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]

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[56] See: https://www.transpower.co.nz/resources/taking-climate-heat-out-process-heat
[57] The electricity market uses spot electricity prices for each trading period to schedule available generation so that the lowest-cost generation is dispatched first. A spot price is the half-hour price of wholesale market electricity. The spot price is determined for each point of connection on the national grid.
[58] The annual demand-weighted average wholesale electricity price was $113 per megawatt-hour (MWh) in 2018; $81/MWh in 2017; $58/MWh in 2016; $71/MWh in 2015; $80/MWh in 2014, according to data from the

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

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

What are the options?

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

Power Purchase Agreement (PPA) Platform

Option 8.1	Introduce a Power Purchase Agreement (PPA) Platform

Description

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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[62] Ballance is not a member of MEUG, but has also recently joined the project.

[63] See: http://www.meug.co.nz/node/1025 Also: https://www.energynews.co.nz/news-story/electricity-generation/44322/big-users-mull-plan-hasten-renewable-projects

[64] Infratec, a solar developer, has modelled electricity costs and shown that government-backed PPAs for 25 years could reduce the levelised cost of a grid-scale solar project to $80/MWh and $50/MWh for wind.

[65] "Perm" alludes to traditional permanent financing, which the borrower in this case has not yet been able to secure. Mini-perm financing is something a developer would use until a project has been completed and can therefore start producing income. In other words, a developer will use this type of financing prior to being able

Government guarantees cover the risk of Platform insolvency.

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

Case study: Melbourne Renewable Energy Project (MREP)

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

Analysis

Benefits

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

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

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

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

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

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

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

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

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

Costs and risks

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

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

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

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

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

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

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

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

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

Questions

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

Demand-side participation and demand response

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

Description

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

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

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

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

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

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

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

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

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

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[73] See: https://www.transpower.co.nz/keeping-you-connected/demand-response/demand-response-journey-so-far
[74] See: https://www.enelx.com/au/en
[75] See more about this project: https://www.eeca.govt.nz/standards-ratings-and-labels/equipment-energy-efficiency-programme/products-under-the-e3-programme/measures-under-consideration/smart-appliances/
[76] EV uptake is also expected to increase with some residences opting for smart chargers (or smart metering) to manage the timing and rate of battery charging. See the smart appliances consultation underway at the Energy Efficiency and Conservation Authority: https://www.eeca.govt.nz/standards-ratings-and-labels/equipment-energy-efficiency-programme/products-under-the-e3-programme/measures-under-consideration/smart-appliances/
[77] The Code sets out the duties and responsibilities that apply to industry participants and the Electricity Authority.

Analysis

Benefits

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

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

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

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

Costs and risks

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

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

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

Questions

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

Energy efficiency obligations

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

Description

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

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

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

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

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

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

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

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

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

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

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

Case study: Energy efficiency programmes in the United States

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

Analysis

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

Benefits

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

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

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

Costs and risks

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

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

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

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

Questions

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

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

Developing offshore wind assets

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

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

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

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

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

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

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

[85] The IEA notes that "these markets face permitting and grid connection challenges however, and cost remain relatively high. Innovation is needed to reduce the costs of installation processes and foundation design". See: https://www.iea.org/tcep/power/renewables/offshorewind/
[86] Offshore wind turbines are significantly larger than onshore wind turbines – 9 MW is common today with 12 MW turbines in development.
[87] C.A. Ishwar; I.G. Mason (2019), Offshore Wind for New Zealand, Proceedings of the EEA Conference and Exhibition, 25-27 June 2019, Auckland, NZ
[88] See: http://www.environment.gov.au/climate-change/government/renewable-energy/proposal-conduct-offshore-wind-farm-activities and http://www.starofthesouth.com.au/

Analysis

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

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

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

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

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

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

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

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

Further investigation needed

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

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

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

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

Questions

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

Other options for feedback

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

Renewable electricity certificates and portfolio standards

Option 8.5	Renewable electricity certificates and portfolio standards

Description

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

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

Case study: New Zealand energy certification for Garage Project beer

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

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

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

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

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

Case study: Ecotricity electricity retailer's carbonzero certification

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

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

Analysis

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

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

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

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

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

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

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

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

Case study: Google's renewable power purchase programme

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

Benefits

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

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

Costs and risks

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

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

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

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

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

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

Questions

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

Phase down thermal baseload and place in strategic reserve

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

Description

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

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

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

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

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

Case study: Huntly Power Station

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

[100] Based on company announcements and publicly available information

Case study: Taranaki Combined Cycle Gas Turbine

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

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

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

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

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

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

Analysis

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

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

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

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

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

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

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

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

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

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

Benefits

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

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

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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

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

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

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

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

Questions

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

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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.