2 November 2023

Electricity Market Measures Submissions
Ministry of Business, Innovation and Employment
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Manawa Energy submission – Measures for Transition to an Expanded and Highly Renewable Electricity System

Manawa Energy **(Manawa)** welcomes the opportunity to provide a submission to the Ministry of Business, Innovation and Employment **(MBIE)** on *its Measures for Transition to an Expanded and Highly Renewable Electricity System* consultation paper **(Electricity Measures paper).**

Manawa's views on the Electricity Measures paper follow. These views are supported by the following expert reports (which are attached as appendices):

- The Lantau Group *Transition to a Highly Renewable Electricity System* (**Lantau report)**
- Sapere *The contribution of mid scale Distributed Generation* (DG) *in a highly renewable electricity system* **(Sapere DG report)**
- Sapere *Barriers to getting the full value from Distributed Generation (DG) in a highly renewable electricity system* **(Sapere barriers to DG report)**
- Calderwood Advisory *Kaimai Case Study* **(Calderwood report)**.

NZES objectives

Manawa supports the Government's New Zealand Energy Strategy **(NZES)** objectives of striking a balance between:

- energy affordability and energy equity,
- security and reliability through transition as we adapt to climate change effects and global shocks,
- transition at pace to deliver net zero by 2050, and
- an energy system that supports economic development/productivity.

There are tensions and trade-offs between these objectives including different perspectives on what 'affordability' means. The Lantau report notes that whether something is considered affordable is not about the value created but about how it is paid for. It suggests that a more actionable objective might be 'cost effectiveness.'[1]

The Lantau report also comments on the importance of ensuring New Zealand's decarbonisation keeps pace with international efforts and allows space for new insights and global developments.[2] The pathway to decarbonisation globally depends on developments which have not yet occurred.

[1] Lantau report page 8
[2] Lantau report pages 3 -10

We anticipate that the Government will need to provide guidance on how its objectives are to be balanced over the NZES term. It will not be possible to do this in a single strategy issued in 2024 so Manawa suggests the NZES provide for the issue of a Government Policy Statement (**GPS)** which addresses the key issues for the current decade. This GPS can then be updated to take into account new challenges and opportunities in subsequent decades as they emerge.

Part 1: Growing renewable generation

Investment in new generation

The current structure of the wholesale market including the spot market pricing mechanism and contract market (comprising ASX futures and bilateral arrangements) provides sound signals for generation investment. To date, these signals have served New Zealand electricity customers well, as investment has come forward to meet demand since the formation of the market.

Manawa is confident that the private sector, given the right regulatory settings, will continue to deliver this investment at the lowest possible cost.

In relation to the new generation build Manawa notes:

- the technology required to meet NZES targets is well understood and not very complex to install, and
- renewable energy generation projects are eligible for a fast-track resource consenting process.

Assuming the resource consent process works as intended and there are no unexpected regulatory interventions, the necessary capital will be available for investment if there is transparent information about the pace of future demand.

The Lantau Group's core recommendations[3] is to:

- allow the market to work as best as possible,
- remove unnecessary obstacles to efficient decisions,
- recognise that investors are irresponsible if they ignore real risks to which they are exposed – as such they will and should sit on the side-lines if the longer-term outlook is insufficiently clear or attractive,
- markets abhor a vacuum and have, by corollary, a robust appetite for well-structured and objective information about system current and expected future conditions, and
- minimise backstop measures to the extent possible and avoid 'think big' type projects, especially if they involve multi-year planning and development, and come at high cost and materiality. The time for these is not now.

It notes:

> *"The challenge is to approach the energy transition in a way that avoids heavy handed intervention whilst providing firm guidance regarding the problem the market is supposed to solve. Afterall, that is what any market is for: to solve the problem of balancing supply and demand through choices and efficient prices. Define the problem well, align the problem with customer preferences and supplier capabilities, and ensure adequacy of competition through ease of entry and exit.[4]"*

[3] The Lantau report page 2
[4] The Lantau report page 2

Transparent information flows

Transparent information flows are particularly important where demand growth is affected by the presence of Government support to promote electrification of process heat or transport services.

The Lantau report observes it is important to:[5]

> *"…provide stakeholders with as much information about future demand drivers and likely outcomes so that stakeholders make informed decisions. Demand projections are not guaranteed, of course, and they may not be seen as credible unless the process and method of their estimation is sufficiently transparent."*

The Lantau report also discusses the impact on demand projections of a Tiwai exit:[6]

> *"So many other uncertainties pale in comparison to this. Given the value that having more time can have when innovation is happening and new technology costs are falling, and given the paralysis that an extraordinary binary risk has on market behaviour, there are few focus areas that can restore a more healthy and efficient energy market than to resolve or figure out how to manage the impact of the Tiwai Point Smelter. Given that it is still only 2023, one could argue that it is prudent to push off any decision whose answer depends on which way the Tiwai outcome falls."*

The value of optionality

The Lantau Group observe:[7]

> *"Our key observation on demand growth projections is not to suggest that one set of figures is more correct than another… but rather to say that any form of electricity projection is prone to error which introduces uncertainty, and the further out you project, the greater these errors and uncertainties become. If the idea is that major infrastructure should be developed 'soon' for such distant effects, that would be a mistake. However, if there are steps that can be taken to shorten the time of development from a point of decisions, that may be prudent. The shorter the time of development, the later the point of decision can be. The option to defer commitment is a positive source of value."*

Retirement of thermal plant in next decade

Manawa considers gas has an important role as a transition fuel and agrees with Concept's analysis that there are sound reasons for thermal plant to remain operational until at least 2032.

Thereafter it is not clear what the best solution for intermittency will be.

The Lantau group suggest that the NZES should have some flexibility about the preferred dates for full thermal retirement:[8]

> *"Whilst it is good to establish firm deadlines, it is reasonable to have well-structured flexibility. Have a clear framework – set a retirement date but allow for the option of deferral of, say, six months upon the payment of a penalty charge whose payment would only make sense if the*

[5] Lantau report page 13
[6] Lantau report page 17
[7] Lantau report page 18
[8] Lantau report page 19

year of retirement happened to be a dry year of sufficient extremity. This approach combines commitment with structured flexibility – moving away from reliance on non-binding commitments or arbitrarily rigid deadlines."

Continued availability of existing renewable generation

Manawa also notes that there is a need to ensure that existing renewable generation continues to be available to meet the forecast demand.

The Sapere DG report describes the significant role DG currently plays in New Zealand's electricity sector[9] and its expected role in the transition. It also outlines the benefits that DG brings to New Zealand's energy system[10]. It notes the focus of regulatory agencies has often been on large scale generation or new forms of distributed energy resources (DER). This means the needs of mid-scale DG are often overlooked[11].

The Sapere barriers to DG report describes some of the regulatory uncertainty Manawa has faced as the largest owners of DG in New Zealand.

DG requires significant resources to:

- secure the consents it needs to operate. By way of example over the next 10 years, Manawa will be reconsenting 11 Hydro-electric schemes. This amounts to 35% of Manawa's existing generation capacity).
- obtain and maintain reasonable access terms from distributors whose loyalties often lie with existing end users rather than the supply system as a whole (this point is expanded on in the section on Networks for the Future).

To assist Manawa mitigate these challenges it would be helpful if the Government formally acknowledged the role DG (and other DER) plays in the overall energy system. This has been done before.

For example, GPSs in 2006 and 2008 included a clause that stated[12]:

"Distributed generation is expected to play an increasingly important role in meeting electricity demand as the cost of smaller-scale and new renewable technologies continues to decline. Distributed generation can improve security of supply by creating diversity of fuel types, locations and technologies, and, where appropriately sited, helps reduce the need for transmission and distribution upgrades. Accordingly, it is important that there are no unnecessary barriers to its development."

Similar statements were also included in the GPSs of 2000, 2002 and 2004.

It would be useful to have an updated version of this clause in place to assist with Manawa's day-to-day engagement with a variety of regulatory agencies and distributors. The updated clause should confirm that new DG must be from renewable sources of energy. The clause could be supplemented

[9] Sapere DG report slides 6-8
[10] Summarised in slide 4 of Sapere DG report
[11] Sapere DG report slide 11
[12] https://gazette.govt.nz/notice/id/2006-go7539, https://gazette.govt.nz/notice/id/2008-go3985

by specific GPS actions to support the deployment of DER as barriers are identified. A couple of suggested actions are included in "Networks for the Future" (below).

Role of large-scale flexibility

Manawa agrees that demand response, demand management and, over time, behind the meter injection (collectively **large-scale flexibility**) will have an important role in reducing or shifting peak demand (and thereby limiting the need for investment in new generation and new network infrastructure). Large scale flexibility can also be used to provide ancillary services, firming capacity and to mitigate market power.

Demand response is a proven technology. It can occur in response to price signals or by remote switching. It can be delivered by end users (large industrial plant or residential consumers), some other party (such as a flexibility provider) or a network operator that has some form of control over an end users' load. New energy technologies (smart meters, energy management systems, other controllable devices) increase demand response capability and enable the prospect of aggregating demand response into *a resource of scale***.**

It has long been known that demand response was an important part of an inclusive energy system.

New Zealand has had various forms of demand response for decades. Examples include:

- bulk energy tariffs were levied for many decades on the basis of peak demand providing incentives for investment by local supply companies in load management and distributed generation,
- ripple control has been used by distributors since the 1950s to support system security, manage outages, reduce transmission charges and defer network investment. It has been estimated that under the previous Transmission Pricing Methodology **(TPM)** there was 644MW of ripple control water heating available during peak periods,
- domestic consumers reducing consumption during public conservation campaigns and
- Transpower has undertaken a number of demand response trials e.g., as an option to defer network investment. Participants include campus-based organisations, like hospital and universities and dairying operations.

However, the Electricity Authority **(Authority)** has questioned the efficacy of previous demand response initiatives:

- the RCPD peak price signal has been removed and replaced by a set of fixed charges, and
- Transpower's demand response scheme curtailed as the Authority thought it would interfere with wholesale prices.

It prefers to see demand response being bid as dispatchable demand in the wholesale market now real time pricing has been introduced.

Manawa notes previous initiatives by the regulator to promote demand side participation in the wholesale market were not very successful and that international jurisdictions have also struggled with the challenges of effectively integrating demand response into wholesale market designs. There is also a complex interplay between price signals for flexibility across all value streams (transmission,

distribution and wholesale market), along with the need to enable value stacking opportunities for DER resources, that need to be worked through to fully unlock the value for flexibility in the future.

For these reasons, Manawa is not sure if New Zealand will get to the optimal levels of demand response solely through market developments under the real time pricing.

Manawa supports the work identified by both the MDAG and Flexforum to facilitate the value of large-scale flexibility being realised across the supply chain, including via more dynamic distribution network pricing. Manawa does not however, consider there is any need to develop a Nega-Watt arrangement for the wholesale market, similar to that adopted in Australia's National Electricity Market **(NEM)**, at this time. This is because there is evidence that large-scale flexibility options are beginning to emerge, for example the recent agreements with Tiwai. Heavy handed interventions to support the large-scale flexibility market developing at pace come with significant risks of creating distortions, as evidenced in overseas jurisdictions.

To support the necessary changes occurring at pace, Manawa suggests that the Government include an obligation on the Authority and the Commerce Commission **(Commission)** (to the extent it has a role in enabling funding for non-wires alternatives such as large-scale flexibility) to address any barriers for the emergence of large-scale flexibility within a specific timeframe.

Suggested measures to address issues raised in Part 1: Growing renewable generation	
Implementation of NZES objectives	Manawa recommends the NZES provides for the issue of a GPS setting out the Government's priorities for the next decade (including guidance to its regulators on how trade-offs between its aspirations should be made). This instrument can then be updated to address new insights and developments as they emerge. Manawa also suggests that the NZES objective of "affordability" be replaced with "cost effectiveness" (which can be more readily assessed).
New renewable generation	Manawa recommends the Government: a) provide stakeholders with as much information as possible about forecasted demand growth, b) consider what steps it might take to shorten the development time for new investments, but otherwise, c) rely on the market to determine the timing and mix of new renewable generation.
Existing renewable generation	DG's ability to receive reasonable access and consenting terms would be assisted if a GPS acknowledged the role that DER (including DG) play in meeting NZES objectives and required regulatory agencies to ensure that these resources do not face barriers.
Large scale flexibility	The Authority and the Commission need to be given a specific action to address barriers to large-scale flexibility (including DER and demand response) with a timeframe for delivery.

Part 2: Competitive markets

Maintaining workable competitive markets

Manawa acknowledges that as thermal plant retires there is a risk, for a period of time, of weakened competition in the market for flexible generation resources (such as hydro storage). This has already been identified by the Authority and the Market Development Advisory Group (**MDAG**).

To address this risk the Authority has introduced trading conduct rules for the spot market and is considering extending them into the hedge market. It has also improved information disclosure and is considering if there is anything it should do to enhance access to firming capacity. It plans to continue market monitoring and active enforcement.

The Lantau report comments:[13]

> *"When we looked at competition in the New Zealand market as part of the Authority's 2021 review, we made a number of observations that still hold true.*
>
> 1. *In any electricity market, we would expect that it is possible for some market participants to have some market power at some time or in some locations. The practical standard for electricity market structure in New Zealand or anywhere to date has not been perfect competition. However, it is not the existence of market power that should give concern, but whether such market power is being exercised to a degree that necessitates consideration of corrective, mitigating, or other forms of targeted action.*
> 2. *In trying to address a problem perceived with short run allocative efficiency it is important that the 'measure' applied does not dampen long-run dynamic efficiency. In an environment where a key policy objective is to attract new investment to support a low emissions economy, such 'measures' run the risk of being counterproductive.*
> 3. *Freedom to contract between well informed and willing buyers and sellers in the absence of market power being an unduly material factor, is a cornerstone of workable markets.*
> 4. *The light cast by transparency helps to ensure an orderly market (absent the possibility of enabling tacit collusion). A salient example being the requirement for disclosure of risk management contracts provided for under part 13, subpart 5 of the Code.*
> 5. *There will need to be a greater acceptance that high prices are sometimes required to allow a market to be both allocatively and dynamically efficient.*
> 6. *The Authority can support the energy transition by ensuring that its regulatory tools do not distort pricing signals through blunt un-targeted measures. The recent weekly trading conduct reports are an excellent example of a prudent regulator lifting confidence in market outcomes through increased transparency.*
>
> *We are pleased to see that following the 2021 review, the Authority's actions to constrain the exercise of market power (refer Section **Error! Reference source not found.**) are well aligned w ith these observations."*

[13] The Lantau report page 29

The Lantau report further notes that market power is mitigated by the speed and flexibility of entry which is likely to significantly increase in the future.[14] This reinforces the view that no further action is required.

Suggested measures to address issues raised in Part 2: Competitive markets	
Weakened competition in supply of firming capacity as thermal exits	Manawa recommends that the Government reinforce the priority of existing workstreams to address potential market power issues but does not undertake extra measures such as mandated ring fencing of generation assets, virtual asset swaps or physical break-up of generation capacity or introduce a single buyer.

Part 3: Networks for the future

Part 3 of the Electricity Measures paper discusses the need to ensure New Zealand's transmission and distribution networks support new renewable electricity and electrification and seeks feedback on the sufficiency of current regulation and future workstreams.

This section begins with the need for more cohesion between the industry's regulators.

Improved regulatory cohesion

The current allocation of regulatory responsibility between the Commission and the Authority involves shared roles with respect to the regulation of monopoly networks.

In transmission:

- the Commission determines Transpower's overall revenues, including the process by which Transpower's regulated asset base is increased by the approval of grid investments,
- the Commission also determines the quality/service standards which apply during each price path, and
- the Authority determines grid reliability standards, which assets form part of the core grid, the terms of default transmission agreements (which also include service standards), and sets guidelines on how transmission revenues are allocated amongst transmission customers.

In distribution:

- the Commission determines price paths and quality/service standards, and sets input methodologies which include the scope of regulated versus unregulated businesses and the recoverability of payments made to distributed generation,
- the Authority has power to determine access arrangements which also include service standards (in the form of regulated access terms or use of system agreement guidelines), create markets for evolving technologies, set the default terms which apply to the connection of DG, and decide if and how tariff structures should be regulated, and
- the Authority enforces the rules requiring the split of certain generation and retailing from distribution.

[14] The Lantau report page 29 - 30

This sharing of responsibility creates the potential for inconsistency, delay, and matters falling between the cracks. It also becomes problematic when the regulators have different views on similar policy issues or where regulated entities face the double jeopardy of parallel regulation. This is why Trustpower[15] suggested in its submission to the Electricity Price Review that a single agency – the Commission- take responsibility for regulating network entities.

Since that submission some regulated entities have been calling for a single Minister of Energy for similar reasons. This is understandable. However, it is acknowledged institutional change takes time and the NZES is focussed on "transition at pace".

For this reason, Manawa thinks the best way to achieve regulatory cohesion is for the Government to:

- undertake more active stewardship of the sector (discussed in the section on Whole of system considerations),
- amend the statutory objectives of the regulators, and
- provide clearer (ongoing direction) on respective priorities for each regulator through the mechanism of a GPS.

Statutory objectives of network regulators

Both the Commission and the Authority have objectives which focus on efficiency of the regulated parties not the broader NZES outcomes. In addition, the Commission is not currently entrusted with a "whole of supply chain view". Instead, its focus is on the consumers of transmission and distribution services not the consumers of other electricity markets (such as generation, retail and behind the meter services) or other industries such as the transport or manufacturing sectors.

Commerce Act

Part 4 of the Commerce Act provides for the regulation of the price and quality of goods or services in markets where there is little or no competition and little or no likelihood of a substantial increase in competition. Its purpose is to promote the long-term benefit of the consumers of such services. The Commerce Act defines the long-term benefit of consumers as being a market where suppliers have incentives to innovate and invest, share efficiency gains and not make supernormal profits. (Sections 52 and 52A)

The Electricity Industry Act

Section 15 provides that the main objective of the Authority is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers. The Authority's additional objective is to protect the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers.

It follows that while both agencies may be able to consider climate change objectives in discharging their duties (as permitted by section 52N of the Climate Change Response Act) they are not empowered to the make decisions which have the effect of advancing these objectives unless they are a convenient by-product of their efficiency imperatives. This needs to be rectified.

[15] Trustpower sold its mass market customers and changed its name to Manawa Energy in 2022

Government policy statements

Manawa acknowledges the concerns of the Electricity Price Review that amending the statutory objectives could pull the regulators in too many directions, require difficult trade-offs between competing objectives and blur accountability. It is likely the changes in the operating environment described earlier in this submission will also have this effect. Manawa's solution is for the Government to take a more pro-active role in guiding its regulators on the priority areas of action and/or difficult trade-offs.

Current legislation permits the issue of a GPS.

Section 26 of the Commerce Act provides that:

> In the exercise of its powers under this Act, the Commission shall have regard to the economic policies of the Government as transmitted in writing from time to time to the Commission by the Minister.

Section 17 of the Electricity Industry Act provides that:

> In performing its functions, the Authority must have regard to any statements of government policy concerning the electricity industry that are issued by the Minister.

There is settled case law as to the meaning of "have regard to". The High Court in *NZ Co-op Dairy Ltd* said:[16]

> *We do not think there is any magic in the words 'have regard to'. They mean no more than they say. The tribunal may not ignore the statement. It must be given genuine attention and thought, and such weight as the tribunal considers appropriate. But having done that the tribunal is entitled to conclude it is not of sufficient significance either alone or together with other matters to outweigh other contrary considerations which it must take into account in accordance with its statutory function."*

This case law explains why a change to the statutory objective is required (as well as the issue of a GPS) as the GPS will not have any effect if it relates to an action outside an agency's statutory functions.

Transmission system for growth

Prudent transmission investment or investment in network alternatives will have a different meaning over the NZES period in the context of a 68% increase in electricity generation[17] then the more recent period of flat demand. This is because in an environment of:

- uncertain but significant future demand growth,
- expected increase in climate change events,
- long lead times for transmission investment (7-10 years) and many
- inter-related critical path dependencies

[16] Pp612-3

[17] Forecast by Transpower in its March 2020 *Whakamanama i Te Mauri Hiko: Empowering our Energy Future*

there is a considerable risk that the "just in time" investment, currently favoured by the Commission and Authority on behalf of consumers, becomes "just too late".

The costs of higher wholesale prices, loss of supply, or higher emissions under a "just too late" outcome will be far greater than the costs of short-term spare transmission capacity. This change in operating environment is relevant to:

(a) the investment approval process administered by the Commission including the grid investment test,
(b) the quality and service standards that apply to the provision of network services, and
(c) the Authority's TPM which is currently designed to set up a contest between beneficiaries and Transpower to encourage the deferral of major investments (and no longer provides any rewards for deferring network peaks).

Grid investment test

Manawa agrees with Transpower that a strict market test is not likely to be flexible enough to take into account wider NZ Inc benefits such as climate change policy and CO2 emissions. Manawa recommends the Commission be invited to review this test following the suggested change to its statutory objective.

Grid reliability standards

The grid reliability standards are administered by the Authority but are an important input into the grid upgrade approval process administered by the Commission.

These standards require Transpower to invest to maintain n-1 reliability on the core grid and for the balance of the grid to achieve the level of reliability that occurs if all economic reliability standards were adopted. The grid reliability standards and the definitions of core grid have not been amended since they were developed by the Electricity Commission (the Authority's predecessor).

The Kaimai case study in the Calderwood report provides a real-world example of how the definitions of core grid, connection and interconnection assets inter-relate to establish the reliability obligations on networks owners and their consequential obligations (if any) to pay for network support.

The report shows that there is at best a lack of clarity about, or at worst limited obligations on, the relevant network operators (Transpower and Powerco) to maintain n-1 reliability for the Tauranga region. As a consequence, there is no appetite for either party to pay for services to meet this standard in the period prior to network upgrades.

Manawa thinks that consumers' expectations of reliable network services are higher than the current legal obligations. It follows that these standards should be revisited by both regulators, particularly in the context of removal of the transmission peak charges which previously encouraged local generation and thereby supported local resilience. Manawa recommends this as a priority area of action for the GPS.

Transmission Pricing Methodology

As noted earlier, the current TPM has been designed to delay investment until the last possible moment.

It is a very complex methodology and is already creating barriers to investment due to the unintended and non-intuitive consequences from its modelling of assumed beneficiaries. The TPM is also at risk of creating new sources of unaffordability in its belief that it is efficient to charge communities with underbuilt networks or sparse populations for the costs of climate change events or resilience upgrades.

The Government's short-term solution to the latter problem has been to expand the criteria for which GIDI funding is available to include transmission infrastructure. However, we think a longer term (less political) solution is required for the NZES term taking into account the need for stability when long-term investments are made.

This would occur if central government took responsibility for the pricing principles which need to be applied for transmission investment including the degree to which it is desirable to socialise pricing and/or signal capacity constraints in particular regions through a simple price signal.

Once these pricing principles were established it would be a relatively straight forward endeavour for Transpower to design a methodology which would allocate its costs in accordance with these principles. This should include the responsibility for adjusting price signals on a regular basis, for example each regulatory control period, as new investments are made, and the capacity restraint eased.

Dealing with the problem at source should avoid a patchwork of socialised pricing through GIDI because the Authority did not consider socialised pricing fitted within its efficiency remit.

Connection to the core grid

Connection barriers are not limited to the distribution networks. There is a potential for inefficient delay to occur at the grid level as well. A significant contributing factor to this is access to skilled resources. Manawa suggests that the progress of access requests should be monitored by regulators so an accurate picture can be built of the sources of delay and possible solutions.

Distribution networks for growth

The Electricity Measures paper identifies four possible gaps in the current regulation of distribution networks:

- the flexibility of the current regulatory model,
- the connection barriers faced by new access seekers,
- the impact of current cost allocation models on first movers, and
- the lack of pricing signals to support more efficient use of networks.

Manawa agrees that these are current issues but note that in some instances the issues (and opportunities) are broader than outlined in the paper. For example, access issues do not just arise at the point of a new connection but throughout the life of the connected plant.

Current regulatory model

A significant challenge in the New Zealand supply chain is the large number of distributors relative to the size of its population. There is a real risk that this structure does not result in the efficiencies available from larger scale entities.

In addition, a different regime for consumer owned distributors makes it more difficult to guide behaviours towards NZES outcomes. Trustpower's submission to the Electricity Price Review suggested that there was an opportunity to simplify Part 4 regulation by bringing all distribution companies into the same form of regulation (simplified individual price quality paths) where the regulator provides a spreadsheet model and some key assumptions (such as regulatory weighted average cost of capital, desired efficiency factor etc). Distributors would then populate the model, the results of which would be reviewed and modified as the regulator saw fit. This process could easily apply to the distributors that are currently exempt as it is a relatively low-cost approach.

Further, an option to fast-track price paths could be included where the proposal meets designated conditions - such as compliance with certain parameters or benchmarks. Ideally these would also include matters currently regulated by the Authority. For example, fast-track price paths could be available if a distributor committed to particular NZES-focused measures e.g.:

- by the end of the regulatory period x% of consumers of class "a" can manage their demand in response to electricity price signals, or
- y% of network support services have been procured through open market tenders.

Trustpower's Electricity Price Review submission also noted that some jurisdictions use totex (a single value for opex plus capex) when setting revenues rather than specific opex and capex forecasts. This is to avoid the potential for a bias on the part of distributors in favour of enhancing the balance sheet by investing in capex at the expense of more efficient opex.

Manawa thinks these ideas still have merit in the context of achieving NZES objectives.

<u>Barriers for new connections</u>

It is clear that there is a wide gulf between access seekers and distribution companies about the appropriate basis for connection. Submissions from access seekers on the Authority's recent *Targeted reform of Distribution pricing* consultation paper:

- requested more transparency about pricing practices both initially and throughout the term of the connection contract,
- shared their frustration about the lack of pro-active information sharing by distributors on network capacity,
- called for more standardisation and consistency in connection policies,
- expressed concern about the ongoing potential for abuse of monopoly power from distributors when setting access prices and terms, and
- sought more regulatory intervention from industry regulators to address bottlenecks, guard against inefficient pricing and unfair contract terms, promote more innovative solutions to connection issues and ensure that the electrification momentum is maintained.

In contrast, distributors did not think there were any systemic issues on connection access or connection pricing. Nor any need for urgent reform.

Manawa's review of distributor submissions suggested that the lens that many distributors apply to connection access issues was that of an advocate for existing end users within their network region. It is possible that if distributors were required to include NZES imperatives into their decision-making about access to their networks, they would approach access requests differently.

However, Manawa has reservations, based on past performance, about whether they, or the Authority will be able to implement the needed 'transition at pace'.

It would be prudent to include action on connection access in a GPS (with specific timeframe for implementation).

Barriers for distributed generation

It is also important to consider the risks that connected parties (load or generation) may face if distributed networks come under pressure.

Manawa has recently come up against an operational policy of a consumer owned distributor which sought to unilaterally impose curtailment rights on existing mid-scale generation if the distribution network became congested (as a result of subsequent connections or a lack of upgrades). In explaining this policy, the network gave no recognition to the value provided by DG to end users or as part of New Zealand's low emissions future. Instead, its focus was simply for existing end users 'who had paid for the network in the past' to face no barriers to connections in the future such as domestic solar panels.

This change of terms after capital is deployed is deeply problematic and underscores the need for a regulatory support for connected parties.

Manawa recommends that all access seekers have the benefit of a regulated regime which allows for non-discriminatory access terms and pricing and gives confidence of the reasonableness of proposed terms. A degree of standardisation will be appropriate for some types of access seekers, but larger connections will need bespoke terms (such as a negotiate/arbitrate regime).

This also should be a priority action in the GPS.

First mover disadvantage

Access seekers should only have to pay for the costs of connection assets right sized for their connection. Any efficient over-sizing should be socialised across all grid users. These costs would be mitigated if depreciation on the over-sized assets was backloaded until subsequent movers arrive.

Distribution pricing

As was noted in Trustpower's submission on the Electricity Price Review the Authority has been working on distribution pricing since its formation. This has taken significant resource and progress towards a regime, which provides simple, clear, and actionable price signals at times of peak demand for DER, has been inexorably slow.

A circuit breaker is needed and it is probably best provided by legislated pricing principles. This should be a priority action in the GPS.

Renewable energy zones

A renewable energy zone is a possible solution to the disadvantages faced by first movers accessing transmission and distribution networks but Manawa thinks it would be better to address the problem at the TPM/distribution pricing methodology level, by providing for socialisation of costs of anticipatory capacity.

Trustpower's expert Creative Energy Consulting advised the Authority of the importance of this issue for the energy transition[18]:

> *"The TPM approach creates a first-mover problem – which the EA recognises but has not been able to satisfactorily address – where an entering generator triggers new investment (whether for connection or for interconnection) incorporating excess capacity for which it is required to pay the lion's share until later entrants arrive. Of course, it cannot know whether these will arrive at all. So moving first is extremely risky, and will result in a crisis of coordination: no project that is planning to connect in an area where there are likely to be later-movers will want to be the one who goes first.*
>
> *The experience in Australia has been that solving this coordination problem is critical to the transition to renewable generation. Like the EA, Australian regulators first attempted to develop arrangements where first movers would be responsible for these costs and risks, but ultimately found these to be infeasible or impractical. These have now been superseded by new arrangements where transmission and generation entry in a REZ are centrally coordinated, and the transmission costs and risks are variously shared between entrants, load customers and taxpayers. I expect that the EA's proposals will similarly fail to meet the needs of the energy transition and be superseded. Notwithstanding that, the TPM could be substantially improved in this area by providing that load customers generally, rather than first movers, bear the initial costs and stranding risks of the excess capacity, through adjustments to the residual charge. This will substantially help with the first mover problem, whilst imposing limited risks and costs onto load customers."*

If there was a move to a socialised cost regime (and more permissive investment environment) the first mover disadvantage issues will be of less concern.

Suggested measures to address issues raised in Part 3: Networks for the future	
Improve regulatory cohesion and alignment	Amend the statutory objectives of the regulators and provide clearer (ongoing direction) on respective priorities for each regulator through a GPS.
Grid investment test	Invite the Commission to reassess the Grid Investment Test after its statutory objective has been changed to take into account the NZES.
Grid reliability standards	Invite the Commission and Authority to jointly assess the appropriateness of the current grid reliability standards and quality paths to ensure that end users expectations of reliability are met. Ensure that opex allowances will support the contracting for non-network services to meet the new standards pending network upgrades.
Transmission pricing	Replace socialised pricing of particular transmission projects through the GIDI fund with a longer-term solution such as legislated transmission pricing principles.
Connection to core grid	Invite the regulators to monitor progress on access requests to core grid to ensure the shortest possible development time for projects.
Extend and simplify price	Bring all distributors into the same simplified price quality path regulatory regime which includes a fast-track approval process for those distributors who

[18] https://www.ea.govt.nz/documents/1859/Trustpower-TPM-submission-2021.pdf

regulation for distributors	meet conditions that align with NZES objectives. Ideally this would include matters currently regulated by the Authority.
Regulate connection access and pricing for all access seekers	Require the Authority to develop a new access regime for load which provides standardised and streamlined process for some access seekers and a bespoke arrangements such as a negotiate arbitrate model for large load. Ensure that all connected parties (including DG) have access to an efficient dispute resolution process for access disputes
Distribution pricing/REZ zones	Legislate 'good enough' distribution pricing principles so the industry can move on from a tortuous reform process. This could include guidance on how efficiently over-sized assets should be recovered.

Part 4: Responsive demand and smarter systems

New Zealand will need a step change in the amount of demand response or large-scale flexibility in its energy system in line with the step change being made in generation and network investment. To help realise these benefits Manawa thinks that there is value in the Government providing clear direction on the value of flexibility markets in the energy system and value in it working with industry to develop specific options for trading flexibility including future digital platforms.

In some cases, as noted in the Calderwood report, what is missing is actually a standard of delivering desired levels of reliability or resilience. If the standards are revised to meet consumers current expectations then there is a much greater likelihood that network companies will contract for non-network solutions to meet their obligations. However, the Commission and the Authority will need to work together to ensure that this is done.

In other cases what is missing is a suitable platform for aggregation of demand response including an efficient digital platform. This is where Manawa thinks the Government could work with industry and provide financial support to identify the best options.

Suggested measures to address issues raised in Part 4: Responsive demand and smarter systems	
Improved government direction and support	Include in GPS a clear statement of the priority afforded to the development of flexibility markets, including those basic hygiene matters that should be addressed as a first priority such as establishment of standards for connection of DER resources, communication protocol and access to necessary data.
Enforce new network reliability standards	Require the Commission and the Authority to work together to ensure that non-network alternatives that add value to the system are identified and rewarded.
Develop suitable trading platforms	Partner with industry to identify and develop suitable trading platforms for the trading of flexible resources.

Part 5: Whole of system considerations

Formal co-ordination

Decarbonisation will involve a coordinated effort of the entire electricity value chain – generation, transmission, distribution, DG, retail and the various behind the meter entities. It will also involve complex trade-offs between the various objectives of the NZES: sustainability, equity, security and economic prosperity.

Part 5 of the Electricity Measures paper discusses whether there is a need for greater formal co-ordination of the system as a whole including the formation of a new agency tasked with such coordination. Manawa does not think New Zealand needs a further agency but does suggest that once the NZES is developed MBIE takes a more active role in monitoring its implementation.

Since the market began technology and demand have been relatively stable. In this environment it might have been appropriate to undertake Ministerial reviews every decade or so on a "re-set and forget" basis[19]. However, in the current environment we think more active market and regulatory stewardship will be required by Government to keep the industry and in particular its regulators on track. This needs to be done transparently and in a way which does not impede incentives to invest. This is why Manawa favours a GPS over a new institution.

The GPS will provide a useful vehicle to address the challenges faced by DG. In the Sapere Barriers to DG report, these challenges are identified as a combination of:

- the nature of existing regulation including convoluted clauses and lack of clarity,
- multiple regulations impact on DG each subject to their own interpretation,
- the added complexity of having two different regulators: one setting standards and the other seeking consideration of non-wire alternatives,
- the interpretation of regulation and the particular lack of governance and compliance on distribution compared to transmission networks,
- the absence of regulations in some cases, and
- the failure to date of market mechanisms to emerge that would unlock DG's ability to fully monetise its value.

In summary, Manawa sees the GPS:

- providing context and guidance to all entities making decisions about energy projects,
- setting out the Government's specific expectations for each part of the electricity value chain (generation, transmission, distribution, DG, retail and behind the meter services),
- establishing the priority areas for action for the industry regulators including delivery timelines and how transitions should be managed, and
- assisting the industry regulators on the trade-offs to be made in relation to the NZES objectives.

Manawa hopes that if the Government sees any further regulatory stumbles, such as those highlighted in this submission (and Trustpower's submission to the Electricity Price Review) it will provide guidance through an update to the GPS so opportunities for more efficient and cost-effective supply are not lost or unnecessarily delayed.

[19] Such as the Caygill inquiry in 2000, Layton review in 2009 and the Electricity Price Review in 2019

Suggested measures to address issues raised in Part 5: Whole of system considerations	
Improved regulatory and market stewardship	Government should engage in more active regulatory and market stewardship using the mechanism of a GPS to both provide initial direction and, over time, address any missteps.

If you have any questions regarding the content of this submission, please contact Grace Burtin, Regulatory Manager.

2 November 2023

Electricity Market Measures Submissions
Ministry of Business, Innovation
and Employment
Electricity markets@mbie.govt.nz

Executive Summary

Introduction

Manawa Energy (**Manawa**) welcomes the opportunity to provide a submission to the Ministry of Business, Innovation and Employment (**MBIE**) on its *Measures for Transition to an Expanded and Highly Renewable Electricity System* consultation paper (**Electricity Measures paper**) which has been developed as a contribution towards the New Zealand Energy Strategy (**NZES**).

Manawa is an independent generator who is ready, willing, and able to support the achievement of New Zealand's decarbonisation and electrification objectives and has a proven track record of investing in local and grid scale renewable generation.

Manawa operates a diverse portfolio of 44 power stations across 25 hydro-electric power schemes, supplying around 5% of New Zealand's electricity needs. A significant portion of these assets are connected to distribution networks, referred to as distributed generation (**DG**). DG provides unique value streams to New Zealand's energy sector including:

- the ability to defer investment in network and transmission capacity,
- regional (and national) security of supply,
- system flexibility and grid stability,
- lower regional wholesale prices,
- reduced transmission losses,
- local economic development, and
- emissions reductions[1].

While this submission focuses on the Electricity Measures paper and the consenting process is out of its scope, Manawa wishes to highlight that a key constraint to growing renewable generation is the ability to obtain resource consents in a timely manner and with suitable consent conditions.

The recent introduction of a range of national direction[2] under the Resource Management Act has led to additional environmental assessments being required to support applications for new renewable generation. A new project can take up to seven to ten years to obtain a consent from the time site assessments commence to when Court appeals processes are completed. In addition, there are currently delays in obtaining connection agreements, particularly to transmission infrastructure. These extended

[1] Further detail on these value streams can be found in *The contribution of mid scale Distributed Generation in a highly renewable electricity system (DG)* by Sapere which accompanies this submission.
[2] For example the National Policy Statemen (NPS): Freshwater Management (NPS:FM) and NPS: Highly Productive Lands (NPS:HPL)

timeframes lead to delays and significant unnecessary cost associated with getting new renewable generation commissioned, which ultimately impacts New Zealand's ability to decarbonise.

This concern also applies to reconsenting existing renewable generation, particularly hydro-electricity generation. Given that hydro-generation forms the backbone of New Zealand's renewable electricity system and will have an increasingly important role in providing flexibility in the future, these delays and significant costs incurred during reconsenting will be problematic for achieving the NZES objectives. Existing renewable generation needs to be afforded protection in the resource management regime through certainty of access to the renewable resource and long-term consent durations.

Submission summary

Manawa is supportive of the objectives of the Electricity Measures paper but sees the development of the NZES is at risk of becoming overly ambitious and a daunting task as both the timeframe and scope that it is required to cover is significant.

The pathway to decarbonisation depends on investments that have not occurred yet and the Treasury has estimated that New Zealand's failure to meet the specific targets under the Paris Agreement could cost anywhere between $3.3 billion and $23.7 billion[3], making the pressure for the NZES to succeed in reducing emissions extremely high. However, decarbonisation at pace also creates a risk of New Zealand being out of step with international efforts which has cost implications for consumers.

Manawa is in agreement with the Electricity Authority (**Authority)** that "*while the electricity market may not be perfect, it has served consumers well and the importance of a well-functioning electricity market to enable the transition to a decarbonised economy cannot be understated*.[4]" Manawa therefore fully supports the Lantau Group's assessment in its report[5] that "*New Zealand is well placed to achieve a reasonable transition to a low-carbon energy sector because of its electricity market*" and are in agreement with its core recommendations to:

- allow the market to work as best as possible,
- remove unnecessary obstacles to efficient decisions,
- recognise that investors are irresponsible if they ignore real risks to which they are exposed – as such they will, and should, sit on the side-lines if the longer-term outlook is insufficiently clear or attractive,
- markets abhor a vacuum and have, by corollary, a robust appetite for well-structured and objective information about system current and expected future conditions, and
- minimise backstop measures to the extent possible and avoid 'think big' type projects, especially if they involve multi-year planning and development, and come at high cost and materiality. The time for these is not now.

While Manawa is confident that the market is well positioned to deliver New Zealand's decarbonisation goals, it is concerned that the unique value streams that DG provide are not being fully recognised or realised under the current regulatory environment. Unlocking these value streams will further assist in the pace of transition. Sapere[6] sees the challenges being faced by DG include a combination of:

- the nature of existing regulation including convoluted clauses and lack of clarity,

[3] https://www.treasury.govt.nz/sites/default/files/2023-04/cefa23.pdf
[4] https://www.ea.govt.nz/news/press-release/electricity-authority-confirms-actions-to-promote-competition-in-the-wholesale-market/
[5] *Transition to a Highly Renewable System* by the Lantau Group which accompanies this submission.
[6] *The contribution of mid scale Distributed Generation in a highly renewable electricity system (DG)* by Sapere which accompanies this submission.

- multiple regulations impact on DG each subject to their own interpretation,
- the added complexity of having two different regulators: one setting standards and the other seeking consideration of non-wire alternatives,
- the interpretation of regulation and the particular lack of governance and compliance on distribution compared to transmission networks,
- the absence of regulations in some cases, and
- the failure to date of market mechanisms to emerge that would unlock DG's ability to fully monetise its value.

With the above advice in mind, Manawa recommends the NZES focuses on:

- supporting the progression of reforms to evolve the wholesale market arrangements, as recommended to date by the Authority's Market Development Advisory Group (**MDAG**),
- developing a Government Policy Statement (**GPS**) that sets expectations for the regulators around priority reforms and gives flexibility to respond as problems become clearer,
- improvements to network regulations to:
    - facilitate timely and efficient upgrades in transmission and distribution infrastructure,
    - provide better access terms for both new and existing load and generators,
    - update reliability standards to ensure they align and reflect consumer expectations across transmission and distribution networks, and
    - recognise the contribution of non-network alternatives to meeting updated reliability standards,
- new measures to promote demand response and other flexibility initiatives as alternatives to generation and network investment, and
- improved regulatory and market stewardship.

Manawa is <u>not</u> supportive of structural changes to the wholesale market and does not consider there is any evidence to support suggestions for structural reforms at this time.

Manawa's recommendations are summarised in further detail below.

Suggested measures to address issues raised in Part 1: Growing renewable generation	
Implementation of NZES objectives	Manawa recommends the NZES provides for the issue of a GPS setting out the Government's priorities for the next decade (including guidance to its regulators on how trade-offs between its aspirations should be made). This instrument can then be updated to address new insights and developments as they emerge. Manawa also suggests that the NZES objective of "affordability" be replaced with "cost effectiveness" (which can be more readily assessed).
New renewable generation	Manawa recommends the Government: a) provide stakeholders with as much information as possible about forecasted demand growth, b) consider what steps it might take to shorten the development time for new investments, but otherwise, c) rely on the market to determine the timing and mix of new renewable generation.
Existing renewable generation	DG's ability to receive reasonable access and consenting terms would be assisted if a GPS acknowledged the role that distributed energy resources (including DG) play in meeting NZES objectives and required regulatory agencies to ensure that these resources do not face barriers.

Large scale flexibility	The Authority and Commerce Commission need to be given a specific action to address barriers to large scale flexibility (including DER and demand response) with a timeframe for delivery.
Suggested measures to address issues raised in Part 2: Competitive markets	
Weakened competition in supply of firming capacity as thermal exits	Manawa recommends that the Government reinforce the priority of existing workstreams to address potential market power issues but does not undertake extra measures such as mandated ring fencing of generation assets, virtual asset swaps or physical break-up of generation capacity or introduce a single buyer.
Suggested measures to address issues raised in Part 3: Networks for the future	
Improve regulatory cohesion and alignment	Amend the statutory objectives of the regulators and provide clearer (ongoing direction) on respective priorities for each regulator through a GPS.
Grid investment test	Invite the Commerce Commission to reassess the Grid Investment Test after its statutory objective has been changed to take into account the NZES.
Grid reliability standards	Invite the Commerce Commission and the Authority to jointly assess the appropriateness of the current grid reliability standards and quality paths to ensure that end users expectations of reliability are met. Ensure that opex allowances will support the contracting for non-network services to meet the new standards pending network upgrades.
Transmission pricing	Replace socialised pricing of particular transmission projects through the GIDI fund with a longer-term solution such as legislated transmission pricing principles.
Connection to core grid	Invite the regulators to monitor progress on access requests to core grid to ensure the shortest possible development time for projects.
Extend and simplify price regulation for distributors	Bring all distributors into the same simplified price quality path regulatory regime which includes a fast-track approval process for those distributors who meet conditions that align with NZES objectives. Ideally this would include matters currently regulated by the Authority.
Regulate connection access and pricing for all access seekers	Require the Authority to develop a new access regime for load which provides standardised and streamlined process for some access seekers and a bespoke arrangements such as a negotiate arbitrate model for large load. Ensure that all connected parties (including DG) have access to an efficient dispute resolution process for access disputes
Distribution pricing/REZ zones	Legislate 'good enough' distribution pricing principles so the industry can move on from a tortuous reform process. This could include guidance on how efficiently over-sized assets should be recovered.
Suggested measures to address issues raised in Part 4: Responsive demand and smarter systems	
Improved government direction and support	Include in GPS a clear statement of the priority afforded to the development of flexibility markets, including those basic hygiene matters that should be addressed as a first priority such as establishment of standards for connection of DER resources, communication protocols and access to necessary data.
Enforce new network reliability standards	Require Commerce Commission and the Authority to work together to ensure that non-network alternatives that add value to the system are identified and rewarded.
Develop suitable trading platforms	Partner with industry to identify and develop suitable trading platforms for the trading of flexible resources.

Suggested measures to address issues raised in Part 5: Whole of system considerations	
Improved regulatory and market stewardship	Government should engage in more active regulatory and market stewardship using the mechanism of a GPS to both provide initial direction and, over time, address any missteps.

If you have any questions regarding the content of this submission, please contact Grace Burtin, Regulatory Manager.

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KAIMAI CASE STUDY

Version Final – 31 October 2023

1 Background

The Kaimai hydro scheme (Kaimai) dates back to the 1925 when the McLaren Falls power station was built by the Tauranga Borough Council to supply the Tauranga Borough and the newly created Tauranga Electric Power Board. Between 1972 and 1994 four additional stations were built with a capacity of 42 MW. With the commissioning of the Ruahihi Power Station, replacing McLaren Falls, the original power station was decommissioned. Kaimai was originally built to meet peak demand requirements for the Tauranga area and therefore has very reliable daily peaking capability.

Kaimai is connected to Powerco's network at Powerco's Greerton substation, which is about 700 m from Transpower's Tauranga substation. The generation from Kaimai connects via Greerton to TGA0331.

Figure 1 shows the local 110kV network in the Tauranga area showing the connection of Kaimai generation via CB2152 and CB2442 at Transpower's Tauranga substation.

The 110 kV circuits highlighted in yellow are connection assets under the Transmission Price Methodology (**TPM**) and those highlighted in blue are interconnection assets.

The lines between Tauranga and Kaitimako are reliant on Kaimai generation to operate at peak times to maintain N-1 security. An outage of either of the circuits connecting the Tauranga substation at peak times would result in loss of the entire Tauranga GXP if Kamai was at low generation levels.

2 Treatment of Tauranga circuits under GRS

The **grid reliability standards** require Transpower to invest to maintain N-1 security in the **core grid**.

The 110 kV Mt Maunganui to Tarukenga and 110 kV Tarukenga to Tauranga links are specified as part of the **core grid** in schedule 12.3 of the Code. However, when the **core grid** was defined Kaitimako substation did not exist with the lines constructed at 220 kV between Kaitimako and Tarukenga being operated at 110 kV. Transpower believe that with the commissioning of the Kaitimako interconnection substation the 110 kV network feeding Tauranga substation is no longer part of the core grid, and as a result is not subject to the requirement to design the grid to a N-1 standard and is only required to meet the requirement of clause 2(2)(a) but not 2(2)(b) of schedule 12.2 of the Code.

> **2 The grid reliability standards**
>
> (1) The purpose of the **grid reliability standards** is to provide a basis for **Transpower** and other parties to appraise opportunities for transmission investments and **transmission alternatives**.
>
> (2) For the purpose of subclause (1), the **grid** satisfies the **grid reliability standards** if—
>
> (a) the power system is reasonably expected to achieve a level of reliability at or above the level that would be achieved if all **economic reliability investments** were to be implemented; and
>
> (b) with all **assets** that are reasonably expected to be in service, the power system would remain in a **satisfactory state** during and following a **single credible contingency event** occurring on the **core grid**.
>
> (3) For the purpose of subclause (2)(a), the expected level of reliability of the power system must be assessed at each and every **grid exit point** and **grid injection point** (wherever located on the **grid**).
>
> (4) For the purpose of subclause (2)(a) and (b), the expected level of reliability, and state, of the power system must be assessed using the range of relevant operating conditions that could reasonably be expected to occur.
>
> Compare: Electricity Governance Rules 2003 clauses 3 to 6 schedule F3 part F

Box 1 - Clause 2 of Schedule 12.2 of the Code

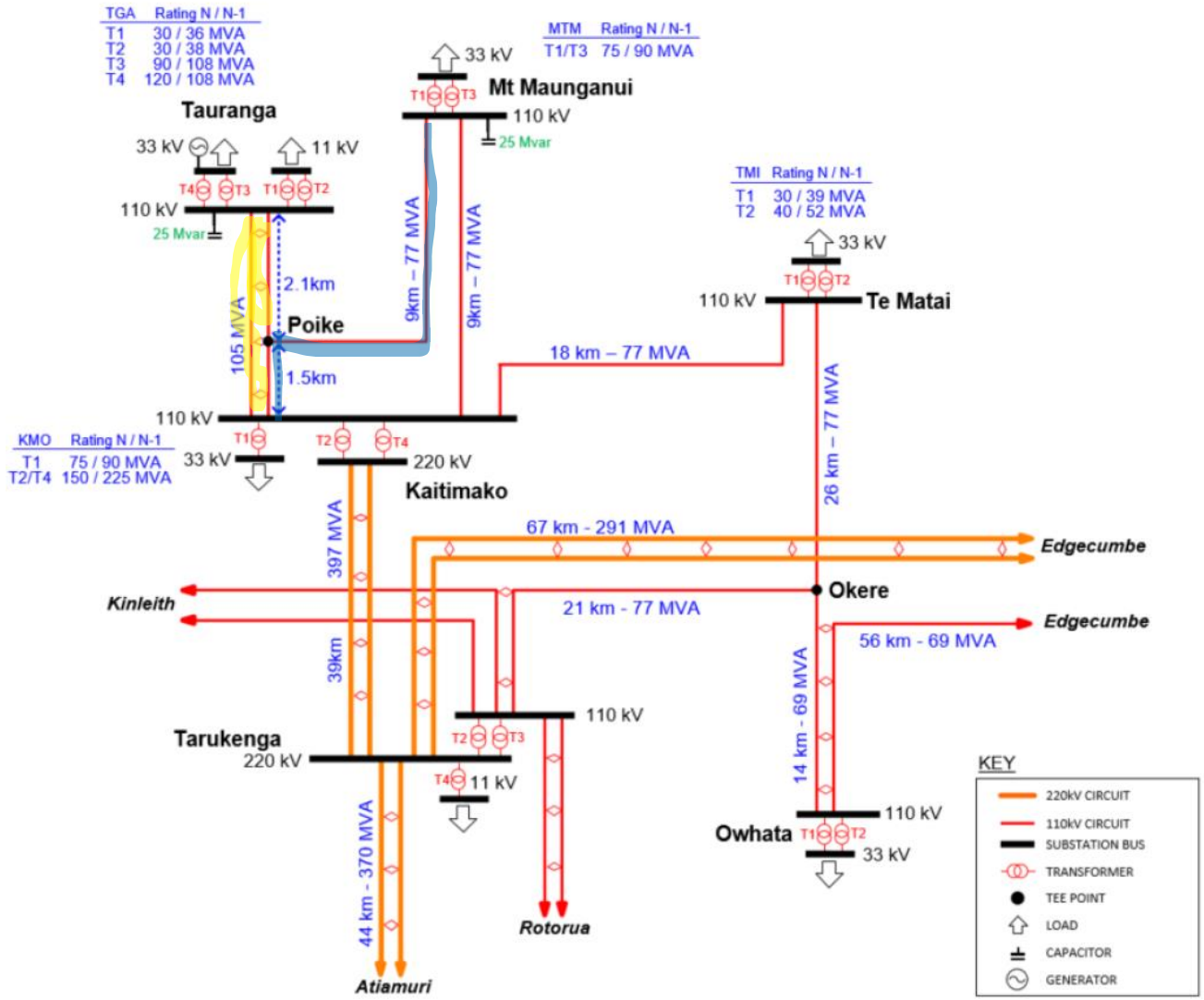


Figure 1 - Transpower Bay of Plenty Network

The **grid reliability standards** have not been amended, so it would be hard to argue that the 110 kV lines are still not part of the **core grid**. The original decision by the Electricity Commission in setting the **core grid** was to include links that provide N-1 for loads above 150 MW. With the addition of the Kaitimako interconnection, the risk of loss of supply has decreased and potentially trigger a review of the links included in the **core grid**. However the total gross load at Tauranga still exceeds 150 MW. In 2022 this occurred in 431 trading periods.

3 Responsibility for Tauranga Reliability

Given the mix of connection and interconnection assets in the lines feeding Tauranga substation I believe there is joint responsibility between Powerco and Transpower in maintaining reliability for Tauranga load customers.

Transpower is required to meet the **grid reliability standards** and Powerco must meet minimum service quality standards set by the Commerce Commission and detailed in schedule 3 of the Default Price-Quality Path Determination. The standards include the standard reliability measures of SAIDI and SAIFI. However, the measurement of SAIDI and SAIFI does not cover outages of Transpower's connection assets. Transpower required to meet the **grid reliability standards** in respect of connection assets but in practice is will not invest in new connection assets without a Transmission Works Agreement with the **customer**.

3.1 Grid Reliability Standards

Clause 12.36 of the Code requires the approval of the Authority if it proposed to operate below the **grid reliability standards** for a particular **grid injection point** or **grid exit point**.

4 Electricity Commission Core Grid Determination

4.1 Discussion Paper

In June 2005 the Electricity Commission published a discussion paper[1] on its proposed **core grid determination** as required under Part F of the EGRs.

This paper proposed that the N-1 test be limited to a loss of supply of 300 MW.

Box 2 describes how local generation is considered when determining the contribution to security of supply. The Tauranga GXP would be fit into the category 'Radial Feed with generation'. In this first iteration of the **core grid determination** the definition of Kaimai as 'Reliable Generation' or otherwise is irrelevant as the 300 MW limit was well above the load in the Tauranga/Mt Maunganui area with or without Kaimai generation.

The resulting proposed **core grid determination** did not include the lines feeding the Tauranga area from Tarukenga. It also did not include these lines when assessing under a 150 MW limit.

[1] https://ndhadeliver.natlib.govt.nz/webarchive/20091121182012/http://www.electricitycommission.govt.nz/consultation/coregrid

Table 5: Practical approach to assessing cascade failure objective

Transmission Link	Description	Core Grid Determination that would be consistent with cascade failure objective
Radial Feed	Radial transmission link feeding an area without generation.	Transmission link is part of Core Grid if peak load in the area is greater than A[8].
Radial Feed with generation	Radial transmission link feeding an area with generation.	Transmission link is part of Core Grid if peak load in the area, minus reliable generation[9], is greater than A.
Radial Generation	Radial transmission link providing a connection to generation.	Transmission link is part of Core Grid if loss of the generation in-feed would lead to loss of load greater than A.
Parallel Link	Transmission link running in parallel with other transmission links	Transmission link is part of Core Grid if loss of the link would lead to loss of load greater than A.
Meshed Link	Transmission link in a meshed part of the grid	If the load at a node minus the reliable generation at the node is greater than A, then there must be at least one Core Grid link connected to that node.
HVDC Link	HVDC transmission between the islands	HVDC is part of Core Grid if loss of the link would result in a loss of load greater than A.

Box 2 - Extract from Discussion Paper

[9] Reliable generation excluded intermittent generation such as wind and run-of-river hydro, except to the extent that diversity of supply would provide a reliable supply. Thermal power stations were assumed to have full fuel availability.

Box 3 - Definition of Reliable Generation

In the discussion paper the Electricity Commission concluded that there is no need for consistency between the definition of the **core grid** for the purposes of the **grid reliability standards** and the definition of **interconnection assets** for the purposes of determining transmission pricing. This implies that a **connection asset** such as the links highlight in yellow in Figure 1 could be defined as **core grid** and need to meet the N-1 standard, unless approved otherwise by the Authority.

4.2 Explanatory Paper

Following the receipt of submissions, the Electricity Commission published an explanatory paper on 24 August 2005.[2] This paper responding to those submissions.

The paper:

(a) reinforced the Electricity Commission's view that the Bay of Plenty was not a main load centre[3];

(b) suggested there is no need for consistency between the **core grid determination** and the definition of interconnection assets; and

(c) concluded that most submitters supported a wider definition of **core grid.**

As a result, the use of the 300 MW loss of supply test was not changed. There were some minor changes to the core grid links.

A short period of time was allowed for final comments from interested parties.

[2] https://ndhadeliver.natlib.govt.nz/webarchive/20091121182012/http://www.electricitycommission.govt.nz/opdev/transmis/gridreliability/

[3] para 3.8 of the Explanation Paper.

4.3 Second Round Consultation

The Electricity Commission published a second round of consultation on 21 October 2005[4].

In this consultation the Electricity Commission proposed to reduce the loss of load criterion to 150 MW, and revised the definition of 'reliable generation' as seen in Box 4. As a result the 110 kV lines from Tarukenga to Tauranga and Mt Maunganui were included in the new proposed **core grid determination**.

> [14] The methodology applied for this discussion paper is slightly different to that applied to the original discussion paper. Reliable generation excludes intermittent generation such as wind and run-of-river hydro, and in isolated regions with relatively limited diversity of generation sources, where it is unlikely that a stable post-contingent generation/load island would develop, it is assumed that no generation is available. Thermal power stations were assumed to have full fuel availability.

Box 4 - Revised Definition of reliable generation

4.4 Revised Explanatory Paper

The Electricity Commission published a revised explanatory paper in December 2005[5].

This paper summarised the submissions to the second-round consultation and confirmed the core grid as in that consultation, including the 110 kV lines into Tauranga would be included.

5 Situation Today

5.1 Grid Reliability Standards

The Code provisions for the **grid reliability standards** and the definition of the **core grid** have not changed since originally incorporated into the EGRs.

It is my view that both Kaitimako to Tauranga 110 kV links are **core** grid because:

(a) both links are still listed in Schedule 12.3 of the Code; and

(b) if the same rules that applied when the Electricity Commission originally determined the **core grid,** were re-applied the Tauranga grid exit point would still qualify as a result of the gross load now expected to be above 150 MW from 2025.

Figure 2 is taken from Transpower's 2022 Transmission Planning Report[6]. It shows the gross demand at Tauranga reaching 150 MW in about 2025.

4 https://ndhadeliver.natlib.govt.nz/webarchive/20091121182012/http://www.electricitycommission.govt.nz/consultation/revcoregridoct05

5 [Insert link to National Library]

6 https://static.transpower.co.nz/public/uncontrolled_docs/2022%20Transmission%20Planning%20Report.pdf?VersionId=v6h_P0VwhmysBEpp3OGicM1aj4Fr_OZ

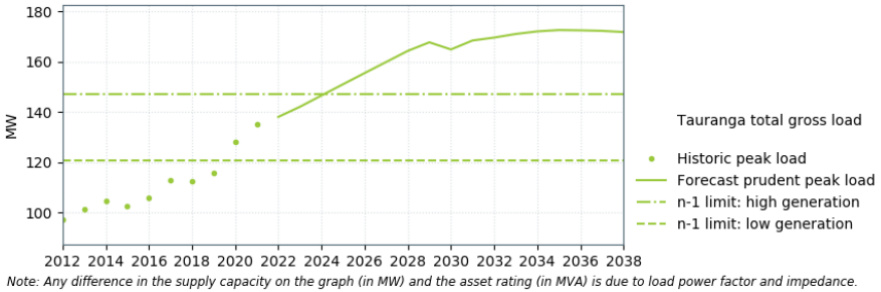


Figure 2 - Kaitemako-Tauranga transmission capacity

Actual gross demand at Tauranga GXP has actually reduced in the last two years. Figure 3 shows the peak gross demand at Tauranga and the number of trading periods where this exceeded N-1 security with no Kaimai generation. This peaked in 2021 when there were 474 trading periods where gross load exceeded 106 MW[7].

The reduction in the past two years has been caused by the transfer of load from Tauranga to Kaitimako 33 kV (approximately 20 MW increase at Kaitimako). Transpower's Western Pay of Plenty Development Plan: long-list consultation[8] suggests that this is not a long-term solution with load being transferred back to Tauranga GXP from 2027 as loads on Powerco's 33 kV network increase. In addition the peak load on the Tauranga 33 kV transformers is expected to exceed N-1 capacity even with full Kaimai Generation.

[7] The N-1 capability of the 110 kV lines supplying Tauranga GXP is 106 MW (winter capacity).

[8] https://static.transpower.co.nz/public/uncontrolled_docs/WBoP_Development_Plan_MCP_long-list_consultation-Attachment-1.pdf?VersionId=hd641WbeKKuzfutqMswqwbd9BWMA_cDo

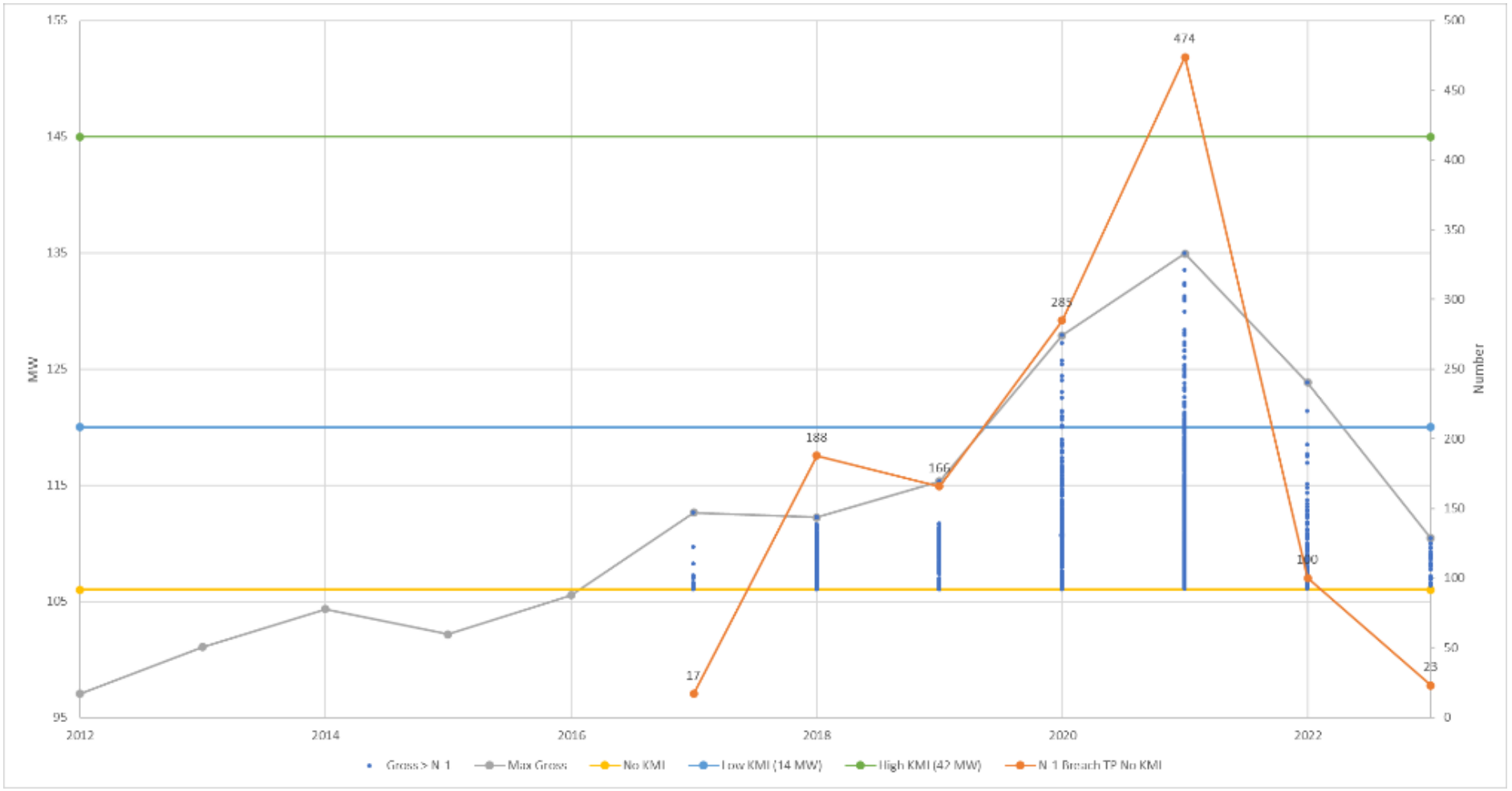


Figure 3 - Tauranga Substation N-1 exceedance

6 Transpower Major Capex Proposal

Transpower has begun consultation as required under the Commerce Commission's Major Capex process for investments over $20 million. It has published and received submissions on the long list of options.

The consultation paper argues that considerable investment is required over the next ten years with a step change in load at Tauranga GXP post 2025. Although the eventual transmission solution may negate the need for N-1 support from Kaimai, it is clear that Kaimai generation will have a key role to play in the period until new assets are built. Kaimai clearly will have an increasing role in supporting N-1 during this transition period.

7 Kaimai Support

Prior to the new TPM that came into effect from 1 April 2023 Kaimai was incentivised to generate at times of maximum demand in the Tauranga area through the payment of ACOT. Because Manawa was paid to support Tauranga and the wider area demand during peak demand periods Transpower could reasonably expect Kaimai to be generating at near to maximum capability during peak demand periods. This is no longer the case. Kaimai is only incentivised to generate to maximise spot energy revenue. In 2023, even though the average monthly generation over the peak demand winter period was higher than normal due to favourable hydrology conditions, the average generation during the maximum demand periods (greater than the N-1 limit of 105 MW) was lower than previous years.

Figure 4 is an example of the change in incentives for Kaimai operation under the previous TPM with RCPD signalling and the present incentives which is only to maximise spot revenue. Figure 4 shows in blue the top 100 RCPD periods for the Upper NI and in orange the actual generation from Kaimai during each trading period. In grey is the estimated generation from Kaimai during each of the top 100 RCPD periods if Kaimai was perfectly operated in the highest price trading periods on each day.

As can be seen there are a 18 periods where Kaimai would not have operated if only incentivised by price.

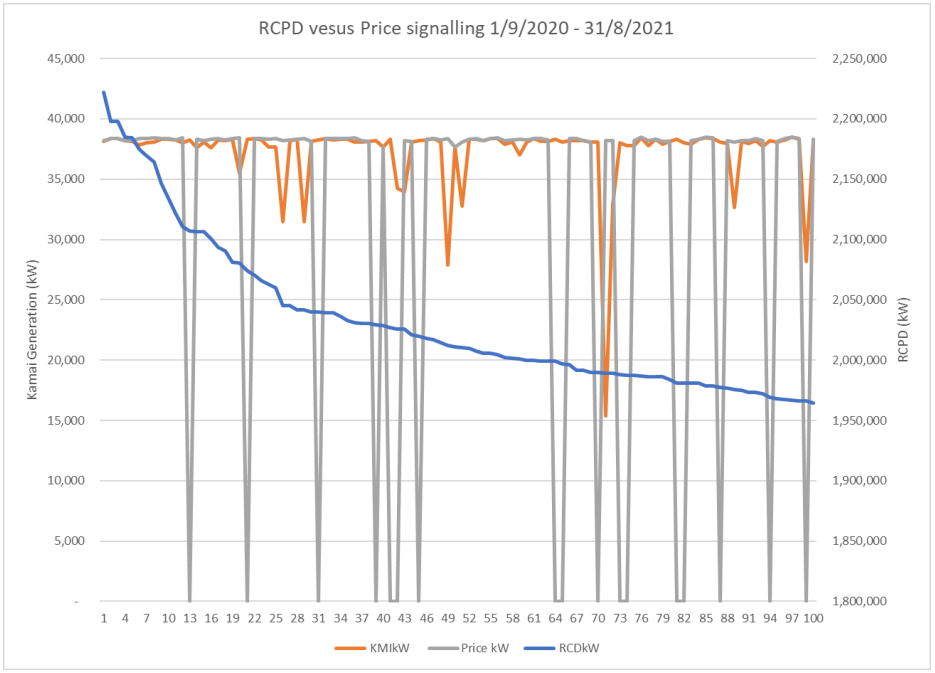


Figure 4 - Incentives on Kaimai Operation

8 Conclusions

With the lines feeding Tauranga from Kaitemako being a mixture of connection and interconnection assets there appears to be confusion as to whether Transpower, Powerco or both are responsible for the reliability of these assets.

Thus:

(a) there needs to be clarification of the responsibility of distributors and grid owners for reliability particularly where there is co-mingled assets;

(b) it should not be possible for a load centre the size of Tauranga to have a risk that neither network owner is accountable for reliability;

(c) as a minimum the regulators should agree the quality standards that apply on this set of assets; and

(d) more broadly the quality standards under price-quality path and the grid reliability standards (and associated definitions) may need to be reviewed to ensure they are fit for purpose.

This is an important first step to assessing whether networks companies are using non-network alternatives appropriately.

9 Glossary

Words in bold have the meaning in the Code.

Term	Definition
Authority	Electricity Authority
Code	Electricity Industry Participation Code
EGRs	Electricity Governance Rules 2003
TPM	Transmission Pricing Methodology in Schedule 12.4 of the Code

Barriers to getting the full value from Distributed Generation (DG) in a highly renewable electricity system

Toby Stevenson, David Reeve and Corina Comendant

October 26 2023

Executive Summary

Distributed generation plays an important role in providing New Zealand with a low-emissions, reliable, and affordable electricity. These benefits have not been well recognised.

Distributed generation (DG) is any generation using any technology that generates electricity at or near where it will be used.

Regulation and commentary on the merit of various forms of electricity generation often ignores mid-scale distributed generation (DG). The reality is that mid-scale DG provides some benefits that large-scale generation cannot. By definition, DG draws on fuel supply close to the load it serves, and thus reduces transmission costs and contributes to local resilience.

In the past few years, New Zealand has made international commitments and adopted a clear framework for pursuing emissions reductions. At the heart of the imperative lies electrification of transport and industrial processes, while simultaneously aiming for increasingly higher levels of renewable electricity. The value of our fleet of renewable distributed electricity generation is raised as a result, even though regulation and connection issues has the potential to undermine further investment in such generation investment.

In this paper we discuss some of the barriers to getting the full value from Distributed Generation (DG) in a highly renewable electricity system. Barriers apply to getting the full value from both existing DG and new investments.

Regulatory settings have not always acknowledged the value of DG. DG investments need certainty and a level-playing field

The regulatory approach to DG is a muddle. Now more than ever existing DG needs to be able to operate efficiently, new investment in DG needs to be able to connect to the network and, in both cases, DG needs to be able to monetise all of its value. This is not where we find ourselves.

Failure to recognise the full value of DG in the early 2000s led to the development of the DG connection regulations (now Part 6 of the Code). Below we summarise the regulatory challenges DG face but the key issue hampering DG is the absence of an enforceable standard on network reliability, so that DG can be accommodated alongside new generation coming into the grid.

Failure to give DG equal access and monetise its benefits undermines 11% of New Zealand's current electricity generation, including 4% that is currently supplied by hydro DG. It also jeopardises new DG investment.

The source of the challenges for existing and new DG to achieve the value

Existing mid-scale DG and new investment in DG face challenges to realising its full value as a result of the regulatory environment. The challenges arise from a combination of:

- the nature of existing regulation including convoluted clauses and lack of clarity. For example it is not clear when DG has to meet technical Code requirements or not and it is possible that DG could be charged more than incremental cost under Part 6 due to unclear clauses
- multiple regulations impact on DG each subject to their own interpretation. For example DG could be subject to Parts 6, 8, 12, and 13 of the Code, especially if relatively large
- the added complexity of having two different regulators: one setting standards the other seeking consideration of non-wire alternatives,
- the interpretation of regulation and the particular lack of governance and compliance on distribution compared to transmission. For example there is little accountability for a distributor's pricing methodology, and none for its operating standards, or congestion management
- the absence of regulations in some cases, for example, any requirement for economic dispatch within a distribution network, and
- the failure to date of market mechanisms to emerge that would unlock DG's ability to fully monetise its value, where, for example, DG cannot benefit from loss reduction, helping manage congestion, and where ACOT is practically impossible to access, there is generally no incentive for distributors to investigate ACOD.

1. History of DG

The distinction between transmission and distribution is an artefact of the past used to determine grid ownership

Distributed generation (DG) is any generation using any technology that generates electricity at or near where it will be used. In the early days of electricity development, power stations were developed locally and there was no grid. Generation investment was, by definition, distributed.

Some definitions of DG are narrowed to only include network connected or embedded generation but that tends to be specific to the application of some regulations.

Government set the arrangements delineating transmission and distribution in the 1920s. The Government would build the bulk of power stations and transmission. Power boards would build distribution. The boundary was agreed between the Government department and the local power boards. Therefore, there is no clear engineering distinction between transmission and distribution.

The category of assets called sub-transmission is above distribution level but not owned by Transpower. Neither voltage nor capacity give clear guidance on whether an asset is owned by Transpower and is, therefore, 'the grid'.

Access arrangements for DG are a creature of distribution network ownership rather than power system characteristics

By 1934, the North Island had a joined-up 'grid' linking three new hydroelectric power stations - Mangahao (Manawatu), Tuai (Lake Waikaremoana) and Arapuni (Waikato River). By 1938, power from the Waitaki River hydro scheme joined a network connecting two-thirds of the South Island - from the West Coast to Canterbury through to Otago and Southland.

In 1960, the government decided to construct a line sending South Island power to the North Island. It would run from the 540MW Benmore hydro station (New Zealand's biggest before Manapouri), then being built, to a substation in the Hutt Valley. The cable was complete in 1965 and at over 600 kilometres, including 40 under water, it was the longest HVDC link in the world at the time.

By the 1970s the national transmission grid as we know it today was fully operational and power was available to 99% of the population.

Thus, access arrangements for DG are a creature of distribution network ownership and the relationship to the evolution of the grid rather than power system characteristics

2. A timeline summary of how the regulatory environment for DG got to where it is today

DG has been faced with distribution network access delays and regulatory uncertainty since 1998

Excerpt from Trustpower's submission on the Electricity Price Review - October 2018

Access for DER (including DG)

Introduction

It is common ground that distributed energy resources (**DER**) will become an increasingly important part of New Zealand's energy mix as it plans the transition to a low emissions future, just as distributed generation (**DG**) was an important part of the supply solution when New Zealand was concerned about supply shortfalls in the mid 2000s.

DER includes traditional forms of DG such as wind and small hydro, small standalone diesel generation and domestic or commercial photovoltaic solar generation connected into local distribution networks as well as new technologies such as batteries and new forms of energy management and demand response.

It is therefore important that the regulatory frameworks which govern DER, including those that provide access to distribution networks have the stability and predictability required for investment in long life assets.

Our experience of recent DG reform has raised issues about whether this is currently the case.

History of DG regulation

A brief history of DG regulation is set out in the following table:

Pre 1998	Energy supply businesses were provided incentives to invest in generation close to load in the form of lower charges for wholesale energy.
1998	Lines energy split meant that new access contracts were entered into between: • distributors and retailers • distributors and DG
	In some cases part of the sale consideration for the retail businesses involved a transfer of the right to receive the benefit of lower transmission charges.
2000	Caygill Inquiry raised the prospect that the incentives on distributors to enter fair and reasonable access contracts was weak.
2008	Following an unsuccessful attempt at developing an industry approach to improving the terms for DG access, the Government stepped in and directly regulated access terms. The approach adopted was a legislated default contract which applied if contractual terms were not agreed.
2012-15	The Electricity Authority identified a concern with the legislated default terms following its receipt of submissions on its 2012 TPM proposal and consulted on the impact of that matter in a TPM working paper.
2016	The Electricity Authority proposed the removal of the default price terms (known as Distributed Generation Pricing Principles (**DGPPs**)) from the Code. This was followed by a decision to defer change to some elements of the DGPPs and amend others. The amendment to the DGPPs comes into effect on a staggered basis for the four transmission pricing regions from 1 April 2018 to 1 October 2019. There was no consultation on the Code amendments, which implemented this decision.
2017-20	The reform process has resulted in a patchwork of access terms depending on the extent to which the default or bespoke terms govern existing access arrangements and whether the distributor is price regulated or not. Further, expert advice has demonstrated that the Electricity Authority's original assessment as to the contribution existing DG was making to the power system understated its benefits, significantly reducing confidence in its assessment that urgent reform was needed to existing DG arrangements to protect consumer interests.
Unknown	The Electricity Authority has indicated that it plans to further review the access terms that apply for DG no later than five years after the new arrangements have commenced in each transmission pricing region.

3. Regulatory challenges facing DG today

Summary of the regulatory challenges DG faces today

The regulatory challenges that DG faces are not consistent, for example, residential solar PV faces far less challenge than larger renewable projects with new technology. The full range of challenges fall across the attributes shown below.

Distribution	Transmission
Connection – initial and ongoing access	Connection – initial and ongoing access
Payment – for network services to and from distributors	Payment – for true ACOT and ancillary services
Congestion	Congestion
Connection and operation standards	Grid reliability standards

Connection

Distribution

- Part 6 of the Code facilitates connection of DG, but the regulations are not always clear and have some problems, especially for larger DG (>10kW)
- Part 6 allows a distributor to approve connection on a first come first served basis for a period that allows an investor to then secure finance, however the distributor can also (intentionally or accidentally) convey an enduring property right, blocking other investors even if the first investor doesn't go ahead. A distributor's own project could be the beneficiary of such an agreement

Transmission

- DG over 30MW must, and DG over 1MW may need to, meet code requirements. These requirements primarily relate to frequency response but the SO also applies a pragmatic definition of requirement to voltage ride through
- The Code is out of date and is written on the basis that DG is relatively uncommon, therefore the burden of problems that may be due to a quantum of small DG could fall on larger DG
- The Code is written for synchronous rotating plant with exceptions for wind generation, some of these exceptions don't yet apply to other new technology and could be unnecessarily restrictive; not recognising either the differing limits for new technology or new capability that could support the power system, including through access to ancillary services

Payment - distribution

Distribution

- Part 6 requires that only incremental costs are charged for DG connections and "… must include consideration of any identifiable avoided or avoidable costs." Part 6 anticipates that incremental costs can be negative (and the DG is providing network services) but there is no incentive for the distributor to robustly assess this and there is no compliance regime
- An exception to DG only paying incremental cost is where multiple generators share an investment. This was probably supposed to be permissive and allow a DG to opt to pay more upfront for a shared investment where they were paid back (and less overall) once other DG connected. However, this is not clear and could be used by a distributor to require DG to share an investment where they all might incur more than incremental cost
- The reduction of network losses is a benefit of DG but distributors are not exposed to losses or required to minimise them. Losses can be an avoidable cost that DG cannot access.
- Distributors are asking for, and the EA is considering, making DG pay from incremental to standalone cost. However, standalone cost from a monopoly business is a complex concept and could simply be used to move common costs to DG – exceeding true standalone cost. Noting that community owned distributors have incentives to cross-subsidise residential customers from others

Payment - transmission

Transmission

- In developing the TPM the EA chose to eliminate the previous ACOT payments. This has led distributors to consider that they shouldn't pay ACOT, however, the new TPM was supposed to create the right incentives to do so when beneficial. The mechanism is supposed to be through the Beneficiary Based Charges (BBC) where DG in a scarce location could offset or delay the need for a Benefit Based Investment and, therefore, the BBC. However, the BBCs are so complex and unpredictable that a distributor could not identify when, or how much, ACOT would be efficient
- Being anchored to 1990s standards and performance in the Code limits the contribution of new technology to ancillary services and slows development of new ancillary services

Congestion

Distribution

- Distributors are required to have Congestion Management Policies but have little guidance on how to approach these. Distributors don't have experience in dynamically managing energy flow on their networks and so CMPs are of minimal merit. Some distributors and other parties are investigating better mechanisms (such as dynamic operating envelopes) but the regulations are lagging far behind
- It is highly likely that most congestion managed under current regulations will be overdone and uneconomic

Transmission

- Congestion is managed on the transmission network through nodal pricing. However, where DG participates in the market through an distributors network then multiple DG gets the same price signal. Where they have the same offer price then the SO must apply an arbitrary dispatch allocation. If at least some distribution network information was included in the pricing model (such as network losses and capacity limits between GXPs and DG) then economic dispatch could still occur

Operation and standards

Distribution

- Distributors must publish their connection and operation standards but have little guidance on how to approach them and limit changes. This was a major bone of contention with the original transmission agreements as it gave the network owner a unilateral right to change terms and conditions of the contract. Distributors should have stronger guidance on the connection and operations standards and there should be a process which guides how they can change them. There should also be a dispute process

Transmission

- The Grid Reliability Standards ended up being another convoluted approach in the Code. The GRS are deemed to be the standard at which every economic change to reliability has been done, except that the standard cannot fall below N-1 on the core grid. This is best explained in that Transpower can only change a level of service (up or down) if it is economic to do so (but limited to N-1 on the core grid). However, when the Authority was seeking to restrict ACOT to DG Transpower did not apply an economic test but only an N-1 test. This improper approach to the GRS was endorsed by the Authority, which then further entrenched its view on the value of ACOT

Case study Waipori Power Scheme

Waipori Power Scheme

- The Waipori Power Scheme consists of four power stations originally commissioned to power Dunedin in 1907. Waipori is currently connected to both the distribution network and the transmission network - also known as the national grid. Two stations are connected to Aurora's distribution network and two are connected to the grid on Transpower's 110 kV line.

- In fact, the two machines on one of the stations can switch between the distribution network and the grid which shows the challenge created in relying on an arbitrary delineation. From an engineering perspective, there is no clear distinction between the two types of networks. The distinction is an artefact of the past when it was used to identify parties that contracted directly with the grid owner i.e. Transpower.

The distinction between connection status survives for no compelling reason

- **The current 'definition' of Waipori connections are an outcome of changes in the regulatory settings of the NZ power system, not of changes in the significance of services that Waipori provides.**

- Generally, sub-transmission assets are lower voltages than 'the grid' but this is not always the case. **Neither voltage nor capacity give clear guidance on whether an asset is owned by Transpower and is, therefore, 'the grid'.**

- **The reason an arbitrary distinction was continued in our modern arrangements is because the original wholesale electricity market was a voluntary arrangement under light-handed regulation.** This could only work because Transpower could require any party that transported energy across its network to belong to either the Metering And Reconciliation Industry Agreement (MARIA) or the Rules of the New Zealand Electricity Market (NZEM). Therefore, the original trading rules for 'the grid' could only apply to those parties who connected to, and had to contract with, Transpower. With reregulation in 2003, which mandated participation in the Code, there was no compelling reason to change the definitions.

The distinction between transmission and distribution needs to be reviewed

- Power system connections are still based on what makes engineering sense, which often means that upgrading existing connections makes more sense than establishing new ones.

- Waipori has always provided critical services to both transmission and distribution in the Dunedin region. It offsets peak demand on Aurora's Halfway Bush connection assets. It provides stability in a relatively weak 110kV network that is also susceptible to constraints.

- Regional stability and peak management are critical services in facilitating the electrification of loads around Dunedin and South Otago, reducing the need for expensive transmission and distribution upgrades. Since Aurora's Halfway Bush connection has been supplied by the 220kV line on the grid Waipori's contribution may not be as great as in the past but its historical role still serves as an example of the role mid scale DG plays.

Case Study
Kaimai hydro scheme
Calderwood Advisory Limited
25 October 2023

Kaimai hydro scheme

Provided by Calderwood Advisory Limited

Peter Calderwood has provided a case study on the Kaimai hydro scheme. This illustrates the real issues facing one mid scale hydro DG under the current set of arrangements.

The Kaimai hydro scheme is connected to Powerco's network at Powerco's Greerton substation. The generation from Kaimai connects to the grid via Greerton to Transpower's Tauranga substation TGA0331.

Peter observes that the Code provisions for the **grid reliability standards** and the definition of the **core grid** have not changed since originally incorporated into the Electricity Governance Regulations (2003).

The situation today (1/2)

Arguably Kaitimako to Tauranga 110 kV links are **core grid** because:

a) both links are still listed in Schedule 12.3 of the Code; and

b) if the same rules that applied when the Electricity Commission originally determined the **core grid** the Tauranga grid exit point would still qualify as a result of the gross load now expected to be above 150 MW from 2025.

The **grid reliability standards** require Transpower to invest to maintain N-1 security in the **core grid**.

- A reduction in load in the past two years has been caused by the transfer of load from Tauranga to Kaitimako 33 kV (approximately 20 MW increase at Kaitimako).
- Transpower's Western Bay of Plenty Development Plan: long-list consultation suggests that this is not a long-term solution with load being transferred back to Tauranga GXP from 2027 as loads on Powerco's 33 kV network increase.
- In addition the peak load on the Tauranga 33 kV transformers is expected to exceed N-1 capacity even with full Kaimai Generation.

The situation today (1/2)

In addition to the **grid reliability standards** and Transpower's obligations Powerco is required to maintain reliability in order to be entitled to its full regulated revenue.

Transpower argues that considerable investment is required over the next ten years with a step change in load at Tauranga GXP post 2025. Although the eventual transmission solution may negate the need for N-1 support from Kaimai, it is clear that Kaimai generation will have an increasing role in supporting N-1 through until new assets are built.

Prior to the new TPM coming into effect from 1 April 2023 Kaimai was incentivised to generate at times of maximum demand in the Tauranga area through Avoided Cost of Transmissions (ACOT) payments. Because Manawa was paid to support Tauranga and the wider area demand during peak demand periods Transpower could reasonably expect Kaimai to be generating at near to maximum capability during peak demand periods. This is no longer the case. Now, Kaimai is only incentivised to generate to maximise spot energy revenue.

Kaimai - conclusion

With the lines feeding Tauranga from Kaitemako being a mixture of connection and interconnection assets there appears to be confusion as to whether Transpower, Powerco or both are responsible for the reliability of these assets.

Thus:

a) there needs to be clarification of the responsibility of distributors and grid owners for reliability particularly where there is co-mingled assets;

b) it should not be possible for a load centre the size of Tauranga to have a risk that neither network owner is accountable for reliability;

c) as a minimum the regulators should agree the quality standards that apply on this set of assets; and

d) more broadly the quality standards under price-quality path and the grid reliability standards (and associated definitions) may need to be reviewed to ensure they are fit for purpose.

The contribution of mid scale Distributed Generation (DG) in a highly renewable electricity system

Toby Stevenson, David Reeve and Corina Comendant

October 26 2023

Executive Summary

Distributed generation plays an important role in providing New Zealand with a low-emissions, reliable, and affordable electricity. These benefits have not been well recognised.

Regulation and commentary on the merit of various forms of electricity generation often ignores mid-scale distributed generation (DG). The reality is that mid-scale DG provides some benefits that large-scale generation cannot. By definition, DG draws on fuel supply close to the load it serves, and thus reduces transmission costs and contributes to local resilience

In the past few years, New Zealand has made international commitments and adopted a clear framework for pursuing emissions reductions. At the heart of the imperative lies electrification of transport and industrial processes, while simultaneously aiming for increasingly higher levels of renewable electricity. The value of our fleet of renewable distributed electricity generation is raised as a result, even though regulation and connection issues has the potential to undermine further investment in such generation investment.

The transition to high levels of electrification and a significant increase in the proportion of supply coming from renewable electricity has its challenges. In this paper we focus on the value mid scale DG contributes to the system.

DG value streams

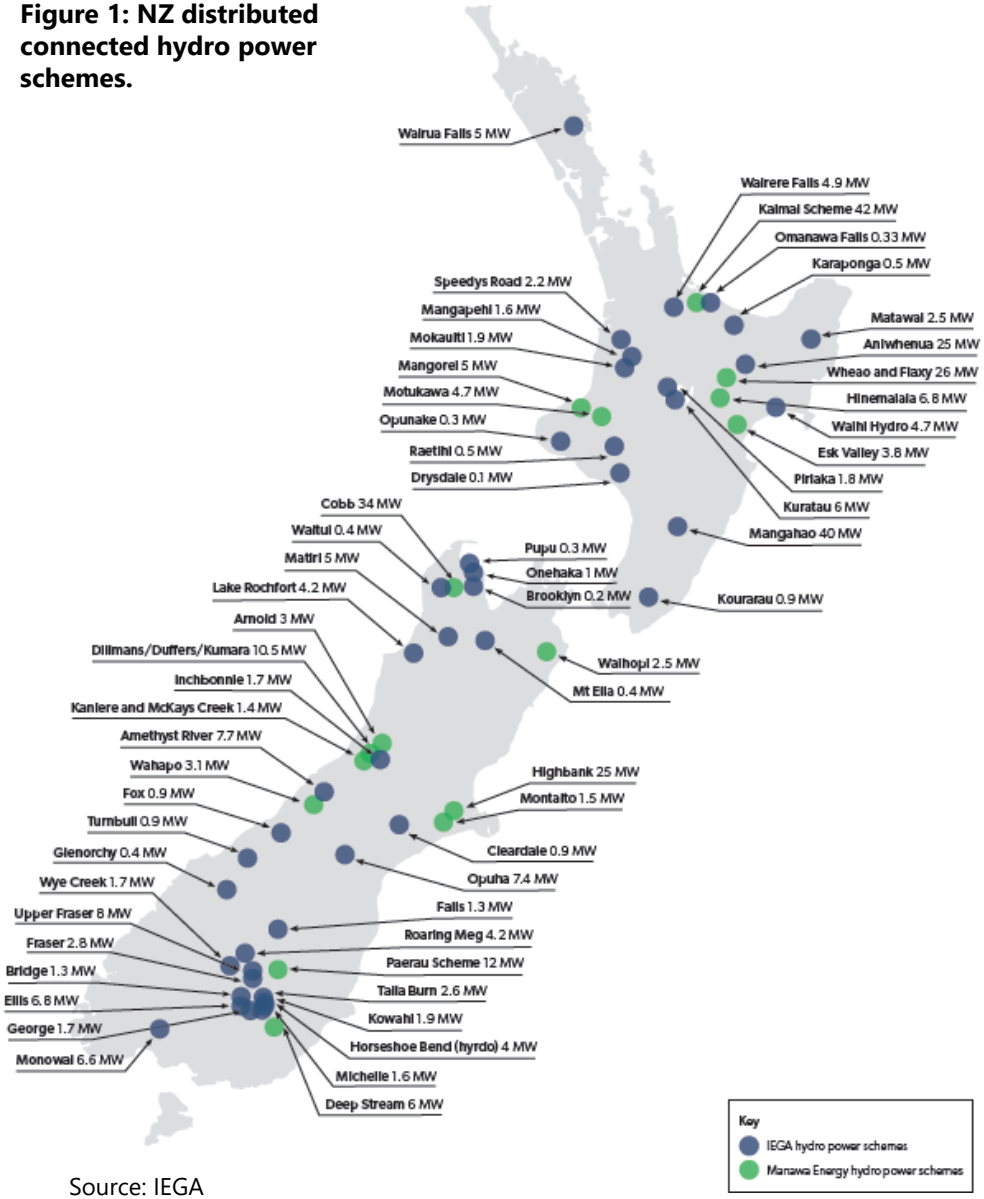
Value stream	Regional value	National value
Network investment	Defers investment in network capacity	Defers investment in transmission capacity
Security of supply	Regional security of supply and reliability is better for having local generation.	DG contributes around 11% of total national electricity production with a steady and renewable source.
System flexibility and grid stability	Embedded hydro can provide: inertia and voltage support, some black start, support during outages, quick response during events, flexibility services	DG, especially with storage, contributes to flexibility in the system and better National Grid stability than would otherwise be the case.
Wholesale prices	Regional generation lead to better regional wholesale prices.	DG provides low SRMC generation and competition
Transmission losses		System wide transmission losses are reduced by virtue of generation close to major load centres i.e. DG.
Economic development	More competitive electricity prices economic development in a region. DG owners are local employers.	
Emissions reductions	Contributes to regional/local plans for reducing emissions.	Renewable DG contributes to the Government's aspiration for high levels of renewable electricity generation

1. The role of distributed generation in New Zealand's electricity system

Distributed generation plays a significant role in New Zealand's electricity sector

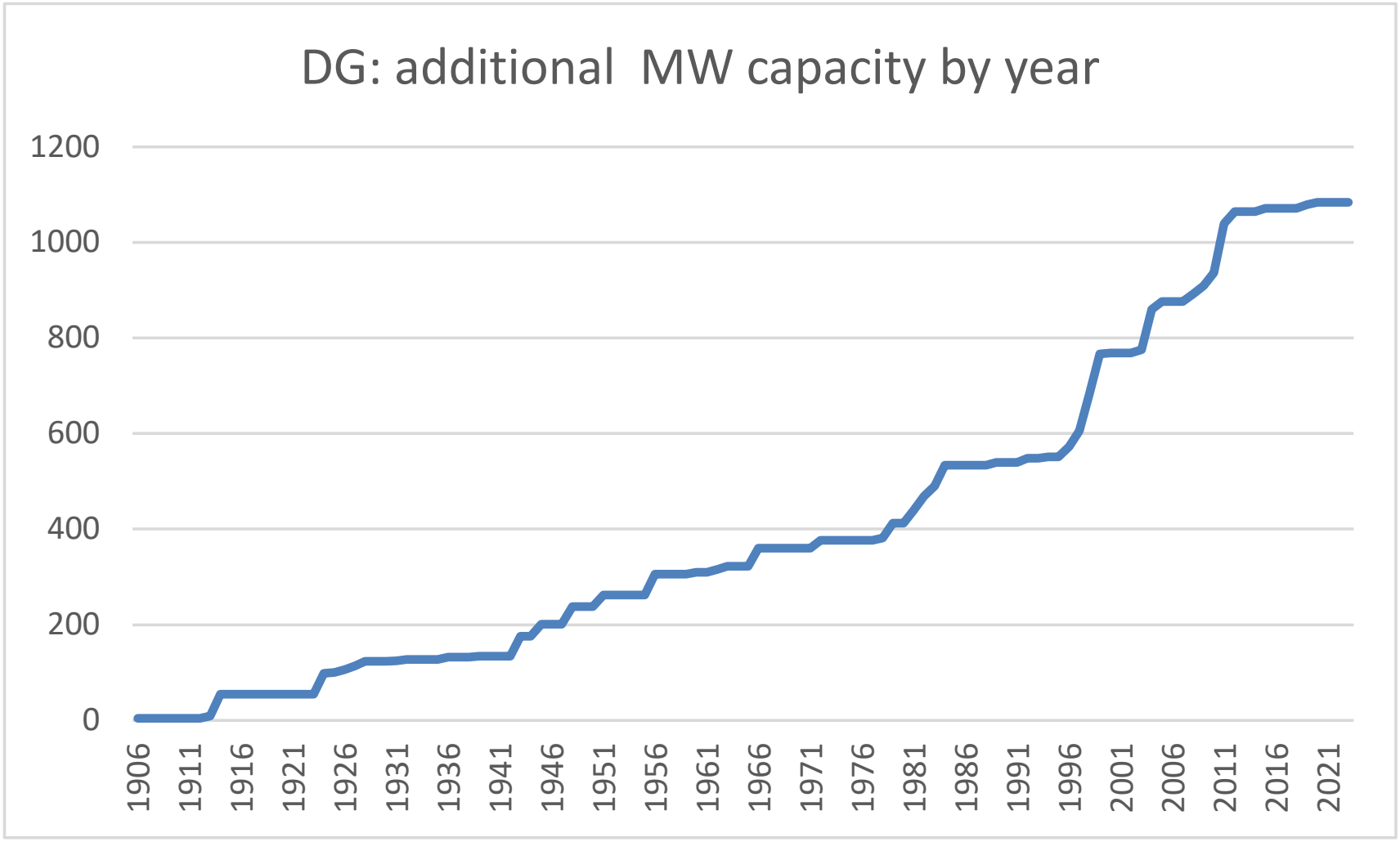
- DG facilities are located across all NZ (see figure), and supply ~12% of total NZ demand (IEGA).
- DG supply over 20% of network demand in 9 networks and ~60% of electricity consumed on the West Coast (IEGA)
- In 2022, there were ~170 embedded generation plants of approx. 1.8 GW total capacity (all DG fuels, and incl. cogeneration). Of these, ~103 plants provided renewable generation, with a total capacity of 1.3 GW. Over 30% of renewable DG capacity is provided by DG hydro-electric schemes (EMI, Manawa Energy data).
- Manawa Energy's generation accounts for 5% of total NZ output, and 8% of NZ hydro-electric output (Manawa Energy data)
- In some regions in New Zealand, Manawa Energy's hydro DG schemes are the substantial generators
  - Tasman (Cobb hydro-electric scheme is the only generation source in that region)
  - the West Coast (there are numerous other small schemes, but no grid connected schemes)

Figure 1: NZ distributed connected hydro power schemes.



Source: IEGA

Annual growth in distributed generation capacity

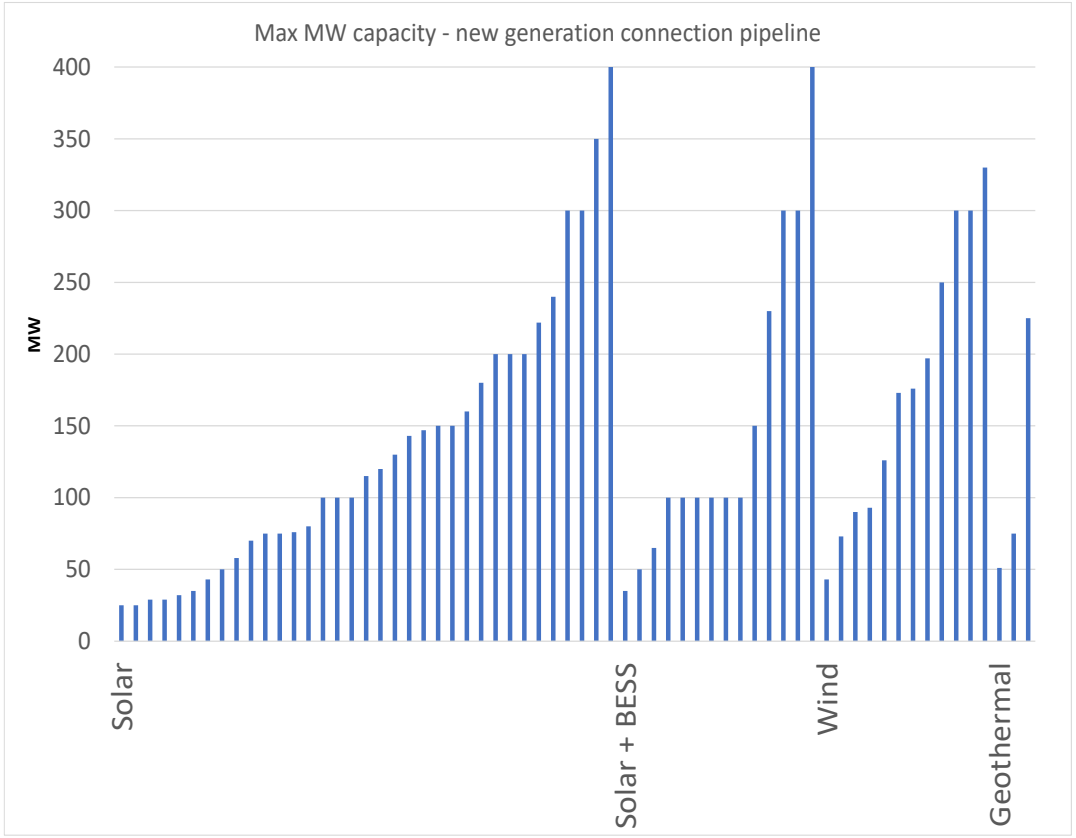


Role of DG in the energy transition

In the following slides, we present a series of charts based on available information on mid-scale DG

- We distinguish between embedded, partially embedded and grid connected distributed generation and, for each category we distinguish between their fuel supply
- We focus in on hydro potential, and note that although each opportunity is small-scale they add up to 436 MW (1.7 GWh)
- The 2019 EA data of all projects of all scale in the pipeline is shown in the first three charts. This database shows 2 geothermal projects of less than 50MW capacity, 8 hydro projects 2 wind and 2 diesel. At that time, no solar projects were indicated.
- In 2023 Transpower advised generation projects currently in the connection pipeline of enquiries. Of the 64 projects in the system 28 (4146MW capacity in total) are in the investigation stage, 30 (4,209MW capacity) have their application confirmed and 6 (900 MW capacity) have had their application accepted. This is shown in the fourth chart
- This is the followed by a table summarising the explosion of plans to install mid-capacity distributed generation in New Zealand especially the emergence of large scale solar and solar + BESS

Generation projects in the connection pipeline of enquiries (Transpower 2023)



Earlier this year Transpower released its pipeline of enquiries for connection. The pattern is replicated in other information releases.

To summarise:

A lot of investment in intermittent solar and wind is planned.

Planned solar plus BESS which would help with peaking.

Planned geothermal will help with baseload generation.

There are no known plans for new hydro

Source: Transpower

Summary of planned mid-capacity distributed generation in New Zealand

	EA (2019)	Transpower (2023)
MW capacity in the pipeline	3,939	9316
Solar projects	0	35
Solar + BESS Projects	0	14
Renewable DG <50MW	12	12

This table raises two points:

- There has been a significant shift in the types and scale of new planned generation investment
- Security of supply will be harder to achieve with the removal of thermal generation and the addition of the styles of generation being planned

Focus has been on DER and large scale generation rather than mid-scale DG specifically

- The Climate Change Commission, MBIE and Are Ake have all promoted distributed energy resources (DER) in recent years. (CCC advice to Government 2021, MBIE's Measures for Transition to an Expanded Highly Renewable Electricity System and Are Ake's announcement of a major collaborative electricity pilot with SolarZero.)
- It is true that DER located in distributed networks or within consumer premises will have greater importance in providing for supply and managing resilience. However, this focus tends to overlook the role mid-scale DG plays.
- Another example of this selective thinking around the DG fleet was during the formation of the NBEA when it was initially proposed that generation would need to shift to a 10 year reconsenting cycle but the large scale generation was exempted*. The 10 year provision was removed. Mid scale DG now enjoys the same reconsenting requirement as larger scale generation which is as it should be given the value it provides to renewable generation in New Zealand.*

* See our report highlighting the value of DG in this context: **The treatment of distributed generation in the Natural and Built Environment Bill** attached to **Manawa Energy submission on the Natural and Built Environment Bill** here

2. How DG contributes to system outcomes

All DG plays a significant role in ensuring NZ energy security

Background:

- Energy security requires the ongoing and timely provision of electricity generation. The "ongoing" requirement is provided by **resource adequacy**, and the "timely" requirement is provided by **energy adequacy.** Specifically:
  - Resource adequacy is the ability to store energy and shift it through time.
  - Energy adequacy is the electricity system's ability to reliably meet the different levels of demand at each point in time through the year.
- Electricity demand is expected to significantly increase between now and 2050 (by 53% in CCC forecasts, or 68% in Transpower forecasts). In addition to usual growth factors there is expected to be significant electrification of transport and industrial process heat.
- MDAG estimates that the share of total supply from intermittent generation will rise from 6% in 2020 to 47% in 2050.
- The combination of significant increases in electricity demand and increasing proportion of the supply needed to meet that demand being provided by intermittent generation will place greater emphasis on the role hydro-electricity plays in the economy including hydro DG with flexibility characteristics.

Hydro DG is important for ensuring energy adequacy in the NZ electricity market

- Hydro DG is integral to ensuring energy adequacy and improving resilience. Because it is located closer to end users and is by definition more dispersed than centralised generation and is generally smaller, the effects of any one unexpected outage at a single generation plant, or constraint on a transmission line, can be reduced.
- Examples of energy adequacy provided by hydro DG (IEGA):
  - DG at Auckland District Hospital Board's Grafton hospital provided emergency power when Vector's network was out
  - Transmission connection was lost to West Coast communities during the Fehi cyclone. Amethyst hydro station was used to black-start Hokitika's electricity supply and powered households and businesses in Hokitika and South Westland during the cyclone event

Hydro DG also provides ancillary services, which help ensure energy security

Hydro DG already provides flexibility services

- Hydro DG provides inertia and voltage support, which includes absorbing reactive power. DG is a large source of flexibility services from proven technology, and can provide benefits without requiring complex lower voltage network monitoring
- Some plants are contracted to supply black start
- Hydro DG can respond quickly to network issues – it is not always restricted to a System Operator's dispatch cycle
- Manawa Energy hydro DG provides voltage support services to Network Tasman, to maintain security and reliability on those local networks.

Hydro DG plays a significant role in meeting NZ's 2050 net zero target

- The modelling of New Zealand's energy future as carried out by multiple authors have assumed that hydro-electricity generation stays at least at its current levels through to 2050. Limits on consent durations for hydro DG operations creates uncertainty in the planning for low emissions electricity supply and the wider economy.
- As more intermittent and inflexible renewable generation is introduced into the grid (e.g. wind, solar), hydro-electricity will be relied on more and more to support system security. The alternative is investment in more thermal peaking plant, which runs counter to government's aspirations for higher levels of renewables and lower emissions.
- If all hydro DG were replaced with gas-fired plant, an additional 317 ktCO2e would be emitted annually. In 2030, this would result in electricity emissions being over 16% higher than where they would need to be (relative to CCC's Demonstration Path scenario).

3. DG value streams

Identifying DG value streams 1/5

Value stream	Regional value	National value
Network investment	DG has resulted in later investment in network capacity than would otherwise be the case. If it were removed increased network capacity would be required. MBIE, in the context of their work on accelerating renewable energy and energy efficiency in 2019: *In some cases, a local or distributed generation project may offer an alternative to new transmission or distribution build, thereby reducing the system cost of delivered electricity.*	DG has resulted in later investment in transmission capacity than would otherwise be the case. If it were removed increased transmission capacity may be required. DG is also utilised to manage transmission maintenance and upgrade work. IEGA advise that at least one of their members is a participant in Transpower's DR programme

Identifying DG value streams 2/5

Value stream	Regional value	National value
Security of supply	Regional security of supply and reliability is better for having local generation. If regional DG were removed that region would be less secure and resilient. MBIE raised it in the context of their work on accelerating renewable energy and energy efficiency in 2019: *Distribution networks and security of supply* *Community energy can contribute to local energy supply resilience and network stability.*	Existing DG contributes to national electricity security of supply, contributing around 11% of total national electricity production with a steady and renewable source.

Identifying DG value streams 3/5

	Regional value	National value
System flexibility and grid stability	IEGA reports: • *embedded hydro plant is used to provide inertia and voltage support* • *some mid scale DG is contracted to supply black start. This service has been used, for example to black-start local electricity supply and powered households and businesses during cyclone events* • *members provide network support for complex lines outages, in lieu of diesel generators, including island mode services* • *DG can respond quickly to network issues – it is not always restricted to a SO dispatch cycle* • *DG is robust as it must satisfy Code standards and operating requirements* • *DG is a large source of flexibility services from proven technology and can provide benefits without requiring complex lower voltage network monitoring*	DG, especially with storage, contributes to flexibility in the system which may become more valuable as the system becomes more renewable. DG has resulted in better National Grid stability than would otherwise be the case. If it were removed increased investment would be required to support larger scale capacity away from load centres. IEGA reports at least one mid scale DG owner provides over frequency support services to the market.

Identifying DG value streams 4/5

Value stream	Regional value	National value
Wholesale prices	Regional generation (i.e. close to local demand) lead to better regional wholesale prices. Prices to consumers in a region would be higher but for the local generation.	DG provides low SRMC generation and competition which has resulted in reduced wholesale electricity prices nationally than would otherwise be the case. Renewable DG in particular supports lower national electricity prices and if it wasn't there prices would be higher.
Transmission losses		System wide transmission losses are reduced by virtue of generation close to major load centres i.e. DG.

Identifying DG value streams 5/5

Value stream	Regional value	National value
Economic development and employment	More competitive electricity prices as a result of DG encourages economic development in a region. Prices have always reflected regional DG and economic development would suffer if it were no longer available. DG owners are local employers.	
Emissions reductions	Contributes to regional/local plans for reducing emissions.	Renewable DG contributes to the Government's aspiration for 100% renewable electricity generation by 2030 and its legislated goal of net carbon zero by 2050. If any of that capacity was suddenly not available the goal would be harder to achieve. If DG fell away for some reason more costly alternative electricity generation would be required and some of it may be fossil fuel powered.

4. DG brings competition benefits

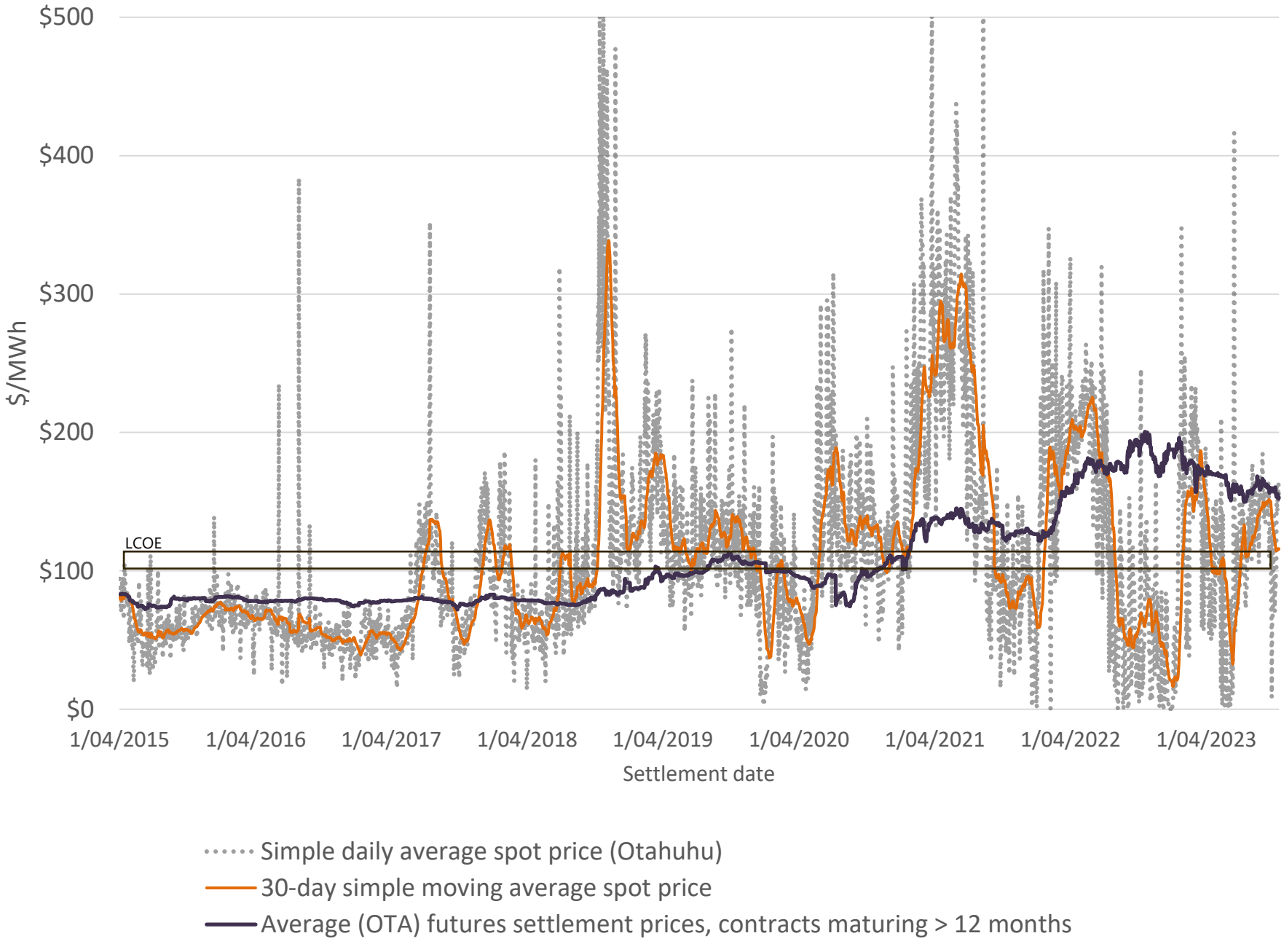
The relationship between DG and competition benefits is important

In its November 2022 paper: **Promoting competition in the wholesale electricity market in the transition toward 100% renewable electricity**, the Electricity Authority summarised the elements supporting an efficient transition to a low emissions energy system. Investment in distributed generation features as shown in the graphic below. This is consistent with the fact that maintaining the current fleet of mid scale DG and enabling investment in new midscale DG is an integral feature of the transition.

What the market tells us about risk and competition

A way to test gauge the market is competitive and whether it believes the level of investments required for the transition to a more renewable system given the rising demand from electrification is to look at the New Zealand electricity futures market.

- Electricity price risk is managed by parties entering into hedge contracts. These may be bilaterally negotiated contract for difference (CFD) style hedges or fixed volume fixed dated exchange traded futures contracts settled against the average spot electricity prices for the period.
- When futures prices trade above average spot prices the market is sending a signal that sellers are building in a risk premium. Generators worry that conditions could lead to higher prices in each future settlement period
- An assessment of futures prices compared to LRMC is also revealing. A plot of average futures prices greater than one year shows futures prices were below the levelized cost of energy (LCOE) when the net zero Act was introduced and the idea that we could reach "100% renewable electricity" began to be talked about.


$500
$400
$300
$200
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$/MWh
LCOE
1/04/2015
1/04/2016
1/04/2017
1/04/2018
1/04/2019
1/04/2020
1/04/2021
1/04/2022
1/04/2023
Settlement date
Simple daily average spot price (Otahuhu)
30-day simple moving average spot price
Average (OTA) futures settlement prices, contracts maturing > 12 months

Futures prices are indicating concern

- By April 2021 futures prices had risen above LCOE and remain there today. This suggests generators are worried that conditions could lead to higher prices in each future settlement period and amongst the reasons for that would be that investment is not keeping up with increasing demand

Genesis Energy Limited released its **Climate Related Disclosures for the period 1 July 2022 to 30 June 2023** on 23 August 2023. Genesis reports on the head winds facing generation investment:

"The work on our Future-gen strategy is progressing. No new PPAs were entered into in FY23. Competition in the renewable space remains strong with many of the larger renewable projects in the development stage. *The construction of some commercially feasible renewable projects in New Zealand in the near term has been delayed as a result of supply chain constraints, rising material costs and ability to access to local civil and electrical contractors as a result of flood remediation work*. Renewable projects have also been impacted by delays in network connection applications due to the volume of proposed projects being submitted."

Electricity Authority on the importance of maintaining a competitive market in this environment

- "Whether competition will weaken during this transition depends on the speed and amount of investment by independent developers in alternatives to gas and coal generation (e.g., renewables, green peakers fueled by biomass or green hydrogen, batteries) and in market innovations that enable increased participation by flexible demand."
- "The amount of new intermittent generation that is now in the development pipeline is encouraging, but so far there are few signals of flexible alternatives becoming available to improve competition in that part of the market." EA **Promoting competition in the wholesale electricity market in the transition toward 100% renewable electricity**
- To the extent that this new intermittent generation qualifies as mid scale DG, on the basis of the above they will be pro competition. That is, of course, unless the barriers to mid scale DG discourage investors.

The role of DG in supporting competition in the wholesale market

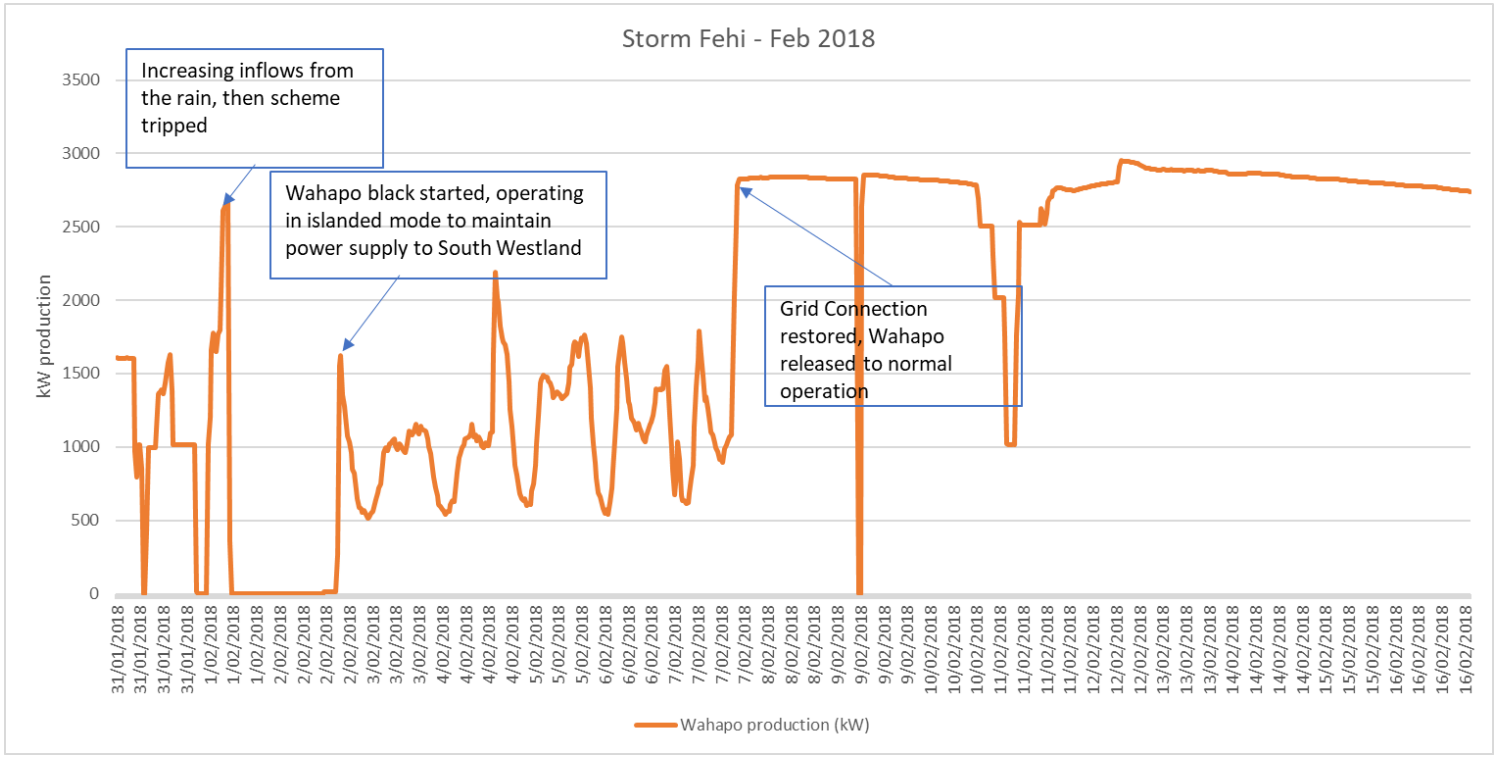
- "The (threat of) entry or expansion by competitors is one of the most powerful forces to mitigate the exercise of market power. It is a crucial complement to conduct-based regulation of market power, and the Authority's approach to promoting competition for the long-term benefit of consumers. The persistence of high spot and forward prices, well above the cost of new renewable supply, raises questions about whether there are impediments (including anticompetitive barriers) to entry by new supply. If there are, then entry may not be able to be relied on to help constrain the exercise of market power." EA **Promoting competition in the wholesale electricity market in the transition toward 100% renewable electricity**
- This paper is about the value of DG. It is not an essay on competition in the wholesale electricity market. The takeaway from this section is simple. The electrons generated by DG are the same as electrons generated by large scale generation and the proximity to load compared to large scale gernation has value. Adding to those two features the diversity of ownership of mid sale DG is positive for competition in the wholesale market and the Electricity Authority is clear about the importance of that.

Case study Wahapo Power Scheme

Case study Wahapo Power Scheme

"When Cyclone Fehi hit the West Coast in 2018, Transpower's line went down and so it was the local hydro-electric power stations that kept the power on for businesses and households in Hokitika and South Westland." **Greymouth Star, Saturday 30 September 2023**

"Security of supply is always going to be a major concern in this area as it is fed by a very long single-circuit line; however, local hydro generation schemes such as the Wahapo and Amethyst Hydro Schemes play a significant role in improving security of supply to South Westland." **Westpower AMP**

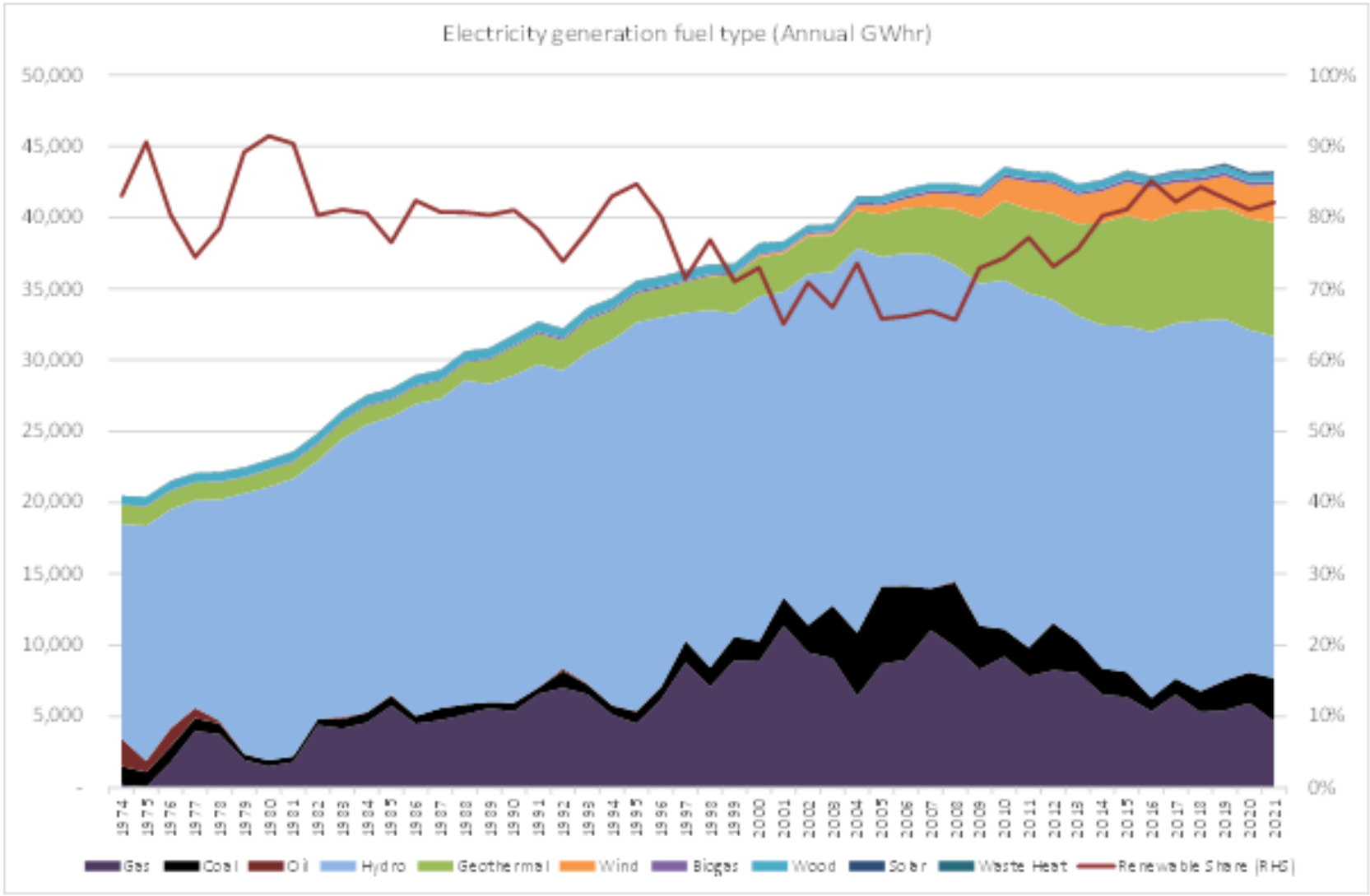


Appendix: Renewable electricity generation in NZ

Electricity generation by fuel type

- The following slide plots annual electricity generation of all scale (including mid-scale DG), by fuel type (technology), from 1974 to 2021.
- Between 1974 and 1995, the proportion of renewable generation remained high, while total annual demand rose from 20,000 GWh to 35,000 GWh.
- The wholesale market was introduced in 1996 and, for the next 15 or so years, a higher proportion of supply was met from coal and gas-fired generation.
- From 2005, investment in wind and geothermal generation outpaced investment in thermal generation. Demand flattened out following the global financial crisis and the proportion of renewable generation rose to where it is today.
- Critically, by 2017 the high proportion of renewable electricity outcome was achieved without subsidy and without any intervention by government.

Electricity generation by fuel type



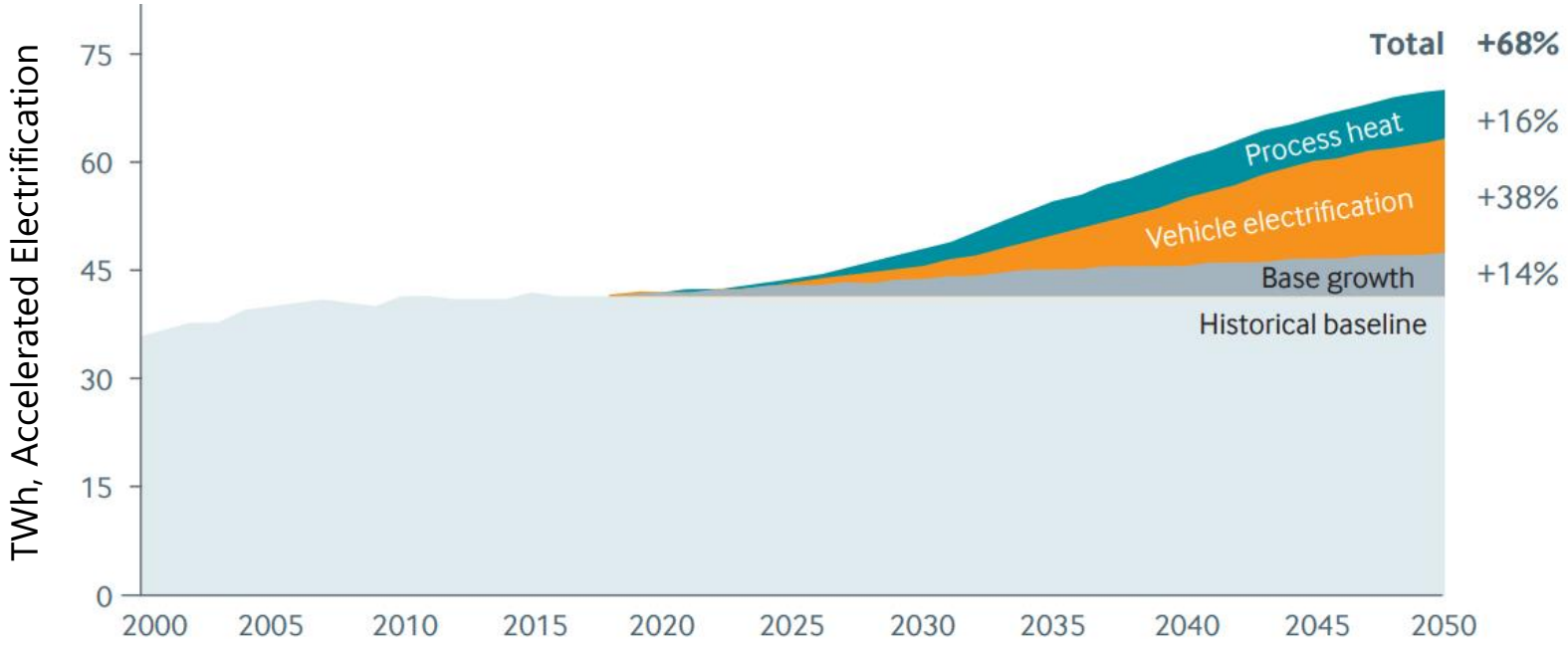
Generation development

- In 2019, the net zero by 2050 target was legislated in the Zero Carbon Act. In 2022, New Zealand's first Emissions Reduction Plan was adopted, setting the direction for climate change action over the next 15 years.
- This direction relies on large and small consumers electrifying industrial processes, transport and any other fossil-fuel. Modelling by Transpower and the Climate Change Commission showed demand will increase significantly as a result of electrification (see next slide).
- In the ERP, the Government states its aspirational target of 100% renewable electricity by 2030. Against the backdrop of policies to reduce New Zealand's emissions, investment in new thermal generation, refurbishment of existing generation and development of thermal storage facilities has frozen. On the other hand, investors in renewable electricity generation can see the need and the opportunity but there are consenting issues, supply chain issues, labour issues and skills issues. Renewable electricity generation investment has, to date, largely brought only investment in intermittent generation into the system.

Energy demand growth

Whakamana i Te Mauri Hiko estimates a 68 per cent increase in required electricity generation by 2050. In the 2025–2030 period total energy demand increases by approximately 10 per cent from 44 to 48 TWh. The sustained, strong growth in electricity demand between 2025 and 2050 is driven primarily by transport electrification and the electrification of process heat.

Figure 6: Projections of electricity demand



Source: Transpower, Whakamana i Te Mauri Hiko – Empowering our energy future, March 2020

Problems for electricity supply

The challenges to investment in renewable electricity generation create two problems for electricity supply:

- **Security of supply.** Thermal generation plays a major role in providing security of supply. As it is replaced by renewable electricity generation, maintaining reliability and security of supply becomes more challenging. The Electricity Authority's advisory group (MDAG) estimated the share of annual average supply from intermittent generation such as wind and solar will rise from 6% in 2020 to 31% in 2035 and 47% in 2050.
- **Scale of investment.** The sheer scale of investment required to replace thermal energy, meet the accelerated demand and provide security of supply is massive. A recent report by BCG estimates the system will need a total of 4.8 GW of new utility-scale renewable electricity generation capacity in the 2020s, i.e. more than a 50% increase on installed capacity in the system today.

Final Report

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1. EXECUTIVE SUMMARY

The New Zealand Government has committed to reaching net zero for long-lived gases by 2050; has set a target that 50 per cent of total energy consumption will come from renewable sources by 2035; and has set an aspirational target to reach 100 per cent renewable electricity by 2030. While electricity generation only contributes about 6% of New Zealand's greenhouse gas emissions it has a larger role to play in meeting overall emission reduction targets through the electrification of the wider energy system (especially transport and industrial manufacturing) which accounts for 40% of greenhouse gas emissions.

The NZ Government recently released a range of discussion papers including "Measures for Transition to an Expanded and Highly Renewable Electricity System" (Electricity Measures Paper). In some ways these papers are analogous to working out what you need in your backpack before you set out on your journey. However, in this case, where your journey extends out until 2050, knowing in advance everything you may need along the way is clearly impossible. Truth is, we're going to make a couple of stops along the way where we can refill and even upgrade our backpack. Being overly ambitious comes with the burden of carrying too much, going too fast, or taking off before having considered all relevant factors. We just need to get to the next check point.

The ongoing transition of the NZ electricity system brings a range of challenges but also opportunities. As the main incremental contribution of the electricity sector is to support electrification of higher emitting sectors, such as transportation and industry, the main manifestation of this contribution is the need for the electricity system to serve additional load growth over time. Growth can be forecast and the associated system infrastructure requirements can be planned.[1]

1.1. TAKING STOCK AND GETTING READY

New Zealand is rich with hydro resources, abundant wind, reasonable sunshine, and blessed with geothermal resources at the boundary between two tectonic plates. New Zealand also has a well-regarded and well-functioning electricity market that provides efficiently priced electricity to consumers in a secure and reliable manner. It is a market that is regularly under review, with three decades of lessons learnt having been applied to help ensure it remains relevant to ever evolving stakeholder requirements.

1 Most of Asia is growing faster than New Zealand's more aggressive outlook scenarios. From any objective external perspective, the growth in expected future transmission and grid requirements in general is not especially remarkable, however, different it may appear compared to New Zealand's more recent history. The more important challenge is to not to make grid and other investments so far in advance of growing load that the effective cost per kWh increases faster or higher than necessary. The related challenge is to ensure that prices incentivise efficient use of grid infrastructure which also contributes to lowering the resulting cost per kWh.

This view is shared by the kaitiaki of NZ electricity - the Electricity Authority – in their recent press release which stated that:

> *"While the electricity market may not be perfect, it has served consumers well and the importance of a well-functioning electricity market to enable the transition to a decarbonised economy cannot be understated."*

Three decades ago, electricity market development was a response to perceptions of inefficiency and overbuild flowing from a past Think Big era and the realisation that complex hydro-dominant systems could be operated efficiently in a decentralised manner using price signals. The efficiency and reliability of supply track record of New Zealand's electricity market era has been exceptional even despite a disproportionate number of so-called 1 in 100 year droughts.

1.2. CORE RECOMMENDATIONS

As New Zealand examines possible 'measures' to prepare for the energy transition, our core recommendations are simple:

- Allow the market to work as best as possible;
- Remove unnecessary obstacles to efficent decisions;
- Recognise that investors are irresponsible if they ignore real risks to which they are exposed – as such they will and should sit on the sidelines if the longer-term outlook is insufficiently clear or attractive;
- Markets abhor a vacuum and have, by corollary, a robust appetite for well-structured and objective information about system current and expected future conditions;
- Minimise backstop measures to the extent possible and avoid 'think big' type projects, especially if they involve multi-year planning and development, and come at high cost and materiality. The time for these is not now.

The challenge is to approach the energy transition in a way that avoids heavy handed intervention whilst providing firm guidance regarding the problem the market is supposed to solve. Afterall, that is what any market is for: to solve the problem of balancing supply and demand through choices and efficient prices. Define the problem well, align the problem with customer preferences and supplier capabilities, and ensure adequacy of competition through ease of entry and exit.

Anyone can try to solve a complex problem by spending too much money, but where is pride in that? The most complex challenge is not decarbonisation but decarbonisation over time at a reasonable cost. That's exactly the challenge that a market-based system is well situated to deliver.

Accordingly, we suggest that a better approach for this journey would be to pack lightly, have some emergency supplies at the ready should conditions change and re-provision regularly along the way.

1.3. AVOID DO OR DIE

The transition to low carbon economies is an international endeavour. In signing the Paris Climate Change Agreement, NZ joined this endeavour. In advancing its response NZ should not act in isolation, but rather keep pace with the rest of the world, observing and learning from those 'out in front', including those who may stumble along the way.

Setting an 'aspirational' target may sound lofty but it often comes at a price. A reasonable set of steps, pacing, possible trajectories, options and costs must be defined not based solely on what happens in New Zealand but on what is happening throughout the world.

Making very substantial progress towards decarbonisation is not something that requires desperate acts or measures. Achieving full, absolute, decarbonisation of the power sector can increase costs based on present understanding, but that is not the challenge for 2023. The weight of the global community moving forward will drive innovation, bring costs down and create efficiencies. Everyone may fail despite their best efforts if enough make only poor efforts. Equally, however, those who move too quickly risk persistent higher costs by missing out on future optimisation. Success is not measured by how fast New Zealand decarbonises but on how cost-effectively New Zealand decarbonises in concert with the global community.

1.4. MAKING USE OF THE MARKET YOU HAVE

It is easier to destroy a market than to build one. Markets depend on stakeholders believing that the context within which the market operates is stable. In a sense, well-functioning markets depend on faith. Upon a loss of faith, markets only exist to the extent that there is a balance of power between suppliers and demanders. Market governance, economic regulation, and market design aim to regulate power so that stakeholders can transact with trust. Courts exist to empower those who shake hands or have pieces of paper with signatures, rather than to empower only those who have armies. The point is that markets are incredibly fragile. Markets do not work merely because of their associated rules and systems; they work because there is a reason to believe in the stability and comprehensiveness of those rules and systems.

The biggest risk and uncertainty of decarbonisation is and will continue to be the question of what an investor in an energy system believes he or she is competing against. Are carbon options still on the menu, are carbon options simply priced higher, are the competing stakeholders operating to the same profit motive? Will new projects have protective long-term contract cover not otherwise available? And so forth. It is not that difficult to understand or recognise the problems that arise for market-based-stakeholders or potential market-based investment responses in an energy transition in which government policy or action are responding to non-market signals.

1.1. RECOGNISING UNCERTAINTY

The further transition to a highly renewable future carries with it a number of uncertainties. Many of these uncertainties aren't particularly novel in nature and are part of the reasons markets came into existence in the first place, but they may be exacerbated.

The key ones we raise in this paper are the pace of future demand growth (which sets the need for new renewable investment), energy efficiency, potential demand exits (Tiwai), the frequency of dry years, and the emergence of new technologies.

Managing such uncertainties requires transparent information flows – such as an annually prepared Statement of Opportunity outlining the need for further system investment; providing sufficient detail for investors to perform their own due-diligence and respond accordingly. Markets present the collective views of participants, but rely on a transparent and level playing field of information being provided.

If new investment is not forth coming at the pace that is believed necessary, then two things may be happening – the market is failing to respond or the market is trying to tell you something. It is easy to assume the former at the expense of the latter. For example, perhaps investors are not convinced at the pace of New Zealand shifting to EV electrification in the absence of clear and specific non-partisan government policy; perhaps investors have taken a more global view of hydrogen production costs, or question the implicit willingness to pay associated with faster, deeper, decarbonisation.

Whilst it is tempting to simply say that markets require clear policy frameworks, that would be incomplete. A clear policy framework today that changes to another clear policy framework tomorrow can be just as problematic. The key desirable characteristic is that the underlying approach remains consistent. However, if the framework is that the government will simply make investments as it wishes from time to time, then that would not be a robust framework as no one can compete with a sovereign entity that is not necessarily committed to making decisions on the same basis as a commercial player would. And so forth.

Markets rely on expectations – if no one believes the story then they won't come in. Once certainty is introduced, investment will follow. This is where we differ in our perspective compared to the point of view inherent in the Electricity Measures Paper. To achieve meaningful emission reductions in the energy system begins with setting clear policy (including specific targets, dates, milestones and what will create the force of action) around the need for electrification of transport and industrial manufacturing – these two components alone produce over four times the emissions of electricity generation in NZ – and drive the anticipated increase in new renewable generation to be built. As demand increases, evidence-based planning becomes possible and will always be less expensive. Aspirational planning risks building out too much, too soon.

1.2. 'SILVER BULLET" SOLUTIONS

Big, high-capex, long-to-develop projects cast a long shadow on markets. Will they or wont they go forward? If they go forward, will they or won't they be completed on time? And if completed on time, will they or won't they come through at or under budget, or will they constitute a long-term burden on future generations? And, ultimately, if no management or shareholders feel the pain, will the decision process take financial risk into account? These are the questions that should be answered before starting. Having reasonable basis for answering these questions is what evidence-based planning is all about. For as long as such projects are in discussion but not resolved, the market faces a chilling, wintry wind, not unlike the uncertainty around future demand at Tiwai.

This is why a return to silver bullet schemes such as the seemingly ill-fated Lake Onslow pump storage facility, can be so damaging to the market context. It may be tempting to use a bigger stone to kill many birds at once, but the stone risks becoming so heavy it cannot be thrown at all. How does Lake Onslow fit into a market-based system? What market failure or evidence of failure exists to justify an intervention on such scale at this time?

Also illustrated by Lake Onslow is the additional uncertainty such grand plans present when there is no clear nonpartisan political support. While acknowledging that "we can and should be doing more to get renewables built", the National Party (as the leading party of the newly elected coalition Government) has previously advised that it will "immediately cancel the Lake Onslow project if elected in October"[2].

There may come a day when such projects may need to rise up and become a part of the overall system, 'but it is not this day'. In summary, our concern is that 'silver bullet' projects invariably take longer to implement, are expensive (with costs often exceeding expectations), concentrate risk of failure, and close out future optionality.

It would be a pity and a grave cost (waste) to take such actions 'today' as to compromise the electricity market's ability to contribute towards enhancing the economic efficiency and innovation of New Zealand's decarbonisation journey.

1.3. FLEXIBLE SOLUTIONS ARE REQUIRED

Flexible solutions, such as Demand Response (DR) have become increasingly used in electricity systems to help manage the increase in volatility, as well as to reduce peak demand and contribute to system reliability. Practical lessons can be drawn from the wide and varied use of demand response internationally to help maximise DR participation levels in New Zealand's renewables transition. DR can be both a permanent solution to market requirements or to act as a transitional measure to buy time while other solutions are developed.

2 Stuart Smith, National's Energy and Resources spokesperson, 16 March 2023

1.4. FREEDOM TO CONTRACT

Allowing investors to manage their price and volume risk is also important in managing the transition. This involves the freedom to contract with counterparties to set prices outside of the market through Contracts for Differences (CfD) and other agreements. Expanding the range of risk products on organised exchanges is beneficial but needs to be well considered alongside liquidity levels and market maker costs and risks.

The greater use of green corporate PPA agreements to support new renewable investment is part of a global trend. It matches renewable generation with load, especially those seeking 'green' solutions and starts to de-risk price volatility and volume certainty.

1.5. THE WAY FORWARD

Ultimately, we believe that New Zealand is well placed to achieve a reasonable transition to a low-carbon energy sector *because* of its electricity market. Taking steps known to undermine the market's effectiveness should be avoided. Reinforcing market effectiveness by working within the various prerequisites of market competition whilst reflecting the impact of externalities is still a viable and attractive approach. Setting targets that are aligned with international best practice reduces the risk of stakeholders having to second guess future commitment to current policies and positions. The fastest way to undermine a market is to take actions that cause market participants to wait for government action out of concern that any market-based investment exposure risks being undermined by such action anyway. As with any borderline, the first step is to recognise it exists and that crossing it has potentially unintended and costly consequences.

2. INTRODUCTION

The Lantau Group (TLG) has been asked to provide its expert view on the government discussion paper ***Measures for transition to an expanded and highly renewable electricity system***. New Zealand already has a very high level of renewable generation available to meet its energy needs[3]. The key essence of this discussion paper is on how to achieve the transition away from the remaining thermal generation active on the system; meeting future demand growth for electricity with renewable sources; all while ensuring a "*reliable, and affordable energy system that supports economic growth and productivity*".

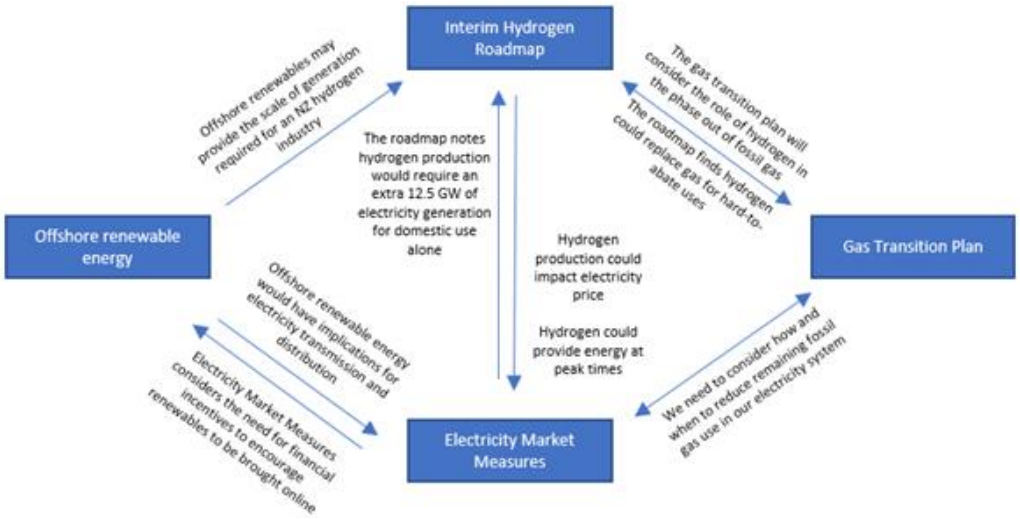
The paper sets out work already underway by government and regulators and seeks feedback on what else might be needed.

3 The renewable share of generation was 87.1% in 2022 according to MBIE annual electricity generation and consumption data.

2.1. NZ GOVERNMENT REVIEW

The Government has committed to reaching net zero for long-lived gases by 2050; has set a target that 50 per cent of total energy consumption will come from renewable sources by 2035; and has set an aspirational target to reach 100 per cent renewable electricity by 2030. A suite of discussion documents (refer Figure 1 below) has been released as part of the process towards developing an overarching New Zealand Energy Strategy (NZES), to be completed by the end of 2024.

Figure 1: Key connections between the discussion documents



Source: Advancing New Zealand's Energy Transition, August 2023, Ministry of Business, Innovation & Employment

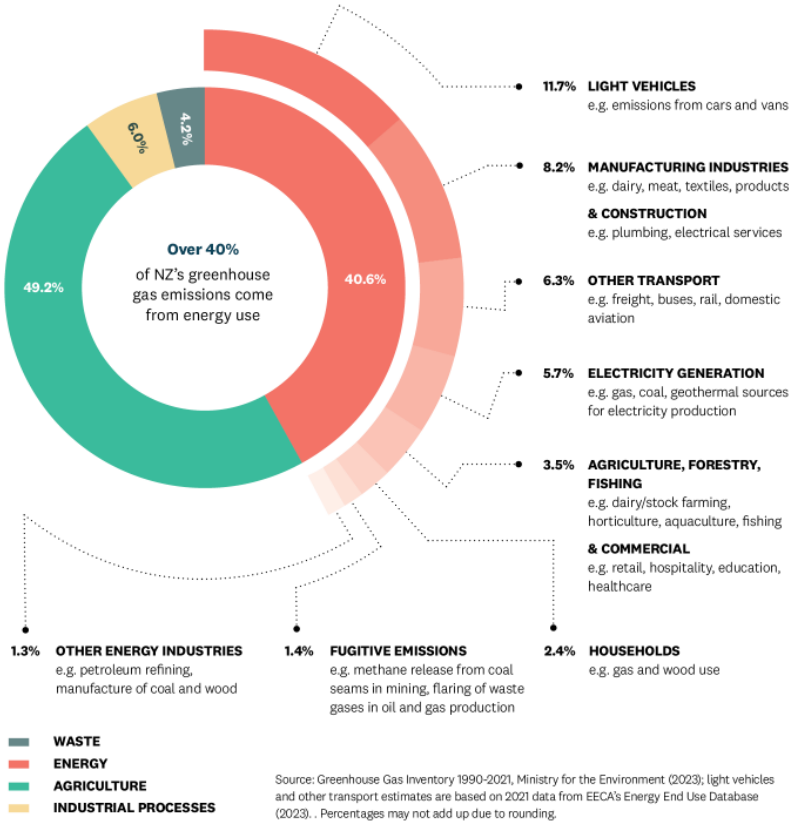
The stated objectives for the NZES are:

- energy affordability and energy equity for consumers;
- ensuring energy supply is secure and reliable, including the adaption to the effects of climate change and global shocks;
- the energy system transitions at the pace and scale required to support reaching net zero by 2050; and
- the energy system supports economic development and productivity growth aligned with the transition.

The above objectives are neither intrinsically unreasonable nor unrealistic. Whether they are reasonable or actually achieved, however, is less about the objectives themselves and more about the common sense and robustness of the efforts to achieve them.

The importance of renewable electricity in helping to meet the energy system objectives stated is disproportionate to its 5.7% contribution to NZ's greenhouse gas emissions. This is because transforming the energy system towards net zero will require significant electrification of transport and manufacturing industries (refer Figure 2).

Figure 2: The make-up of energy-related emissions



Source: EECA website, accessed 12 October 2023

What will it take to make the transition over the next 25 years to full decarbonisation. What can we confidently do? How can we make the best use of market forces? How can we go into the tool box and not just pull out a hammer every time we have a problem?

We observe a temptation around many countries to accelerate the development of roadmaps and plans and proposals for achieving decarbonisation faster, albeit at the risk of introducing greater uncertainty into otherwise functional market-based processes. The energy trilemma which stresses affordability offers no prescriptive solutions as affordability has no universal meaning. Something is sensible to do if the benefits it creates outweigh the associated costs incurred. Whether that same something is considered "affordable" is not about the value created but about how it is paid for. The trilemma would be more actionable if it replaced affordability with cost-effectiveness. That would usefully separate the questions of 'what to do' from the questions of 'who should pay what for them'.

Important dimensions for consideration include:

- Whether the costs incurred and associated with decarbonisation progress made by New Zealand are disproportionate to what is being incurred and achieved by others. A global problem that intrinsically requires a global solution means that the cost of solutions that achieve local decarbonisation are of no economic value to New Zealand unless global solutions are also sufficient and timely. There is clear value in nudging all global stakeholders forward, but that value falls off dramatically if too few follow, and the choices available to New Zealand's power sector are comparatively expensive.

- What the alternatives really are. Decarbonised energy may in fact be more expensive than carbonised energy, but if enough, globally, are committed to decarbonisation, the ordinary economic damage to any one is minimised, allowing all to benefit from the extraordinary global decarbonisation achievement benefits.[4] Robustly mitigating the threat of competing with future lower cost competition from carbonised energy resources leave a fair playing field for everything else. The biggest risk and uncertainty of decarbonisation is and will continue to be the question of what an investor in an energy system believes are the credible, competing opportunities that a possible investment decision must overcome. Paralysis increases with uncertainty. Investment is at the core of the electricity market. Enabling stakeholders to evaluate investments favourably that align with a reasonable decarbonisation pathway is at the core of how an electricity market contributes to efficiency and lower cost over time.

Continually characterising decarbonisation as a higher cost keeps the debate locked in the context of the carbonised energy system which eventually delivers climatic peril. At some point – though not yet today in specific choices – the choice of cheaper but carbonised will not be a choice.

In dealing with such a long-term target (to achieve net zero by 2050) it is clearly not possible to plan with much certainly in advance other than the immediate years ahead. We have created the analogy that preparing for this journey is akin working out what you need in your 'backpack' before you set forth. However, in this case, where your journey extends out until 2050, knowing in advance everything you may need along the way is clearly impossible. Being overly ambitious comes with the burden of carrying too much, going too fast, or taking off before having considered all relevant factors. We just need to get to the next check point.

4 In a prisoners' dilemma, both prisoners have an incentive to turn in the other, as doing so has a higher personal pay-off provided that the other does not do the same. Only if they both hold firm to their prior commitment is the larger total benefit realized as they are both unpunished.

The challenge is to approach the energy transition in a way that avoids heavy handed intervention whilst providing firm guidance regarding the problem the market is supposed to solve. Define the problem well, align the problem with customer preferences and supplier capabilities, and ensure adequacy of competition through ease of entry and exit.

Accordingly, we suggest that a better approach for this journey would be to pack lightly, have some emergency supplies at the ready should conditions change and re-provision regularly along the way. We discuss the initial contents of this 'backpack' in Section 3.5.

2.2. FURTHER CONTEXT

It is essential to note that the NZES follows New Zealand's ratification of the Paris Climate Change Agreement's ("Paris Agreement") emission reduction targets[5]. These targets represent a significant cost and opportunity for the New Zealand economy. The Cabinet paper recommending approval of the Paris Agreement placed the economic cost of New Zealand's 2021-2030 reduction target at $36 billion (2012 prices)[6]. If New Zealand is unable to meet its targets through domestic reductions and carbon offset prices it will need to seek offshore mitigation at a cost estimated to be between $3.3 to 23.7 billion[7].

Whilst absolute numbers seem large, New Zealand's Gross National Income per Capita was approximately NZD 45,000 in 2021. The impact of NZD 36 billion over 9 years represents less than 0.2% per year share of GNI/capita. That is not to argue there is some magical threshold below which we should be concerned with monetary costs, but rather to ensure that we provide the information and context necessary to bring balance and perspective to the challenge ahead. Making very substantial progress towards decarbonisation is affordable, and is not by any measure something that requires desperate acts or measures. Achieving full, absolute, decarbonisation of the power sector too quickly can increase those costs based on present understanding, but that is not the challenge for 2023. We need to allow ourselves at least some time and degrees of freedom to incorporate new insights and information from developments globally over the next decade.

5 This commitment is to reduce net emissions by 50% below NZ's gross 2005 level by 2030.

6 Financial and economic implications will result from obligations to take progressively higher emission reduction targets and provide progressively greater amounts of financial assistance to developing countries. The economic cost of New Zealand's 2021-2030 target is estimated at $36 billion (2012 prices), or 1.20% of RGNDI. The costs of our subsequent targets under the Paris Agreement and future packages of financial assistance to developing countries are unknown.

7 Climate Economic and Fiscal Assessment 2023, NZ Treasury and the Ministry for the Environment

A reasonable set of steps and pacing and possible trajectories, options, costs and so forth must be defined not based solely on what happens in New Zealand but on what is happening throughout the world. Winning the game is not the same as being able to say that a climate catastrophe was "not my fault", but involves working together. Accordingly the climate challenge is the type of problem for which a successful solution will not arise by being out in front like Phar Lap, but being in tight formation like a peloton. This means that market-based solutions will be more likely to emerge in contexts where policy targets appear reasonably aligned with evolving international norms. The UK's recent reversals of more aggressive targets is a good example.[8]

The best way forward in any challenge depends on two key skills:

- **Recognise the Problem.** Will other countries upon which global decarbonisation outcomes also depend keep up their bargain just as New Zealand does? Without the cooperation and participation of all or most, the actions of some or even many, may be fruitless. This uncertainty drives the rationale of a balanced approach that keeps New Zealand as a constantly willing and nudging leader. The solution to the prisoners' dilemma [problem] is to turn it from a single shot game to a repeated game in which the relevant stakeholders have the opportunity to build trust and optimise coordination.

- **Focus.** Removing distracting options from the table whether by increasing their cost or rendering them implausible removes the most debilitating risks from the market, giving it the very best chance of identifying least cost timetables and options. This is nothing more than recognising, through one mechanism or another, that markets fail when the presence and cost of material externalities go unheeded.

They should not be seen as only a cost. If, in fact, all ratifying nations of the Paris Agreement act pursuant to their ratified obligations, the absolute cost of energy may increase globally, but the more damaging and uncertain *relative* impacts (the penalty on a leader if others do not follow) are greatly reduced. Similarly, the presumption that any form of business- as-usual will continue to be available and, if so, predictable, is a sort of hubris as well. Investors in fossil fuel resources globally will also face rising uncertainty regarding both the supplies they would be competing with and the demand they would be able to serve. It is as likely as any other scenario that fossil fuel price volatility increases significantly, as it is now too easy to develop highly different future narratives about how supply, demand, and fuel markets will develop over the next two decades. Continuing the shift to renewable energy gains relative value as a way to reduce exposure to volatility in that context.

8 The British Prime Minister's net zero speech on 20 September 2023 delayed the phase-out date for the sale of new petrol and diesel vehicles from 2030 out to 2035. This came after the March 2023 Carbon Budget Delivery Plan (CBDP) had already scaled back some of the measures being taken from the more ambitious (but ruled unlawful) 2021 Plan. A shortfall has now been acknowledged by the government, which expects future "unquantified" emissions cuts to make up the gap.

The point is uncertainty is rising of a type and nature that neither has been part of the fabric of the historical electricity supply sector nor is a facet known to be handled robustly by competitive electricity markets. Swinging the pendulum away from the market through paralysing uncertainty or heavy handed interventions is equally to be avoided for having a similarly atrocious track record.

The market alone will not guide the sector towards meeting the Paris Agreement. But a highly interventionist approach has no assurance of delivering a lower cost long-term solution. A feeding frenzy of Government projects without the discipline of market forces (including the pricing of the carbon externality) or practical economic frameworks assures the failure of the existing market for any purpose other than short-term balancing, making the most expensive and material decisions the product of partisan sausage making.

2.3. ELECTRICITY MEASURES PAPER

The Government's Emissions Reduction Plan (ERP) contained an action to:

> *"Investigate the need for electricity market measures by 2024 that support affordable and reliable electricity supply while accelerating the transition to a highly renewable electricity system."*

The electricity measures paper is presented in a number of parts and seeks feedback on whether there are any gaps in which further or alternative measures may need to be developed to support a successful electricity system transition. We have been asked to focus our attention on the first two parts of the paper:

- Part 1 – Growing Renewable Generation
- Part 2 – Competitive Markets

The Measures Paper assumes as an endpoint that New Zealand's electricity system will either be 100% renewable or that significant progress will have been made towards a more highly renewable electricity system. It is important that this is an assumption – there is no way to know in 2023 whether it is actually going to be the outcome. The same study done two or three years later may conclude otherwise, given the rapid development of technologies and perspectives. And so forth. This is the conundrum. The pathway to decarbonisation depends on developments that are yet to occur.

Objectives Being Sought

It is useful to break down the objectives enunciated in the paper into a number of components and to differentiate between objectives and constraints.

Achieving the "highly renewable" objective can be broken down to:

- managing intermittency and dry year with less thermal dependence,

- ensuring that future energy demand growth is being met by new renewable sources; and

- retiring thermal in a planned manner.

A key component to achieving these objectives is to have a clear articulation of the value associated with them and the metric(s) to be used to measure their fulfilment. Absent those, there is no chance a market-based mechanism can be expected to work efficiently. It is also important to provide stakeholders with as much information about future demand drivers and likely outcomes so that stakeholders make informed decisions. Demand projections are not guaranteed, of course, and they may not be seen as credible unless the process and method of their estimation is sufficiently transparent. Singapore has a history of secrecy around demand forecast assumptions and outlooks - a history that has, in our view, contributed significantly to investment uncertainty and market inefficiency.

Just because a market demand *forecast* is trending upward does not mean that investors will follow suit. It is also important to provide the tools for stakeholders to conduct their own due diligence around forecasts and any other factors that influence the risks to which they would be exposed were they to take action based on an otherwise attractive forecast opportunity.

2.4. WILL THEY / WON'T THEY

If a thermal investor could deliver a lower cost short term solution but a high risk longer term solution viz a viz a cleantech investor who delivers a higher cost short-term solution and a lower risk long-term solution, who 'wins'? A market can reach a point of stalemate where neither side has clarity to act. To induce investment prices need to increase, but once built there is no assurance that the investment environment will be the same in the future as it is in the present.

Much of the concern about security, adequacy, and reliability can be tied back to this fundamental question of 'will they/won't they' --- the short-term market signals the need, but the policy and other externality exposure risks in the longer-term cannot be overlooked. This is a classic situation in which the solution involves simplification. Either risk must be accepted and managed through long-term PPAs, insulating the investor from the uncertainty of how the market evolves, or the cheaper short-term options must be taken off the table by raising their cost or eliminating their eligibility.

Carbon taxes and fossil fuel moratoria and renewable portfolio standards are common approaches presently. Whilst none are absolute assurances, it is not unreasonable for stakeholders to form their own views as to whether settings for such instruments and mechanisms will be gradually or periodically stepwise changed so as to advance decarbonisation over time.

None of these additional decarbonisation risks necessarily alter anything to do with dry year risk management. Either this is left to the market or the risk is modified through interventions. This is an age old debate whose essence does not change just because of a prospective accelerating shift to renewables or other zero carbon technologies. The nature of volatility may change, but the process of determining whether the market design should change or whether it is a market parameter that should change, or whether it is a particular form of market intervention that is required --- these questions remain the same.

And as one would expect, an increase in intermittent renewable generation sources, all else equal, can require more system resources to be applied to maintaining reliability. If we don't believe the market will deliver this, or if we don't believe that the mechanisms and insights gained from attempting to deal with hydro scarcity in the past have landed on a robust solution, then we should start there. The fact that we are talking about decarbonisation with additional intermittent resources is not necessarily creating an *entirely* new problem. It's mostly a similar, well-established, problem with the additional nuance of pricing the carbon emission externality.

The objective around energy affordability and energy equity for consumers is more of a constraint rather than an objective. It is also difficult to define and thus somewhat illusionary to achieve.

3. ACHIEVING LONG TERM OBJECTIVES

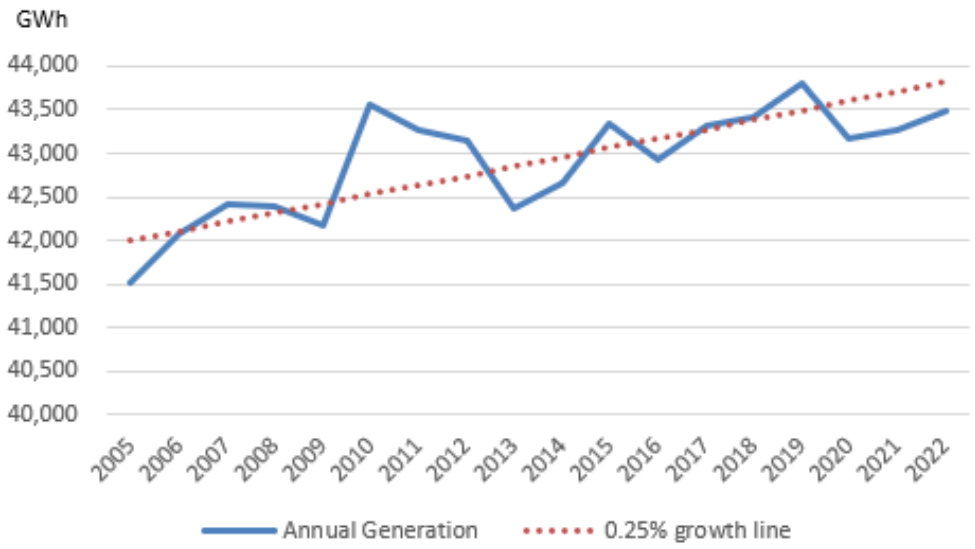
3.1. DEMAND GROWTH UNCERTAINTY

The concept of demand growth uncertainty isn't new, and something that electricity markets have had to deal with since they first came into being, and central planners before that (often solving the problem with investing too early).

However, in the case of managing the Energy Transition a new dilemma arises which is largely ignored by the Measures Paper. It is not the electricity system becoming 100% renewable which has the most material impact on achieving a net zero outcome for energy use in NZ but rather the electrification of transport and industrial manufacturing. Transport and industrial manufacturing contribute 26.2% of NZ emissions vs electricity generation at only 5.7% (refer Figure 2). It is thus extraordinary that attention has not been placed on the plan to achieve the electrification required. How bizarre it thus becomes to expect the electricity sector to plan the build of new renewables to meet a largely unplanned electrification process that is required for NZ to achieve its Paris Agreement targets and thus avoid costly offshore mitigation.

MBIE's analysis projects that electricity demand could grow by 18 to 78 per cent between 2018 and 2050 across five different scenarios assuming different levels of economic growth, technological progress and policy changes. Who should believe this and what should they do about it. The range is wide, the consequences of aiming high and getting low or aiming low and getting high are very different. The forecasts are long term in nature and the rate of growth is low by objective standards even if it is higher than normal for New Zealand (refer Figure 3). Power systems have grown for decades at rates above 6 percent at times throughout the developed and developing world.

Figure 3: Annual Net Generation Growth



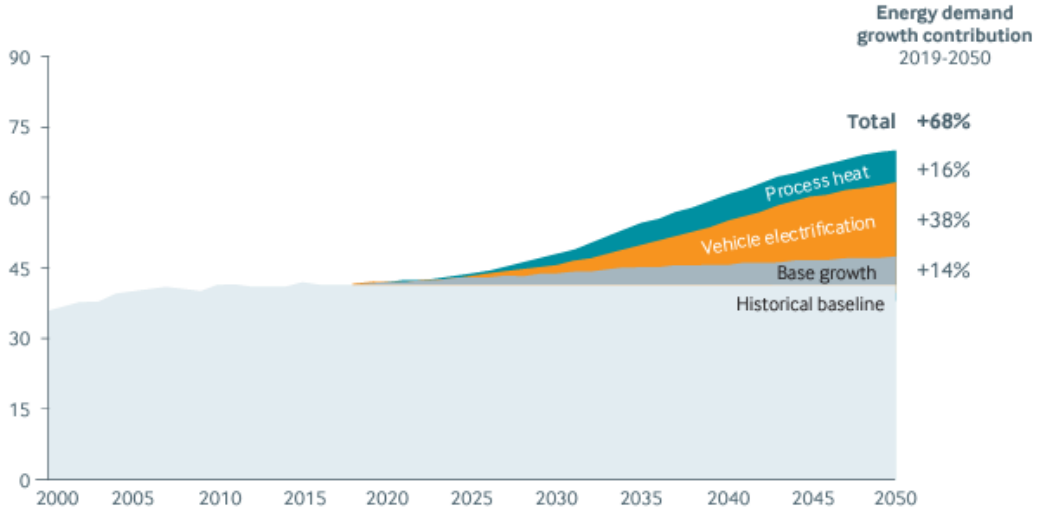
Source: MBIE data tables for electricity (growth line added)

What exactly is the concerning uncertainty surrounding demand growth? The main source of uncertainty concerns transport electrification. Of course if substantial global land transportation is not either electrified or switched to green molecules by 2050, it barely matters what New Zealand's power sector accomplishes. Accordingly, the main risk is to determine when to invest in grid build out and charging infrastructure and what to assume about the relationship between prices and charging behaviour. We would prefer to assume that New Zealand will do the smart thing and do all that is necessary to signal the efficient time to charge and use the grid, and will undertake to plan and build out the grid as needed in closer alignment with actual transportation electrification outcomes. Grid use lowers the cost per kWh. Grid investment without commensurate increase in grid use raises the cost per kWh. Frankly, affordability depends more on alignment of timing of supply and demand, which benefits from smart use of infrastructure, than on investment per se.

If we want to manage cost we should be willing to go the right speed – and not just go fast with investment and potentially slow with utilisation improvement. It's not uncommon to think big about infrastructure, but the more the buildout precedes the utilisation, the higher the cost per kWh will be. The same can be said for the form of rate base recovery. The more that depreciation and return are recovered up front, the more that those who barely use a new grid asset are asked to pay for it, conveying a windfall gain to future generations for whose future use the asset was more specifically designed and intended.

Transpower's Accelerated Electrification base case estimates electricity demand between 2020 and 2050 of 68%, driven primarily by transport electrification and then the electrification of process heat (refer Figure 4).

Figure 4: Gross Energy Demand (TWH) – Accelerated Electrification



Source: Whakamana i Te Mauri Hiko – empowering our energy future, Transpower, March 2020

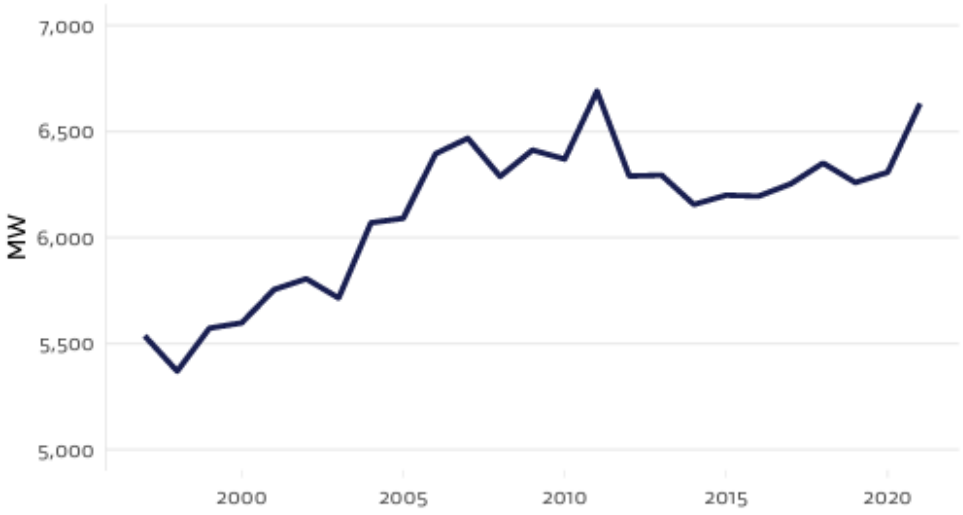
However, focusing just on increasing annual electricity demand can be misleading. The electricity system will need to be sized to meet ***peak*** demand growth and this is projected to be more modest. Transpower have noted in their projections that ""while electricity demand is estimated to increase by 68 per cent, peak demand only increases by 40 per cent, reflecting the increasingly important role of ***demand response solutions***"[9]. This assumption is well aligned with historic peak demand seen in New Zealand which, while fairly volatile, has been largely flat over the last 15 years (refer Figure 5). It also implies a smartening of grid use and a potential significant downward pressure on cost per kWh. Setting aside subsidy options, nothing helps affordability more than efficiency.

Transpower also rightly highlight the impact of electricity efficiency in their projections:

9 Whakamana i Te Mauri Hiko – empowering our energy future, Transpower, March 2020 (emphasis added)

"Despite assumptions around positive economic performance and population, **base electricity demand growth** *– ignoring possible gains from fuel switching – out to 2050* **is largely flat***. This is a consequence of increasing efficiency balancing out energy growth as a result of a growing economy."*[10]

Figure 5: Annual peak electricity demand[11]



Source: Energy in New Zealand 22, MBIE, Calendar Year 2021

A further consideration for projecting future demand growth is also any potential significant demand exiting the system. The elephant standing in this room is the Tiwai Point Smelter. Consuming approximately 12% of New Zealand's total electricity demand, if this demand were to exit the system, then Transpower's base growth projection of 14% out to 2050 could largely be met from transferring existing South Island Hydro northwards.

So many other uncertainties pale in comparison to this. Given the value that having more time can have when innovation is happening and new technology costs are falling, and given the paralysis that an extraordinary binary risk has on market behaviour, there are few focus areas that can restore a more healthy and efficient energy market than to resolve or figure out how to manage the impact of any future Tiwai Point Smelter exit decision. Given that it is still only 2023, one could argue that it is prudent to push off any decision whose answer depends on which way the Tiwai outcome falls.

10 ibid

11 Based on grid export data, averaged over half hourly trading periods. Therefore it does not show the peak instantaneous demand on 9 August reaching 7,157 MW

Related Paper on Hydrogen Production

The Interim Hydrogen Roadmap presents a story with domestic demand for hydrogen of 180,000 tonnes per year by 2035, rising to 560,000 tonnes by 2050. This could require additional electricity output of 11.5TWh in 2035 increasing to 33.9TWh in 2050, or it could require import of H2 from exporting markets.

In 2023, no one yet knows. Truth is no one can answer this question affirmatively. Everything written currently about hydrogen is still bollocks from a larger scale, long term optimisation perspective. Any scenario where New Zealand is an efficient scaled up hydrogen exporter is, by definition, a scenario where New Zealand has no problem meeting decarbonisation using a simpler mix of policy and electricity market mechanisms. If those exports depend on policy or subsidy, however, then all bets are off and the probability is equal that the investments will be wasted or the required resources could have been better used in other ways.

Key observation

Our key observation on demand growth projections is not to suggest that one set of figures is more correct than another, that peak generation required has not been given sufficient focus, or that the hydrogen growth path presented errs on the fanciful, but rather to say that any form of electricity projection is prone to error which introduces uncertainty, and the further out you project, the greater these errors and uncertainties become. If the idea is that major infrastructure should be developed 'soon' for such distant effects, that would be a mistake. However, if there are steps that can be taken to shorten the time of development from a point of decisions, that may be prudent. The shorter the time of development, the later the point of decision can be. The option to defer commitment is a positive source of value.

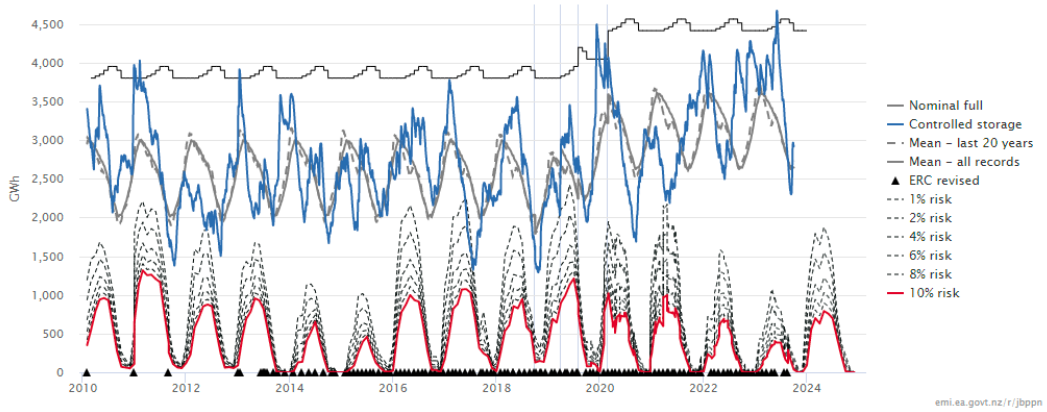
Building policy and regulation on such uncertainties requires the need for flexibility, frequent review, and a willingness to adapt. The firmer or larger the projects for the distant future appear to be, the more risk is transported from the future to the present. This additional risk compromises efficiency in the existing electricity market for no obvious upside benefit.

3.2. MANAGING DRY YEARS

The New Zealand electricity system is prone to the impact of climatic events due to its dependency on hydro generation characterised by limited storage capacity. Thermal generation is currently an essential part of the electricity system. It is required both for firming intermittent renewal and to be held as a contingency for managing dry year risk.

Figure 6 shows historical hydro storage levels in New Zealand relative to risk curves denoting the chance of having insufficient water storage to meet electricity demand. Significant low storage events were encountered in 2012, 2017 and 2019. When such events occur, more thermal generation is called upon to balance the system. These used to be called "1 in a hundred year" events. This is clearly no longer the case. Climate change will only further increase the frequency and volatility of lower storage levels.

Figure 6: Historical electricity risk curves



Source: EMI website, Electricity Authority

One of the issues that will need to be tackled as part of the transition to greater renewables is how to plan thermal retirement around dry year risk. The simple answer is that you can't, given the unpredictability of dry years (albeit there is a relationship with El Niño and La Niña weather cycles).

Whilst it is good to establish firm deadlines, it is reasonable to have well-structured flexibility. Have a clear framework – set a retirement date but allow for the option of deferral of, say, six months upon the payment of a penalty charge whose payment would only make sense if the year of retirement happened to be a dry year of sufficient extremity. This approach combines commitment with structured flexibility – moving away from reliance on non-binding commitments or arbitrarily rigid deadlines.

Ultimately, the risk of extreme hydro-variability can only be mitigated using solutions that draw from insurance analogies.

3.3. EMERGING TECHNOLOGIES

In undertaking long term projections, such as out to 2050, a further uncertainty is introduced by emerging technologies. Some of this uncertainty is about when will known emerging technologies become commercially viable and a further uncertainty is what current unknowns will become known. Illustrating this point is the classic case of Thomas Malthus modelling the limits of population growth to the available increase in agricultural production but failing to predict the impact of the industrial revolution.

A further salient point is the pace that battery technology improves – in terms of cost, energy efficiency, scalability, size (ease to collocate with intermittent generation supply) and reduced lifecycle carbon impact. Betting the farm on alternative present-day technologies may result in long-term regrets. For example, the Lake Onslow 'battery' project currently being investigated (but now largely in doubt following the recent Government elections) proposes a pump storage scheme that will provide 1000MW of generation capability with 5TWh of storage for $15.7 billion and a construction and commissioning timeframe of between 7 and 9 years[12] (following a final investment decision not expected before 2026).

The other problem with such grand schemes is that earlier needed alternative investment is unlikely to enter the market while such Damoclean proposals loom overhead. Dampening the dynamic efficiency of the market at a time when unprecedented new investment is required is something we would caution against.

Demand Response

Another anticipated beneficiary of emerging technologies is the area of demand response. While NZ has historically made good use of demand response with ripple control, industrial interruptability and voluntary reduction (supported by Official Conservation Campaigns), new opportunities should now emerge with the introduction of real time pricing to the wholesale market (refer Table 1). The international shift observed with greater 'hybrid' demand response options is also likely to see greater potential in New Zealand - where loads operate with storage and/or generation behind the meter to provide a more flexible response to the system when called upon.

Table 1: Rollout of Real-Time Pricing

Date	Introduces
1 November 2022	From 1 November 2022 wholesale market pricing is calculated in real time. The settlement price for each trading period will be calculated at the end of the trading period and published immediately. Retailers are able to reliably develop new products and **consumers who are on plans where they buy from the spot market, will for the first time be able to make decisions on prices that they will actually pay.**
27 April 2023	From April 2023 the dispatch notification product will enable the inclusion of Distributed Energy Resources and aggregated demand management in the wholesale market, subject to approval by the system operator. Enhancements to dispatchable demand will allow large industrial consumers to bid in demand management in a way that better suits the physical constraints of their plant and processes.

Source: Real Time Pricing, Electricity Authority, 2022

12 Based on Phase 1 investigations of the NZ Battery Project.

With many systems around the world looking to greater participation of intermittent renewables, including behind the meter, the shape of net grid demand, in particular intra-day demand, has become more volatile. Demand response has become increasingly used in electricity systems to help manage this increase in volatility, as well as to reduce peak demand and to contribute to system reliability.

Practical lessons can be drawn from this wide and varied use of demand response internationally to help maximise participation levels in New Zealand's renewables transition. In particular, we draw attention to two reviews undertaken of Demand Response schemes to determine what features are more conducive to successful outcomes.

- ***Australia*** - The Australian NEM is a particularly useful case study to look at as it has tried multiple demand response schemes in recent years and thus allows different design features to be evaluated against a similar background[13].
- ***UK*** - Another, useful example to look at is the UK, where In 2016, Ofgem surveyed large industrial and commercial consumers to assess the potential for demand response and to identify barriers preventing greater flexibility[14].

3.4. AVOID BIG BANG SOLUTIONS

In general, when dealing with a wide range of uncertainties, in a dynamic environment with emerging technologies, we would caution against the temptation of possible 'silver bullet' or big bang solutions. They tend to be longer to implement, expensive, concentrate risk of failure, become outdated before they commence operation, and close out future optionality. Most importantly, there is so much change ongoing throughout the global clean-tech sectors that the prospect of magically planning the future correctly in 2023 is dim at best.

As much as it would be good to accelerate decarbonisation there are more opportunities to proceed such as allowing investors to learn from international endeavours, making use of emerging technologies as they become available and more cost effective, and using the market as the means of signalling expectations of growing demand (and associated firming and hydro risk requirements) that will need to be met. We discuss this more in Sections 3.6 and 4.1. Such options are not reliant on mega projects. An ill-timed or ill-conceived or unintentionally complex or contentious mega-project crowds out other solutions that should rightly be considered the lower hanging fruit.

13 How does WDR (Wholesale Demand Response) compare to other demand response options? AEMO website: https://aemo.com.au/en/initiatives/trials-and-initiatives/wholesale-demand-response-mechanism/wdr-frequently-asked-questions

14 Industrial & Commercial demand-side response in GB: barriers and potential, Ofgem, October 2016

3.5. COORDINATION AND FOCUS REQUIRED

Managing uncertainties is not a novel concept. It begins with

- clearly defining objectives (example being what is 'affordability');
- correctly identifying and defining problems first so they can be solved;
- setting reasonable and robust targets and milestones; (and more important establishing guidance about how those targets and milestones were set and what factors influence the choices made, as such guidance is necessary to assess robustness in a real-world context);
- avoiding the temptation to move too many pieces at once – it not only creates confusion but also makes it more difficult to identify what actions are working and which ones are not;
- allowing for the review; recalibration, and evolution of all aspects (recognising that you'd always want to be able to reflect the latest thinking in the evolution of plans, targets, and activities);
- coordinating endeavours across multi facets (rather than creating multiple funds that sit with different authorities for their allocation to what is most aligned with their specific perspectives of the problems to solve);
- correctly placing incentives (both carrots and sticks) on those parties best able to solve problems (or to not introduce them); and
- recognising that meeting targets by 2050 will span multiple different governments – nonpartisan agreement will be necessary as the robustness of any singular perspective cannot be assured over time.

We then translate the above approach into what the initial contents of our 'backpack' might contain before we set forth on our journey to carbon net-zero (but bearing in mind that frequent taking stock and re-provisioning of our backpack's contents will be required along the way).

Our suggested packing list might go as follows:

- An update on New Zealand's progress towards meeting its Paris Agreement Obligations with specific progress, targets and milestones to achieve NDC1 (inclusive of shortfalls expected to require offshore mitigation).
- Specific allocations of the above to the 'energy system' with a further breakdown by electricity generation, transport, industrial etc.
- Translation of the above into a strategy – the New Zealand Energy Strategy (NZES).

- Clear guidance from Government to relavant bodies (e.g. regulators and Transpower) through Governmnet Policy Statements in support of attaining the NZES and the expected roles that these bodies will play.
- Workplans from above bodies to confirm how they will meet Government Policy Statements.
- Translation of the NZES into specific Government policy and objectives as it relates to EV adoption, electricfication of industy etc.
- System demand projections created/revised based on the NZES as supported by the electricfication policy, inclusive of anticipated firming requirements and an impact assessment of dry years.
- Translating the above into a 'statement of opportunities', inclusive of sufficient information, for investors.
- An update from the EA on progress towards implementing the findings of its market competition review.
- A plan for regular review and recalibration of electricity industry progress towards balancing additional demand and supply.
- Any relevant actions relating to transmission and distribution (outside scope of this paper).

3.6. CAN WE RELY ON THE MARKET TO DELIVER?

In our view, New Zealand has a well-designed and well-functioning electricity market. We reviewed the electricity market in some detail during the Electricity Authority's 2021 review of Competition in the Wholesale Electricity Market. We fully concur with the statement made by the Authority in releasing its findings into this review:

> *"While the electricity market may not be perfect, it has served consumers well and the importance of a well-functioning electricity market to enable the transition to a decarbonised economy cannot be understated."*[15]

In its decision paper the Authority has confirmed the actions it will take to constrain the exercise of market power and encourage investment in renewable generation to promote competition in the wholesale electricity market:[16]

- continue proactive monitoring and enforcement of trading conduct in the spot market, and investigate the application of trading conduct rules to the forward market;

15 Press release by the Electricity Authority, Promoting Competition in the Wholesale Electricity Market in the Transition Toward a Renewables-Based Electricity System, 12 May 2023

16 ibid

- investigate mechanisms to accelerate the development of the demand response market (in addition to its current work programme directed at this, eg, real time pricing and empowering consumers to participate in the electricity system in new ways);
- clarify disclosure requirements (and consider amending the Code to provide certainty about such requirements) about current or expected constraints that could impact generation capacity, and arrange a centralised location for disclosure; and
- explore better information sharing processes and obligations with the Commerce Commission on any information the Authority collects that may raise concerns about restrictive trade practices, collusion, or misuse of market power.

To facilitate investment in new renewable generation the Authority will:

- undertake regular monitoring of progress on generation investments, and an annual update of the investment pipeline and impediments;
- regularly collect information on offtake and 'firming' agreements (and if feasible declined requests) to understand and build the evidence base about the nature and scale of current and emerging access issues reported by developers of new generation;
- improve the Electricity Hedge Disclosure System to improve its functionality and make contract details more transparent;
- investigate and test the case for providing or requiring longer-dated futures (for instance products traded on the ASX); and
- analyse thermal generation transition risks in the context of demand to 2030, its role in hydro firming and more prevalent solar and wind generation, and options to mitigate transition risks.

However, it is important to recognise what markets do well and where their role is (and should be) limited. A well-functioning market provides price signals to support short-run and long-run efficiency. In the short-term to promote efficient use of available resources (allocative efficiency) and in the long-term to provide signals for new investment when it is needed and incentivise innovation (dynamic efficiency). Electricity markets are also able to reach efficient outcomes subject to technical constraints provided. For example, in the short-term the NZ market will dispatch electricity in the most efficient manner to meet demand while preserving system security requirements.

It is also important to note that markets deliver efficient prices, and these will not be affordable to everyone. Just as the price of food, shelter, clothing or other essentials can be out of reach to some. Affordability is about ability to pay. Efficient pricing is about what resources, including opportunity costs are involved in providing electricity supply. The question of what is efficient or cost-effective is a different question from what affordable to a particular customer segment. The policy instruments that are appropriate and effective in addressing affordability differ significantly from those that are appropriate to ensuring the reasonable efficiency of decision-making and pricing in the electricity sector.

The New Zealand market operates using a sophisticated nodal pricing algorithm which provides locational pricing signals to support investment decisions (and provide a level of transparency) on the trade-offs between transmission expansion vs siting of new generation and loads. It was determined in the TPM that nodal prices would substantially determine efficient timing and location of use of grid resources in the context of the energy transition. Whether true or not, it is a strong assumption that will need to be continually reviewed in association with future grid investment decisions.

Where electricity markets are less able to support the energy transition is:

- to signal investment in technologies which may not be the most efficient option at the time; or

- providing longer-term pricing signals to fully meet the payback period required for investors (and their lenders) to proceed.

In the former case, where a specific technology is being sort, then some additional overlay may be required – such as a carbon cost in the case of bringing forward specific renewable technologies before they become competitive. Where a specific technology is only needed for a short period of time (e.g. more thermal peaking as a transitional measure) or under specific events (e.g. dry year) then market prices must be allowed to rise to compensate for this (which may be problematic). Some form of bilateral contracting may be the better option here in order to have the right resources available with a high degree of certainty and not create intra-marginal rents that may be seen as a windfall to other participants. This then becomes a limited case of ‘competition for the market’ rather than ‘competition in the market’.

Where the market is less able to support the transition, we would suggest that a select and targeted approach be adopted outside of the market (such as bilateral contracting) rather than try to distort market pricing signals or create a subsidy (which tend to be crudely focused and less linked to performance outcomes).

4. GROWING RENEWABLE GENERATION

We focus on two aspects of the Electricity Measures Paper in detail – the first being Part 1 – Growing Renewable Generation. This part addresses the issue of ensuring sufficient renewable generation is built and that fossil fuel generation will be replaced in a way that maintains security, reliability and affordability, including ensuring sufficient firm capacity during transition. It also considers the role of large-scale flexibility to provide demand response.

4.1. ACCELERATING SUPPLY OF RENEWABLES

The Measures Paper highlights a concern that "there remains a risk that signalled investment may not come forward in sufficient time or quantity to enable electrification, while maintaining security and affordability". A number of factors are identified that may inhibit or slow the required new development, with specific attention drawn to regulatory and market uncertainties. Concerns are raised that as more renewables enter the market the price volatility will increase which will translate to heightened investor risk. That's an ironic concern as the energy only market design itself uses and even relies on exposure to price volatility to compel contracting for risk management. The market is, by design, supposed to be volatile. If you want more longer-term contracting activity, an increase in volatility is more likely than not to be essential to achieving that objective.

The range of issues and possible measures for discussion are summarised in Table 2 below.

Table 2: Accelerating supply of renewables

Challenge/issue	• Price risk for investors in baseload renewables • Regulatory and market uncertainties could be hindering investment in new renewable generation
Further potential measures	• Support the development of new renewable generation through financial support mechanisms including power purchase agreements, renewable certificate obligations, contracts for differences and feed-in tariffs.

Source: Electricity Market Measures – Webinar Slides, 29 August 2023

If volatility is seen as a concern by government, then market stakeholders must equally be concerned with reactionary intervention that reduces their access to adequate revenue or even appropriate risk management instruments.

If green technologies are favoured, then the question is whether volatility or price increases would otherwise lead investors to adopt non green technologies. There would then be a clear need for a carbon charge, a carbon-based technology or fuel prohibition, or a quantum-based requirement (such as RPS). The faster and deeper the desired transition, the higher the willingness to pay must be. There is no free, green, lunch.

Statement of Opportunities

We note that as part of the Electricity Authority's actions it will take to encourage investment in renewable generation[17] it has invited MBIE to produce an ***Annual Electricity Generation Investment Opportunities report,*** targeting international developers, with input from NZ Trade & Enterprise, Transpower, the Electricity Authority, Overseas Investment Office, and Ministry for Environment.

Such a report will also start to give greater clarity on the future demand expectations of the system. As we discussed in Section **Error! Reference source not found.**, demand growth uncertainty inherent in New Zealand's renewable transition provides a huge risk for investors to plan around as well as to allow the NZ Government a degree of certainty that their Paris emissions targets will be met and expensive offshore mitigation not required.

Hedging Risk

The next step is to allow the development of risk management tools for investors. We note that some activity is planned in this area following the Authorities review of competition in the market, specifically the Authority plans to:

- improve the Electricity Hedge Disclosure System to improve its functionality and make contract details more transparent; and
- investigate and test the case for providing or requiring longer-dated futures (for instance products traded on the ASX).

While this should help improve the level of hedge products made available, we would always highlight that generation investment is a long-term prospect that extends beyond what can be realistically expected from the tenure of electricity future products. Even the largest most actively traded electricity futures markets will see very little liquidity in long-dated (5-7 year) contracts. For example, baseload German Power Futures traded on EEX are available up to 10 years out[18] but have very little activity more than 4 years out.

17 Electricity Authority confirms actions to promote competition in the wholesale market, Press Release, 12 May 2023

18 EEX began offering 10 year power future from 27 September 2021

Table 3: EEX German Power Futures - Baseload

Future	Last Price	Last Volume	Settlement Price	Volume Exchange	Volume Trade Registration	Open Interest
Cal-24	114.75	8,784	-	3,698,064	2,099,376	84,736
Cal-25	113.99	8,760	-	762,120	972,360	20,992
Cal-26	105.35	8,760	-	236,520	306,600	5,126
Cal-27	91.50	8,760	-	26,280	-	941
Cal-28	-	-	-	-	-	139
Cal-29	-	-	-	-	-	13
Cal-30	-	-	-	-	-	7
Cal-31	-	-	-	-	-	2
Cal-32	-	-	-	-	-	2
Cal-33	-	-	-	-	-	-

Source: EEX website (accessed 5 October 2023)

As we've noted, it is not uncommon for a generator to look to hedge wholesale market price volatility by matching generation output with a load. This can take the form of vertical integration, where a participant owns both generation and either load (such as cogeneration) or has a retail portfolio.

Alternatively, such an arrangement can be reached by way of contract, such as a PPA between a generator and a load or retailer. Such arrangements are commonly referred to as a Corporate PPA, or when the generation is renewable in nature, a Green Corporate PPA. As NZ has a mandatory market, such PPAs would need to be financial, most likely taking the form of a CfD. This will allow the parties to fix prices thereby removing price volatility.

5. COMPETITIVE MARKETS

Part 2 of the Measures Paper considers the competition issues that may arise in the electricity market during the transition away from fossil fuels. The concern is that as the level of dispatchable fossil fuel generation reduces the remaining dispatchable generation and other flexible resources will become more concentrated, resulting in a reduction in competition.

The range of issues and possible measures presented for discussion are summarised in Table 4 below.

Table 4: Workable competitive electricity markets

Challenge/issue	• Increasing market concentration of dispatchable generation providers as the use of fossil fuel generation reduces • Reducing competition could adversely affect electricity prices and reliability
Further potential measures	• Support for conduct or structural measures, including: o horizontal separation of generators with significant market share in flexible hydro storage o regulated access pricing for flexibility services o central procurement of new and existing flexible resources.

Source: Electricity Market Measures – Webinar Slides, 29 August 2023

What we see here is a potential market power issue. However it must also be recognised that the speed with which new flexible capacity can be added to the market will be much faster in the future as the technologies include demand response, biofuel or H2 based OCGT and CCGT or reciprocating engines, as well as battery energy storage – many of these can be installed at smaller scale within a year. Market power can be effectively mitigated by the speed and flexibility of entry, along with ongoing monitoring.

Conduct Measures

When we looked at competition in the New Zealand market as part of the Authority's 2021 review, we made a number of observations that still hold true.

1. In any electricity market, we would expect that it is possible for some market participants to have some market power at some time or in some locations. The practical standard for electricity market structure in New Zealand or anywhere to date has not been perfect competition. However, it is not the existence of market power that should give concern, but whether such market power is being exercised to a degree that necessitates consideration of corrective, mitigating, or other forms of targeted action.

2. In trying to address a problem perceived with short run allocative efficiency it is important that the 'measure' applied does not dampen long-run dynamic efficiency. In an environment where a key policy objective is to attract new investment to support a low emissions economy, such 'measures' run the risk of being counterproductive.

3. Freedom to contract between well informed and willing buyers and sellers in the absence of market power being an unduly material factor, is a cornerstone of workable markets.

4. The light cast by transparency helps to ensure an orderly market (absent the possibility of enabling tacit collusion). A salient example being the requirement for disclosure of risk management contracts provided for under part 13, subpart 5 of the Code.

5. There will need to be a greater acceptance that high prices are sometimes required to allow a market to be both allocatively and dynamically efficient.

6. The Authority can support the energy transition by ensuring that its regulatory tools do not distort pricing signals through blunt un-targeted measures. The recent weekly trading conduct reports are an excellent example of a prudent regulator lifting confidence in market outcomes through increased transparency.

We are pleased to see that following the 2021 review, the Authorities actions to constrain the exercise of market power (refer Section 3.6) are well aligned with these observations.

The Measures Paper provides the range of preferred conduct measures outlined by the Market Development Advisory Group (MDAG):

- Develop a dashboard of competition indicators for flexibility services – to better assess how competition for flexibility products is changing.
- Improve transparency of hedge market information – to make it easier for participants to compare prices, especially for non-baseload contracts. This would also facilitate surveillance of the contract market to assist in detecting breaches of Part 2 of the Commerce Act 1986 or trading conduct provisions in the Electricity Industry Participation Code 2010.
- Extend existing trading conduct rules to the hedge market – to deter participants from exercising significant market power in the market for flexibility products.
- Develop a flexibility access code (non-price elements) – to promote reasonable access to flexibility products. The code would focus on how participants receive and respond to requests for flexibility contracts, modelled loosely on the code being developed in the supermarket industry to address similar types of concerns regarding access to wholesale supply.
- Introduce market-making for a shaped hedge product, such as some form of cap or peak product – to create better forward price discovery and market liquidity for flexibility services.

These are also well aligned with our earlier observations. However, we would caution that expectations of liquidity and cost of market making be appropriately managed when dealing with shaped hedge products.

Structural Measures

More interventionist measures such as separation of generation is not something we would advocate. When previously commenting on proposals for vertical integration in New Zealand we commented that this is not the time to be contemplating untargeted and potentially interventionist regulatory policy or to be re-raising vertically integrated arguments that were previously closed off in the 2019 Electricity Price Review recommendations:

> *The Electricity Price Review concluded in 2018 that the structural separation of Gentailers was "unnecessary" because lower-cost and less risky options were available to "counter the drawbacks of vertical integration" while retaining the benefits of integration.*

The resurrected Single Buyer proposal takes this a step further. This proposal is analogous to a jilted lover unable to find closure.

6. ABOUT THE AUTHORS

6.1. DAVE CARLSON

Dave Carlson is an experienced energy market operator, designer and change manager with a track record spanning Asia, Africa, Australia and New Zealand.

Before returning to New Zealand in 2016 he was a Senior Vice President at SGX (Singapore Securities Exchange), responsible for new initiatives in the gas and power sectors. Prior to that he spent 10 years as the CEO of the Energy Market Company, EMC, the national electricity market operator for Singapore.

Dave has served on and chaired many industry and governance panels in Singapore to further liberalise energy markets including market rule evolution, the implementation of retail contestability, developing gas trading and introducing electricity derivative products.

Dave continues to work with a number of national utilities, regulators, market operators, private generator-retailers, and government clients in Southeast Asia, Australasia and the Middle East. He has a BSc in Mathematics from Victoria University in Wellington and passed the Associate Examinations of the Institute of Actuaries, London.

Dave is a senior advisor to, and board member of, The Lantau Group.

6.2. MIKE THOMAS

Mike Thomas, is a founding partner and the Managing Director at The Lantau Group with 35 years of consulting experience, focusing mainly on the energy sector in the United States, New Zealand, and throughout the Asia Pacific region. He advises clients on market design and development; regulatory matters; commercial transactions and disputes; and business and regulatory strategies.

He was part of a 1988 team advising the New Zealand Treasury on possible market reform directions, and lived and worked and raised three children in Wellington for ten years from 1997 to 2007. In New Zealand, Australia and around Asia, he has focused on the economics of complex energy systems and the crucial decisions that stakeholders must make in relation to those systems, including governance models, policy frameworks, energy security, market design, competition effectiveness, and regulatory oversight.

He started his career in 1988 with Putnam, Hayes & Bartlett, in the United States. Prior to co-founding The Lantau Group in 2010, he headed the Asia Pacific Energy & Environment practice of a global consulting firm. Mike has an MPP from Harvard Kennedy School and a BA in economics from Carleton College.