NEW ZEALAND INFRASTRUCTURE COMMISSION
Te Waihanga

Technical paper

Leveraging our energy resources to reduce global emissions and increase our living standards

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Leveraging our energy resources to reduce global emissions and increase our living standards

Cut to the chase

Energy is a key factor for improving our economic, social, and environmental wellbeing. Energy resources are used to grow the food we eat, manufacture the goods we use, travel to work and education, light and heat our homes, and connect us to the world. Large amounts of energy are needed to build, operate, and maintain our infrastructure networks. However, energy from fossil fuels has a downside, as the resulting carbon dioxide emissions are causing global warming.

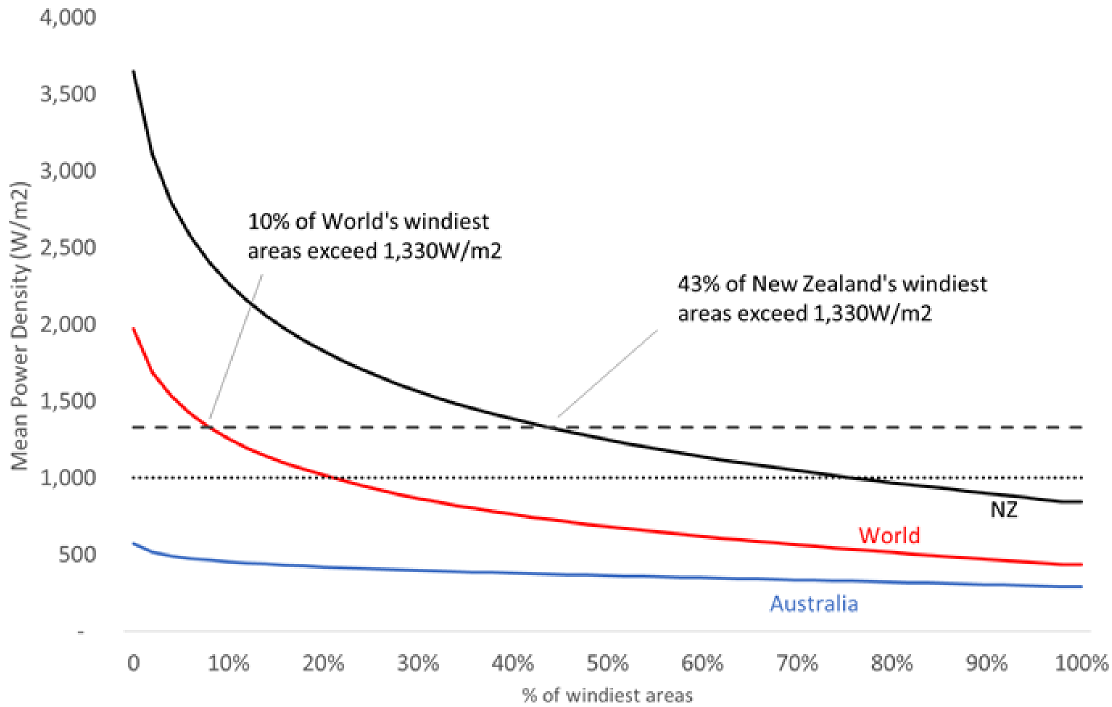
Te Waihanga's *Infrastructure Strategy* highlights the need to significantly increase production and use of low-emission electricity. We have an opportunity to achieve net-zero carbon emissions by 2050, improve economic performance by unlocking new export opportunities, and lift our living standards by leveraging our abundant low-emission energy resources.

This technical paper examines the abundance of Aotearoa New Zealand's low-emission energy resources and outlines what would be required to develop these resources to decarbonise our electricity system and develop new export opportunities.

We have abundant wind resources

Average wind speeds are higher in Aotearoa than in most other places, meaning that our wind farms can produce higher than average output per unit of generation capacity (Figure 5). Notably, the least-windy sites in New Zealand have better wind energy potential than the windiest sites in Australia. Leveraging this resource could allow us to generate wind power at a comparatively low cost by global standards – provided we are efficient at consenting and building new wind farms.

Figure 1: New Zealand has an abundance of potential wind power



Source: Data obtained from the Global Wind Atlas 3.0

Other low-emission energy resources are also abundant in Aotearoa. While we have already used most of the best sites for hydro generation, there are opportunities to increase geothermal electricity generation and develop large-scale solar farms. However, we are unlikely to achieve a competitive advantage in solar generation as places like Australia and the southwestern United States have more sun and seasonal peaks in electricity demand for air conditioning during the summer rather than heating during the winter.

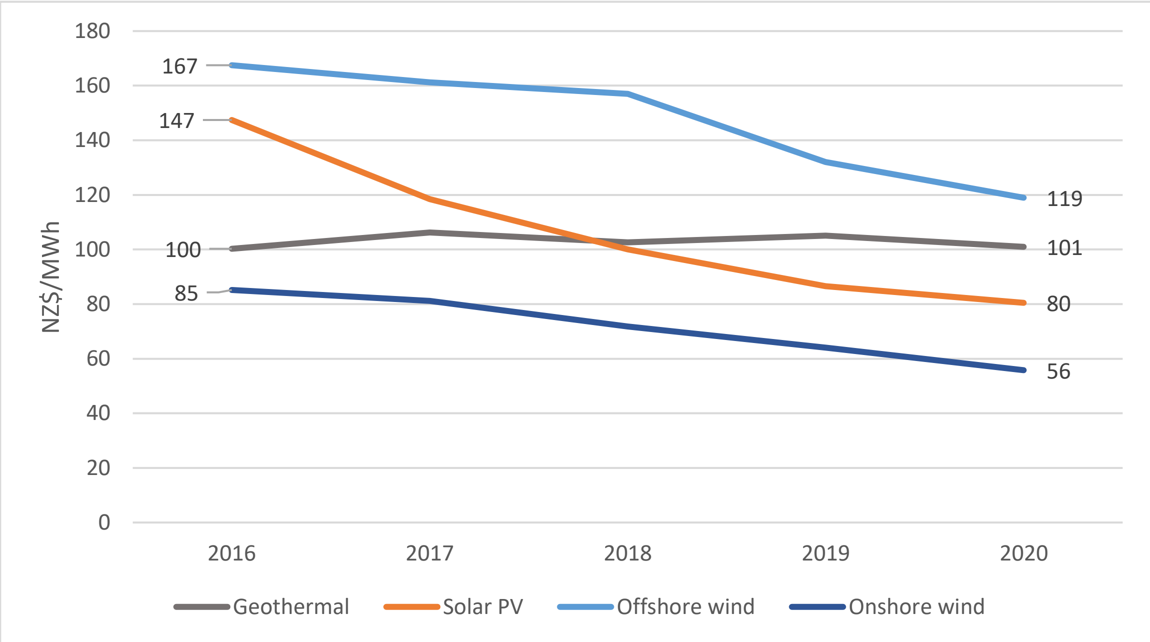
Wind generation is getting cheaper over time

The cost to build wind farms is falling rapidly around the world (Figure 6). Between 2016 and 2020, the cost to generate energy using offshore wind farms declined by 29% and the cost to generate energy from onshore wind farms declined by 34%. This reflects improvements to wind turbine technology and the deployment of larger, more efficient turbines.

These trends are expected to continue, meaning that wind and solar generation will become cheaper relative to other electricity sources. Because we have comparatively abundant wind resources, this could enable us to decarbonise our economy at a lower cost than other countries – and also compete to attract new electricity-using industries.

However, our resource management system needs to keep up with changing technology. We need to be able to consent and build larger-scale wind farms and new turbine technology to generate electricity at a lower cost. We also need a sound regulatory approach for offshore wind farms, which could become cheaper than onshore wind farms in coming decades if current trends continue.

Figure 2: The cost of generating low-emission electricity is falling over time



Source: IRENA datafile

We also need cost-competitive backup generation

Backup generation is needed to cover periods when demand is high, hydro reservoirs are low and the wind is light. We need both short-term backup to cover short periods of low wind and long-term backup for dry years when hydro dams produce less electricity.

For our low-emission energy resources to be competitive, our backup generation needs to be low-cost, or at least no more costly than in other countries. There are a number of potential options for addressing this issue. These could include massively over-building wind and solar generation plus battery storage, building large-scale pumped hydro schemes like the proposed Lake Onslow scheme, building biomass peaker generation plants, or even using emerging technologies like hydrogen and ammonia production and storage to provide large scale seasonal demand-response services to the electricity market. At this stage, it is unclear which option, or package of options, will perform best.

Abundant low-emission energy is an economic opportunity for Aotearoa

Generating low-emission electricity at a lower cost than other countries could provide long-term economic advantages. Empirical evidence suggests that ready availability of low-cost energy can lift per-capita incomes and living standards.

In addition to letting us decarbonise our economy at a lower cost than other countries, it could allow us to attract energy-intensive businesses to locate in Aotearoa and export to the rest of the world.

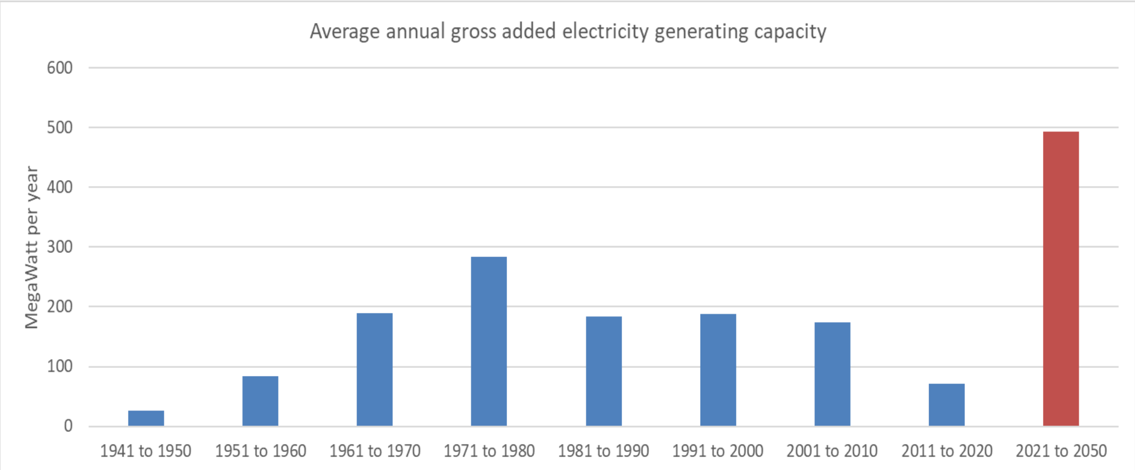
For instance, there have been five recent announcements of investments in large-scale international data centres in Auckland and plans for a hyperscale data centre near Invercargill that will take advantage of the cooler weather and proximity to low emission electricity. These plans are backed up by recent confirmation that a new submarine fibre cable will be built, linking Christchurch, Dunedin and Invercargill with Australia, Indonesia, Singapore and Los Angeles.

However, we are not alone in having abundant low-emission energy. Some other countries already have similar carbon emission profiles from electricity generation, and many more countries will increase low-emission electricity generation in coming decades. We will need to build new generation at a competitive cost and coordinate across different infrastructure networks to ensure we can transport our products to markets.

We have a big task ahead of us...

According to Transpower, we need to add an average of 494 megawatts of low-emission electricity generation capacity every year for the next 30 years to meet electricity's contribution to achieving our net-zero carbon target (Figure 26). This is a large step up relative to the rate at which we have built electricity generation in recent decades.

Figure 3: The generation build requirements for the next 30 years look very challenging



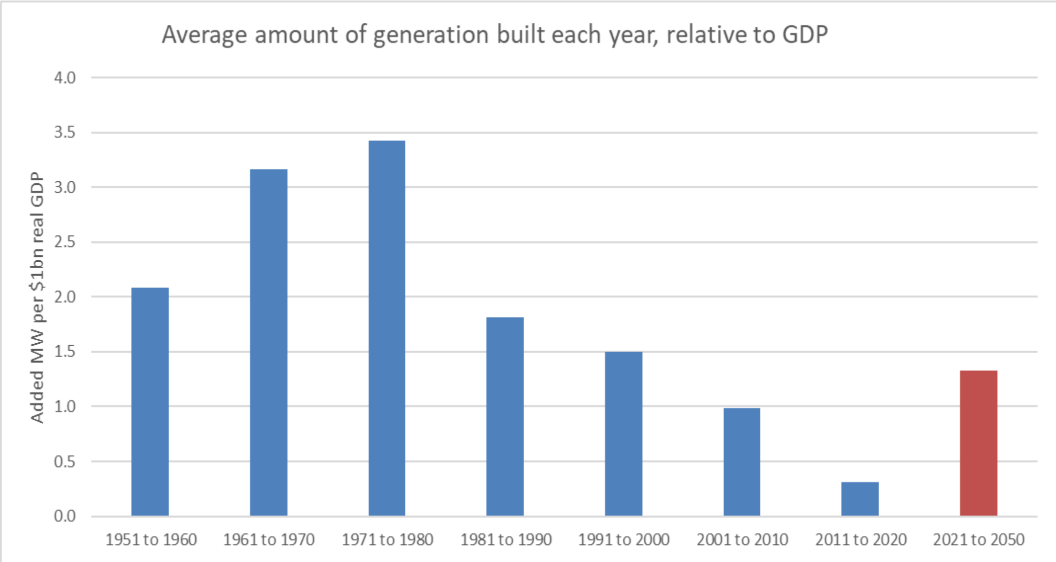
Source: Electricity Authority and Transpower

... but we have the means to build a low-emission energy system

The size of the task ahead may seem challenging. However, history shows that it is possible to sustain significant investment in electricity generation over a long period of time. Relative to the size of our economy, we built more new generation during the 1950s, 1960s, and 1970s than we need to build over the next 30 years (Figure 27).

This means that the funding and workforce required to decarbonise our economy is available – we did more with less in the past. However, putting our resources to work will require a world-class resource management system that provides clear and timely pathways for consenting new wind farms.

Figure 4: Electricity generation build relative to the size of the New Zealand economy



Source: Te Waihanga

1. Introduction and purpose

Section 6.1 of Rautaki Hanganga o Aotearoa 2022 – 2052 New Zealand Infrastructure Strategy (the Strategy) presents the Te Waihanga analysis of the infrastructure challenges for achieving a net-zero carbon economy by 2050. These include building significantly more generation, storage, transmission and distribution capacity over the next 30 years.

The Strategy also encourages readers to be more ambitious for Aotearoa New Zealand, by enabling further development of our low-emission energy resources to create high-wage jobs for New Zealanders and reduce carbon emissions globally. The primary purpose of this technical note is to discuss the prospect of attracting investors willing to develop our resources.

We have abundant natural resources for low-emission electricity generation. We have untapped wind, solar, hydro and geothermal resources that, combined, are treble the amount identified by the CCC for achieving net-zero carbon emissions by 2050. However, the issue is whether they can be developed at prices investors are willing to pay. If yes, we refer to them as commercially viable (or economically abundant) resources.

This note presents our analysis for the ambition we have presented in section 6.1 of the Strategy. It discusses:

- The data we have on the physical abundance of low-emission electricity resources.
- Which resources look to be commercially viable over the longer term to 2050.
- The feasibility of building generation capacity at a faster rate than required to achieve net-zero emissions.
- The economic and environmental benefits of developing our low-emission resources.

Before discussing those topics, we need to be clear about the emissions from electricity generation. Wind and solar generation are often called zero-emission electricity because no carbon emissions occur during their operation. However, this paper refers to them as low-emission sources of electricity because emissions occur in the manufacture, transportation and installation of wind turbines and solar panels.

Appendix A discusses the emissions arising from electricity generation, and reports that wind generation has the lowest emissions. However, hydro, nuclear, solar, biomass and geothermal also have low emissions. Coal and gas generation are high-emission forms of generation but can be treated as low-emission if carbon capture and storage (CCS) is used to prevent emissions escaping into the atmosphere.

2. Physical abundance of low-emission electricity resources

The Ministry of Business, Innovation and Employment (MBIE) recently obtained independent estimates of wind, solar, geothermal and hydro ("low emission") resources available in Aotearoa. MBIE requested the researchers identify the lowest cost sets of resources in their field, so that it could compile a merit-order of generation build for the next 30 years, called a *generation stack*. MBIE uses this information to prepare electricity demand and generation scenarios, and price forecasts, for the next 30 years.

Table 1 presents the data used in section 6.1 of the Draft Strategy. It presents actual output by generation type in 2020 and the CCC's projection for generation outputs in 2050 under its demonstration path. The difference between them is the increase projected by the CCC. The table compares those increases with the potential increases that *could* be achieved if the potential generation stacks were built. For brevity, this is labelled MBIE's potential increase in output.

Table 1: Comparison of current and future low emission generation

	Offshore Wind	Onshore Wind	Solar	Geo-thermal	Hydro	Subtotal	Total All Generation*
1. Annual generation in 2020 (TWh)	0.0	2.3	0.2	7.6	24.0	34.1	43.0
2. Market shares in 2020	0.0%	5.3%	0.4%	17.7%	55.8%	79.2%	100.0%
3. CCC projection for 2050 (TWh)	0.0	17.3	12.4	9.9	24.8	64.4	66.7
4. CCC's proj. incr., 2050 over 2020 (TWh)	0.0	15.0	12.2	2.3	0.8	30.3	23.7
5. CCC's **incr.** as % of CCC's total increase	0.0%	63.3%	51.5%	9.7%	3.4%	127.9%	100.0%
6. MBIE's pot. incr., 2050 over 2020 (TWh)	30.2	40.8	10.0	7.7	7.3	95.9	
7. CCC's **increase** as % of MBIE's increase	0.0%	36.9%	122.2%	29.9%	11.0%	31.6%	
* All generation equals low emission generation plus all other generation (eg, gas, coal, diesel-fired generation)							

Source: MBIE and CCC

Looking at the subtotal column, the CCC's projected increase in wind, solar and geothermal (WSG) generation for 2050 is 30.3 terawatt hours (TWh), which is only 29.9% of the potential additional low emission generation identified for MBIE.

In other words, we have three times more low emission resources available than the CCC considers is needed to achieve our net-zero target by 2050. If we exclude the potential for offshore wind generation, then we have more than double the amount of low emission potential needed to achieve net-zero by 2050.

The rest of this section discusses pertinent aspects of the individual studies provided to MBIE.

2.1 We have abundant wind resources

Wind generation capacity was 690 megawatts (MW) in 2020, producing 2.3 TWh which is about 5% of annual electricity supply of 43 TWh.[1] Wind output varies from year to year, however the average over 2016-2020 was 2.2 TWh per year.

The CCC is projecting wind generation to increase to 17.3 TWh in 2050, which would be a 686% increase on the wind generation achieved in 2020.[2] However, 17.3 TWh is only 37% of potential onshore wind generation sites identified for MBIE by Roaring 40s Wind Power Limited (*Roaring40s*).[3]

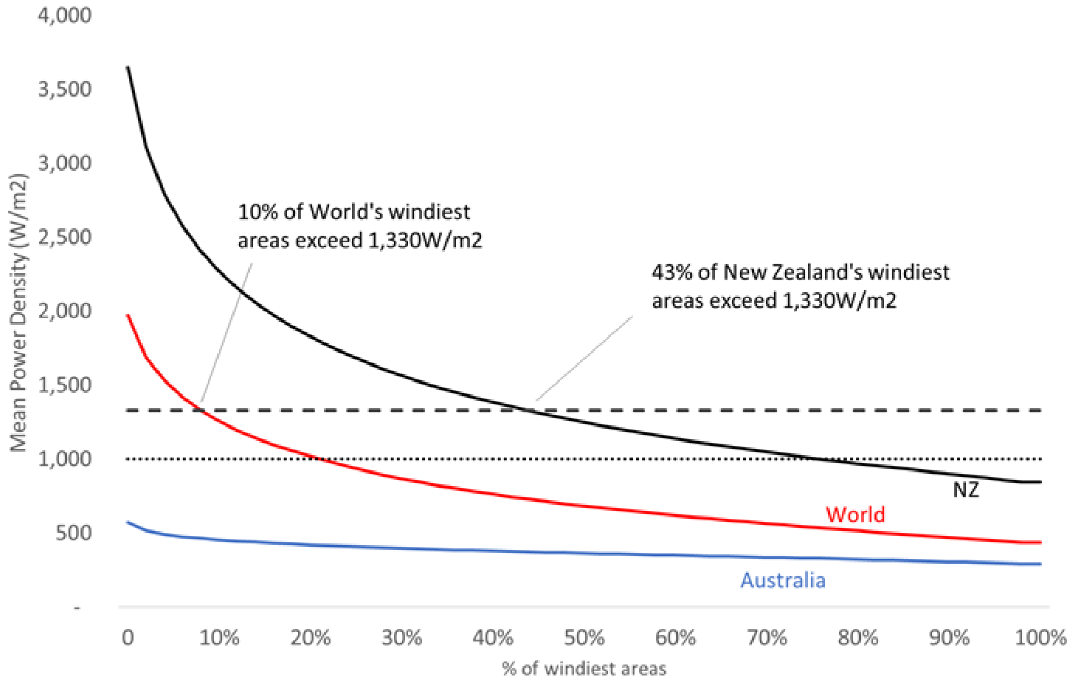
We are fortunate in having comparatively good wind generation resources, primarily due to westerly winds known as the Roaring Forties, which flow over the South Island and the lower portion of the North Island. Onshore wind speeds in these areas average around 8.5–9.8 metres per second.[4]

Mean power density is the annual power available per square metre of swept area of a wind turbine – it is essentially a measure of how much wind energy is available at a location, and so is measured in Watts per square metre.[5] Figure 5 plots the cumulative density functions for mean power densities at 100m above surface level for New Zealand, Australia and globally.

All else equal, wind turbines are likely to be sited in the windiest locations and so the 10% windiest locations are of particular interest. Globally, the top 10% windiest places have mean power densities exceeding 1,330 W/m^2. The corresponding figure for New Zealand is 2,407 W/m^2, which is very high.

However, the South Island is a particularly narrow mountainous region and so many of the 10% windiest locations are not accessible. Nevertheless, Figure 5 shows that 43% of our locations exceed the 1,330 W/m^2 global figure for the 10% windiest locations in the world. Moreover, only 23% of locations in the world exceed 1,000 W/m^2 whereas about 75% of New Zealand locations exceed that power density level. Aotearoa clearly has an abundance of wind energy.

Figure 5: New Zealand has an abundance of potential wind power



Source: Data obtained from the Global Wind Atlas 3.0[6]

Australia has invested heavily in solar power but also a reasonable amount has been invested in wind power and they have plans for large scale offshore wind farms. Yet its windiest locations have very low power density (refer Figure 5), with a mean of only 464. No Australian location has a wind power factor exceeding 600, whereas all New Zealand locations exceed that level.

The Roaring40s report identified 78 onshore sites, with two-thirds of them able to be accommodated on the existing grid. Roaring40s used a range of databases and approaches to identify good wind generation sites. They examined factors expected to provide attractive project returns or presented obvious 'fatal flaws' from a construction or consenting perspective, including:[7]

- wind speed
- proximity to major roads and the transmission grid
- whether it was of extreme elevation or on steep or extremely complex terrain
- whether it was of an appropriate size, away from densely populated areas and outside Department of Conservation (DoC) administered land.

They also considered non-physical factors affecting development potential, including:[8]

- difficulty of securing investigation and development agreements for land access
- the type and nature of stakeholders (e.g. councils, DoC, iwi etc.) and the anticipated level of community acceptance
- potential planning issues (eg classification of activity, coastal zones etc.)
- potential land constraints (eg, proximity to National Parks, protected or special character areas etc.)
- overall consent risk assessment and whether it will be pursued for consent.

Total generation capacity from the 78 sites was estimated at 10,800 MW, with over 70% of the capacity in the North Island. A high and low figure for annual energy was estimated for each site, giving a simple average of 39.4 TWh per year.[9, 10]

The Roaring40s report also identified high quality offshore wind resources in the Auckland, Waikato and Taranaki coastal areas. The Auckland and Waikato areas have an average wind speed of 8.3 m/s, whereas the Taranaki area is 9.6 m/s. Total energy potential from these three sites averaged 30.2 TWh per year, from a total capacity of 8,000 MW.[11]

2.2 We may have significant solar resources

Current solar generation capacity is only 140 MW, with over 80% of it being small scale units (typically installed at homes and small businesses).[12, 13] Solar generation produced 0.18 TWh of electricity in 2020, or 0.4% of annual electricity supply.[14]

The CCC is projecting solar generation to increase to 12.4 TWh in 2050.[15] This exceeds the volume identified for MBIE by Allan Miller Consulting Limited (*Miller*).[16]

According to Miller, our commercially viable solar resources is modest compared to Australia and other sunny and arid countries and compared to New Zealand's wind resources. Miller argues that large scale solar farming displaces other farming activities, and so their commercial viability is enhanced if it sits on poor quality grassland, of which we have relatively little. This contrasts with small scale solar, which is typically on the rooftops of existing buildings or on other unproductive surfaces such as water treatment ponds.[17]

Miller concludes that large scale solar generation has not generally been commercially viable in New Zealand and is not projected to be viable until 2025–2030 (the key driver being the falling capital cost of building utility-scale solar). Interestingly, Transpower expects small scale solar to account for 69% of solar expansion in the next 30 years, with more than two-thirds of that to come from residential sources and the rest from the "rooftops" of commercial entities.[18]

To estimate the likely timing for large scale solar development, Miller prepares a longlist from detailed modelling of:

- economic factors, such as electricity prices, hardware and installation costs, operating costs and discount rates
- solar irradiance at each location, as this varies substantially due to weather conditions, latitude and topographic shading
- land availability in locations with good irradiance (while there is ample land suitable for utility-scale solar systems, its availability will be constrained by alternative uses)
- solar system design, as it is now economic to incorporate tracking systems to track the sun throughout a day, and to over-size module capacity to improve inverter loading ratios and offset module degradation, improving system performance
- proximity to electricity grid infrastructure (both transmission and distribution) and its capacity to connect PV solar
- proximity to roading infrastructure.

A shortlist was then compiled based on the sites likely to deliver the highest return on investment (ROI) and that are within the capacity of the relevant transmission or distribution lines.

The results are presented separately for large solar farms connected to the transmission grid versus those connected to a local distribution network:[19]

- *Grid-connected*: The best locations are the Mackenzie District and Waitaki Valley, both in South Canterbury, due to their poor grassland. These locations are followed by sites in Marlborough, Waikato, Hawke's Bay, Bay of Plenty and Central Otago.
  Note, the Tasman region is a high yield location due to its sunshine and higher wholesale electricity prices but the higher cost of land in the Tasman area (relative to South Canterbury, for example) counteracts those benefits.

- *Network-connected*: The best locations are the Far North District, Tasman and Marlborough, followed by the Bay of Plenty, Hawke's Bay, Waikato and Canterbury.

Miller identifies 1,000 – 11,500 MW commercially viable large-scale solar resources ranging from, with a base case estimate of 6,300 MW that could produce 23.3% of current annual demand.[20]

2.3 The size of our geothermal resources is sensitive to consenting assumptions

Current geothermal energy production is about 196 petajoules (PJ) per annum, which can be sustained over the next 30 years from existing sources. Most of our geothermal fields are in the Taupō and Kawerau regions, but there is also a field in the Far North at Ngāwhā.

1,028 MW of generation capacity comes from geothermal resources, supplying 7.7 TWh in 2020 or about 18% of New Zealand's annual demand in 2020.[21]

The CCC is projecting geothermal generation to increase modestly, to 9.9 TWh per year in 2050.[22] This is only 30% of potential geothermal generation identified for MBIE by Lawless Geo-Consulting Limited (Lawless).[23]

Despite having plentiful geothermal reserves relative to other countries, Lawless estimates we have only 1,038 MW of additional geothermal capacity available for development, and this is sensitive to assumptions about consenting outcomes. Depending on consenting assumptions, our geothermal reserves could be as low as 835 MW or as high as 1,591 MW (about half of New Zealand's high-temperature geothermal resources are currently classified as a protected geothermal system under the Regional Policy Statements of both the Waikato and Bay of Plenty Regional Councils).[24]

Modest technological advances in geothermal development and operation are expected over the next 30 years, which means modest cost reductions. Large-scale development is likely to remain in high temperature areas, such as the Taupō Volcanic Zone and at Ngāwhā. As a result, lower temperature geothermal resources are not likely to be economic, especially with carbon pricing increasing geothermal costs.[25]

The weighted average emissions-intensity for existing geothermal projects is 76 tonnes of carbon dioxide equivalent (tCO_2e) per MWh, which is lower than in 2015 and is expected to continue to decline.[26] Nevertheless, this is almost double the intensity reported by NREL mentioned earlier in this note. Carbon capture and storage (CCS) technology exists for removal of greenhouse gases from geothermal plants and reinjection into nearby reservoirs, which Lawless states is likely to be lower cost than CCS for fossil fuel projects.

2.4 We have some additional hydro generation potential, but it is costly

Grid-connected hydro generation capacity is currently 5,312 MW, with two thirds located in the lower South Island. Although no new plants have been added to the grid for 30 years, hydro capacity has increased by 118 MW over the last decade due to refurbishment and enhancement of existing plants.[27]

Although resource consents for many of our hydro power schemes expire in the next 30 years, the general expectation is that all existing large schemes are likely to be re-consented. However, Roaring40s (2020b) suggests there is likely to be an overall decrease in the amount of electricity that can be generated due to additional restrictions placed on the consents.[28]

Grid-connected hydro generation provided 24.0 TWh of electricity on average 2020, amounting to 55% of New Zealand's annual demand in 2020.[29] Hydro generation depends on rainfall, and so the annual amount varies from year to year. Over the preceding five years, annual hydro generation averaged 25.1 TWh, with a 2 TWh range. The CCC is projecting annual hydro generation of 24.8 TWh in 2050.[30]

Roaring40s (2020b) assesses potential new large-scale hydro electricity generation in New Zealand. They review and update information about potential hydro schemes identified in 2012 as having received consent or in the process of seeking consent. They also consider other possibilities based on reports of previous investigations by other parties and on their own experience in their work for the Electricity Corporation of New Zealand (ECNZ) and others. They exclude rivers within national and forest parks, rivers covered by a national water conservation order and rivers where another scheme would take water from another generator. They also exclude potential 'double ups', where multiple potential schemes are identified but only one could be undertaken.

In total, Roaring40s (2020b) identifies 2,286 MW of potential new large-scale hydro capacity. However, many of them may not be able to obtain consents. Roaring40s score the 'consentability' of each scheme out of 10, where 10 implies very likely to be consented and 0 is no chance. This assessment is informed by the history of previous investigations and opposition to them but is ultimately subjective.

To adjust for consentability, this paper weights each scheme by their score out of 10. For example, we assume a score of 7 out of 10 implies a 70% chance of gaining consent. On this basis, potential capacity reduces from 2,286 MW to 1,345 MW. If all schemes with a consentability score less than 5 are excluded from the list, then potential capacity reduces to 1,257 MW. Details of these calculations are provided in Appendix B.

Based on these consentability adjustments, annual generation from large scale hydro plants could increase by 7 – 7.5 TWh, with an average of 7.3 TWh.[31] However, as Roaring40s (2020b) notes, the majority of the potential hydro projects are in the South Island, reducing their attractiveness from a commercial standpoint due to the possible exit of the Tiwai Aluminium smelter.

Moreover, hydro is a relatively mature technology and has not been experiencing cost reductions. This suggests solar and wind are likely to outcompete hydro over the next 30 years. Wind is already cheaper than new hydro and looks likely to experience ongoing cost reductions.

2.5 Concluding comments

The above analysis is for large-scale solar, wind, geothermal and hydro generation. This excludes small scale solar generation, such as residential rooftop solar which Transpower has projected could supply 4.5 TWh/year by 2050.[32] Roaring40s (2020c, p18) estimates there is the potential for 236 MW of small-scale hydro generation, which could produce 1.3 TWh of energy. However, many of these are on Department of Conservation land, and may have difficulty gaining consent.

3. Commercial viability of low-emission electricity resources

Section 2 discussed the physical abundance of our low emission resources. This section discusses whether those resources are economically abundant. That is, are they sufficiently valuable to justify the costs of developing them? If they are, we refer to them as commercially viable low-emission resources. To address that question we need to consider the global demand for our low-emission electricity at prices reflecting the cost of supply.

The section is structured as follows:

- Section 3.1 presents an economic framework for assessing commercial viability.
- Section 3.2 discusses our inherent advantages and disadvantages in wind, solar and geothermal generation.
- Section 3.3 explains that it can be misleading to compare the cost of generation with wholesale electricity prices.
- Section 3.4 explains the importance of including the cost of backup resources when assessing the cost of serving demand.
- Section 3.5 concludes with a discussion of the competitive advantage of our wind, solar and geothermal resources.

3.1 Framework for assessing commercial viability of electricity resources

The generation stacks in section 2 were compiled using partial equilibrium investment decision-making models for each type of resource: wind, solar and geothermal. The three models were bespoke, but in general they included inputs of forecast electricity demand, wholesale electricity prices, land, capital and operating costs and estimated capacity factors for each identified site.

Each study produced a list of sites at which new generation is projected to be installed before 2050, based on modelled rates of return exceeding a hurdle return on investment. The timing of the development of each site depends on the growth rates of the relevant variables, but particularly on electricity demand growth and on the relative attractiveness of the sites, called the merit order.

Capacity factor definition

The *capacity factor* of a generator is the amount of output it can realistically achieve divided by the output it could achieve if it always operated at maximum capacity.

The MBIE generation stacks are based on exogenous demand growth scenarios. Hence, they do not consider electricity demand as a function of production undertaken here rather than elsewhere, which in turn depends on our electricity prices relative to other countries.

Grid-connected consumers use a portfolio of generation, and so the marginal cost of the system is what matters for serving consumer demand

In principle, a dynamic general equilibrium model of the electricity market is needed to assess the commercial viability and timing of generation investments.[33] This is particularly important when considering investments in wind and solar generation, as they need to be combined with other types of generation to cover periods when they do not match demand.

It is useful at this stage to refer to wind, solar and geothermal generation as *inflexible generation* and to use the term *backup generation* to refer to other generation used to fill gaps between demand and supply from inflexible generation.[34] In this paper, backup generation is generation that can be controlled to match demand.

Specific forms of backup generation include:[35]

- thermal generation, provided they have sufficient fuel and operating flexibility
- generation from hydro reservoirs, provided their operators are willing to draw down their hydro reservoirs
- batteries, provided they have sufficient stored energy.

The issue is whether our untapped low emission resources offer a competitive advantage for firms to locate production in Aotearoa. For now, assume those firms are only interested in countries that can serve their demand, D, from "zero-emission" electricity.

To discuss this in a simple way, let S denote the supply of additional inflexible generation to serve an increment in D. Further, let M denote the aggregate mismatch *betwee*n demand and inflexible supply, ie, $M = D - S$, and let $s = S/D$. The larger is s the greater the share of the increase in demand served by inflexible generation.

A dynamic general equilibrium model will choose combinations of inflexible and backup generation that achieve the least cost to serve the increment in demand, D. In simplistic terms, the system long run marginal cost (LRMC) of serving D is given by:[36 37 38]

$$System\ LRMC = s.LCOE + (1 - s)LCOB + LCOT$$

Where:

- $LCOE$ is the levelised cost of electricity from the marginal source of inflexible generation
- $LCOB$ is the levelised cost of the marginal source of backup generation needed to fully serve D, including any additional generation needed to cover for uncertainty about the supply/demand match
- $LCOT$ is the levelized cost of any additional transmission or distribution network costs.

The above equation represents the LRMC of locating additional demand in Aotearoa. In deciding where to locate their production, firms will compare a wide range of factors across candidate countries. For energy-intensive firms, one of those factors will be the cost of electricity. They will also consider:

- factors specific to each country, such as exchange rate risk, regulatory risk
- factors specific to the firm's sector, such as the availability of iron sands if the firm is a steel smelter
- factors specific to the firm, such as its preferences regarding the risks of concentrating its production in the lowest-cost country versus spreading its production across multiple countries.

LCOE definition

The levelised cost of electricity (LCOE) is the net present value of the cost of a generation plant over its lifetime divided by the net present value of output expected over its lifetime. Analogous definitions apply for other levelised costs, such as LCOB and LCOT.

To keep things simple at this stage, it is useful to lump all non-electricity factors relevant for deciding where to locate production in a catch-all term called LCON. *LCON* denotes the levelised cost of the non-electricity factors, such as transport costs for exporting to markets, the costs of securing feedstock, and so on.

A deterministic formulation of the decision problem would have firms locating their production in Aotearoa if:

$$s.LCOE + (1-s)LCOB + LCOT + LCON < s^*LCOE^* + (1-s^*)LCOB^* + LCOT^* + LCON^*$$

where asterisks denote the best investment location outside of Aotearoa.

This formulation asks: "if *D* is going to occur somewhere, is it attractive to locate it in Aotearoa"? This avoids explicit consideration of whether the increment in demand yields profits to the firm. It assumes profit-making firms make their investment decisions in two steps: (1) they determine an investment they want to make (2) they choose the least cost location for their investment. This caters for firm's choices about where to locate hydrogen and ammonia plants, even though they are unlikely to be profitable investments.

It is important to keep in mind the electricity variables in the above inequality are for optimal combinations of inflexible and backup generation. The LCOE on the left-hand-side may be for wind or geothermal generation in Aotearoa whereas the LCOE* on the right-hand-side may be for solar generation (eg, for Australia) or nuclear generation (eg, for France). In general, it can be misleading to compare domestic and foreign LCOEs for the same generation technology.

Clearly, if our optimal LCOE is lower than other countries due to inherent natural advantages, then Aotearoa may be a competitive location for some forms of production. For example, if we use the same low-emission backup generation technology as other countries (such as batteries), such that $(1-s)LCOB = (1-s^*)LCOB^*$, then our untapped inflexible generation resources may be commercially viable.

Further, if we have natural advantages that provide a cheaper form of "zero-emission" backup option – such as utilising additional hydro storage or building new hydro generation and storage – then presumably that backup option would be chosen, and our "zero-emission" electricity resources would be even more competitive internationally.

Similarly, if our inflexible generation better matches D (ie, $s > s^*$), then we may be more competitive against other countries. For example, according to the analysis in section 2, we have untapped geothermal resources, which are generally well matched to industrial demand. In that case s would be close to one and the primary issue is whether our geothermal has a lower LCOE than "zero-emission" baseload generation in other countries, such as nuclear energy.

In practice, firm location decisions are irreversible and made under uncertainty

An action is (totally) irreversible when none of the costs of the action can be recovered if the decision maker changes its mind. Location choices are often irreversible to some degree, especially for choices that involve investment in specialised industrial plants, such as smelters, pulp and paper processing plants, and so on.

In the above deterministic formulation, there is no uncertainty and so firms should locate their production in the lowest-cost country, all factors considered. But when there is uncertainty and entry is irreversible to some degree, firms may choose higher-cost locations if they have less uncertainty about them.[39] For example, they may have a better understanding of the laws of the country and of the risks of adverse legal and political outcomes.

Given these real-world complexities, firm location decisions involve probabilistic analysis and subjective judgements about the future. Economists model these decisions using methods that treat the choice of locations as having a stochastic aspect to them. Under these approaches, changes in electricity prices in one location (relative to other locations) alter the probability of firms locating their production in that location.[40]

To date, it appears there have been very few empirical studies on the significance of energy prices in production location decisions of multinational firms. The empirical analysis in Saussay & Sato (2018) suggests that electricity prices may have minimal impact on the location choices for foreign direct investment. However, it would be wise to consider a wider range of studies when they become available.

In practice, firms choose among electricity systems with differing emission intensities and supply reliabilities

Clearly, not all firms will insist on their demand increments being served entirely by generation with zero operational emissions. Many may consider locating their new production where they can improve their emissions profile at lower cost than would occur if they located in a zero-emission location. In this case, they may consider countries with thermal generation despite having preferences for low emissions.

To cater for this situation, let E_j denote the emission intensity of electricity in country j over the lifetime of a consumer's increment in demand.[41] Then E_j would be another factor in a stochastic model of location choice. Countries with emission intensities declining relative to their competitors may have an increasing probability of attracting energy-intensive production.

Modelling location choices in this manner caters for the possibility that countries may be able to increase their international competitiveness by making the right trade-offs between reducing emission intensities and increasing electricity costs. To date there does not appear to be any rigorous empirical evidence about the impact of these trade-offs on locational choices.[42]

However, conceptually at least, depending on firm's preferences and the cost of reducing the emissions intensity of our energy system, it is possible that our low-emission resources may give us a competitive advantage.[43] Of course, it would not be a unique advantage as two OECD countries (Iceland and Norway) are already more renewable than Aotearoa and two others (Austria and Denmark) have similar levels to us.[44] Moreover, our nearest competitor, Australia, is projected to reach a 79% renewable electricity system by 2030, up from its current 25% level.[45] Also, presumably the global pressure for decarbonisation, as evidenced by pledges made at the recent COP26 conference and previous such conferences, implies many other OECD countries can be expected to greatly improve their emission profiles over the next 10–30 years too.

Similar considerations apply for differences in supply reliability across locations.[46] For any given supply cost, firms prefer more reliability because it reduces their interruption costs or the costs of backup resources to minimize interruptions. Clearly, higher-cost and higher-reliability locations can be more attractive to firms than lower-cost but lower-reliability locations.[47]

> *Competitive advantage* does not require us to have lower electricity costs than elsewhere. Rather, what matters is whether our combination of costs, reliability and emissions intensity (CRE) is more attractive to firms than the CRE of our competitors.

Firms take a long-term view of emissions policies

In general, higher ETS prices will drive generation investors to choose higher-cost, but lower-emission, forms of inflexible and backup generation.[48] This reduces emissions intensity as new (low-emission) generation is added to the grid.

This means our emissions intensity may reduce gradually whereas the LCOE and LCOB for new generation may increase sharply due to the jump in ETS prices. This could create a short- to medium-term dynamic where we are an unattractive location for production. However, as our average emissions continue to decline over time the reverse dynamic may occur.

Forward-looking firms will therefore consider our current emissions policy and the likely future path for it relative to the emissions policies of other investment locations. This suggests it is important to have clear, credible and sustainable emissions policies to encourage optimal investment responses.

If our competitors are also decarbonising their electricity sectors, then even our most expensive low-emission resources could become commercially viable

Looking to the next 30 years, other countries are likely to switch their electricity sectors toward low emission sources. If they ban new thermal generation, for example, then their marginal source of inflexible and backup generation will have to be low-emission generation, which may be higher cost than ours. The same logic applies if they impose or increase carbon taxes or emission trading schemes.

Hence, as carbon mitigation efforts increase here and internationally, will our low emission resources offer a competitive advantage in the production of energy-intensive goods and services?

- If yes, then a larger share of global production may locate here, and our electricity sector will respond by developing its low-emission resources to meet the increased demand.
- If no, then those resources are not commercially viable, and they'll be left undeveloped. Instead, firms will put their capital into more valuable activities.

In practice, the real-world is more dynamic than indicated above. Wind, solar and battery costs are declining rapidly whereas the costs of new thermal, geothermal and hydro generation are relatively static.[49] There may come a time when low emission resources are so cheap that the system LRMC of serving a large increment in demand is lower than currently.

More generally, countries and firms can gain competitive advantages by innovating and investing in R&D to improve their productivity. These efforts are most likely to succeed when innovation occurs in areas where a country or firm has an inherent *comparative advantage* and when innovations build on previous successful innovations.[50]

Another important feature is that Aotearoa is a small open economy. In general, we are unable to increase global prices for our exports by withholding supply from international markets or reduce the prices we pay for imports by reducing our demand for them.[51] [52]

Technically, our electricity sector is a closed sector of the economy because we do not export or import electricity. However, in effect, we export electricity in the form of energy-intensive manufactures, such as dairy products, aluminum from Tiwai Point, pulp and paper products from the central North Island and hosting international data centers. As we are a small open economy in these sectors, our electricity prices have no effect on global electricity prices.[53]

The above framework is consistent with the mandate of Te Waihanga

Te Waihanga promotes an approach to infrastructure that improves the wellbeing of New Zealanders.[54] It therefore considers international trade and investment, and how we can use our infrastructure resources to improve wellbeing.

In contrast, a key function of the CCC is to advise the Government on how to reduce carbon emissions to achieve net-zero by 2050.[55] This leads it to focus on identifying the amount of low-emission energy needed to achieve net-zero, rather than the wider consideration of maximising the wellbeing of New Zealanders. We discuss these issues further in section 6.

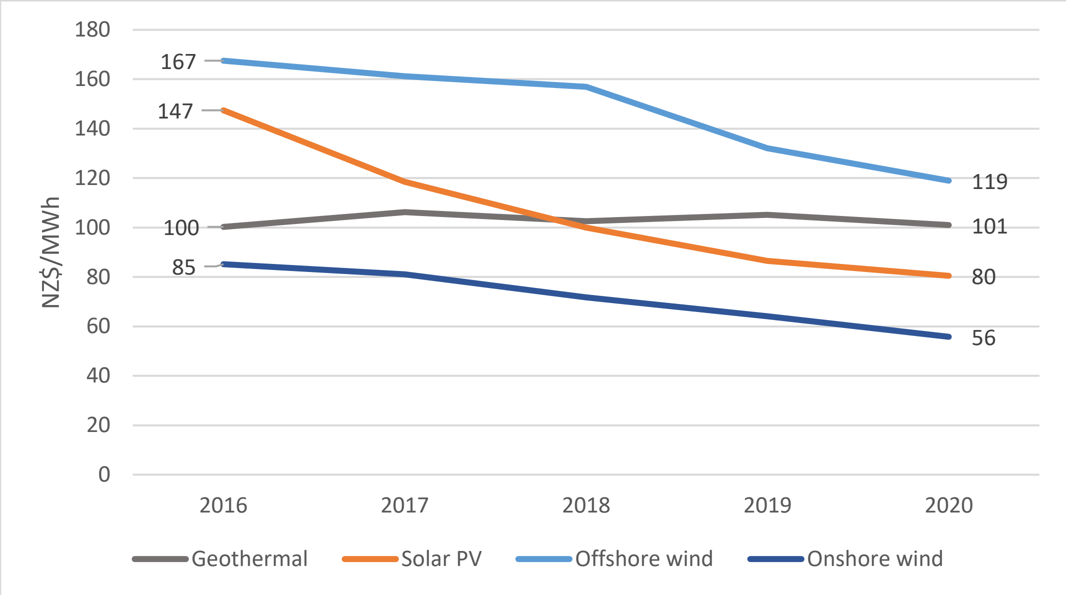
3.2 Inherent advantages and disadvantages of our low-emission resources

The framework in section 3.1 considered several factors affecting the international competitiveness of our low-emission electricity resources. It emphasised that competitiveness depends on the system LRMC of serving an increment in demand, rather than considering the LCOEs for individual types of generation. With that said, this section discusses LCOEs for wind, solar and geothermal generation to provide the building blocks for considering system LRMC.

Global LCOEs for wind and solar have declined rapidly, but not for geothermal

Figure 6 shows recent trends in global weighted-average LCOEs for four sources of low emission electricity generation, based on data published by the International Renewable Energy Agency (IRENA). These costs were converted to New Zealand dollars at rate of US$1 to NZ$1.42.[56]

Figure 6: Global average LCOEs, 2016-2020



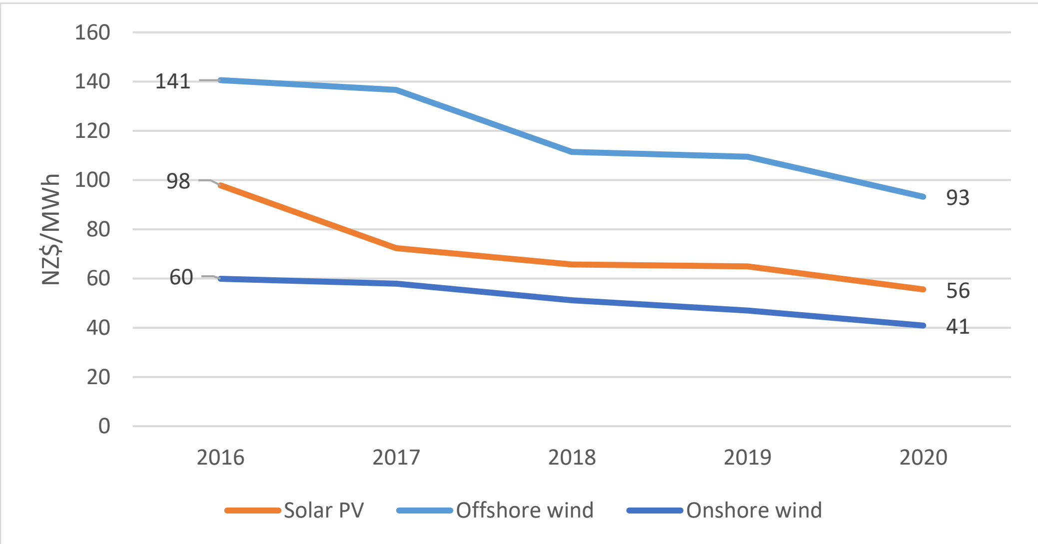
Source: IRENA datafile[57]

Globally, geothermal LCOEs remained flat at around $100 per MWh. In contrast, the LCOEs for solar, onshore wind and offshore wind reduced by 14%, 10% and 8% per year respectively.[58]

IRENA also provides data for the fifth percentile LCOEs for each generation type, which is helpful for considering the international competitiveness of our low emission resources.

Figure 7 shows the LCOEs declined at similar rates to the global averages shown above.

Figure 7: Global 5th percentile LCOEs, 2016-2020

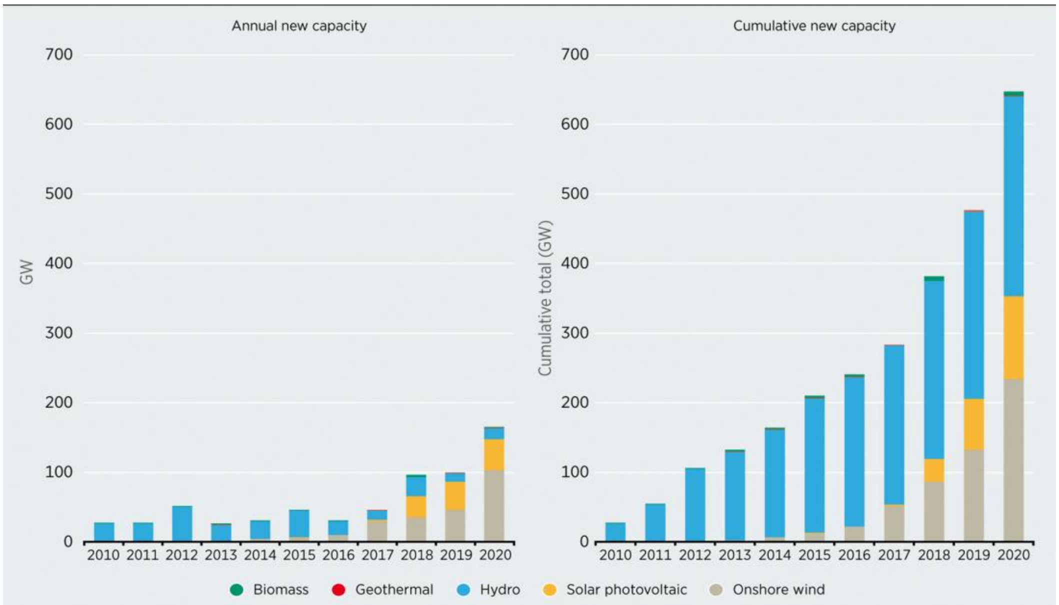


Source: IRENA Datafile

In 2020, the fifth percentile of LCOEs for onshore wind was $41 per MWh, 27% below the $56 per MWh global average in Figure 6.[59] Similarly, the fifth percentile of LCOEs for solar was $56 per MWh, 30% lower than the $80 per MWh global average.

Global investment in wind and solar generation appears to be accelerating due to their low costs relative to thermal generation. Figure 8 shows the amount of "low cost" renewable generation each year, where "low cost" refers to renewable generation with a lower LCOE than the cheapest fossil fuel-fired option.

Figure 8: New capacity of low-cost low-emission generation, 2010-2020



Source: IRENA Datafile

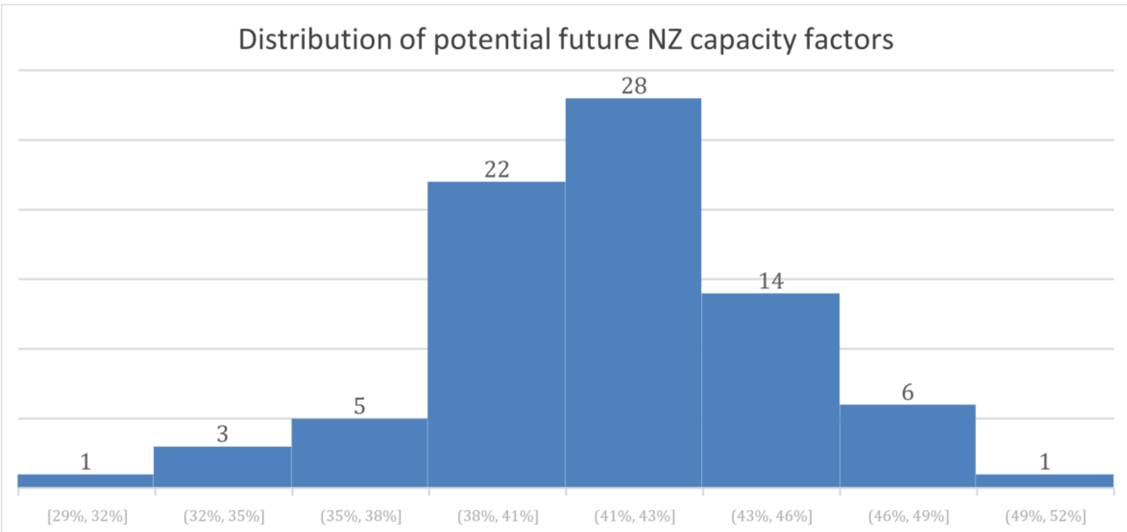
In 2020, 99 GW of “low-cost” onshore wind capacity was added globally, more than double the 46 GW of “low-cost” solar PV capacity added in 2020.[60] Very little “low-cost” geothermal generation capacity was added, in part because most geothermal is not lower cost than the cheapest thermal generation.

Fortunately, we have a capacity factor advantage in wind generation

The reductions in global LCOEs for wind are driven by declining turbine prices and improving capacity factors. Capacity factors have been improving due to larger and better designed rotor blades. According to IRENA data, the global weighted-average capacity factor for new onshore wind farms was 36.0%, which is a 31% increase since 2010.[61]

Figure 9 provides a histogram of the capacity factors estimated by Roaring40s for onshore sites in Aotearoa. Most of the sites have an average capacity factor between 38–46%, and the weighted average capacity factor of the Roaring40s sample is 41.7%.[62] [63]

Figure 9: Estimated wind capacity factors for New Zealand (NZ) sites, 2020

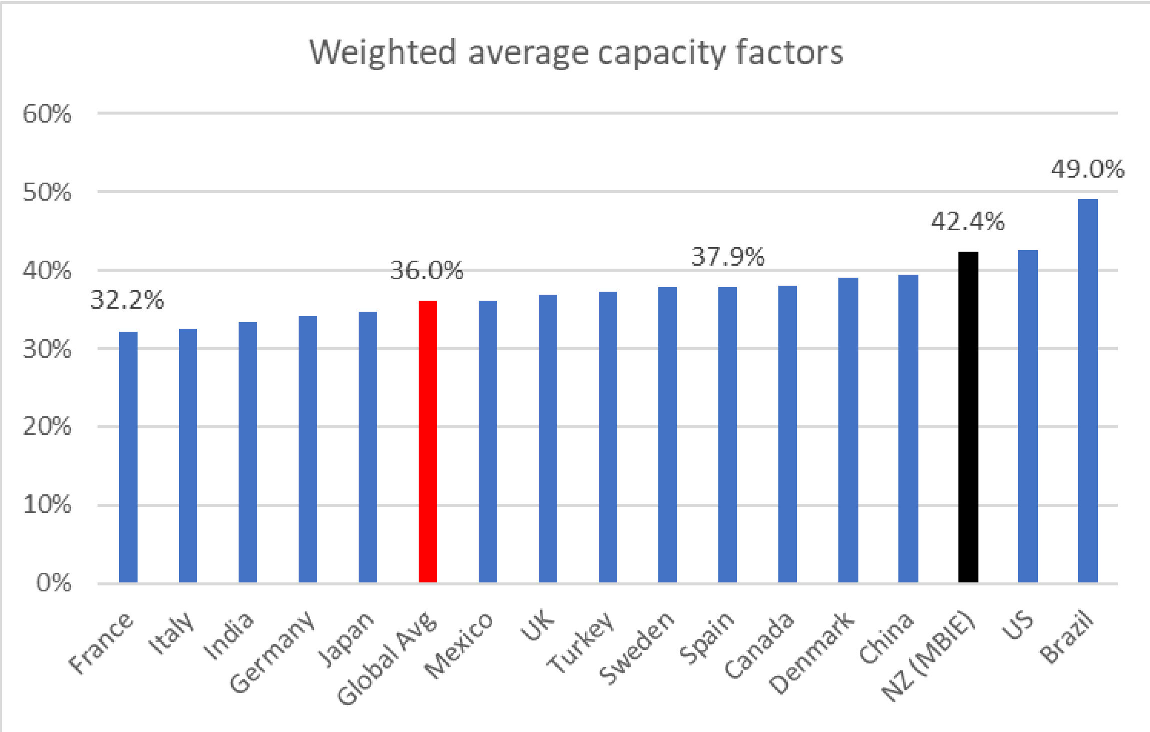


Sources: Roaring40s, MBIE

Fortunately, we have relatively high capacity-factors for onshore wind compared to many places in the world.

Figure 10 shows the average capacity factors reported for new wind farms installed in a selection of countries in 2020. The bar labelled “NZ (MBIE)” refers to the weighted average from the first 1,500 MW in MBIE’s dataset, which was obtained from the Roaring40s study of potential wind farm sites in Aotearoa.[64] Hence, the chart is comparing actual 2020 capacity factors against potential near-term capacity factors for Aotearoa, estimated in early 2019. Nevertheless, the comparison seems reasonable as the 42.4% figure for NZ (MBIE) straddles the capacity factors for the two large wind farms installed in Aotearoa in 2021. The 222 MW Turitea Wind Farm had a modelled capacity factor of 46% and the 133 MW Waipipi Wind Farm has a 39% capacity factor.[65]

Figure 10: Comparison of onshore wind farm capacity factors, 2020



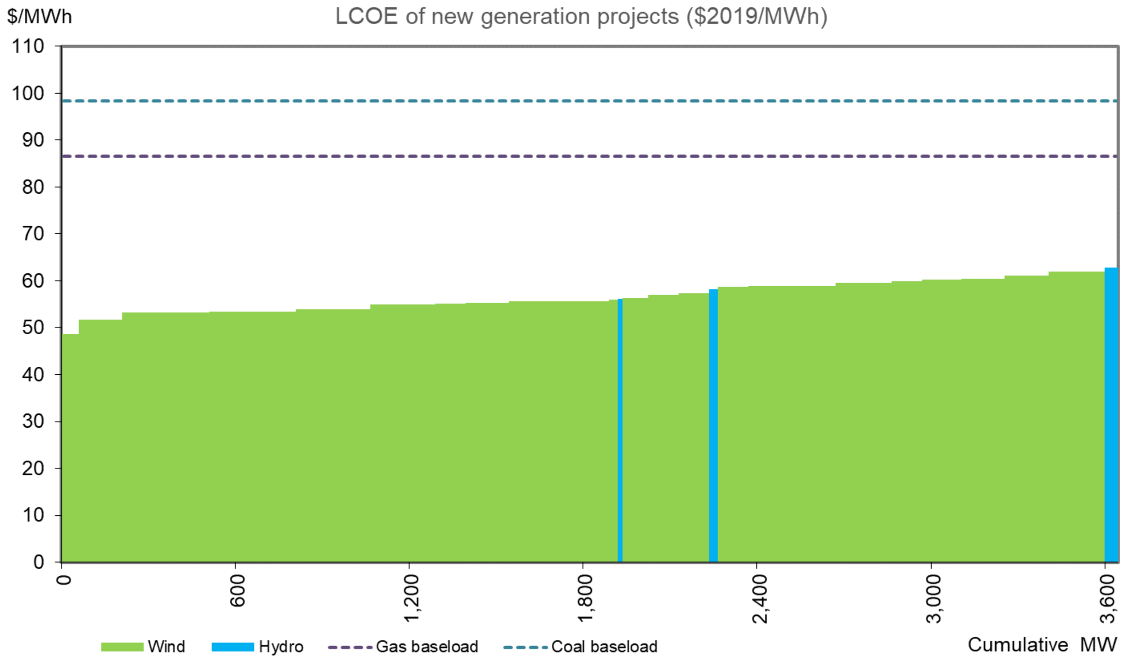
Sources: IRENA Datafile[66]

High capacity-factors imply lower LCOEs if all other costs were equal. For example, the 42.4% average in the MBIE dataset is 18% higher than the 2020 global average of 36.0%, which implies (all else being equal) the LCOE for a New Zealand wind farm should be 18% lower than the global average.

LCOEs for our onshore wind farms are only modestly lower than the global average

Figure 11 plots the generation merit order for Aotearoa using the MBIE’s interactive LCOE comparison tool.[67] This tool uses the site-specific capacity factors and costs reported in section 2. The dashed horizontal lines provide an indication of the LCOE for gas and coal baseload generation, which are clearly ‘out of the money’ compared with wind (and some hydro) generation.

Figure 11: Estimated LCOEs for New Zealand onshore wind sites compared to other New Zealand generation, 2021



Source: MBIE and Te Waihanga

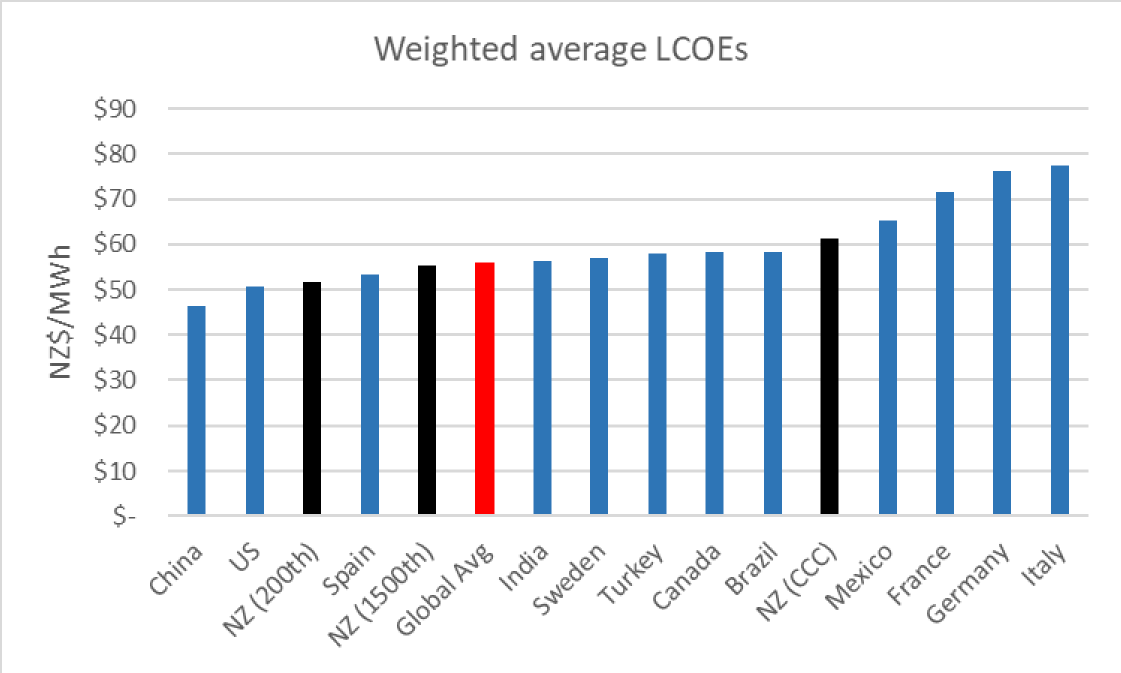
The first 1,500 MW of wind generation in Figure 11 has an LCOE less than $56 per MWh. Remember this was the global weighted average in 2020 in Figure 6 (p17).

The relatively flat slope of the merit order in Figure 11 indicates we may be able to expand our onshore wind generation without pushing up prices greatly. Increasing wind generation capacity by 3,600 MW would provide about 12.8 TWh per year of electricity, which would increase total generation output by 31%. The LCOE for the marginal wind generator would be 24% higher than the lowest-cost wind farm in the chart (on the far LHS).[68] Of course, what matters is our LCOE relative to global competitors.

International comparisons depend on the assumptions used to estimate LCOEs, and in some cases the overseas estimates for wind and solar are based on subsidized costs. However, the above conclusions hold for other LCOE calculations. For example, Lazard has been estimating electricity generation LCOEs for many years and takes particular care to adjust for subsidies. That study presents an LCOE range of $36–$76 per MWh for new onshore wind farms in 2020.[69]

Figure 12 compares the LCOEs discussed above against the average LCOEs for new wind farms in a selection of countries in 2020. The bar labelled “NZ (200th)” is MBIE’s LCOE for the wind farm that adds the 200th MW of new wind generation in Figure 11 above, and likewise the bar labelled “NZ (1500th)” is the LCOE for the wind farm that adds the 1500th MW of new wind generation. The bar labelled “NZ (CCC)” is the minimum drawn from the CCC’s datasets. It is not obvious we have a strong competitive advantage based on cost.

Figure 12: Comparison of onshore wind farm LCOEs, 2020

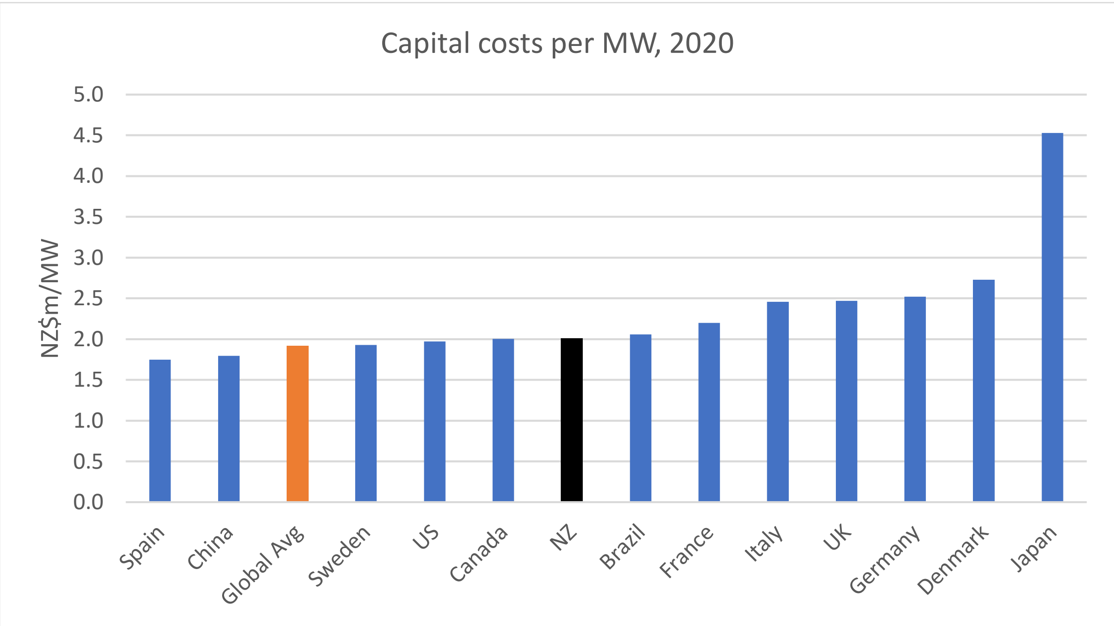


Sources: IRENA Datafile, MBIE dataset, CCC dataset

Wind generation installation costs in Aotearoa are slightly above the global average and have declined at a slower rate than the global average

For a further reality check, we reviewed Electricity Authority data on the real cost of wind generation plant previously built in Aotearoa. Two wind farms (Waipipi and Turitea) were completed in 2021, at a cost of $2.1m per MW.[70] Figure 13 shows this is slightly higher than the global weighted average of NZ$1.9m per MW in 2020.[71]

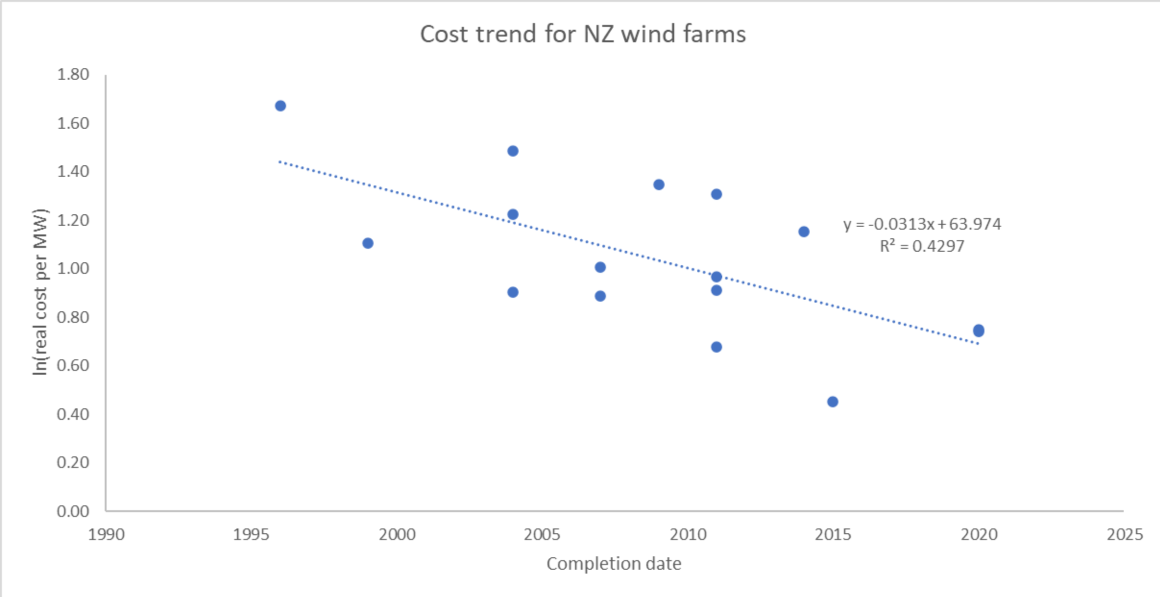
Figure 13: Comparison of installation costs for onshore wind, 2020



Sources: IRENA Datafile[72]

The following chart (Figure 14) shows the log of the real cost of wind generation plant previously built in Aotearoa.[73] With the exception of 2020, each dot is a single wind farm, reflecting the date it became operational and the cost per MW.

Figure 14: Installation costs have declined in Aotearoa



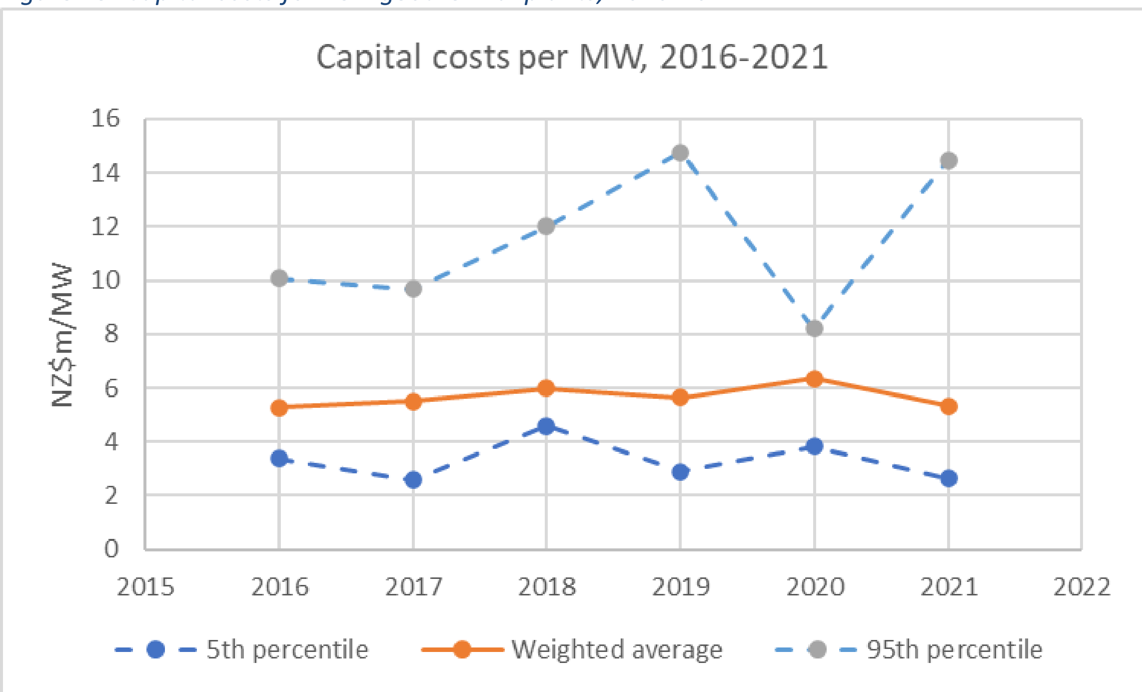
Source: Electricity Authority, Te Waihanga

Figure 14 suggests the capital cost of wind farms has declined over 1995–2020. A simple regression (the dotted line) suggests the rate of change was -3.1% per annum. This compares favourably to a -2.8% rate of decline for the global weighted-average capital cost of wind farm installations over the same period.[74]

We also have relatively average-cost geothermal generation resources

Capital costs are also a key driver of the commercial viability of geothermal projects. Figure 15 presents IRENA data for installation costs in 2020, converted to New Zealand dollars.[75] The global weighted average fluctuates between NZ$5.3m per MW and NZ$6.3m per MW.

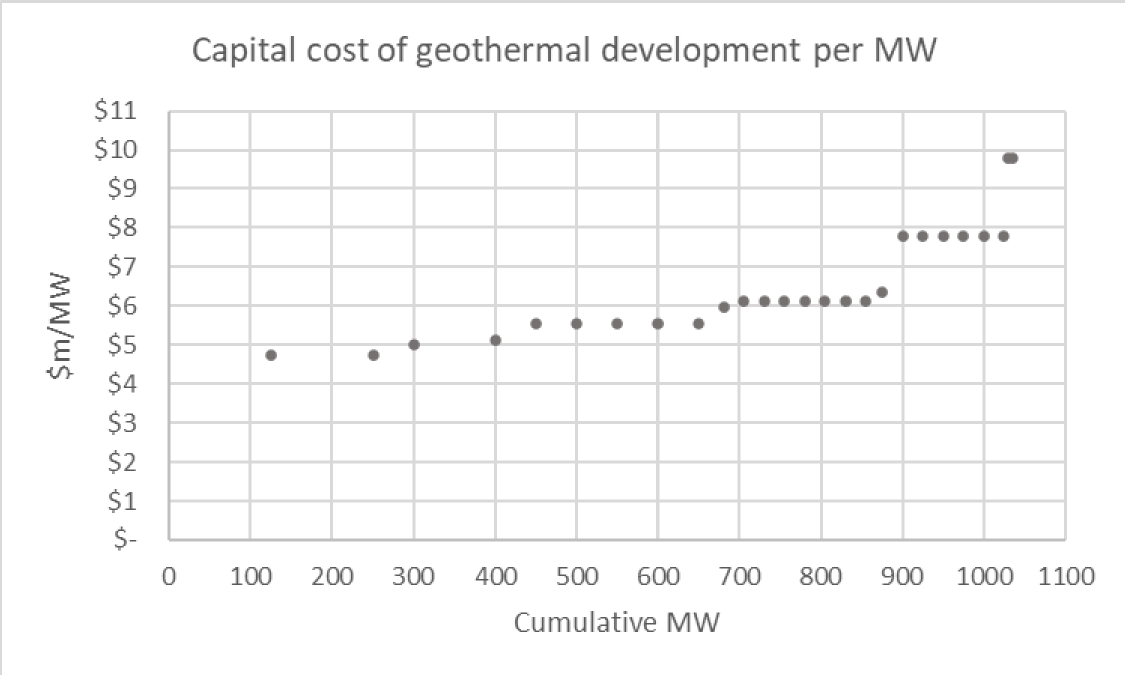
Figure 15: Capital costs for new geothermal plants, 2016-2021



Source: IRENA Datafile

Figure 16 shows a supply curve for potential geothermal projects in Aotearoa, expressed in terms of estimated capital cost per MW. The average of the cost estimates is $5.8m per MW, which is within the variation of the global average plotted above.[76] About 855 MW of our potential geothermal sites would cost less than $6.3m per MW to develop, which is within the fluctuating range for the global average discussed above. At a 92% capacity factor, the 855 MW would produce 6.9 TWh of additional generation per year.[77]

Figure 16: Geothermal supply curve for Aotearoa



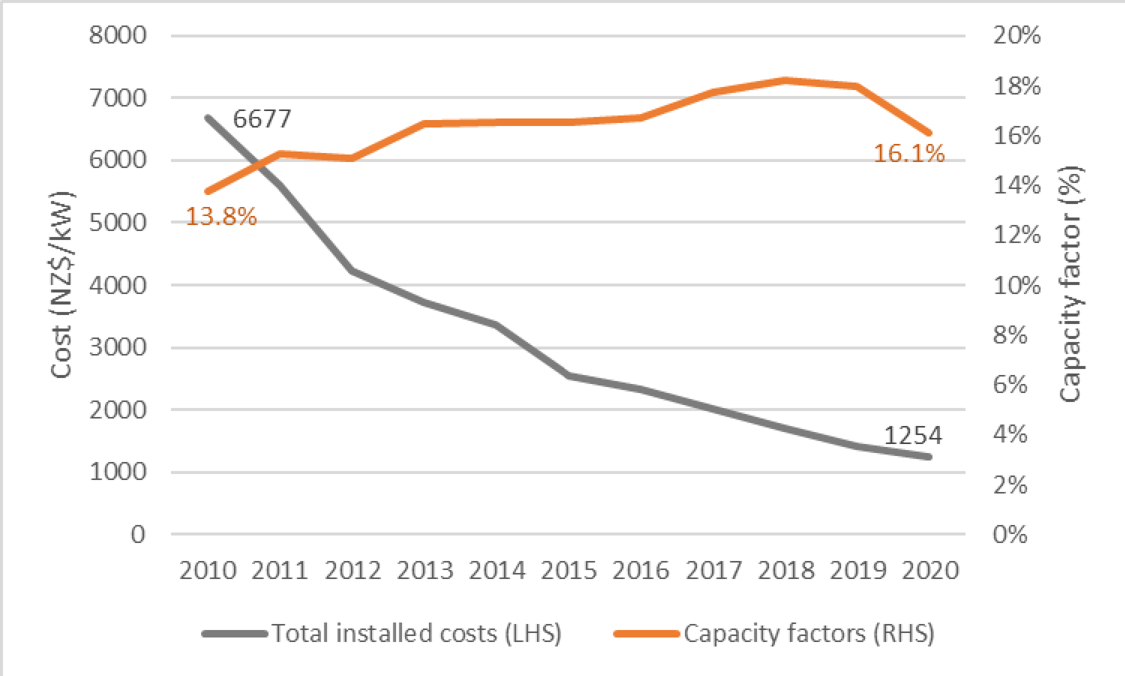
Source: Lawless (2020)

Geothermal generation operates at a reasonably constant power output and are only taken out of service for maintenance or to fix technical issues. For new geothermal plants in 2020, the global weighted-average capacity factor was 83%, with a 76–91% spread (the 5th and 95th percentiles).[78] This contrasts with capacity factors here, which tend to be in 90–95% range.[79]

Unfortunately, we have average capacity-factors for solar generation

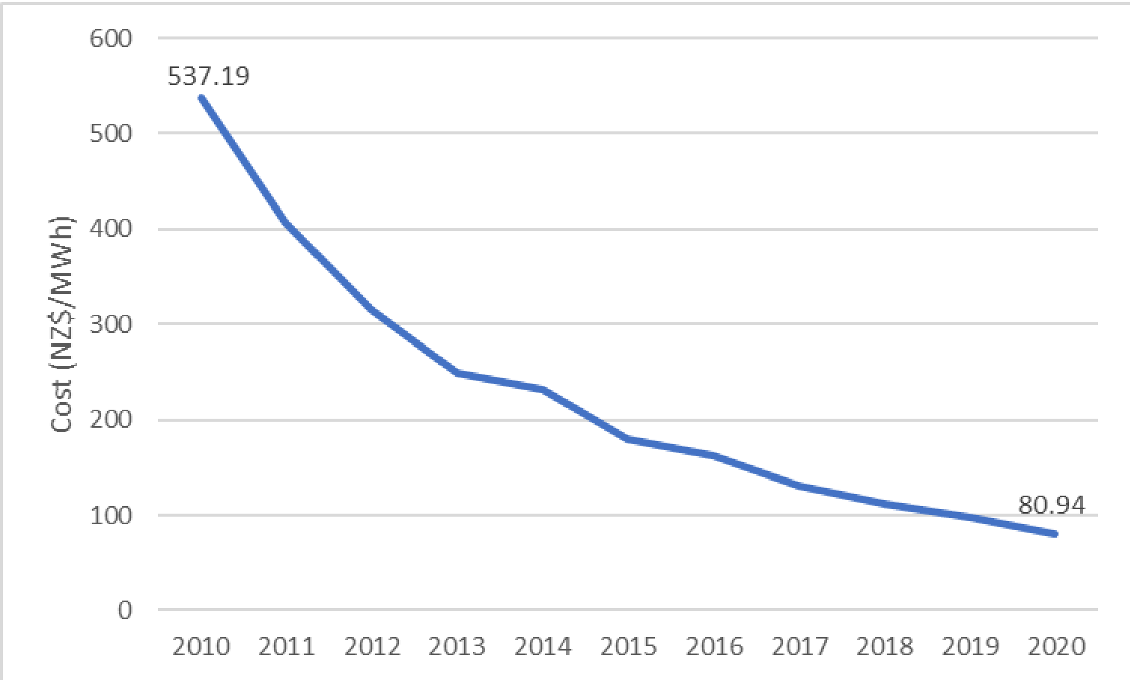
Capital costs are also a key driver of the commercial viability of solar generation projects. The following two charts present IRENA data for the last 10 years, with cost data converted to New Zealand dollars. The LCOE for solar photovoltaic (PV) generation has declined dramatically over the last decade, driven primarily by declining capital costs (total installed cost).

Figure 17: Global average costs and capacity factors for solar PV generation, 2010–2020



Source: IRENA Datafile[80]

Figure 18: Global average LCOE for solar pv generation, 2010–2020



Source: IRENA Datafile

Globally, capacity factors for solar PV are far lower than for wind turbines, around the 15–18% range for solar versus 35–40% for wind. That is one reason why solar PV has an emission intensity about four times higher than wind.

Solar capacity factors are largely a function of the quality of the solar resource, solar module efficiency and inverter characteristics. Miller (2020) notes it is now economic to incorporate systems to track the sun throughout a day, and to over-size module capacity to improve the inverter loading ratio and offset module degradation, improving system capacity factors. Based on the assumption that all large-scale solar farms will in the future adopt those approaches, Miller estimates that solar capacity factors will likely range 12–20% throughout Aotearoa.[81] Although we have some excellent solar resources – Miller identifies 1,400 MW of solar sites with 19%–20% capacity factors – our capacity factors are low relative to the global top five percent of capacity factors, which averaged 25.2% for 2011–2020 (and many of these would be even higher if recent tracking and inverter loading ratios had been used).[82]

Naturally, for a given location and design (yielding a given capacity factor), the return on investment (ROI) is also sensitive to electricity prices and capex costs.[83] As we have no large-scale solar farms operating here, Miller infers the LCOEs have been too high to generate an acceptable ROI.

However, large scale solar generation is about to enter the New Zealand market

Miller's view in 2020 was that the falling capital costs for solar PV were getting close to a point where the ROI becomes acceptable to build here. This is reflected in his base case scenario, where over 1,000 MW is projected to enter the New Zealand market between 2025 and 2029.

This projection was based on a real spot market price of $85 per MWh for the next 30 years, a real discount rate of 5% and a real ROI criterion of 6.5%.[84] Also in this scenario, land price inflation was assumed to be three percent higher, and wage inflation one percent higher, than CPI and electricity price inflation.

With interest rates currently at historically low levels, and long-term electricity contract prices at historically high levels, exceeding $100 per MWh, the conditions for large scale solar to enter the market have never been better. And that is what appears to be occurring.

Lodestone (a new entrant generator with executives with extensive generation and retailing experience in Aotearoa) announced earlier this year plans to build five large scale solar farms in the upper North Island. The five farms are to be installed by the end of 2023, producing in aggregate 0.4 TWh per year.[85]

According to Lodestone's website, the farms will be designed to support continued agricultural activities around the solar infrastructure, with over 85% of baseline farming yield expected when the solar farm is operational. According to news reports:

"The solar farms will cover 500 hectares and will comprise 500,000 solar panels which will be erected at a height of about 2.3 metres, in lines about 10 metres apart, allowing livestock to graze underneath and tractors to move in between … Lodestone has an agreement to source modern panels that will move automatically to track the sun and are double-sided, so they can also generate power from light reflected from the ground."[86]

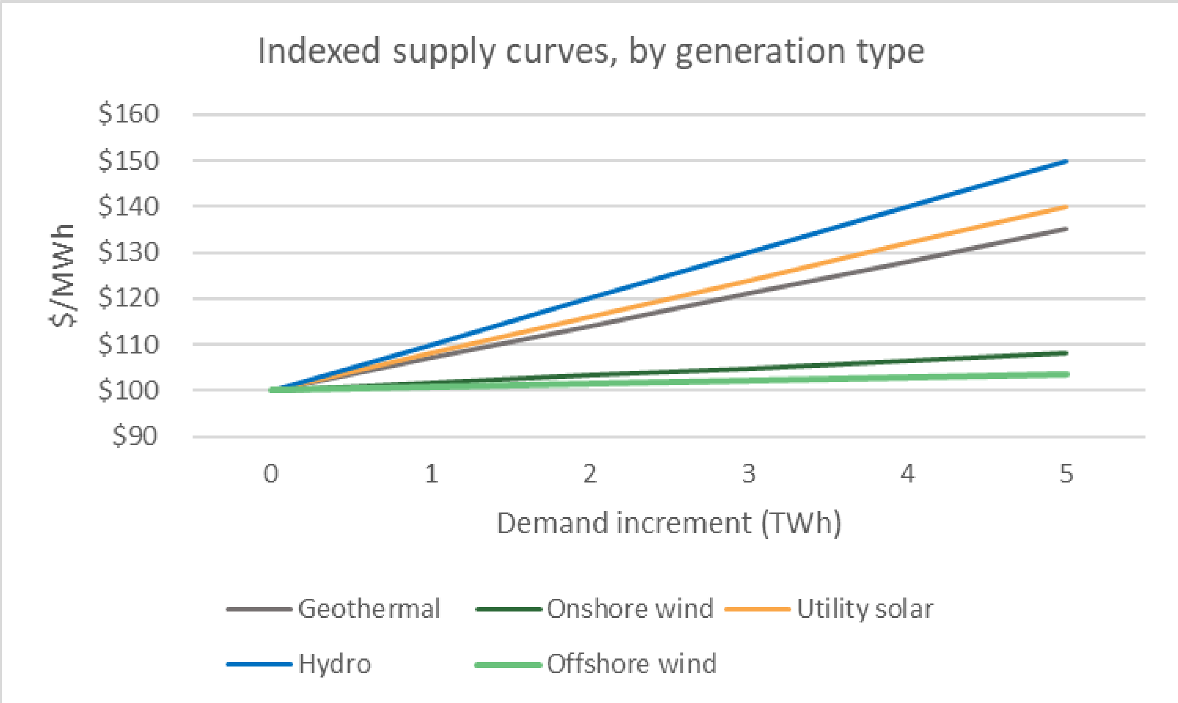
In the previous section on physical abundance, we noted that Miller's base case estimate was for 6,300 MW of solar PV by 2030. These estimates didn't consider the possibility of having solar panels on stilts so that farming can largely continue. Clearly, if Lodestone's approach is commercially viable and sustainable in the face of extreme weather events, then substantially more solar generation may develop than identified in Miller's base case scenario.

Another new entrant, Far North Solar Farms, which is part Australian-owned (where solar is a significant portion of the market), has also announced plans for large scale solar farms in Aotearoa. Christchurch Airport has also announced it will build a 220-hectare solar farm at Kowhai Park, near the airport, delivering enough electricity to power 30,000 homes. Also, one of our largest generators, Genesis Energy, has announced plans to install 500 MW of solar in the next five years.

Concluding comment #1: onshore wind is our most abundant and lowest-cost low-emission resource (for now)

Figure 19 shows *stylised* supply curves for each source of low-emission generation in the CCC's analysis, sourced from MBIE's generation stacks discussed in section 2 above. Each curve is based on a single marginal cost estimate and indexed to 100 to make it easier to see the different supply slopes.

Figure 19: Comparison of supply curve slopes (absent technology advances)



Source: CCC[87] and Te Waihanga

Generation sites are generally developed in a merit order, in that the best sites are chosen first, and then the next best, and so on. Hence, as more generation sites are developed over time, good quality options become scarcer. Absent technology advances, increases in electricity demand push the system along the supply curves shown above, putting upward pressure on LCOEs. It is useful to refer to this as *the scarcity effect*.

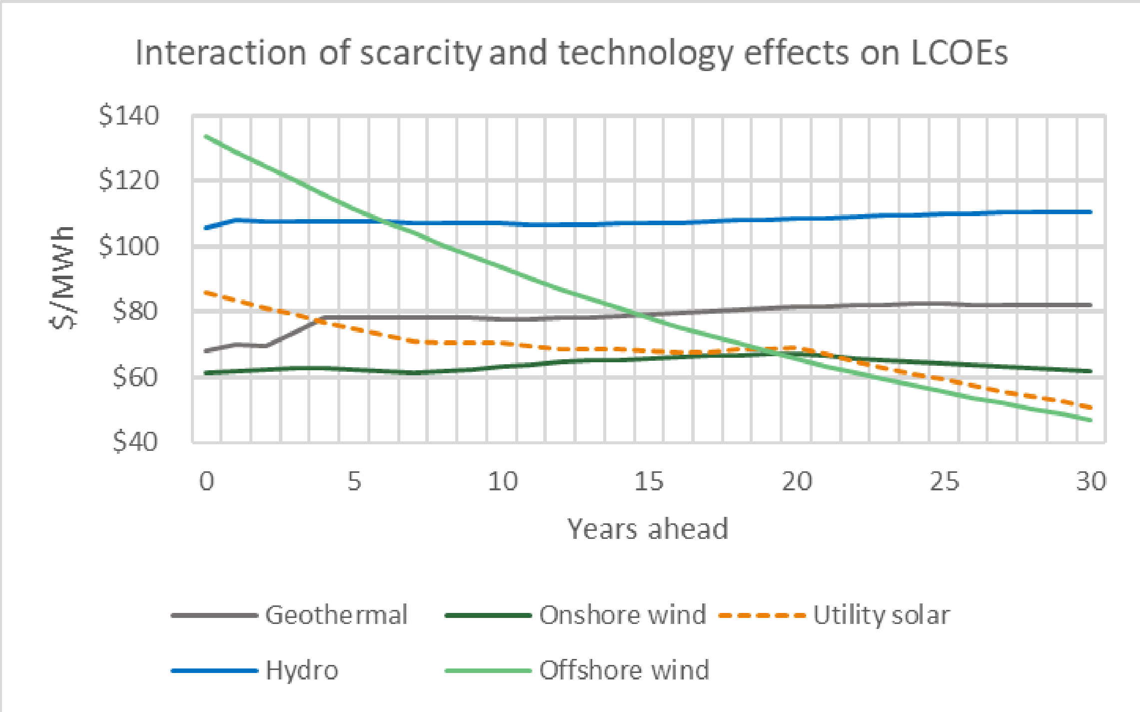
The supply curves for onshore and offshore wind are very flat in Figure 19, indicating an abundance of good quality wind sites. A 5 TWh per year increment in offshore wind increases costs 3.6%, whereas onshore wind increases 8%. The supply curve for utility solar is significantly steeper. A 5 TWh per year increase in solar generation increase solar LCOEs by 40%, reflecting the scarcity of good quality solar sites in Aotearoa. Good quality hydro and geothermal sites are also scarce.

Concluding comment #2: Offshore wind may become our low-cost resource in about 20 years

The supply curves in Figure 19 ignore technology change, which we know is significant for wind and solar. Figure 20 illustrates the effect of incorporating ongoing cost reductions for the above supply curves, based on CCC analysis.[88] In line with international agencies, the CCC assumed annual reductions in LCOE of -3.5% for offshore wind, -3.0% for utility solar, -0.8% for onshore wind and -0.1% for both hydro and geothermal.[89] It is useful to refer to these cost impacts as *the technology effect*.

To capture the scarcity effect mentioned earlier, we assume the increases in generation in the CCC's analysis occur,[90] with one minor adjustment: when offshore wind reaches cost-parity with onshore wind, we assume increases in wind generation come from developing offshore wind sites.[91]

Figure 20: Supply costs with technology advances



Source: Te Waihanga

Although offshore wind currently has the highest LCOE, Figure 20 illustrates it could become cheaper than solar and onshore wind in about 20 years. It also illustrates that the technology effect swamps the scarcity effect over time, because solar becomes cheaper than onshore wind despite solar having a steeper supply curve.

Importantly, if the technology effect swamps the scarcity effect, then any competitive advantage a country has with wind or solar energy will be eroded over time. For example, suppose Aotearoa has a 30% advantage in terms of wind capacity factor relative to global average and assume the global average LCOEs is (say) $50 per MWh. Then our higher capacity factor would give us a $15 per MWh cost advantage. If over 20-year period global average LCOEs for wind dropped to (say) $5 per MWh, then our capacity factor advantage would now only be worth $1.50 per MWh.

Of course, different assumptions about the rate of cost reduction produce different results. A recent assessment of cost reduction trends for energy technologies suggests our assumptions may be too conservative.[92] If that is correct, then offshore wind may become commercially viable far sooner than shown in Figure 20.

3.3 Comparing LCOEs with wholesale market prices

Section 3.2 discussed LCOEs for wind, solar and geothermal generation, globally and in Aotearoa. LCOE estimates are often compared with wholesale electricity prices, with the inference that generation with LCOEs lower than wholesale prices are profitable. Such comparisons are misleading, for the reasons outlined in the above framework.

It is misleading to compare LCOEs with average wholesale market prices

Figure 21 shows the prices for electricity futures contracts at Otahuhu for the period 2009 to September 2021.[93] These prices are for long-dated baseload contracts, which are contracts maturing in the next one to four years for a constant amount of electricity, 24x7, for the duration of each contract.[94]

Figure 21: Prices of long-dated electricity futures contracts at Otahuhu, 2009 - 2021

Source: Electricity Authority

On the face of it, investing in onshore wind generation could be profitable, with estimated LCOEs of $55–$70 per MWh, well within the long-run trend of wholesale electricity prices shown above.

But profitability is not assured because average spot market prices for intermittent generation, such as wind and solar, are typically well below average wholesale market prices – this is called the *cost of intermittency* (COI).

A similar problem occurs for all providers of inflexible generation. This includes intermittent generation (such as wind and solar), but also geothermal generation and baseload thermal generation (these are usually called combined cycle gas turbines, or CCGTs). The problem for all forms of inflexible generation is that they cannot be altered to perfectly match market demand patterns within a day, week or season. If there are some periods when inflexible generation falls short of demand, backup generation is needed to fill the gap. The costs of doing that is called the *cost of backup* (COB) in this note. This is a broader concept than COI, and in some cases COB = COI.

The rest of this subsection explains these issues further and discusses their magnitude. It is important to appreciate these are not matters of detail; they are key to discussing the longer run competitive advantage of our low emission electricity resources.

The cost of intermittency (COI) for wind generation

It is useful to first discuss wind generation. When wind generation is operating, it tends to increase total electricity supply, suppressing spot market prices. This is because when the wind is blowing it is typically blowing across large areas of the country, and so wind generator output at one wind farm tends to be positively correlated with wind generation in other areas of the country.[95] Also, rainy seasons tend be windy, and so run-of-river hydro generation will tend to operate around the same times (seasonally). For these reasons, the average price earned by a wind generator is typically below the market average price.

To get a measure of this, suppose a wind generator could operate at a constant power output 24x7. It would receive revenue equal to the fixed quantity of output times a simple average of spot market prices. In the electricity sector, the simple average is often referred to as a *time-weighted average price* (TWAP). The TWAP for the spot market corresponds to prices for baseload futures contracts, as they both assume constant power outputs 24x7.

However, the average price a wind generator receives over a period of time depends on how much it generated at each price level, and this is called the *generation-weighted average price* (GWAP). As spot market prices are often suppressed when wind generation operates, GWAP is generally lower than TWAP, which means the GWAP/TWAP ratio is less than 100%.

The larger the share of electricity provided by wind the smaller the GWAP/TWAP ratio. According to modelling prepared for the Interim Climate Change Committee, the ratio declines about 3% for each 5-percentage point increase in wind penetration.[96]

Wind is currently at 5% penetration and the ratio is about 92%. At 15% market share, the ratio reduces to 86%,[97] which means a wind generator would receive spot market revenue equal to 86% of the TWAP.

For example, if the TWAP for the spot market was $75 per MWh a wind generator would typically only receive $64.50 per MWh. This price is towards the low end of the $60–$70 per MWh LCOE estimated by Roaring40s for favourable wind generation sites in their study. At those market prices, lower quality wind sites are unlikely to earn revenue sufficient to cover their levelised costs.

The GWAP for solar and geothermal generation

A similar price suppression effect could occur in the future for solar generation, because when it is sunny in one area of the country it is often sunny in many areas.[98] Currently we have minimal solar generation and so solar is not currently suppressing spot prices.

Solar has the advantage of operating during the business day when daily demand and spot market prices are high compared to overnight. However, solar produces less output on cloudy days and output slumps significantly during the winter months when our daily demand (and the spot price) is high. Hence, solar tends to miss out on earning the highest prices.

In locations where peak electricity demand occurs during summer (such as Australia, California, Texas, Germany and Spain), the solar GWAP/TWAP ratio exceeds 100% for solar penetrations of 5%. In contrast, in modelling undertaken by Energy Link the ratio is less than 90% for 5% solar penetration in Aotearoa. Moreover, the ratio can be expected to fall 12% for each 5% increase in solar penetration.[99] The rate of decrease is greater than for wind as the capacity factor of solar is lower and the correlation between solar supply is high.

In other words, not only does Aotearoa have lower solar capacity factors than these jurisdictions it also has lower solar GWAP/TWAP ratios. Solar in Aotearoa does poorly in terms of both productivity and prices. It is clear we do not have a competitive advantage in solar generation.

Geothermal generation is not intermittent. These plants essentially operate at a constant power output, 24x7, until they are taken out of service for maintenance. As generators schedule maintenance for periods when spot market prices are usually low, for example during our summer holidays, the GWAP for geothermal is likely to slightly exceed TWAP.

3.4 The cost of backup (COB) for combinations of generation and demand

The LCOE estimates in section 3.2 ignore the cost of any backup energy needed to cover mismatches between generation and consumer demand. However, these costs can add significantly to the true LCOE from some types of generation.

In the United Kingdom, for example, the cost of backup generation and additional transmission costs increases the true cost of onshore wind and solar by 45-50% and reduces the LCOE for some types of thermal plants by about 40%.[100] A literature review in 2015 identified a similar level of adjustment for wind generation.[101]

To consider the competitiveness of our low-emission electricity resources, we need to consider whether developing those resources requires a higher or lower COB relative to other countries.

Different demand types have different load profiles

Electricity demand from residential and commercial consumers varies greatly over a 24-hour period. It is typically high during the day and low during night hours, especially between midnight and 5am. Many commercial consumers are shut in the weekends and for public holidays.

Industrial consumers, on the other hand, tend to operate at a constant rate, day and night, 365 days a year, and so TWAP is a pretty accurate measure of the average price paid by these consumers. This is particularly the case for steel mills and aluminium smelters. However, some industrial consumers, such as dairy processing factories, have seasonal variations in their demand for electricity.

Supply interruptions are very costly

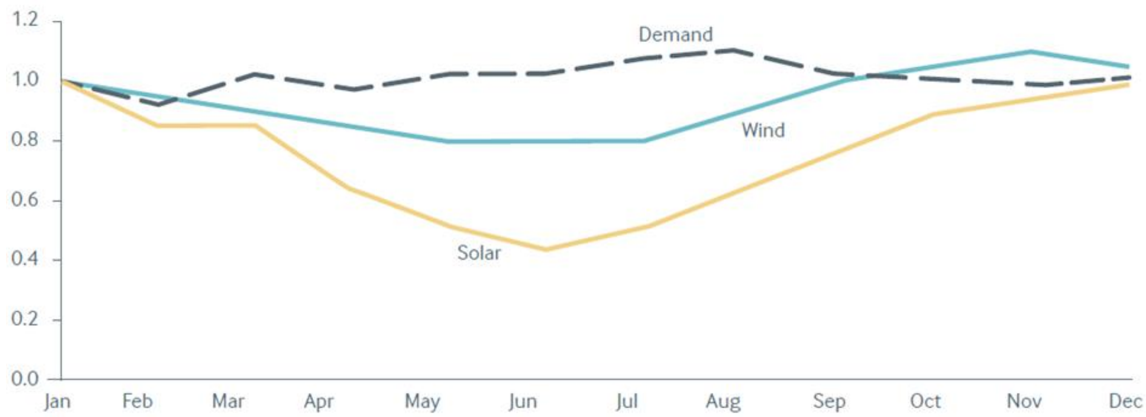
A technical feature of power systems is that total electricity supply must match total electricity demand on a second-by-second basis to keep the system stable. Otherwise, the system can collapse, leaving all consumers without power. Sudden power interruptions are extremely costly, ranging from $3,900/MWh for large non-residential consumers in Auckland to nearly $70,000/MWh for small commercial consumers in Christchurch (Electricity Authority, 2013, p2).

Large supply-demand mismatches can occur when inflexible generation is used

Large supply-demand mismatches occur for wind and solar generation because their power output depends on how windy and sunny it is, and these are poorly correlated with consumer demand.

Wind and solar are also a poor match for electricity demand on a monthly or seasonal basis. Figure 22 shows how wind and solar output and demand vary on average throughout the year relative to their average value for January (which is indexed to 1.0). The chart shows that wind and solar output slump over winter months, by up to 20% for wind and 50% for solar.[102] Statistical analysis of actual and synthetic wind data across the country, undertaken for the Interim Climate Change Committee, suggests no seasonal slump in wind generation will occur in the future.[103]

Figure 22: Wind and solar generation in Aotearoa reduce significantly over winter months



Source: Transpower

These seasonal effects vary across countries. For example, Australian electricity demand is generally higher in summer than winter, which correlates well with solar which has maximum output over summer.[104] Wind generation in the UK is higher over winter when their demand is high.[105] As neither correlation occurs in Aotearoa, it reduces the relative competitiveness of our wind and solar resources.

As mentioned earlier, geothermal generation is normally built to operate at a reasonably constant power output, making it a generally good match for flat industrial load.

The extra cost of backup for different combinations of demand and inflexible generation

The average price paid by industrial consumers buying from the spot market depends on how much electricity they consume at each price level. In the electricity sector, power demand at any instant is called electrical *load*. The average price a consumer pays is called the *load-weighted average price* (LWAP). The LWAP for industrials with completely flat load profiles will equal TWAP, but demand by some industrials varies seasonally and some may offer demand-side response (DSR).

The COB for different combinations of load and inflexible generation is $LWAP.D - GWAP^S.S$, where *D* is the increment in electricity used by a consumer over a period of time, *S* is the quantity of inflexible generation over that time period, $GWAP^S$ is the GWAP received by the inflexible generation over that period and LWAP is as defined above.[106]

However, we are interested in the extra costs of backup generation, ECOB. This is the cost the consumer pays over and above what it would have paid if inflexible generation could somehow have supplied the entire increment in demand. Dividing ECOB by *D* gives us LECOB, that is the levelised extra cost of backup. It is easy to show that LECOB = *m*.*pd*, where *m* is the average size of the physical mismatch and *pd* is the average price difference between backup generation and inflexible generation.[107] Hence, LECOB is large when *m* and *pd* are both large, and small when they're both small.

We are interested in what type of load would be best suited to use our abundant low-emission resources. Table 2 provides a qualitative assessment of ECOB for various scenarios, where "+/-" means extra cost of backup is positive/negative.[108] Details of the qualitative assessment are provided in Appendix C, which also includes discussion of commercial and residential load profiles.

Table 2: Extra COB for various combinations of load and primary generation

	Geothermal	Wind (with 20% winter slump)	Solar (with 50% winter slump)
Flat load with no DSR capability (eg, aluminium or steel smelters)	- (m>0, pd<0)	++++ (m>>0, pd>>0)	+++++++++ (m>>>0, pd>>>0)
Flat load with short-term DSR capability (eg, data centres)	- (m>0, pd<0)	++ (m>>0, pd>0)	++++++ (m>>>0, pd>>0)
Primary sector seasonal load with no DSR capability (eg, primary sector processing plants)	---- (m>>0, pd<<0)	+ (m>0, pd>0)	+ (m>0, pd>0)
Flat load with short-term & seasonal DSR (suitable for wind) (eg, hydrogen plants)	- (m>0, pd<0)	+ (m>0, pd>0)	++++ (m>>0, pd>>0)

Source: Te Waihanga

An overall conclusion from the table is that geothermal has negative ECOB for industrial load, as it is a very good match for flat industrial load. The only time geothermal doesn't match flat load is when it is taken offline for scheduled maintenance, but that will be when market prices are low and so *pd* will be negative ($GWAP^b < GWAP^s$).

In contrast, wind generation has moderately positive ECOBs for three of the four industrial load profiles (rows 2, 3 and 4). It does particularly well for load that reduces over winter (row 3) or can reduce over winter (row 4). Of course, if wind has no seasonal slump, as some analysis suggests, then its ECOB reduces considerably in rows 1 and 2.

Solar has far higher ECOBs than wind for three of the four profiles. Overall, solar is not a good fit for our electricity system.

The stochastic nature of supply-demand mismatches increases the cost of backup (COB)

The discussion above was deterministic, for ease of discussion. But in practice consumer demand and generation are stochastic (ie, have an unpredictable component to them). In practice, all generation is stochastic because any plant can breakdown. However, the volume of generation from weather-dependent generators is more unpredictable overall.

To cover for increased uncertainty as more wind and solar are added to the electricity system, more "insurance" is purchased in the form of spare backup resources of various types, including from the demand side and perhaps also investment in more accurate forecasting tools.[109] These costs are a component of LCOB.

Thermal and hydro generation are generally very good backup options for wind, solar and geothermal

Thermal and hydro generation are controllable forms of generation. Their owners determine how much power to offer to the market over the next few hours and days ahead, and the system operator determines how much each operates to balance total supply and demand at any point in time.

Provided they have sufficient fuel and water, thermal and hydro generators can be operated to closely match variations in system demand. Hydro incurs additional 'wear and tear' costs from ramping up and down quickly over short periods of time and CCGTs are more costly to operate in that manner too. Those types of generators are best for covering intra-day, intra-week and seasonal demand variations. Open cycle gas turbines (OCGTs) perform very well at filling intra-hour demand variations, and for that reason are often called *gas peakers*. They can also be used to cover intra-day and intra-week variations but are more costly than CCGT generators. In Aotearoa, the diesel-fired generator at Whirinaki is also a peaking generator.

Thermal and hydro generation can become less flexible if their "fuel" supplies are very scarce. Hydro generation in Aotearoa depends on seasonal rain patterns, as our hydro reservoirs are relatively limited. When full, they hold potential energy equivalent to six weeks of total electricity demand.[110]

If an extended dry period occurs, our hydro generation becomes very constrained and more expensive thermal generation is used to cover seasonal shortfalls. In general, supplies of gas and coal enable unlimited operation of plants running on those fuels. However, gas supplies (for generation) were constrained over winter in 2021, and in 2003 Aotearoa experienced a period when generation was constrained by shortages of both gas and coal.[111] The CCC used a $269–$295 per MWh range for the LCOE for gas peakers.[112]

Pumped hydro storage (PHS) schemes are where low-priced electricity is used to pump water to a catchment area, and the stored water is used to generate hydroelectricity when prices are high. This is a commercially viable backup option when the price differentials are sufficient to cover the levelized costs of the scheme.

Analysis for the Interim Climate Change Committee estimated the proposed Lake Onslow PHS scheme could cost $150m per year (about 3–5% of wholesale market costs).[113] This equated to $195 per MWh of electricity generated to cover *residual dry year risk* – that is, the additional dry year risk from moving the electricity system from 98% renewable to 100% renewable.[114]

Note MBIE is currently undertaking a two-phased feasibility study into PHS and other dry year storage solutions. Phase 1 includes initial geotechnical and environmental investigations, to inform a decision on whether to proceed to Phase 2 (an engineering design and further field work on any environmental, geo-technical and seismic issues). Phase 1 is scheduled to be completed in April/May 2022,[115] at which point more detailed cost estimates of the options should be available.

Demand-side response (DSR) is also a backup option

So far we've discussed backup generation to fill supply-demand gaps, however in demand-side response (DSR) can also play a significant backup role. In general, DSR will occur when it is a cheaper option than increasing generation.[116]

DSR for dry year cover is considerably more costly than DSR for short intervals, due to the greater disruption to production schedules. Analysis for the Interim Climate Change Committee assumed firms would charge a fee of around $500 per MWh for prolonged interruptions (eg, lasting several months or more). On the basis that a dry year event may occur once every five years, the cost to cover residual dry year risk, spread over all years, was estimated at $384m per year.[117]

DSR has zero or negative emissions

DSR involves temporarily reducing electricity demand, and subsequently increasing it to meet production scehedules, which presumably leaves a firm's average demand unchanged. This would leave emission levels unchanged for electricity systems with a constant emission intensity. In practice, emissions intensity is positively correlated with spot prices because thermal generation tends to operate when prices are high and not when prices are low. Hence, DSR is likely to reduce emissions overall.

Green hydrogen is sometimes suggested as a solution to decarbonising hard-to-abate activities, such as heavy long-distance vehicles or high temperature process heat.[118] One of the attractions of hydrogen is that the production process is easily interruptible, and it is energy dense and so large amounts of energy can be stored (as hydrogen gas or in the form of ammonia). However, about 30% of electrical energy is lost from converting electricity to hydrogen.[119]

In principle, hydrogen is an excellent candidate for provision of short-term and seasonal DSR. Rather than have supply vary to match demand, it may be possible to have hydrogen production and electricity demand vary to match fluctuations in wind or solar generation.

However, even more so than batteries, hydrogen is an emergent technology. Although it is currently very uneconomic to produce, ongoing innovation and productivity improvements are likely to significantly reduce costs over time. The Interim Climate Change Committee considered how much it would cost to cover residual dry year risk, by converting the Ahuroa Gas Storage Facility to store hydrogen and converting hydrogen to ammonia to provide sufficient storage. The annual cost of this backup option was estimated to be $625m per year, significantly due to large losses of electricity in converting to hydrogen (and then ammonia) and then re-converting back to electricity.[120]

Batteries and over-build of wind and solar are also backup options

Large-scale electrical batteries have recently become a backup option. At current prices they are a very expensive option for providing frequent backup services because the commercial lifetime of a battery depends on the number of charge/discharge cycles they have gone through.[121, 122] At this stage, like DSR, batteries are a better backup option for covering risks that occur infrequently, such as a generation or transmission or distribution failure.[123]

Another approach, sometimes presented as a backup option, is to over-build wind and solar to reduce the demand-supply gap. It is called over-build because there would be too much wind and solar generation at times, which would be dealt with by curtailing the output of some plants. This is called *spill* as it is analogous to hydro generators spilling water when they cannot generate fast enough to avoid reservoirs exceeding maximum allowable levels (determined by resource consents).

One of the reasons some commentators suggest over-building renewables is that the LCOE for wind and solar have recently fallen below the short run marginal cost (SRMC) of coal-fired generation and are now falling below the SRMC of combined-cycle gas generation.[124]

However, even though the LCOEs for wind and solar are reducing rapidly, massively over-building them in the next decade would be very costly.[125] Without batteries, their electrical power is wasted a large percentage of the time and security of supply would be compromised. But adding batteries is currently very expensive.

Analysis for the Interim Climate Change Committee found that massively over-building wind and solar would cost in the order of $2.7b and another $1b would be spent on batteries. The annualized cost of this combination would be $412m per year. Note, if batteries were installed without any over-build of wind and solar, the annualised cost would be a whopping $28b per year.[126]

Table 3 summarises the above discussion of the annualised cost of covering the additional dry year risk arising from moving from a 98% renewable electricity system to 100% renewable. On this basis, all renewable options are considerably more expensive than the Onslow scheme.

Table 3: Annualised costs of covering residual dry year risk from renewable sources

Renewable forms of backup	Annualised cost ($m)
Onslow PHS scheme	150
Demand-side response	384
Over-build of wind & solar and some battery capacity	412
Hydrogen and ammonia storage	625
Long-term battery storage without over-build of wind & solar	28,000

Source: Culy (2019b)

However, there is an option value to be gained from waiting for battery prices to fall

Covering dry year risks with batteries would involve spending $270b, equivalent to 87% of our annual GDP in 2019.[127] By comparison, the Onslow scheme is far cheaper. For example, if it cost $3.2b to build, the Onslow scheme would provide the same amount of dry year cover for only 1.2% of the cost of the battery alternative. Even if the estimated cost of Onslow ballooned to $10b, it would cost only 3.7% of the battery alternative.

However, batteries are easy and quick to install, and the investment decisions are reversible. The Onslow scheme is the opposite. It would probably take a decade from the time a decision was made to do it to completing the scheme. And once it is installed the investment is irreversible. These considerations mean there is an option value to deferring a final decision on Onslow until 2040.

At the time of writing this paper, there is only 19 years until we reach 2040. Our calculations show that battery prices would need to decline by -20.8% per year over the next 19 years for them to become a cheaper option than building the $3.2b Onslow scheme.[128] If the costs of the Onslow scheme increased to $10b, then battery prices would need to reduce by -15.9% per year for batteries to be a better option.

Over the last decade, battery prices have declined 90%, which is -21% per year.[129] Interestingly, the International Energy Agency (IEA) is projecting prices for battery packs for transport applications to decline through to 2050 at rates between -2.2 to -2.8% per year.[130] These assumptions seem implausibly conservative given the price declines so far. Way, Ives, Mealy & Doyne (2021) document the IEA's record on price projections, showing it has consistently been far too conservative in its price forecasts for other technologies such as solar and wind.

3.5 The competitive advantage of our low-emission generation resources

A key feature of many of the above backup options is they utilize technologies that are, or will be, widely available throughout the world, such as batteries, over-building wind and solar, storing energy in the form of hydrogen or ammonia, and of course gas and diesel peakers with and without CCS (carbon capture and storage). Deploying those options is unlikely to create a competitive advantage for us.

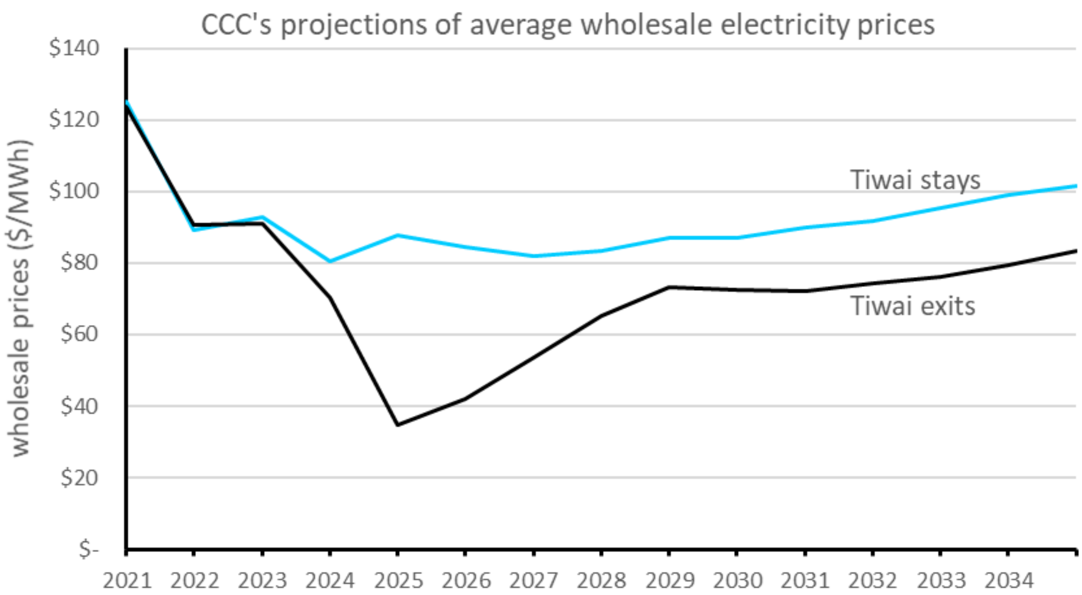
However, in addition to our onshore wind resource, we have a comparatively abundant supply of hydro and geothermal generation due to New Zealand's geological features. These may provide a competitive advantage for a period.

Some generators have identified that our hydro generation may give us a temporary competitive advantage if Tiwai closes down

A recent study of the prospects for producing green hydrogen and ammonia in the South Island argues our existing hydro generation offers only an *initial* competitive advantage.[131] The initial advantage is based on the Tiwai smelter closing in December 2024, freeing up a large amount of hydro generation (5 TWh per year) for other uses from 1 January 2025.

The potential impact of a 'Tiwai exit' on wholesale electricity prices is shown in Figure 23, based on CCC data. A Tiwai exit is predicted to reduce prices in the year or two before the exit and for three to four years after the exit. The largest reduction is in 2025, where prices are predicted to be 60% below the level they would be if Tiwai stays.

Figure 23: A Tiwai exit creates an initial competitive advantage for New Zealand electricity



Source: CCC[132]

Looking at 2029 – 2035, Figure 23 suggests a Tiwai exit could permanently reduce wholesale electricity prices, with prices suppressed by an average of $17 per MWh, or 18%.

Conversely, suppose the Tiwai smelter stayed, and demand increased an additional 5 TWh per year due to another industrial consumer choosing to locate their energy-intensive production in Aotearoa. Would our wholesale electricity prices increase another 18% or so?

Permanent demand increments are likely to drive up our electricity prices

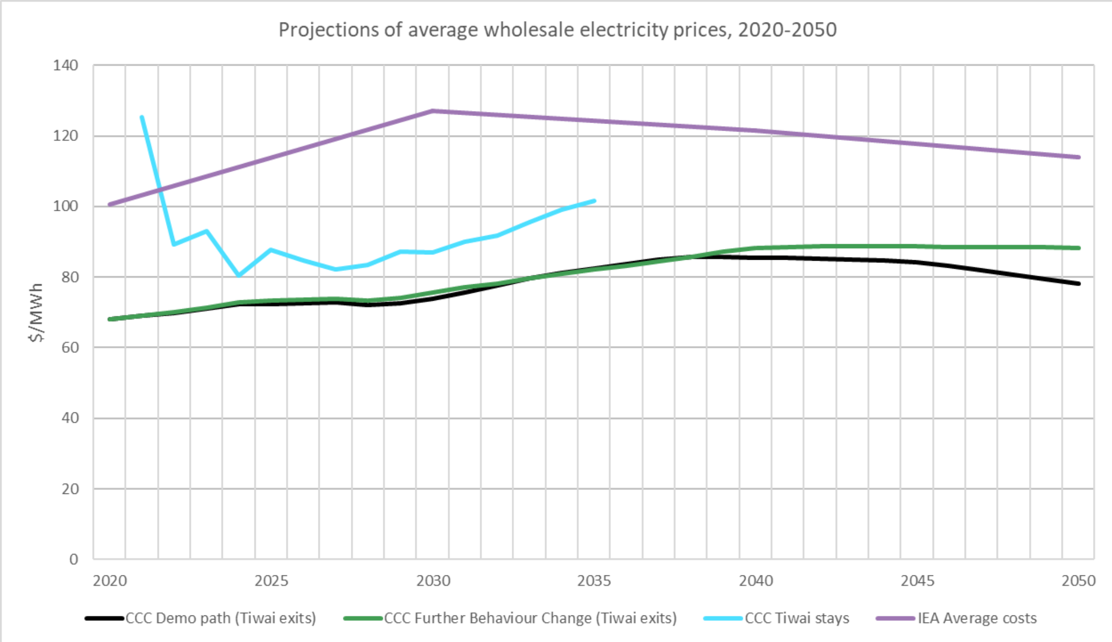
One option for generating an extra 5 TWh per year would be to build 650 MW of additional geothermal generation. This would be sufficient to supply 5.2 TWh of flat load per year. However, the last 200 MW of the 650 MW increment has a capital cost of $5.56m per MW, which is 17% higher than the capital cost of $4.74m per MW for the first 250 MW of additional geothermal capacity.[133] Under this approach, wholesale electricity prices would increase by at least 17%.

It is not clear that permanent demand increments will drive up our electricity prices relative to global prices

A cheaper approach may be to install a combination of geothermal, wind, solar and gas generation and using existing hydro to help cover demand-supply gaps. For example, the first 250 MW of geothermal costs only $4.74 per MW and would provide 2.0 TWh of additional generation per year. Another 2.95 TWh per year could be provided by installing more onshore wind and solar generation. Additional gas generation could be installed, depending on the extent that existing hydro is unable to cover the demand/supply gaps. Whether it would be cheaper depends on how much additional gas generation capacity would be needed.

The previous paragraph is just an illustrative example, as we have not used a dynamic general equilibrium model to consider the options. However, the CCC used those types of models to produce wholesale price projections for seven scenarios in which Tiwai exits the market.[134] Figure 24 shows two of those seven scenarios and the 'Tiwai stays' scenario from Figure 23.[135] The chart also shows average global generation cost projections provided by the IEA.

Figure 24: Comparison of domestic and international price projections, 2020 – 2050



Sources: CCC[136] and IEA

In the main 'Tiwai exit' scenario (the black line), wholesale electricity prices in Aotearoa are expected to increase from $72 per MWh in 2028 to $85 per MWh in 2038 (an 18% rise) before tailing off to $78 per MWh in 2050, for a net gain of only 8% on the 2028 price. Prices rise over the decade to 2038 due to the scarcity effect (demand growth drives the installation of higher-cost generation) but prices plateau and then decline as the technology effect (ongoing reductions in capital costs for new solar generation, and for wind to some extent) outweighs the scarcity effect.

The IEA predicts a similar pattern for average global electricity costs. Average costs are expected to increase from NZ$101 per MWh in 2020 to $127 per MWh in 2030 (a 26% rise) and then decline to NZ$114 per MWh in 2050, for a net gain of 13%.[137] It is important not to place too much weight on comparisons of CCC and IEA price projections as the IEA's dataset provides only three data points (2020, 2030 and 2050) and it appears to measure average generation costs, not the long run marginal cost of generation.[138] Moreover, the impacts on wholesale electricity prices depend greatly on the type of decarbonisation policy adopted, for example carbon taxes raise wholesale prices whereas renewable energy tax credits tend to reduce wholesale prices.[139]

The Onslow scheme cannot provide us with a cost advantage until 2037 at the earliest, and is very unlikely to provide a sustainable cost advantage thereafter

As discussed in section 3.4, the Onslow scheme is being considered as a 'dry year' backup option for Aotearoa. If it was installed, it would also provide backup for short-term variations in wind and solar generation, reducing the need for expensive batteries.

If Onslow was installed tomorrow, then we could gain a cost advantage over other countries. However, it can't be installed tomorrow. The earliest feasible date would be 2037 if the Government committed to it in 2025. This assumes another two years to tender and award a contract to build it, seven years to build it and then another three years to fill it.[140]

These timeframes mean Onslow cannot provide us with a competitive advantage prior to 2037. Furthermore, if battery prices decline at 21% per year for the next 19 years, then batteries would be a cheaper option by 2040 even if the Onslow scheme only cost $3.2b.[141] We would only get a three-year competitive advantage from Onslow. On the other hand, if Onslow cost $10b to build, then it would be cheaper to install batteries (near demand sources) from 2035 onwards.[142]

Future battery prices are unknown of course. If they declined at 15% per year for the next 9 years until 2030 and then at 10% per year thereafter, for example, then a $3.2b Onslow scheme would be a cheaper option until 2058.[143] However, if Onslow cost $10b to build, then it would only be a cheaper option until 2047 (ie, for 10 years).[144, 145]

Although future battery prices are highly uncertain, it is an emergent technology and prices are likely to continue to decline rapidly.[146] Similarly, other modular approaches, such as converting existing gas and coal-fired plants to biomass and/or paying for seasonal demand response services from large industrials such as the Tiwai Smelter, may also offer considerable option value. This is because they also avoid the risks of locking-in high fixed costs.

The above analysis suggests Onslow is unlikely to provide Aotearoa with a lengthy competitive advantage unless the cost to build it is substantially below $10b.

Rather than invest in a static technology like pumped hydro storage, it could be better to invest in an emergent storage technology, such as hydrogen and ammonia production and storage facilities, but it is a longshot

As mentioned earlier, green hydrogen and ammonia are currently very expensive forms of energy storage. However, if the Tiwai smelter exited at the end of 2024, electricity prices would fall sharply for several years, reducing the costs of the large energy losses incurred from converting electricity to hydrogen and ammonia.

A case might be able to be made for investing in a modest-sized green hydrogen production and storage facility if it enables us to create a sustainable competitive advantage over time. This would only occur if the initial experience enabled a dynamic to develop where we maintain a competitive advantage over other countries by continually expanding the global technology frontier in this area.

This would be a longshot, and even if it did succeed the net economic benefits could take decades to accrue.

Two of our large electricity generators are arguing for government investment for hydrogen and ammonia production and storage, however they also admit that “the relatively small scale of New Zealand’s hydrogen capacity means it may not remain competitively viable against larger global suppliers.”[147] In that case domestic production would shift towards primarily supplying domestic uses.

Investing in large-scale hydrogen production and storage would be very costly source of backup for our wind energy resources, rendering them uncompetitive. A lower-risk strategy would be to adopt the technology when it becomes economic, presumably in a couple of decades. Of course, we would only do that if it turned out to be a cheaper and more effective storage option than batteries.

Near-term, low-cost, backup options are needed to give us a cost advantage over the next 10–20 years

Both the Onslow and hydrogen backup options will not enable us to leverage our abundant wind resources within the next two decades. Realistic options need to be low cost and feasible in the next 10 years, before storage with batteries, hydrogen and ammonia become cost-effective options for our competitors.

One option might be to alter existing hydro storage regulations, so that hydro lakes can be drawn down further than currently allowed. However, there is probably limited scope to do this as there is already provision for our major hydro generators to access additional storage (called *contingent storage*) when certain electricity market conditions are met.[148]

Another option could be to make some geothermal generation plants controllable, to cover for short-term supply and demand mismatches. One of main issues with doing this is that it spills the steam from the geothermal field when it is not producing electricity. Hence, if it is only producing electricity when wind and solar are not operating, the capital costs of the plant will need to be recovered from a far lower energy output, increasing the LCOE of the plant.[149] Another issue with spilling steam is that it adds to carbon emissions when not producing electricity.

More importantly, even if all new geothermal generation plants were made controllable, they would cover only a small portion of hourly and daily variations in wind generation if all of our wind resources were developed.[150] Substantial backup generation from hydro would be needed, as well as backup sources of energy from battery and hydrogen storage. If the costs of battery and hydrogen capacity decline substantially over the next 20 years, then various combinations of hydro, batteries and hydrogen flexibility could turn out to be commercially viable sources of backup energy.

In principle, permanent demand increments could drive up our electricity prices relative to global prices and yet we could remain internationally competitive

The discussion in section 3.5 focused on cost competitiveness. However, our electricity system could become more internationally competitive as firms and consumers become more aware and accepting of the link between burning fossil-fuels, greenhouse gas emissions and climate change. As mentioned in section 3.1, this could lead energy-intensive firms to locate their production in countries with low-emission electricity systems, even if doing so may be more costly.

Putting aside the price comparisons in Figure 24 (page 37), it is reasonable to assume that current levels of energy-intensive production broadly reflect our current international competitiveness. If not, then energy-intensive firms would be exiting if locating here was a competitive disadvantage or entering if it gave them a competitive advantage. We are currently seeing some of both.

However, the recent exit of energy-intensive firms are from industries that are experiencing, or are expected to experience, declining demand for their products (for example, the recent closure of the Marsden Point oil refinery and the Kawerau pulp and paper mill). Conversely, the new entry seems to be occurring in emergent industries, with five large scale data centres announced for Auckland.[151] There are also plans for a hyperscale data centre in North Makarewa, near Invercargill, to take advantage of the cooler temperatures and proximity to low emission electricity generation to provide data storage and cloud computing services to Australia and beyond.[152] This announcement looks more likely following recent news that a new submarine cable to link Christchurch, Dunedin and Invercargill with Australia, Indonesia, Singapore and Los Angeles.[153]

3.6 Concluding comments on commercial viability of our low emission resources

In addition to the factors discussed above, section 3.1 also identified transmission and distribution costs as potentially affecting the competitiveness of our electricity system. There will also be other factors, such as additional transport costs, the education and skills of our workforce, and regulatory barriers.

It is too soon to determine whether the recent entry of energy-intensive data centres is the start of a trend that could significantly increase demand for our electricity, over and above the levels anticipated by the CCC.

However, it makes sense to pursue policies that reduce the cost of installing new generation in Aotearoa, to maximise the opportunities to leverage our low-emission resources. In our view, this would benefit New Zealanders through higher wages (refer section 5) and it would reduce global carbon emissions (refer section 6).

4. Can we build at a faster pace than needed to decarbonise the economy?

The previous section considers whether developing our low emission resources would improve or harm the competitiveness of our electricity sector, and answers "maybe". This section switches focus and asks whether we can build at a faster pace than needed to decarbonise the economy. To answer this question, we need to focus on 'build rates' relative to the resources available to build electricity generation. These resources include our economic capacity to purchase capital goods from offshore and the workforce needed to install them.

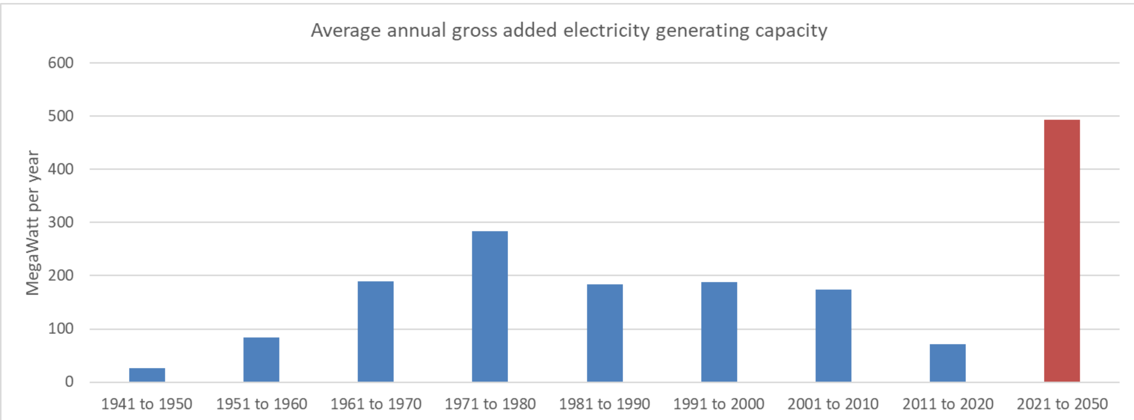
Over the next 30 years we need to build about 494 MW of new generation every year

According to Transpower, we need to add an average of 494 MW to generation capacity every year for the next 30 years to meet our net-zero carbon target, equivalent to a 3.2% annual growth rate.[154] It is this type of comparison that leads many commentators to view the required build programme for the next 30 years as challenging. However, wind and solar farms comprise modules of standardised turbines and solar panels, and so are far easier to install than the hydro, geothermal, gas and coal plants built in previous years.

Figure 25 suggests this task far exceeds the additions to generation capacity over the last 80 years.

It is this type of comparison that leads many commentators to view the required build programme for the next 30 years as challenging. However, wind and solar farms comprise modules of standardised turbines and solar panels, and so are far easier to install than the hydro, geothermal, gas and coal plants built in previous years.[155]

Figure 25: The generation build requirements for the next 30 years look very challenging



Source: Electricity Authority and Transpower

Our electricity construction workforce will need to increase greatly, as has occurred in the past, but this should be achievable

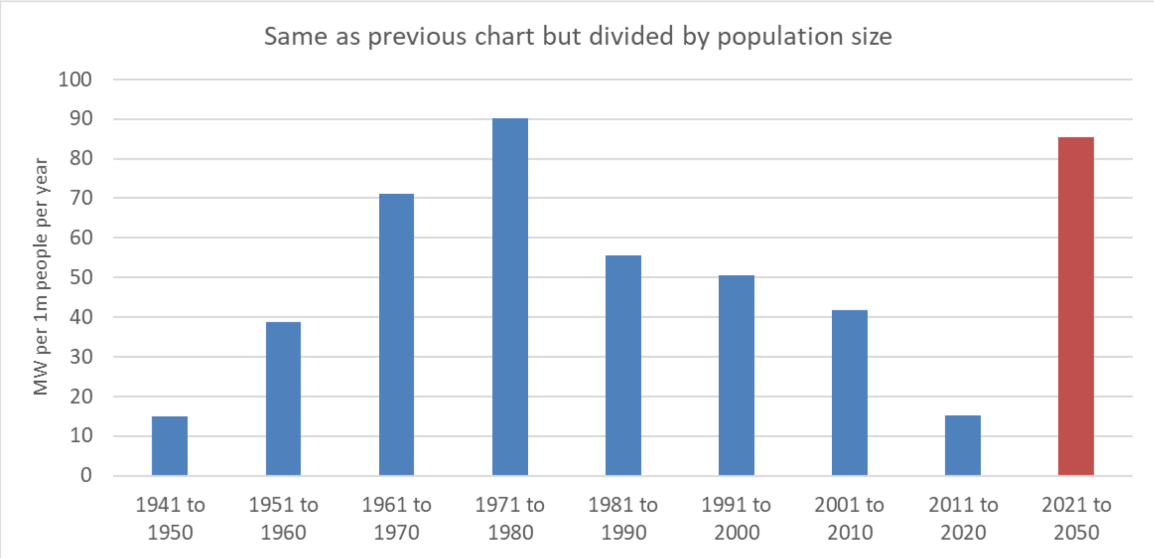
Another consideration is the size of our construction sector workforce. Over 1978–2020, our construction workforce has almost doubled, increasing by 98%.[156] Clearly, these additional workers have not been building power stations over the last 40 years, but it suggests we have a far greater capacity to deploy construction workers to that task now than we did 40 years ago. Also, historically, we have increased our electricity construction workforce through immigration of skilled workers and through training of local workers. There is no reason this could not be done again.

Simplistically, one way to view the implications of the doubling of the construction workforce since 1978 is to mentally downscale the red bar in Figure 25. It is this type of comparison that leads many commentators to view the required build programme for the next 30 years as challenging. However, wind and solar farms comprise modules of standardised turbines and solar panels, and so are far easier to install than the hydro, geothermal, gas and coal plants built in previous years.

The challenge is less daunting from that perspective.

A slightly more sophisticated approach is presented in Figure 26, which shows annual average additions to generation capacity for each decade divided by population in the middle of each decade (the blue bars). The red bar is the 494 MW of additional annual generation capacity required over the next 30 years divided by the population Statistics New Zealand is projecting for 2035.[157] These adjustments show that, on a per capita basis, the capacity expansion required over the next 30 years is slightly smaller than achieved in the 1970s.

Figure 26: On a per capita basis, the challenge looks more achievable



Source: Te Waihanga

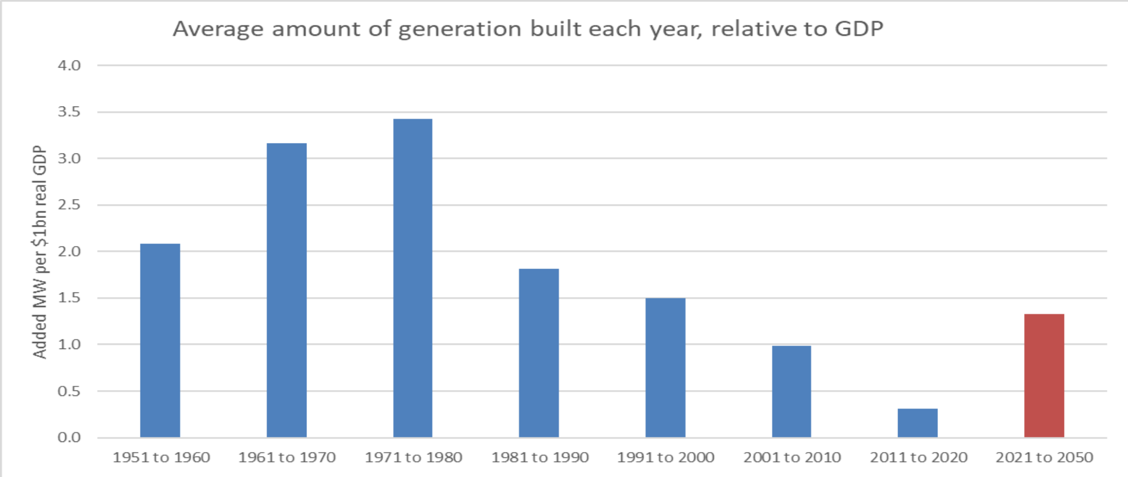
Of course, the above comparison is hypothetical, but it is intended to bring another perspective on the challenge ahead. Significant increases in the electricity sector's construction workforce will certainly be needed to meet the challenge.

We have far greater economic capacity to procure the required capital inputs

Almost all of the equipment and materials for building low-emission generation is imported. This suggests we should consider the build requirements over the next 30 years relative to real GDP, as real GDP is a measure of the aggregate income available to purchase capital goods.[158]

For the historical figures (the blue bars), Figure 27 divides generation capacity added in each decade by the real GDP occurring over the decade. For the 2021–2050 period (the red bar), the 494 MW annual requirement is divided by projected real GDP for the 30 years.[159] This shows that, relative to the size of the economy, the build requirements over the next 30 years are far smaller than for most decades since the Second World War. From this perspective, the challenge is far from daunting.

Figure 27: Relative to the size of the economy, the new generation capacity required over the next 30 years is considerably smaller than achieved in the past



Source: Te Waihanga

The key challenge for Aotearoa is executing the task well. The country will need to train the workforce, manage the logistics of importing and transporting the materials, and adopt appropriate consenting requirements and processes.

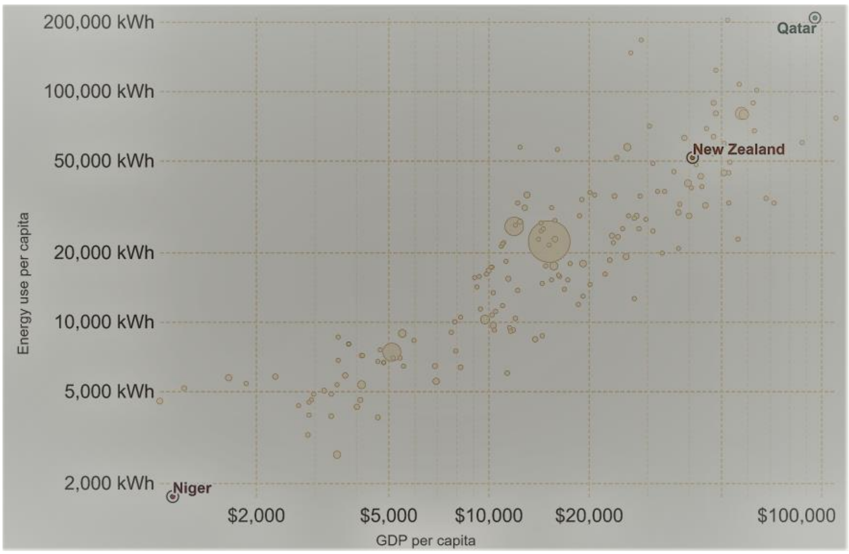
5. Economic benefits from developing low-emission resources

To the casual observer, energy is an essential factor of production because all producers use electricity and other forms of energy to produce their goods and services. Moreover, energy is used to extract and deliver energy. This suggests the supply of energy is pivotal to economic activity.

This logic would appear to be supported by Figure 28, which shows a strong positive correlation between energy usage per capita and a country's economic prosperity, measured as GDP per capita. The chart shows rich countries use a lot of energy per person, whereas poor countries do not.

Figure 28: Energy usage is strongly correlated with productivity and economic prosperity

Energy use vs GDP, 2015 (log scales)



Source: OurWorldInData[160]

Not only do we want to sustain high levels of economic activity per capita, but many people think in terms of economic growth, which (in this paper) refers to ongoing increases in GDP per capita. Based on the above logic, an abundant supply of low-cost energy would seem to be essential for economic growth over the next 30 years, and conversely, economic growth is presumably constrained anytime that energy becomes scarce and expensive.

To analyse these issues, this section draws from a 2018 overview paper by David Stern, in *The New Pelgrave Dictionary of Economics*.[161] Section 5.1 argues that abundant low-cost energy is not necessarily pivotal for ongoing economic growth, and section 5.2 presents the counter arguments. Section 5.3 discusses the statistical evidence on the issue.

Summary of the analysis

At this stage, the evidence is largely inconclusive. However, a robust finding is that energy prices drive short-run growth of GDP and energy use. This suggests that removing obstacles to the development of low-cost low-emission resources *could* increase per capita GDP, permanently increasing wages and improving living standards. While a case can be made for removing unnecessary obstacles to developing our low emission energy resources, it is not strong enough to justify for subsidising their development.

5.1 Reasons why energy may not be pivotal for ongoing economic growth

Energy is not essential because manufactured capital can be substituted for energy

Mainstream economists assume capital and labour are the only inputs in production, which means they ignore energy in their analysis of economic growth. They model various ways in which innovation increases the effectiveness of capital or labour in the production of goods and services, which increases the *effective supply* of capital or labour to the economy.[162] The increase in effective supply increases economic activity, which of course means more GDP per capita.

Ongoing increases in the effective supply of capital and labour drive ongoing growth in GDP per capita. In standard endogenous growth models, economic growth can occur indefinitely provided that, over the long run, the effective supply of capital and labour increase at the same rate so that relative factor prices remain constant. This is called a *balanced growth path*.

One of the reasons for ignoring energy in growth models is that manufactured capital – machines and buildings – can be substituted for energy as energy becomes scarce. Mainstream economists argue that, under certain “optimistic” assumptions about the rate of substitution, energy is not essential at all.[163] However, to-date the empirical evidence on the substitution of capital for energy does not support the optimistic assumptions.

Another argument is that innovation will always overcome energy constraints

In endogenous growth theory, economic growth can occur indefinitely because innovation over the long run is directed at increasing the effectiveness of whatever inputs are constraining production.[164] For example, if the effective supply of labour is failing to keep pace with the effective supply of capital goods, then higher wages incentivise innovations that boost the effective supply of labour and relieve constraints on economic growth.

The same logic applies to energy when it is included in these types of models.[165] If energy becomes relatively scarce, then innovation would be directed to increasing the effectiveness of energy.

According to endogenous growth theory, economic growth can occur indefinitely because (a) innovation is the substitution of knowledge for other production inputs and (b) anyone can use knowledge without depriving anyone else from using it (knowledge is *non-rival*). This implies there need not be any limit to innovations to improve the effective supply of energy. Hence, under this approach, energy is not a long-run constraint on per capita GDP growth.

5.2 Reasons why energy could be a key enabler of, or constraint on, economic growth

The core argument from environmental economists

A key concept in energy economics is the *energy return on investment* (EROI), which is the ratio of useful energy gained from the energy used to extract energy. *Useful energy* refers to the amount energy available for consumption and for use in the production of goods and services.

EROIs typically decline as more of an energy resource is extracted. For example, the EROI for an oil reservoir declines as the reservoir is depleted because it gets harder and harder to extract the remaining quantities of energy from the reservoir.

In general, in the absence of innovation, the aggregate EROI for the world declines over time because the easiest sources of energy are extracted first. This means ongoing economic activity requires ongoing energy extraction, and the latter implies a declining aggregate EROI. A declining EROI implies declining global economic growth.

> Intuitively, a declining EROI is analogous to a declining interest rate on invested funds. A declining interest rate reduces the rate at which an investment can grow.

But innovation does occur, and so mainstream economists argue that EROIs will not decline over time. However, environmental economists argue that the second law of thermodynamics implies there are theoretical limits to how far EROIs can be improved. They argue that knowledge must be used in conjunction with the other inputs that use energy, such as capital and labour, and so our ability to increase knowledge is ultimately limited by the useful energy available to us, which in turn will be constrained once theoretical limits on EROIs are reached. Hence, in their view, scarce energy supply and high energy prices will eventually be a key constraint on economic activity. [166]

The discovery of high-quality energy resources temporarily boosted economic activity

In addition to the role of innovation, EROIs can increase when higher quality sources of energy are discovered, such as when our main energy sources switched from biomass and muscle power to coal at the start of the industrial revolution, and from coal to oil at the start of the transport revolution.[167]

Environmental economists argue the phenomenal rise in living standards since the industrial revolution was enabled by the discovery of abundant sources of low-cost primary energy in the form of coal, oil and natural gas and the discovery and spread of electricity in the early 20th century facilitated a far more efficient organization of industry and facilitated mass education.

However, although the empirical evidence supports that contention for the 19th and early 20th centuries, that is not the case for the second half of the 20th century, which was driven by innovations that increased the effectiveness of labour, consistent with mainstream economic growth models.[168]

In principle, the same analysis applies with renewable energy

As renewable energy is infinite, one might be tempted to think we can escape the constraints arising from finite energy resources. But the second law of thermodynamics implies there are theoretical limits to the rate at which primary energy, whether finite or renewable, can be converted to useful energy. As the raw materials needed to convert primary energy into useful energy are finite, environmental economists argue it is not possible to maintain economic activity indefinitely even with an infinite amount of energy.

In contrast, the mainstream view argues that the limits from thermodynamics are not a realistic constraint on improving EROIs, and this also applies for EROIs for renewable energy.

In conclusion

Ultimately, the issue is whether the thermodynamic limits will be constraining in practice, which is an empirical question. This is discussed next.

5.3 Empirical evidence regarding the energy-GDP relationship

In essence, we are left with the empirical question of which causes which? Does energy availability and energy prices materially affect per GDP growth, or does per capita GDP growth drive growth in energy usage and energy prices? Untangling these effects requires empirical methods that test for causality among time series variables.

Bruns, Gross and Stern (2014) undertake a meta-analysis of 75 studies comprising more than 500 tests of causality. They find that most of the statistically significant results are probably the result of various biases. In their view, the most robust findings were that economic growth causes energy use (when variations in energy prices are taken into account).

Stern (2018) repeats the above results but also reported on the results in Costantini and Martini (2010), which examined data for 26 OECD countries over the 1978–2005 period. The key empirical result from this study is that GDP growth drives energy use and energy prices in the long-run, but in the short-run the reverse occurs: energy prices drive GDP and energy use. Also in the short-run, energy use and GDP are mutually causative.

However, Stern also reports a finding from Bruns et al (2014), which shows that studies that consider the role of capital in economic growth do not find a genuine effect of energy on economic growth or vice versa. He concludes that:

> *Empirical research on whether energy causes growth or vice versa is inconclusive, but meta-analysis finds that the role of energy prices is central to understanding the relationship.*[169]

6. Implications for domestic and global carbon emissions

Te Waihanga's main function involves promoting an approach to infrastructure that improves the wellbeing of New Zealanders. In contrast, a key function of the CCC is to advise the Government on how to reduce carbon emissions to achieve net-zero by 2050. This leads it to focus on identifying the amount of low-emission energy needed to achieve net-zero, rather than the wider consideration of maximising the wellbeing of New Zealanders.

Although this paper focuses on the ambition of developing more of our wind, solar and geothermal generation than considered by the CCC, doing so is likely to add very little to our domestic emissions and would reduce global emissions.

6.1 Carbon emissions under the CCC scenarios

The Government has set a target of net-zero carbon emissions by 2050 to contribute to the global challenge of mitigating climate change, and it established the CCC to recommend carbon budgets for five-yearly periods, for fifteen years ahead.

The CCC is projecting a 74% reduction in net emissions by 2050

The CCC has recommended carbon budgets that would reduce carbon emissions below 2019 levels by:

- 7% over the 2021–2025 period (Budget 1)
- 20% over the 2025–2030 period (Budget 2), and
- 35% over the 2030–2035 period (Budget 3).[170]

To check consistency with the 2050 net-zero emissions target, the CCC has projected emissions for the next 30 years for various scenarios regarding technology and behavioural changes and the prices of key variables, such as natural gas and ETS prices.

In its base case, which it calls the demonstration path, the CCC is projecting gross emissions from long-lived greenhouse gases will reduce 67%, dropping from 47.2 million tonnes of carbon dioxide equivalent (mtCO2e) in 2020 to 15.7 in 2050.[171]

Net long-lived emissions are gross long-lived emissions minus the emissions absorbed by our forests. Net long-lived emissions are projected to fall from 38.6 mtCO2e in 2020 to -5.7 in 2050.[172] This is an important figure because our net-zero emission target is in regard to long-lived emissions.

Electricity is expected to play a pivotal role in reaching net-zero emissions by 2050

Reducing emissions from low- and medium-temperature process heat (heat used primarily in food processing and wood, pulp and paper production) is also projected to make a significant contribution to reducing emissions.

Switching these processes to electricity and biomass is key to reducing these emissions, but this will take time due to the long-lived nature of industrial boilers and practical engineering, commercial and workforce skill constraints for those businesses. In some cases there will also be capacity expansion implications for electricity transmission infrastructure and for low-emissions fuel supply chains.

Figure 29 shows the CCC's projections for reductions in long-lived emissions for key sectors. In 2019, transport contributed 33 percent of New Zealand's long-lived emissions, with over 70% arising from the use of light vehicles. Electrifying the transport system and making greater use of biofuels and green hydrogen is expected to play an important role in reducing carbon emissions from the transport sector. shows the CCC's projections for reductions in long-lived emissions for key sectors. In 2019, transport contributed 33 percent of New Zealand's long-lived emissions,[173] with over 70% arising from the use of light vehicles.[174] Electrifying the transport system and making greater use of biofuels and green hydrogen is expected to play an important role in reducing carbon emissions from the transport sector.

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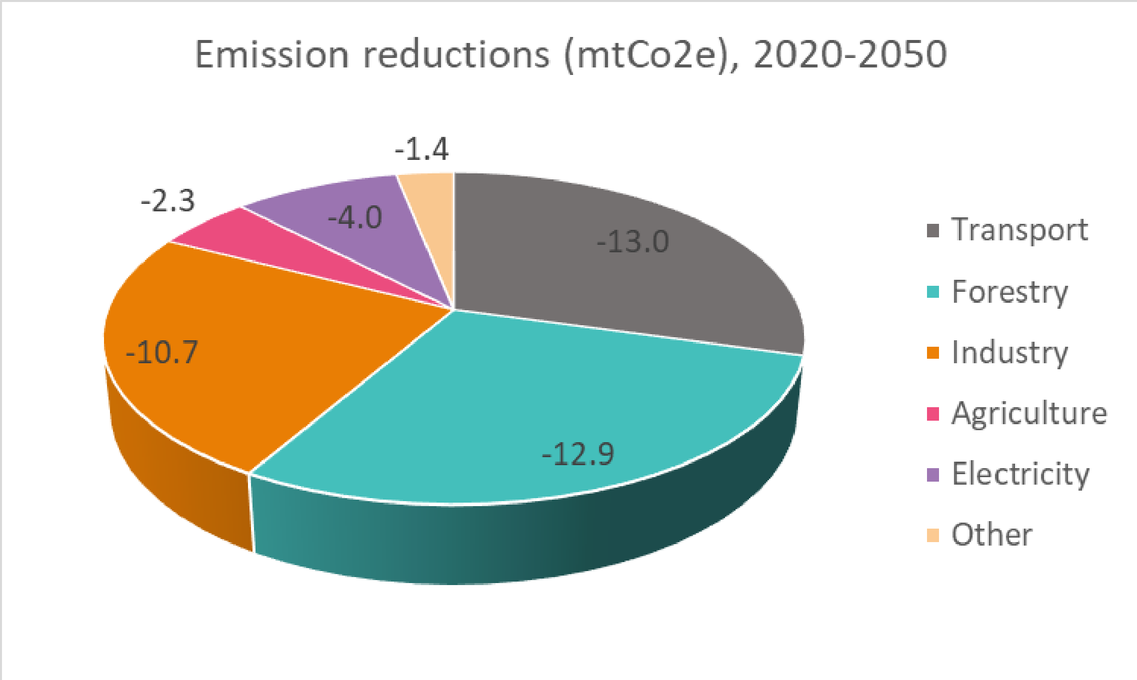
Figure 29: Sectoral contributions to reducing net long-lived emissions



Source: CCC datasets[177]

High-temperature process heating in Aotearoa uses coal or gas and switching most of them to electricity and biomass is not commercially feasible in the next 15 years. The CCC called for research and innovation to identify cost-effective approaches to reducing these emissions,[178] and suggested significant forestry expansion may be needed to offset gross emissions from these kinds of hard-to-abate sectors.[179]

Increases in wind and solar generation do not add to our emissions profile

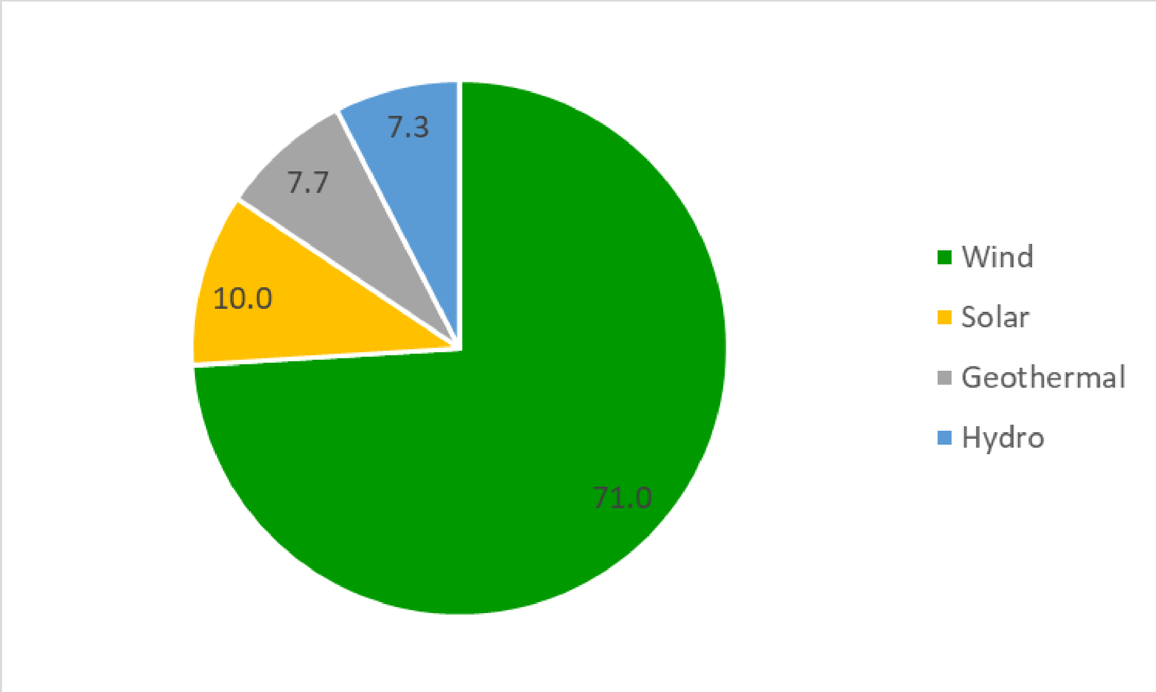
Overall, our annual electricity supply will need to increase by 54–68% by 2050 to meet the needs of population growth and electrify most of our transport and process heating.[180]

In the demonstration path, the CCC projects that electricity in Aotearoa will reach 97% renewable in 2050, with wind and solar generation increasing in aggregate by 27.2 TWh per year.[181] The CCC attributes zero domestic emissions from the additional wind and solar generation because under global carbon accounting rules emissions from the manufacture of wind turbines and solar panels are attributed to the country that manufactures them.

6.2 Additional carbon emissions for Aotearoa are likely to be very modest

Table 1 (page 7) listed the additional wind, solar, hydro and geothermal generation resources that are potentially commercially viable to develop, based on the research undertaken for MBIE. Figure 30 shows the resources are overwhelmingly (onshore and offshore) wind resources.

Figure 30: Potential increase in generation, TWh per year



Source: Table 1

Also, recall that our analysis in section 3.2 showed onshore wind would likely have the lowest LCOE in Aotearoa for the next 10–20 years, after which solar PV and offshore wind may have lower LCOEs.

Although geothermal has the advantage of requiring minimal backup generation to serve flat industrial load, it is significantly disadvantaged by a steeper supply curve and minimal prospect of significant cost reductions over time. Those disadvantages suggest only a modest portion of the 7.7 TWh of geothermal will be commercially viable over the next 30 years. New hydro appeared to be even more costly than new geothermal.

Minimal additional carbon emissions would occur if the backup for additional wind generation was a combination of hydro, biomass, battery, hydrogen storage and demand-side response

Using the same assumptions as the CCC, developing our wind resources would not directly add to our domestic emissions. However, as discussed in section 3.4, additional backup generation would be needed to cover for variations in wind generation, which could in involve additional emissions.

Section 3.5 suggested that in about 20 years a combination of hydro, battery and hydrogen storage may be an optimal combination of backup energy (if battery and hydrogen costs fall substantially over that time). Some biomass and demand-side response options may also be cost-effective.

Battery and hydrogen energy would not add materially to our domestic emissions as the capital inputs for them would be sourced from other countries and neither energy source involves significant emissions from the installation process. Similarly, demand-side response does not create emissions.

There also would be no additional emissions from drawing more flexibly on existing hydro generation resources. Further, if the Onslow scheme is going to be built anyway to cover dry year risks from decarbonization, then drawing on it to cover larger variations in wind generation would not add to domestic emissions. Additional transmission infrastructure might be required, but again most of the materials for that are imported.

Domestic emissions would come from biomass forms of generation to the extent that harvesting of biomass disturbs soils, and to the extent that fossil fuels are used to harvest, process and transport biomass. However, over time, these activities will also be replaced by low emission forms of energy.

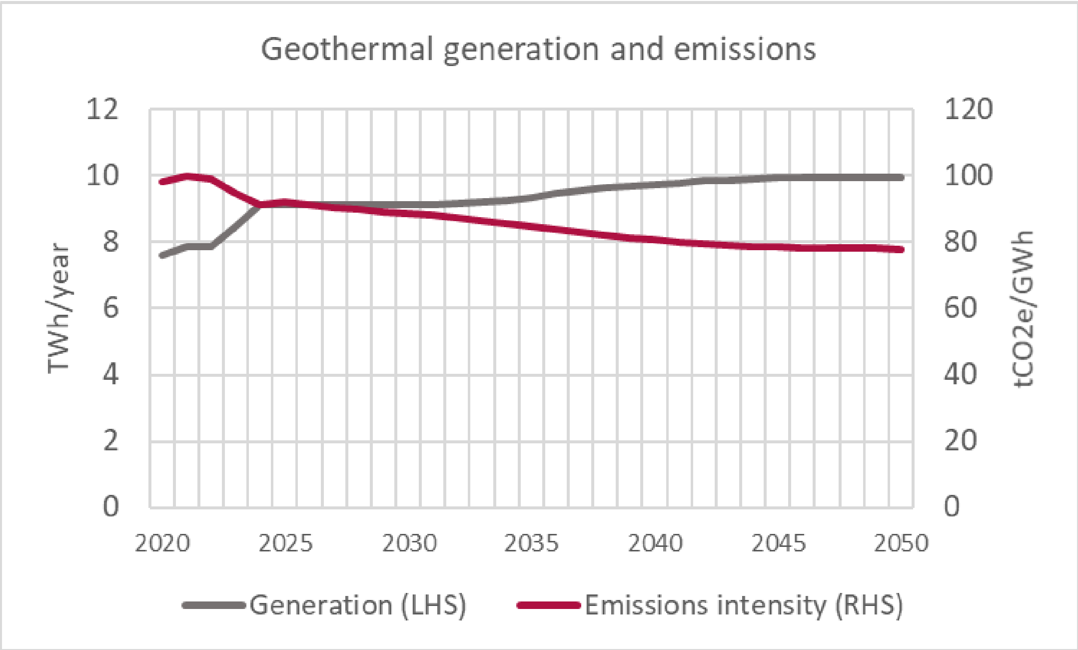
Although unlikely, if all of our potential geothermal resources were developed then the additional carbon emissions would be minimal

One potential source of additional emissions is backup generation from controllable geothermal plants. However, it is very unlikely this approach would be economic as geothermal provides a valuable source of baseload generation to serve new sources of industrial load. Instead, consider the additional emissions from using all of our potential geothermal resources to serve industrial load.

The CCC projects that annual geothermal generation will increase by 2.3 TWh by 2050. This is shown in Figure 31, where geothermal generation increases from 7.6 TWh in 2020 to 9.9 in 2050. However, annual emissions from geothermal peak in 2024 and then decline steadily despite generation increasing over the rest of the period. The red line in

Figure 31 shows the CCC is projecting the emissions intensity of geothermal to decline from 98 mtCO2e per GWh in 2020 to 78 in 2050.

Figure 31: Projections for annual geothermal generation, 2020-2050



Source: CCC dataset[182]

Given the CCC's analysis projects 2.3 TWh of additional geothermal generation by 2050, assume the rest of our potential geothermal resources were added to the generation fleet by 2050. This would add 5.4 TWh of additional generation per year by 2050. Assuming the average emission intensity applies, the additional geothermal generation would add 1.1% to total gross emissions in 2050 or 2.9% to gross long-lived emissions in 2050.[183]

6.3 Developing our low emission resources is likely to reduce global carbon emissions

As discussed above, expanding our low emission electricity generation beyond that needed to achieve net-zero carbon emissions is not likely to materially add to our domestic emissions, especially if there is no additional geothermal generation. The focus below is on whether it would reduce or increase global carbon emissions.

Additional low emission generation here is likely to reduce global carbon emissions

Substantial increases in wind, solar and geothermal generation would only occur if firms locate more of their production here to benefit from a lower emission electricity system, or lower electricity prices, or better reliability or for a combination of those reasons.

Provided our backup options are also low-cost and have low emission-intensity, then a switch of electricity demand from the rest of the world to Aotearoa is likely to either (a) reduce global emissions or (b) not affect global emissions.

The reduction in (a) occurs if the demand reductions in other countries lead them to retire high-emission thermal generation earlier than otherwise. The neutral impact in (b) occurs if the demand reduction leads them to reduce their installation of low emission forms of electricity generation, which is basically a one-for-one offset against the additional low emission electricity in Aotearoa.

On balance, additional low emission generation in Aotearoa is likely to reduce global carbon emissions, as instances of both (a) and (b) are likely to occur.

Offshore mitigation should be considered to cover any additional domestic emissions

In principle, as we would be reducing global emissions, we should consider sourcing emission units from the international market (this is called *offshore mitigation*).[184] This wouldn't require any technical changes to Government policy as it already intends to undertake 102 mtCO2e of offshore mitigation to meet its new carbon targets.[185]

The CCC, however, is recommending against offshore mitigation unless exceptional circumstances occur, such as earthquakes or volcanic eruptions.[186] This approach could unnecessarily constrain the electricity sector and unnecessarily harm New Zealanders' wellbeing.

To see this point, suppose a larger electricity sector increases our domestic emissions. This would increase demand for New Zealand emission units and put upward pressure on ETS prices. This would either lead to larger emission reductions elsewhere in the economy if the ETS price ceiling is not breached, or it would lead to more frequent breaching of the ETS price ceilings. If the latter occurs, the government could adopt tougher emission reduction measures (eg, raise the ETS price ceilings), which would reduce emissions elsewhere in the economy, at a cost to New Zealanders.

Alternatively, the government could undertake offshore mitigation, which would allow our electricity sector to expand (beyond that needed to achieve net-zero emissions) to reduce global emissions. As discussed in section 5, this could improve New Zealanders' wellbeing, and so should be consistent with the CCC's requirement to consider the distributional, economic and fiscal effects of its advice.[187]

Appendix A: What are our low-emission sources of electricity?

Embedded emissions occur for all types of electricity generation. Emissions also occur when generation units are deconstructed. Assessing the emissions over the life of a generation unit, including deconstruction, is called a Life Cycle Assessment (LCA).

There are many published LCA studies, applying many different methodologies. To compare the different forms of generation on a like-for-like basis, lifetime emissions are divided by the amount of electricity they are estimated to produce over the life of a typical generator. This leads to a metric called *tonnes of carbon dioxide equivalent per GigaWatt-hour* of electricity (tCO_2e/GWh). We refer to this as the emissions intensity of different types of generation.

The National Renewable Energy Laboratory (NREL), a division of the United States Department of Energy, has recently published estimates of the emissions intensity of most types of electricity generation. It has reviewed a wide range of published estimates and scrutinised the methodology in each study.

For studies satisfying its rigorous standards (85% of studies were rejected), the NREL adjusts the results to account for different methodological approaches and assumptions to provide *harmonised* results. It has done this to provide more precise estimates, clarify inconsistent and conflicting estimates in the published literature, and reduce uncertainty. NREL publishes both the harmonised and non-harmonised results.

The NREL estimates that wind turbines average 11 tCO_2e per GWh and solar PV averages 44.[188] This compares to 7 for hydropower, 40 for both bio-power and geothermal, 477 for gas-fired generation and 979 for coal-fired generation.[189, 190] Although the efficient size for nuclear plants means they are not suitable for our electricity system, it is worth noting that NREL estimates nuclear plants have an average emissions intensity of 12 tCO_2e per GWh.

Table 4 compares NREL's results with a literature review conducted in 2015 by the World Nuclear Association (WNA). This study has wind and hydro at 26 tCO_2e per GWh, nuclear at 29, biomass at 45, solar PV at 85, natural gas at 499, coal at 888 and lignite (aka. brown coal) at 1,054.[191]

Although the WNA's estimates for hydro, wind, nuclear and solar are generally more than double the NREL's estimates, it is clear those forms of generation have far lower emissions intensity than gas and coal-fired generation.

Table 4: Comparison of emission intensity estimates, tCO_2e per GWh

	NREL	WNA	MBIE	McLean & Richardson
Hydro	7	26		
Wind	11	26		
Nuclear	12	29		
Bio-power	40	45		
Geothermal	40		130	76
Solar PV	44	85		
Gas	477	499		
Coal	979	888 - 1054		

Sources: Provided in the text

Carbon emissions from geothermal fields vary substantially from field to field and over time, and they depend on the technology used. There is considerable variation in average emissions from geothermal fields in Aotearoa, with MBIE estimating it at 130 tCO_2e per GWh.[192] However, based on more recent and detailed data, the best estimate appears to be 76 tCO_2e per GWh.[193] Two fields exceed 300 tCO_2e per GWh, however they are both small fields.

Based on the above figures, we define low-emission electricity as electricity sourced from wind, hydro, nuclear, solar, biomass and geothermal resources. Low-emission electricity also includes thermal generation when carbon capture and storage prevents emissions entering the atmosphere.

Appendix B: List of potential new large-scale hydro generation in New Zealand

The following table lists the potential new hydro schemes identified in Roaring40s (2020b).[194] Column 4 provides estimated annual generation, in GWh/yr. The entries rounded to whole numbers were obtained directly from Roaring40s (2020b). The entries rounded to one decimal place in column 4 were estimated under the assumption of 65% capacity factors. In those cases, GWh/yr = MW x 24 x 365 x 0.65/1000.

Table 5: List of potential new large-scale hydro schemes in New Zealand

Roaring40s Table	Project Name	MW	GWh/yr	Consent-ability score	Consentability -weighted MW	Consentability -weighted GWh/yr
3	Wairau	72	380	10	72.0	380.0
3	Lake Pukaki Gate 18	35	120	10	35.0	120.0
3	North Bank	260	1480.4	7	182.0	1036.3
3	Rakaia	3	17.1	10	3.0	17.1
3	Arnold Valley	46	261.9	10	46.0	261.9
3	Mokihunui	100	569.4	2	20.0	113.9
3	Ngakawau	24	140	10	24.0	140.0
3	Hawea Gates	17	70	9	15.3	63.0
4	Clutha A	350	1992.9	6	210.0	1195.7
4	Clutha B	100	569.4	6	60.0	341.6
4	Clutha C	80	455.5	6	48.0	273.3
4	Clutha D	80	455.5	6	48.0	273.3
4	Clutha E	110	626.3	6	66.0	375.8
4	Grey River	250	1423.5	7	175.0	996.5
4	Haast-Landsborough	60	341.6	2	12.0	68.3
4	Hawea River	80	455.5	6	48.0	273.3
4	Mohaka River	70	398.6	6	42.0	239.1
4	Motu River	80	455.5	2	16.0	91.1
4	Taramakau-Taipo	80	455.5	6	48.0	273.3
4	Waiau River (Canterbury)	65	370.1	5	32.5	185.1
4	Waiau River (Southland) A	80	455.5	2	16.0	91.1
4	Waiau River (Southland) B	60	341.6	4	24.0	136.7
4	Waimakariri River	50	284.7	5	25.0	142.4
4	Waimakariri River B	84	478.3	5	42.0	239.1
4	Whangaehu	50	284.7	7	35.0	199.3
	Total	**2286**	**12883.8**		**1344.8**	**7527.3**

Source: Roaring40s (2020b)

Consentability-weighted results in the last two columns are derived by treating the consentability score as a score out of 10 and using that result as an implied probability of consent. That is, a score of 7/10 led to a 70% weighting. The authors of Roaring40s (2020b) may not have intended their scoring to be used in this manner.

Appendix C: Qualitative assessment of the extra cost of backup for various combinations of load and inflexible generation

Table 6 Is a more comprehensive version of Table 2, page 31.

The flat load profile in row 1 is self-explanatory. For the three different forms of generation:

- Flat load matches well to geothermal generation as it is also flat. However, *m*>0 as geothermal has periodic maintenance. But *pd*<0 as maintenance can be scheduled for low price seasons, such as summer.
- Flat load does not match well with wind, for two reasons:
    - over winter: wind generation slumps 20% over winter, creating large physical matches with demand when spot market prices are likely to be very high
    - outside of winter: there are many calm days outside of winter, leaving significant physical mismatches although spot prices are not particularly high as total demand in the market is lower outside winter than during winter.
- Flat load matches very poorly with solar because solar generation slumps 50% over winter, leaving the load highly exposed to very high prices for several months every winter. Outside of winter, solar is similar to wind in that there are cloudy days but prices are not particularly high.

Table 6: Extra COB for various combinations of load and inflexible generation

	Geothermal	Wind (with 20% winter slump)	Solar (with 50% winter slump)
1. Flat load with no DSR capability[1]	- (m>0, pd<0)	++++ (m>>0, pd>>0)	+++++++++ (m>>>0, pd>>>0)
2. Flat load with short-term DSR capability[2]	- (m>0, pd<0)	++ (m>>0, pd>0)	++++++ (m>>>0, pd>>0)
3. Primary sector seasonal load with no DSR capability[3]	---- (m>>0, pd<<0)	+ (m>0, pd>0)	+ (m>0, pd>0)
4. Flat load with short-term & seasonal DSR (suitable for wind)[4]	- (m>0, pd<0)	+ (m>0, pd>0)	++++ (n>>0, pd>>0)
5. Commercial load with no DSR	++ (m>0, pd>>0)	++++ (m>>0, pd>>0)	+++ (m>0, pd>>>0)
6. Residential load with no DSR	++ (m>>0, pd>0)	++++++ (m>>>0, pd>>0)	++++++++++++ (m>>>>0, pd>>>0)

Source: Te Waihanga

In row 2, short-term DSR capability refers to load customers can cut for an hour or two. They do that to avoid paying extremely high spot prices, and so the *pd* terms in row 2 tends to be smaller than in row 1. However, physical mismatch *m* is not much affected, if at all.

In row 3, the seasonal load is assumed to be dairy sector load, which reduces considerably over winter months. However, geothermal operates constantly over winter and so physical mismatches are larger than in row 1. Also, *pd* is significantly negative as LWAP for primary sector load is less than TWAP and GWAP for geothermal exceeds TWAP due to maintenance during low-priced seasons. Without further empirical evidence about the correlation of the seasonal load with wind and solar, we are unable to draw a distinction between these forms of generation.

In row 4, the load is flat unless prices entice it to offer DSR. We've assumed it has the capability to provide seasonal DSR sufficient to match the winter slump of wind generation but not the winter slump for solar.[195] This assumption means solar is a significantly poorer match than wind. I've also assumed the load needs to maintain production schedules and so it will not generally offer DSR outside of winter as spot market prices will not be enticing. None of these matters make any difference for the matching of geothermal with flat load.

Commercial load is relatively constant during business days and increases modestly over winter months. It matches solar reasonably well as solar also operates during the business day. The main issue for solar is it slumps over winter when spot electricity prices are high. Geothermal operates 24x7, and so it is a poorer physical match for commercial load than solar outside of winter but the converse applies during winter.

Residential load is shown in row 6. Residential load is high during business days and particularly high during winter months, and especially over 6–9am and 5–8pm. For each form of generation:

- Residential load does not match well to constant geothermal generation, and so *m*>>0. Also, residential LWAP greatly exceeds TWAP. Although geothermal GWAP also exceeds TWAP, residential LWAP > GWAP and so *pd* >0.
- Residential load does not match well with wind either:
    - Over winter: load increases whereas wind generation slumps by 20%, creating larger physical matches than occurs with flat load, hence *m*>>>0. This mismatch occurs when spot market prices are likely to be very high, as occurs for row 1.
    - Outside of winter: there are many calm days outside of winter, leaving significant physical mismatches although not as large as for flat load. Spot prices are not particularly high as total demand in the market is lower outside winter than during winter.
- Residential load matches solar generation reasonably well outside of winter months because solar operates during the business day. However, solar slumps 50% over winter, leaving residential load highly exposed to very high prices for several months every winter.

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End Notes

1 CCC (2021b, Demonstration Path tab, cells AF212-AJ212).

2 CCC (2021b, Demonstration Path tab, cell BN212).

3 Roaring40s (2020a).

4 Roaring40s (2020a, p27).

5 Wind power density = 0.5(air density)(wind speed)^3.

6 The Global Wind Atlas 3.0 is a free, web-based application developed, owned and operated by the Technical University of Denmark (DTU). The Global Wind Atlas 3.0 is released in partnership with the World Bank Group, utilizing data provided by Vortex, using funding provided by the Energy Sector Management Assistance Program (ESMAP). For additional information: https://globalwindatlas.info.

7 Roaring40s (2020a, p16).

8 Roaring40s (2020a, p17).

9 This is an average of low and high scenarios. Note the gap between the high and low scenarios is modest, at only 13%.

10 Roaring40s (2020a, p27).

11 Roaring40s (2020a, p27).

12 MBIE (2020, table 2, 2019 column).

13 Electricity Authority (2020).

14 CCC (2021b, Demonstration Path tab, cell BN213).

15 CCC (2021b, Demonstration Path tab, cell BN212).

16 Miller (2020).

17 See https://www.watercare.co.nz/About-us/News-media/New-Zealand%E2%80%99s-first-floating-solar-array-unveiled

18 Transpower (2020, pp33& 35).

19 Miller (2020, p3).

20 Miller (2020, p52).

21 CCC (2021b, Demonstration Path tab, cells AF211- AJ211).

22 CCC (2021b, Demonstration Path tab, cell BN211).

23 Lawless et al (2020).

24 The Waikato and BOP Regional Councils have adopted very similar classification definitions for geothermal systems. In the Waikato Regional Policy Statement, "**protected** systems contain vulnerable geothermal features valued for their cultural and scientific characteristics. Their protected status ensures that their underground geothermal water source cannot be extracted and that the surface features are not damaged by unsuitable land uses" Lawless et al (2020, pp42-43).

25 Lawless et al (2020, pp42-43).

26 Lawless et al (2020, p1).

27 Roaring40s (2020b, p10).

28 Roaring40s (2020b, p12).

29 CCC (2021b, Demonstration Path tab, cells AF210- AJ210).

30 CCC (2021b, Demonstration Path tab, cell BN210).

31 Roaring40s (2020b) did not provide annual generation estimates for all schemes. For those cases, we have used a 65% capacity factor, which is the same value they used for embedded hydro generation. Refer Roaring40s (2020c, p16).

32 Transpower (2020, p35).

33 Productivity Commission (2018, pp52-54) provides a simplified description of these kinds of models. More detailed descriptions and models of the electricity market are provided in MBIE (2016), Concept et al (2018, pp13-14), Energy Link (2019, pp15-33) and Concept (2021, pp2-8).

34 Note, backup generation is more expensive than inflexible generation. If that was not the case, then least-cost optimisation would result in backup generation becoming the primary source of generation to serve demand, in which case it is not operating in a backup role.

35 The wider electricity market and transmission grid also provides backup for customers, as it enables generation in one part of the country to cover shortages in another part of the country. It also enables different types of inflexible generation to partly cover for each other, for example a combination of solar and wind generation may minimise the need for backup generation. Over-build of wind generation is another example. Demand-side response (DSR) can also be another source of backup available from the market. This occurs when customers reduce their load in response to high wholesale prices or when call options are exercised.

36 Putting aside the LCOT term for now, the total cost of generation $C \equiv \sum S_t P_t^s + \sum M_t P_t^b$ incurred to supply the increment in demand, D. where $M_t \equiv (D_t - S_t)$, P_t^s is the price of inflexible supply and P_t^b is the price of backup generation. Hence, $LRMC \equiv \frac{C}{D} = \frac{S}{D} . \frac{\sum S_t P_t^s}{S} + \frac{M}{D} . \frac{\sum M_t P_t^b}{M} = sLCOE + mLCOB$. By definition, $m = 1 - s$. This description of LRMC omits several complications. See Culy (2019a) for a more complete discussion of system LRMC, particularly pages 8-10.

37 BEIS (2020, pp41-46) estimates systemwide costs of different generation technologies for the UK and refers to them as enhanced LCOEs.

38 LCOB corresponds to profile and balancing costs in Hirth et al (2015, p928) and LCOT corresponds to grid-related (or location) costs in Hirth.

39 See Dixit and Pindyck (1994) for introductory analysis of irreversible entry into a market when there is uncertainty. It is straight-forward to infer from analysis shows that costs in one location may need to be significantly below costs in another location when there is more uncertainty in the former than the latter location.

40 There are two main methods employed to empirically assess location decisions. One is called the discrete choice method (DCM), which analyses the issue from the perspective of firms making location decisions. This approach considers how firm characteristics and those of the chosen territory affect location decisions. The other approach is called the count data method (CDM), which considers the issue from the perspective of the chosen location. This approach analyses which characteristics of a location affect the rate at which new concerns setup in the location. This is called CDM because the rate of entry equals the number of new concerns per period. See Arauzo-Carod *et al* (2009) for an overview of the literature on industrial location.

41 Note this refers to the emissions intensity of the electricity system rather than the emissions intensity of an additional increment in electricity supply. Although firms locating their production in Aotearoa end up paying the marginal cost of supply, if they're connected to the national grid, either directly or indirectly through a distributor, they draw their power from an electricity pool. They cannot claim to be using electricity from any particular type of generator. They could undertake load flow analysis to show the addition of their demand hasn't increased emissions, but that would be costly and not easy for their customers and investors to comprehend and accept.

42 Wu et al. (2017) is an early attempt to include emissions intensity in firm location choices. The bulk of the paper is focused on the impact of carbon prices on location choices, rather than on the implications of consumer's preferences for product's with a low carbon footprint. The paper suggests that incorporating consumer preferences makes firm's location decisions more sensitive to changes in carbon prices, and low emission regions become more attractive than would otherwise be the case. It is an unpublished manuscript, however, and so its results should be treated with caution.

43 In practice, incumbent firms may have different emissions preferences than new entrants. If so, policy initiatives to reduce our emissions intensity could increase our optimal LCOE and LCOB, increasing our wholesale electricity prices and driving some incumbents to close-down or exit

Aotearoa. In that case the new sources of demand may not require any additional generation, leading to a slower decline in our emissions intensity because the building of low-emission generation may be deferred.

44 See https://ourworldindata.org/renewable-energy. Outside of the OECD, high rates of renewable electricity can be found in Costa Rica, Central African Republic, Democratic Republic of Congo, Ethiopia, Kyrgyzstan, Namibia, Nepal, Paraguay, Uruguay and Tajikistan produce more than 90% of their electricity from renewable sources. Brazil's electricity system was 84% renewable in 2020.

45 The Australian Energy Market Operator (AEMO) is projecting a central case scenario of 79% renewable electricity by 2030 but also presents a Hydrogen Superpower scenario in which Australia would reach nearly 100% renewable electricity by 2030. See Parkinson (2021) for an overview of the AEMO report and AEMO (2021) for additional details.

46 The discussion up to this point implicitly assumed sufficient backup generation is always available from the grid to serve demand, but this is not the case in practice. Currently, electricity reliability is very similar among developed countries, however this may change as descarbonisation progresses.

47 Firms may also have preferences in relation to the stability of wholesale electricity prices. However, in this case there is no need to include price stability in the location choice functions of firms because they can purchase hedge cover – which are fixed price fixed volume (FPFV) contracts – or buy electricity under a fixed price variable volume (FPVV) contract, which is what residential and small business consumers typically do.

48 If that wasn't the case, then the lower-emission sources of generation would already have been chosen.

49 See projections in IRENA (2020a) and Way et al (2021).

50 Smith (2006). See Aarstad at al. (2016) for recent evidence regarding the importance of related variety.

51 It is difficult to find evidence directly testing the widely-held view that Aotearoa is a small open economy. However, see Wongsaart & Ward (2004), Matheson (2006) and Fielding (2011) for macroeconomic tests regarding New Zealand as a small open economy.

52 Over the very long term, global warming will make hot countries hotter, resulting in colder countries attracting higher levels of migration. So, as Australia gets hotter over the next 80 – 300 years, Aotearoa may experience high levels of trans-Tasman migration. This would also increase demand for our low emission sources of electricity.

53 Similarly, we substitute our electricity for imported electricity when we produce energy-intensive goods for domestic consumption rather than import them, such as steel at Glenbrook or refining oil at Marsden Point.

54 NZIC Act (2020, s9).

55 CCRA Act (2019, ss5Q(1)(a) and 5ZA(1)(d)).

56 https://www.xe.com/currencyconverter/convert/?Amount=1&From=USD&To=NZD. At 1:47pm on 2 September 2021, the rate was US$1:NZ$1.42.

57 IRENA (2020b, tab Figure 1.6, rows 6-13). Converted at US$1:NZ$1.42.

58 Longer time trends for utility-scale solar show impressive LCOE reductions. For example, the LCOE for utility-scale solar reduced from NZ$540/MWh in 2010 to NZ$147/MWh in 2016 (based on US$1:NZ$1.42), amounting to cost reductions of 19.5% per year (IRENA (2020, tab Figure 3.1, row 23)). However, there's little value in reporting cost performance for that period as even in 2016 solar was clearly uneconomic.

59 IRENA (2020b, tab Figure 1.7, rows 10, 17 &25). Converted at US$1:NZ$1.42.

60 IRENA (2020b, tab Figure 1.3).

61 IRENA (2020b, tab Table H1).

62 Roaring40s (2020a, p26).

63 This is significantly higher than the 36% average capacity factor achieved in Aotearoa over the last five years (coincidentally the same as the global weighted average capacity factor for new wind farms in 2020). The average for the last five years is calculated from MBIE (2020), tabs Table 2 for

annual wind generation output for 2016-2020 and Table 7 for wind generation capacity.

64 See MBIE (n.d.).

65 Bradley (2019) for Turitea and Tilt Renewables (n.d) for Waipipi.

66 IRENA (2020b, tab Figure 2.7, cells AM8-22). The global weighted average is from tab Figure 2.1, cell M17.

67 See MBIE (n.d.). The tool was used with the parameters set by MBIE, except for the US:NZ exchange rate which I set to US$1 : NZ$1.42 and I turned off the TWAP/GWAP adjustment.

68 All data in this paragraph are Te Waihanga calculations from data provided by MBIE (n.d.).

69 Lazard (2020), chart entitled "Levelized cost of energy comparison – unsubsized analysis". Converted at US$1:NZ$1.42.

70 Electricity Authority (2014, p18).

71 IRENA (2020b, tab Figure 2.4). The average for the five percent of wind farms with the lowest capital cost of installation per MW was NZ$1.49m/MW. The average for the five percent of wind farms with the highest capital cost of installation per MW was and NZ$3.23m/MW. All figures converted at US$1:NZ$1.42.

72 IRENA (2020b, tab Figure 2.5, cells AM8-22). The global weighted average is from tab Figure 2.4, cell D45. All figures converted at US$1:NZ$1.42.

73 Electricity Authority (2014, p18).

74 IRENA (2020b, tab Figure 2.4). The rate of cost reduction was -2.7% for the five percent of wind farms with the lowest capital cost per MW and -1.0% for the five percent of wind farms with the highest capital cost per MW.

75 IRENA (2020b, tab Figure 7.2). All figures converted at US$1:NZ$1.42.

76 Lawless (2020, p44).

77 Beyond 650 MW, each new generation plant is 25 MW or smaller. See IRENA (2020a, p137) for a depiction of the size of new geothermal plants since 2010.

78 IRENA (2020b, tab Figure 7.1).

79 Lawless (2020, p14).

80 IRENA (2020b, tab Figure 3.1). Converted at US$1:NZ$1.42.

81 Miller (2020, pp1&6) states that it is now economic to incorporate tracking systems to track the sun throughout a day, and to over-size module capacity to improve the inverter loading ratio and offset module degradation, both of which improve system capacity factor. The 12-20% estimate is based on the assumption that all large-scale solar farms will have increased inverter loading ratios and single-axis tracking.

82 See Miller (2020, p52) for the 19-20% figures and IRENA (2020b, tab Figure 3.1) for the 95th percentile capacity factors for 2011-2020.

83 Miller (2020, p1).

84 Miller (2020, pp2-3) expresses the discount rate and ROI in nominal terms and assumes a CPI inflation rate of 2%.

85 "Lodestone Energy." Accessed August 31, 2021. https://lodestoneenergy.co.nz/.

86 https://www.stuff.co.nz/business/125090584/300m-plan-for-five-solar-energy-farms-providing-1pc-of-countrys-supply

87 CCC (2021c, cells H16-H20 in Power tab).

88 CCC (2021c, cells K16-K20 in Power tab).

89 The CCC's cost reduction assumptions are similar to ones in BEIS (2020) and IEA (2021).

90 CCC (2021b, rows 2010-213 in Demonstration path tab).

91 To be clear, this chart is just an illustration and so the investments in solar, onshore and offshore wind are entirely hypothetical. However, they reflect profit-maximizing choices by generation companies.

92 See Way et al (2021).

93 Data source is www.emi.ea.govt.nz/r/io4fa.

94 Electricity futures contracts mature within the next 12 months are called short-dated contracts. Peak-load futures contracts are available, which are for 0.1 MW of electricity for all hours between 7:00am and 10:00pm on each business day within the contract's duration. Baseload and peak-load contracts are available at Benmore in South Canterbury, and the price difference between Otahuhu and Benmore is a long-term price for transmitting electricity between those locations (note, this is different from financial transmission rights). All types of electricity futures contract are for quarterly periods, however some are also available for monthly periods.

95 Culy (2019c, pp14-15).

96 Culy (2019a, p29).

97 Culy (2019a, p12).

98 Culy (2019c, p19).

99 Culy (2019a, p27).

100 BEIS (2020, p45). The 45% figure is for large-scale solar and the 50% figure is for onshore wind. The 40% figure is for CCGT H Class thermal generation. BEIS provide a central LCOE for each generation type but report a range for the impact of including COB and other additional system costs. The % figures reported in this paper are the mid-point of each range divided by the central estimate.

101 Hirth et al (2015, pp932-4). Note Hirth uses different terminology; balancing and profile costs in Hirth are included in the definition of LCOB in this paper. Locational costs in Hirth are included in LCOT in this paper.

102 Transpower (2018, p29).

103 Culy (2019c, p12)

104 See https://www.aer.gov.au/wholesale-markets/wholesale-statistics/seasonal-peak-demand-nem. Note these statistics are for electricity demand on the national grid. True summer demand will be even higher once adjustments are made for the output from distributed solar generation.

105 Gavin (2014, pp73-76).

106 Hirth et al (2015, p926).

107 Note $m \equiv \frac{D-S}{D} = \frac{M}{D}$ and $pd \equiv GWAP^b - GWAP^s$, where $GWAP^b$ is the GWAP for the backup generation and $GWAP^s$ is the GWAP for inflexible supply. Also $ECOB \equiv COB - LCOE.M$ as the last term is the cost that would be incurred if mismatched demand was supplied by inflexible generation. Hence, $ECOB = M.\frac{COB}{M} - GWAP^s.M = M(GWAP^b - GWAP^s)$. Hence, $LECOB \equiv ECOB/D = (M/D)(GWAP^b - GWAP^s) = m.pd$.

108 The table illustrates the trade-offs captured in electricity market dispatch models, such as the Emarket model provided by Energy Link. In these models, the ECOB from adding a new load depends on the type of load added and how well it is matched to the type of generation added to the system to serve the increased demand, and on existing generation and load patterns.

109 These purchases are called ancillary services in Aotearoa and balancing services in the UK and in most of the academic literature.

110 When full, our hydro reservoirs hold about 4,500 GWh of energy (refer emi.ea.govt.nz/r/flttd). In 2020, annual electricity demand served by generation (other than co-generation) was about 41,100 GWh (refer MBIE (2021, table 6, column L). Hence, hydro storage covers 5.7 weeks of electricity demand (after netting off co-generation). Norway's hydro-electricity system has the benefit of large hydro reservoirs, where at maximum level they hold potential energy equal to two years of national electricity demand.

111 Hansen (2003, p6).

112 CCC (2021e, cells F13-F14 in Generation stack tab).

113 The 5% figure is based the CCC's wholesale electricity price assumptions for its demonstration path ($68/MWh). With total generation in 2020 of 41.8 TWh, total wholesale costs would be $2,845m and the $150m annual cost of Onslow would be 5.3%. In 2020, wholesale electricity prices actually averaged $105.43/MWh. At that price the Onslow cost would equal 3.4% of total wholesale costs.

114 Culy (2019b, p6). The $195/MWh figure is $150m/yr divided by 700 GWh, which is the estimated average generation required to cover dry year risks from moving our electricity system from 98% renewable to 100% renewable. The actual amount of dry year generation needed depends on the weather (mainly hydro inflows and wind) and so ranges 100 – 2,600 GWh/yr.

115 https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/low-emissions-economy/nz-battery/

116 The incentive for firms to provide DSR increases with their electricity intensity because the higher their electricity intensity the larger are their electricity costs as proportion of their total costs, and so the larger the financial savings the firm can make from shifting a unit of demand from one period to another. Of course, the larger the costs of altering their demand, then the weaker the firm's incentive to provide DSR.

117 Culy (2019b, p7).

118 Green hydrogen is hydrogen made from low-emission electricity, such as wind and solar.

119 Culy (2019b, p15) assumes a 70% conversion rate from electricity to hydrogen.

120 Culy (2019b, pp6, 12-25).

121 ICCC (2019, p69) and Culy (2019b, p9).

122 See Lazard (2020), item 3 in chart entitled "Unsubsidized levelized cost of storage comparison – capacity ($/kW-year)." His figures, converted at US$1:NZ$1.42, translate to a levelized cost of storage (LCOS) of NZ$0.267m - $0.467m per MW-year.

123 Meridian Energy (2021, p60).

124 Lazard (2020), chart entitled "Levelized cost of energy comparison – renewable energy versus marginal cost of selected existing conventional generation".

125 ICCC (2019, p69) and Culy (2019b, p9). For a contrary analysis based on probabilistic modelling, see Way et al (2021).

126 Culy (2019b, pp5&8).

127 Culy (2019b, p8). Nominal GDP was $306.9b in 2019, from Statistics NZ at http://infoshare.stats.govt.nz/ViewTable.aspx?pxID=7497079c-2caa-4191-873a-641e18e650ca.

128 20.8% = $(3.2/270)^{1/19} - 1$. The 2040 date allows time for Onslow to be built if the battery option is not looking likely to be cheaper.

129 The 90% figure is from IEA (2021, p133).

130 The high and low prices for these calculations are from IEA (2021, p202).

131 Contact Energy et al (2021, p29).

132 CCC (2021e, tab Demonstration path and tab Sensitivity 2. Tiwai stays).

133 See

Figure 16 on page 24 or Lawless (2020, p44). The $4.47/MW figure is for Tauhara 2a and 2b and the $5.56/MW figure is for Ngatamariki-2, Rotokawa-3, Kawerau-2, Rotokawa-4 and Tikitere-2.

134 The Climate Change Commission considers a Demonstration path and six other scenarios. Apart from the 'Further Behaviour Change' scenario, all other scenarios tracked the demonstration path (black line) closely and so are omitted from this chart. All scenarios through to 2050 assume Tiwai exits.

135 Note the Climate Change Commission used a different model to produce the 'Tiwai stay' outcomes – see CCC (2021e, tab Demonstration path and tab Sensitivity 2. Tiwai stays). The outcomes for the Demonstration path and Further Behavioural Change scenarios are from CCC (2021b, row 501 in Demonstration path and other tabs).

136 CCC (2021b, row 501 in Demonstration path and other tabs) and CCC (2021e, tab Demonstration path and tab Sensitivity 2. Tiwai stays).

137 IEA (2021, p164). US$70.9MWh for 2020, US$89.5/MWh for 2030, US$80.3/MWh for 2050. Converted at US$1:NZ$1.42.

138 The IEA estimates are of average generation costs, derived by dividing total generation costs by generation output. In contrast, the wholesale electricity price projections reported by the Climate

Change Commission are averages of prices based on the long run marginal cost of generation.

139 Stock and Stuart (2021, p22), for example, show that carbon taxes would increase US wholesale electricity prices whereas an extension of the current renewables production and investment tax credits would slightly reduce wholesale prices relative to a business as usual (BAU) scenario.

140 These timeframes are conservative "educated guesses." Kieran Devine stated at the 2021 Downstream conference it would take five years to fill Onslow.

141 $T = \log{(FV/PV)}/\log{(1 + r)}$. T=18.8 when r=-0.21, FV=3.2, PV=270. Hence, 2021 + T =2039.8.

142 See endnote 141, with FV=10 instead of 3.2 we get T=14.0 and 2021 + T = 2035.

143 The cost of batteries in 2030 is given by $FV = PV(1 + r)^9$. With PV = 270 and r = -0.15, FV in 2030 is 62.537. Calculating T from 2030, use the formula for T in endnote 141. With FV=3.2, PV=62.537 and r = -0.1, we get T = 28.2 and so 2030 + T = 2058.

144 The first stage of the calculation is the same as endnote 143. With FV=10, PV=62.537 and r = -0.1, we get T = 17.4 and so 2030 + T = 2047.

145 One attribute potentially in favour of Onslow is that it may stabilize wholesale electricity prices by providing a credible and effective upper bound to spot market prices. This could occur if the Onslow scheme is large relative to the rest of the system but low cost to build. Energy-intensive firms, with variable load patterns, may value greater price stability if they are unable to properly hedge their electricity consumption. However, most large industrial firms have flat loads, for which futures contracts are well-suited.

146 The -21% rate of price reductions is feasible. Even though solar PV prices had been declining at a rapid pace since 1980s, they still declined at a -19.6% rate over 2010-2020.

147 Contact et al (2021, p35).

148 For example, Meridian Energy can take Lake Pukaki below its normal minimum during official conservation campaigns, which occur when the risk of electricity shortages in the next few months exceeds 10%. Likewise, Contact Energy and Genesis Energy can access contingent storage in Lake Hawera and Lake Tekapo, respectively, in certain circumstances. Refer Transpower (2012, slide 4).

149 Lawless (2020, pp1, 25 & 45) discusses how geothermal can be made controllable and discusses issues with doing that.

150 This is obvious from the generation stack data in

Table 1 (page 7), which shows additional generation of 7.7 TWh per year from geothermal versus 71 TWh per year from wind. Lawless (2020) estimated a mid-point for additional geothermal capacity of only 1 GW, which falls far short of the 18.8 GW of additional commercially viable wind generation capacity identified by Miller (2020).

151 Collectively, Keall (2021) and BusinessDesk (2022) discuss announcements by Amazon Web Services, Microsoft, Canberra Data Centres (CDC), DCI Data Centres, and Spark.

152 See Bannerman (2021a) and Pullar-Strecker (2022) for these announcements by Datagrid.

153 Bannerman (2021b) and Pullar-Strecker (2022) for these announcements by Hawaiki Submarine Cable Limited Partnership (Hawaiki). The new submarine cable is to be called Hawiiki Nui.

154 Note the estimate for the next 30 years is from base case scenario in Transpower (2020), and other scenarios produce even larger increases in required capacity. On the other hand, the base case assumes the Tiwai Aluminium smelter remains operational: if it exits at the end of 2024, as currently announced, then 10% less capacity would be need by 2050 (ie, capacity requirements reduce by 2,200 MW).

155 New sources of backup generation and storage will also be needed and are included in the data used for the charts in this section.

156 StatisticsNZ, Industry Productivity Statistics ANZSIC06, construction industry, labour input column.

157 http://nzdotstat.stats.govt.nz/wbos/Index.aspx?DataSetCode=TABLECODE7585.

158 Alternatively, we could have estimated historical and future purchase costs and divided those

figures by real GDP. This would have further reduced the red bar relative to the blur bars. Although there is considerable uncertainty about new wind and solar installation costs over the next 30 years, all global predictions are for declining per MW costs. As the LCOE for onshore wind is already at or below parity with hydro and geothermal LCOE, the additional calculations were not worth undertaken.

159 The real GDP figures were obtained from Sense Partners (2021).

160 Insert "GDP per capita vs energy" in the search bar at the top of the OurWorldInData.org/energy page. Note, energy use is use of primary energy measured in kilowatt-hours (kWh) and gross domestic product (GDP) for each country is measured with purchasing power parity (PPP) exchange rates against the United States dollar.

161 See Stern (2018, pp3697–3714). A less technical but less concise discussion of the issues is provided in Elkomy et al (2020).

162 The standard Solow model of economic growth has a Cobb-Douglas production function $Q = (A_L L)^{\beta} K^{(1-\beta)}$ where *Q* is output, *L* and *K* are measures of labour and capital and A_L reflects the impact of innovations that augment the effectiveness of labour. *β* is the elasticity of output with respect to capital and $0 < \beta < 1$. Note, in the economics literature an innovation is called capital-augmenting if it increases the effective supply of capital and labour-augmenting if it increases the effective supply of labour.

163 This result occurs when the elasticity of substitution of capital for energy exceeds unity. If the substitution elasticity equals unity, then energy remains essential but production can be maintained with infinitesimally small amounts of energy. If the substitution elasticity is less than unity then the result coincides with the arguments of the biophysical economists. See Stern (2018, pp3705-6).

164 More precisely, in the long run innovation is biased towards enhancing the effectiveness of the factor of production with the relatively smaller supply elasticity. See Li & Bental (2017).

165 Stern (2018) specifies $Y = [(1-\gamma)Q^{\emptyset} + \gamma(A_E E)^{\emptyset}]^{\frac{1}{\emptyset}}$, where *Q* is defined in Endnote 162 and now *Y* is output, γ is a share parameter, *E* is a measure of energy and A_E reflects the impact of actions that augment the effectiveness of energy. These actions may be innovations or changes in the average quality of energy. $\emptyset = (\sigma - 1)/\sigma$ and σ is the elasticity of substitution between energy and the capital-labour aggregate, *Q*. As *Y* is produced from a constant elasticity of substitution (CES) production function, it does not impose a value for the elasticity of substitution between energy and *Q*, and so this formulation caters for both the biophysical and mainstream views on the elasticity of substation of capital for energy.

166 See Stern (2018, p3705 & 3707). Note the same result occurs for mainstream economists using a model where technical progress is exogenous. In those situations, economic activity is sustainable indefinitely only if (a) the welfare of future generations is given equal weight to that of the present generation, which implies a zero discount rate to aggregate costs and benefits over time or (b) if the rate of technical progress divided by the discount rate exceeds the output elasticity of natural resources (Stern, 2018, p3706).

167 Energy quality is the relative economic usefulness per heat equivalent unit of different fuels and electricity. Fuels have physical attributes that affect their relative qualities, including energy density (heat units per mass unit); power density (rate of heat units produced per unit or per unit time); ease of distribution; the need for a transfer medium; controllability (the ability to direct the position, direction and intensity of energy use); amenability to storage; safety; and environmental impacts. See Stern (2018, p3703).

168 Stern (2018, p3709).

169 Stern (2018, p3697).

170 CCC (2021a, p74).

171 CCC (2021b, Demonstration Path tab, row 42).

172 CCC (2021b, Demonstration Path tab, row 41).

173 CCC (2021a, p88).

174 CCC (2021a, p262).

175 CCC (2021a, p288).

176 CCC (2021a, p288).

177 CCC (2021b, Demonstration Path tab, rows 35-42, 138, 155 and 227).

178 CCC (2021a, p289).

179 CCC (2021a, p120]).

180 The lower number is from CCC (2021d, p31) and the higher figure is from Transpower (2020, p24).

181 The 97% figure is from CCC (2021b, Demonstration Path tab, cell BN235). The 27.2 figure is derived from CCC (2021b, Demonstration Path tab, BN212+BN213-AJ212-AJ213).

182 CCC (2021b, Demonstration Path tab, rows 211 and 232).

183 The total available is 7,700 GWh but 2,300 GWh already used in the CCC's projections. This leaves an additional 5,400 GWh/year of electricity. In the CCC's analysis, the emissions intensity of geothermal averages 85.6 tCO2e/GWh over 2020 to 2050. This gives total additional emissions of 0.462 mtCO2e per year. As the CCC's projections for gross greenhouse gas emissions for 2050 is 40.8 mtCO2e, the additional geothermal emissions would increase gross emissions by 1.1% in 2050. Alternatively, the CCC is projecting gross emissions of long-lived gas of 15.7 mtCO2e in 2050, giving a percentage increase of only 2.9%.

184 The Ministry for the Environment (MfE) defines offshore mitigation as emissions reductions and removals, or allowances from emissions trading schemes that: (1) originate from outside New Zealand, (2) are expressed as a quantity of carbon dioxide equivalent, (3) are robustly accounted for to ensure that, among other things, double counting is avoided, (4) either: (a) represent an actual additional, measurable, and verifiable reduction or removal of an amount of carbon dioxide equivalent or (b) are an emissions trading scheme allowance that triggers the reduction of carbon dioxide equivalent. MfE (2021) provides further details on the Government's offshore mitigation policy.

185 Llewellyn (2021).

186 Climate Change Commission, Inaia Tonu Nei: A Low Emissions Future for Aotearoa, He Pou a Rangi Climate Change Commission, May 31, 2021. Wellington, New Zealand, 84. https://www.climatecommission.govt.nz/

187 "Climate Change Response (Zero Carbon) Amendment Act 2019 No 61, Public Act Contents – New Zealand Legislation," 2019, s5ZC(2)(b). November 18, 2019. https://www.legislation.govt.nz/act/public/2019/0061/latest/LMS183736.html.

188 Box & whisker plots are at https://openei.org/apps/LCA/. See NREL (n.d.).

189 Note all figures are the harmonised figures published by NREL, except for gas generation which is non-harmonised as NREL have not completed that work. As harmonization makes only a modest impact for the other forms of generation, it is reasonable to use the non-harmonised results for gas.

190 NREL (n.d.) estimates 40 tCO_2e/GWh for geothermal generation, whereas I estimate 7.6 from Climate Change Commission data. The difference is likely to be due to the CCC's data capturing only fugitive emissions and omitting embedded emissions.

191 WNA (2015, p6).

192 ICCC (2019, p29-30).

193 McLean and Richardson (2019, p2).

194 Roaring40s (2020b, pp 15 & 17).

195 Clearly, a load party with DSR sufficient to match the winter slump for solar also has sufficient capacity to do so for the winter slump for wind, and so there is little value in discussing that situation.