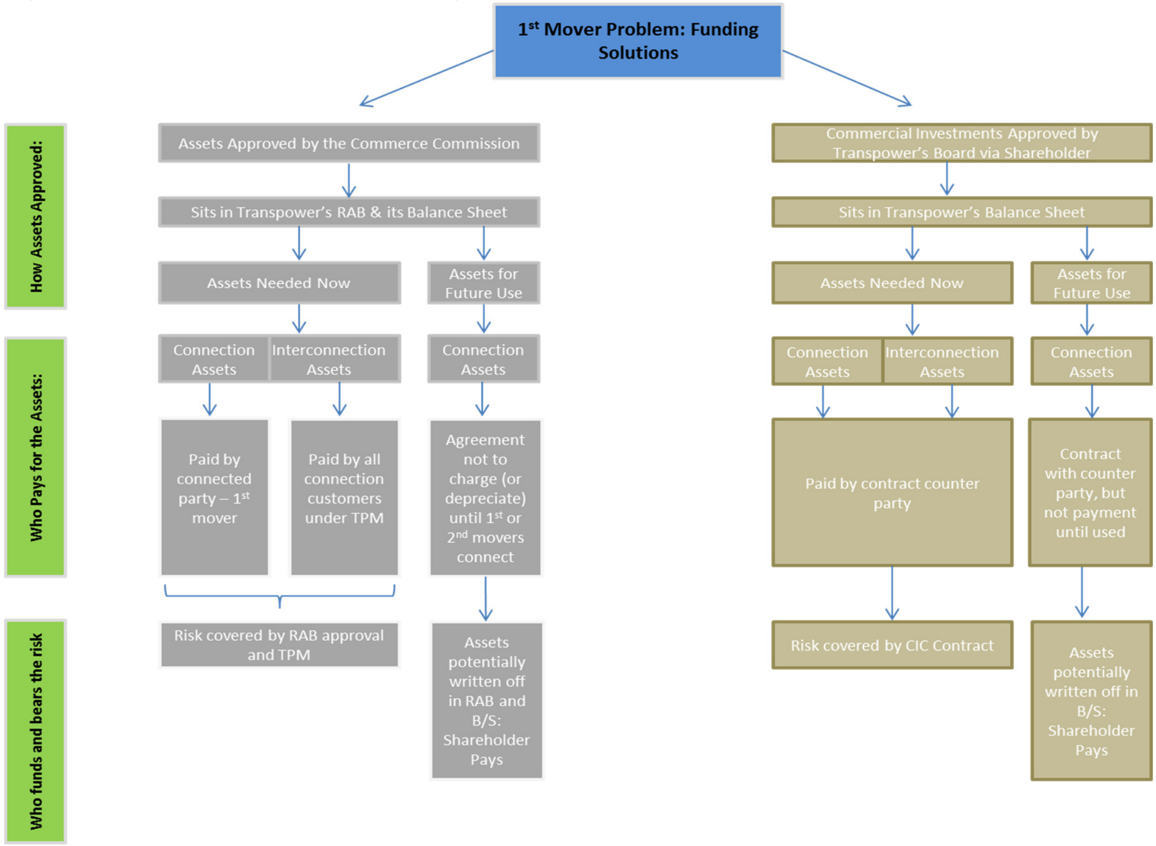
These options would lessen the incentives on Transpower to not overbuild transmission assets and (all else being equal) could increase electricity costs.

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:

[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*.

"…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."

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?