Toward 100% Renewable Electricity

How New Zealand can develop a fully renewable electricity system.

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Caveat

The insights in this report are limited to publicly available information and cannot be relied on as describing the characteristics of individual potential project characteristics, and are not suitable for investment decisions. Where a particular system or project is named it is in relation to an insight from a referenced work and is without prejudice to the commercial context or future of a current or future project with a similar name.
Executive Summary

With New Zealand’s principally hydro sourced electricity system back in the 80-90% renewables range, achieving a 100% renewable electricity target has broad appeal to New Zealander’s wider sense of ‘clean green’.

A new impetus has been created for renewable electricity with the signing of the COP21 global agreement on greenhouse gas (GHG) emissions reduction. By world standards a power system like New Zealand’s with 82% renewable electricity (and heading to 90%) is unique and increasingly desirable. Achieving greater than 90% renewable generation is likely for the New Zealand electricity system under business as usual, and should get to 94-98% over the next decade and a half. 100% renewable generation is entirely possible, but like most power markets in the world, some changes are required to enable the necessary shift.

Managing New Zealand’s variable annual hydro water charge - discharge cycle has been key to improving renewable energy proportions overall, and will remain important to the country’s productive future. However, a multifaceted focus on both demand and supply side aspects of the system, their drivers, and how they affect system resilience is needed if New Zealand is to advance beyond 90% renewables and realise multiple benefits to the country and its economy. This is already starting to happen in New Zealand.

Changing drivers for demand for electricity are reducing peak demand and improving resilience in the system as it shifts to renewables.

- Since 2006 the demand for electricity in New Zealand has stayed at just under 40,000 GWh per annum. System demand looks like it will remain in a flat-lining stasis in the medium term.
- Transpower have contracted 133MW of demand response. Enernoc, a private-sector energy management company, already had 100MW of contracted demand response in 2012. Transpower are pursuing a target of 650MW of contracted demand response.
- Demand reduction is growing. 370MW of demand reductions was added in 2015 by a broad range of end use electricity efficiency measures across the economy. Cumulative demand reductions reached 750MW – a trend that continues to grow as minimum energy performance standards, appliance labelling and electricity efficiency reduce both electricity use and peak demand. These reductions were delivered at 0.6c/kWh, 7% of current system long run marginal cost – the current cost of new marginal supply, indicating large yet untapped demand-side electricity efficiency potentials.

The above measures will continue to put downward pressure on the demand for electricity, cost structures in the electricity system, and slow the need for investment in new centralised generation stock and peaking plant. The upstream benefits available from electricity efficiency and demand management flexibility are significant. One study identifies that cost effective demand side measures could reduce New Zealand’s required electricity system investment by up to $3.5 billion in 2030 and up to $10.6 billion in 2050. International studies also highlight similar prospects. This places new challenges on an industry that has historically assumed persisting growth of 2% per annum for many years.

Progress to increased levels of renewable energy depends currently on the retirement of coal and gas plants as they reach end of life and their role is diminished by reducing system and regional peak demand. A significant reserve of consented renewables is already available should new generation be required.

The electricity sector is starting to change. Novel demand and supply side technologies and practices are already disrupting traditional industry paradigms on both sides of the meter and offer a new tranche of questions:
Until now, electricity has been used for stationary end-use consumption in homes, businesses and manufacturing. Now electric vehicles look like a key driver of demand growth while stationary electricity demand is decoupling from population and economic activity. If new renewable energy generation was used for electric vehicles and we remained at 90% for stationary electricity use but reduced transport emissions, would that be better or worse for the environment, and New Zealand generally?

Large industrial plants provide on-going benefits of employment, while consuming electricity generated from renewable resources. Wouldn’t it be better from a global environmental perspective to encourage these processes than replacing their output with products from countries with high emission coal power systems? It is important to consider the impacts on national energy production and consumption, but also the global impacts of choices in New Zealand.

Distributed photovoltaic power systems generate on the demand side of the meter. Global prices are falling and supplied volumes are growing logarithmically. Already these make an attractive investment for some consumers. How much will be generated as thousands of home owners and businesses install photovoltaic systems, How will these systems affect national supply and demand peaks? How will they access back up supply while minimising peak demand costs? The answers lie in how the electricity system sends time of use price signals that reward generators for their contribution to addressing peak demand and capacity costs.

The energy landscape is changing fast in this new environment. Low-carbon electricity is no longer just focused on renewable generation options, now we see a richer set of objectives emerging and taking over. This report draws on analysis that shows energy efficiency is rapidly reducing peak demand at cost of avoided power below a cent per kWh. Energy efficiency is central to managing overall system costs and is also key to enabling higher levels of renewables.

A stronger focus on consumers is evolving and has the potential to improve system performance. While existing power prices are cost-reflective and provide efficiently balanced incentives for demand side energy efficiency, supply side renewables and conventional generation, both consumers and generators need to receive more dynamic time of use energy and capacity signals, reflecting the realities of multiple users and suppliers in real time. This also offers more accurate rewards for demand management, energy efficiency and exported power based on supply – demand dynamics. The power system is transforming from one dominated by centralised generators to one where novel consumer offers and the decisions of 4.5 million actors on a persistent path of electrification will influence the system’s response to everything from weather perturbations, design of homes and business processes and future power plant investments. This in turn influences New Zealand’s future wellbeing, and economic productivity.

The above foreshadow much change for generators, some retailers are adapting already. However distribution companies face the largest shift in their operating paradigms as they will need increasingly to become capacity managers, not just lines operators. It is likely that small distributors will need to collaborate with larger neighbours to implement new capacity management systems.

Achieving a richer time of use and capacity pricing system through engagement of consumers is key to advancing energy efficiency and both centralised and distributed renewables. Despite their variability, with energy efficiency, renewables can offer New Zealanders a much more diversified, resilient and affordable power system. Getting it demands new thinking; moving beyond historical paradigms, and a focus on system value; utilisation, capacity costs, resilience, and system economics, not just the marginal cost of a kWh or the percentage of renewable energy.
New Zealand’s electricity system.

A history of renewable variability, system security responses and renewable electricity targets.

Since the commissioning of New Zealand’s first power station in Reefton in 1888, the electricity system has had to manage the variability of New Zealand’s hydrology, which is regularly perturbed by:

- A complex interrelation of the El Niño – La Nina climate cycles and the inter-decadal Pacific oscillation, along with global climate change effects. “The key drivers of New Zealand climate variability and change discussed here are the El Niño-Southern Oscillation (ENSO) phenomenon, the Interdecadal Pacific Oscillation (IPO), and anthropogenic climate change/global warming. The ENSO cycle has a significant effect on New Zealand climate, in particular upon rainfall over the South Island. Summer inflows to the main South Island hydro-generation reservoirs are significantly lower during La Niña conditions than in non-La Niña summers. The IPO acts as a longer-term modulator of ENSO activity and is associated with decadal-scale variations of mean inflows of about 10-15%.” (Renwick et al 2010)
- New Zealand’s geography - New Zealand’s alpine snow storage and spring melt and a geography of relatively short and fast river systems, means New Zealand has a system driven by annual cycles of snow reservoirs and limited water storage of around 35 days assuming no inflow (Mason et al 2010) and a dependence on the timing of snow fall and melt for hydro stability.

One measure of the impact this resource variability has on the system is the availability of the New Zealand power system, which is the ratio of actual annual generation (42,180GWh) to annual generation capacity at full rated output (9759GW). (MBIE 2015). In 2014 this availability was 50%. Simply, the variability of the resource used in most of the generation system means much of the plant capacity operates at part-load over a year.

**New Zealand’s early power system was almost entirely hydro based.** The North and South Island hydro systems were developed from the 1930’s (Arapuni the first of the Waikato stations in 1929, Tokaunu the first of the Tongariro stations in 1973, and Waitaki the first of the Waitaki River stations in 1936). Geothermal power plants were developed from the late 1950’s (Wairakei 1958). In 1930, hydro made up 92% of electricity generation, (McKinnon M. 1997), and 74% in 2010. (NZEECS 2011)

Power cuts were not unusual as the largely hydro-based system was challenged to expand to meet growing demand and annual hydrology variability. Historically, times when supply and demand were not well-matched led to insufficient supply to consumers and demand reduction efforts:

- 1940s when power supply lagged post-war demand growth.
- 1958 when North Island consumers faced a 15 per cent cut in supply.
- 1973 when TV broadcasts stopped earlier than usual and daily blackouts occurred in some areas.
- 1992 when water shortages resulted in water heating being cut, the aluminium smelter reduced output.
- 2001 when a dry, cold winter prompted a power-saving campaign.

In 2003 a power shortage taskforce initiated a process where the government established the Electricity Commission regulator and charged it with ensuring that the electricity system is able to cope with up to a 1-in-60 dry year. Since then the power industry has been held accountable for managing dry year risk. New Zealand’s larger industrial consumers face increasing exposure to spot prices in their tariffs, and commercial tariffs commonly include demand or capacity pricing and/or time of use energy price signals.
New Zealand has previously set renewable electricity targets.

- **NEECS Renewable Energy target 2001** set at 30PJ by 2012 with 19PJ (5,278GWh) of new renewable electricity; 9PJ of biomass and 2 PJ of renewable transport fuels. Electricity demand growth was a key factor in determining the target for renewable electricity.  (NEECS 2001)

- **Emissions trading scheme** September 2007, included a national target of 90% renewable electricity by 2025. (Clark H. 2007)

- **NZEECS 2007.** October 2007, This strategy introduced a target for 90 per cent of electricity generated from renewable sources by 2025 (based on an average hydrological year) (New Zealand Government 2007)

- **NZES 2011** “The Government retains the target that 90 percent of electricity generation be from renewable sources by 2025 (in an average hydrological year) providing this does not affect security of supply” This target is challenging but realistic, given New Zealand’s untapped renewable energy potential, our expertise in renewable development, and our Emissions Trading Scheme.” (New Zealand Government 2011)

- **The National Policy Statement on Renewable Energy** which seeks to ensure that:
  - the relevant benefits of renewable electricity generation and the national significance of associated activities are more explicitly recognised in policy development and consenting processes delivered under the RMA,
  - renewable electricity generation activities are recognised and provided for in resource management policies and plans, and
  - a more consistent national approach is applied to renewable electricity generation activities within the resource management planning framework. (MfE 2011)

**Current progress towards the target**

Current progress, and the dynamic nature of the system are highlighted by the system operator Transpower on 9 August 2016; the peak percentage of renewables reached 93% on the week starting 27 June 2016, peak percentage of renewables has been 90% or higher for each month since February 2016, HVDC transfer has been consistently high in 2016. North transfer in 7 months of 2016 was nearly the same as the full 12 months of 2015. (Transpower 2016b)

**Hydro inflow variability, water storage and system risk management**

Hydro status and inflows are tracked closely within an electricity market policy framework, which has been designed to anticipate the likely future risks at any point in time and includes provisions for managing abnormally low storage levels. Figure 1a shows the publically available plot of storage relative to historical mean storage levels at July 2016, with full storage, defined system risk levels and a defined emergency zone.
Figure 1a: New Zealand controlled storage and risk.

Figure 1b shows the typical analysis of responsiveness of the system and its storage capabilities to a range of scenarios from a given point in time. The resultant risk curves indicate ahead of time the likelihood of incurring a recognised level of risk in the system with a central mean scenario (the black dashed line) and calculated risk ranges (the red 10th percentile and blue 90th percentile ranges).

Figure 1b: Storage Scenarios and system risk.

Source: Transpower, System Operator SOS weekly reporting.
Figure 1c points to a 2,580 GWh drop in controlled storage from 2011 (a wet year with peak controlled storage) to 2012 (an adjacent dry year with minimum controlled storage). This recent step change in controlled storage represents a hydro risk of 7% of system annual electricity demand, equivalent to something like 600MW at average system utilisation. This can be met by a range of supply side generation options, and is increasingly being met by demand side measures, increasingly it doesn’t have to be specifically thermal plant.

Electricity System Status 2016.

1. A demand stasis.

Since 2006 the demand for electricity in New Zealand has stayed at just under 40,000 GWh per annum or thereabouts. (Figure 2).

Figure 2: Electricity consumption trends from 1990.
Despite an on-going linear trend of population growth (figure 3a), from 2006 electricity demand has decoupled from population growth to show characteristics more like a logarithmic decay of electricity demand growth into the future. (Figure 3b)

**Figure 3a and 3b: Population – power demand growth trends.**

![Graph showing population trend and power demand growth trends](image)

**Data Sources:** New Zealand Statistics and World Bank – population data, MBIE - electricity consumption.

New Zealand’s per capita electricity consumption grew linearly from 1960 to 1990. Since 1990, it has stabilised at about 8-9000 kWh per capita. (Figure 4). The trend is also seen in a limited number of other developed countries – for example Australia and Canada.

**Figure 4: Per capita power consumption trends.**

![Graph showing per capita power consumption trends](image)

**Source:** World Bank.

In most countries, projections of electricity demand have been based on population projections, but recent trends suggest a more complex set of drivers of power system demand have emerged. Declining per capita consumption implies a mix of factors at play across different sectors: increasing end-use efficiency, increasing consumer price response dynamics, more distributed generation, and changing economic structure. The trend in New Zealand is also observed in other mature developed countries, for example:

- Australia, where an 8TWh decline in 2013 has been attributed to; the impact of (mainly regulatory) energy efficiency programs (37% of the ‘demand gap’), structural change in the economy away from electricity intensive industries since 2010, and the price response of electricity consumers to higher
electricity (and gas) prices in the National Electricity Market (NEM) (19% of demand gap). Growth in distributed generation including rooftop PV contributed 13% of the ‘shortfall’ in consumption. NEM demand in the financial year to 2013 was almost eight terawatt hours (TWh), or 4.3 per cent lower than in the peak year of 2009. All of the decline in consumption has in fact been at the expense of coal-fired generators, with the result that many are now barely profitable. GHG emissions fell by 9.2 Mt CO2-e, roughly two per cent of Australia’s total emissions in 2012 alone. (The Australian Institute 2013)

- The United States of America, where declining sales in the industrial sector and flat sales in the residential and commercial building sectors, despite growth in the number of households and commercial building space (EIA 2013)
- Japan, where population and energy are decoupling; “decomposition analysis results of changes in electricity consumption in Japan clearly show that contribution by demographic is not so large and major factors are energy conservation, electrification and economic growth. Acceleration of the population decline is expected in the future, but still, for example, the rate of decline in the next decade (2013-2023) is expected to be about 0.4% per annum. The connotations of the term “population decline” may give us the impression that a serious impact on various fields in the society is occurring. However, in reality, contribution by the population decline to decreases in electricity consumption is limited”. (IEEJ 2015)

Regardless of system operation, fuel types, technologies, degrees of low growth in electricity demand have persisted since 2006 in New Zealand and other developed economies. While an economy functions effectively and there are no system failures, this is a desirable state. The economy can expend the capital it might have spent on new power plants on other social and economic investments and the environmental and resource impacts of new power plants are avoided.

**Capacity, consumption and security**.

While the demand for electricity has flattened, the impact on system capacity is driven by a number of factors as well as energy demand. Figures 5a and 5b show New Zealand system capacity to 2014 and the range of possible capacity prospects.

**Figure 5a: Capacity peaks; Trends from 2011, projected to 2025.**

![Graph showing system capacity trends](source: Transpower 2016d)
Figure 5b: Prudent peak – Electricity forecasts.

Source: Transpower 2015

Capacity requirements are driven by complex regional demand and supply side drivers. With Otahuhu and Southdown shut from the end of 2015, and the Huntly units under consideration for retirement the upper North Island System is an area for concern. Transpower’s Upper North Island generation decommissioning report identifies “upper North Island winter N-1 and NG-1 stability limits at 2534MW and 2219MW respectively. This compares to the actual winter 2015 peak of 2150MW and 2020 prudent load forecast of 2550MW. (Transpower 2016b) In the report Transpower state they are investigating options.

Historically the obvious options to manage projected capacity constraints would be supply side or transmission options. The commitment to CoP21 GHG reduction goals and the current mix of new demand side and economic distributed renewable generation options demand new processes for discovery and motivation of diverse economic GHG minimising solutions. Transpower’s demand response process is one example. A distributed mix of demand and supply side capacity management options should offer greater system resilience than a discrete number of supply options.

Transpowers 2016 Grid Reliability Report (Transpower 2016c) lists system stability challenges: upper North Island voltage stability, from 2025; north of Whakamaru, from 2029; Wairakei, from 2029/2027; Central North Island, existing; and Bay of Plenty transmission constraints, existing. In all cases the report notes these are short-term issues and can be managed operationally. Transpower maintain an active programme of grid upgrades and replacements. See Summary Table 1 in (Transpower 2015)

With the Huntly units contracted to supply power to 2022 and scheduled to remain in operation until December 2022 (Genesis 2016), some further time has been bought for a variety of options for managing stability to be explored.

(Transpower 2016d) used probabilistic analysis to determine a winter capacity margin (WCM) of 630 - 780MW for the North Island. The rate at which successive prudent peak forecasts (figure 6) have declined is material. From 2011 to 2015 the forecasts have dropped by 1.7GW for 2015 and 2.5GW to
2025, an average of 0.34GW per year decline in projected peaks in 2015. The lower bounds of both figures 5a and 5b are flat demand.

**Renewable electricity progress in New Zealand.**

A number of observations show a system already adapting to change.

1. **Significant recent shifts towards renewables.**

   **Non-hydro renewables capacity** grew by + 0.55 GW at an average annual rate of (+6.2%) over the past 6 years despite the suppressed growth in demand for electricity. Over the same period coal capacity dropped by - 0.55GW (-16%/ann.), and annual gas fired generation capacity increased by 0.3 GW from 1.2GW to 1.5GW (+22%). (MBIE 2016) With the 404MW Otahuhu B station retired in September 2015 there is a net decrease of 0.1GW of gas capacity from that date.

   **Non-hydro renewables electricity generation grew as fast as fossil fuel generation declined.** Coal and gas electricity generation reduced substantially while hydro geothermal and wind increased. At an average annual growth rate of 8.1% over the past 6 years, non-hydro renewables reached 3000 GWh or 7% of total generation output in 2014. Over the same period fossil fuel generation dropped by 32%, a 5%/ann decrease, amounting to 3,039 GWh reduction or 7% of total generation) (MBIE 2016). Figure 6 shows the scale of shifts in the generation mix that can occur over a 1 year period.

![Figure 6: Changes in generation output by fuel mix 2013-2014.](image)

   **Source:** MBIE 2016.

These New Zealand trends are not dissimilar to trends in other developed countries where substantial growth in renewables is underway. In most countries renewables and high efficiency gas plants are expanding and displacing older thermal plant, with a net reduction in power sector emissions.

In ‘Revolution Now’ (US DoE 2014) the US Department of Energy describes the rapid price declines and uptake of Wind, Solar photovoltaic, LED lighting and Electric Vehicles as “the historic shift to a cleaner, more domestic and more secure energy future is not some far-away goal. We are living it, and it is gaining force”. In the United States, solar accounted for 32 percent of the nation’s new generating capacity in 2014, beating out both wind energy and coal for the second year in a row. (GTM Research 2015)
Global renewable power generation grew by an estimated 5% in 2015 and now accounts for around 23% of total electricity generation globally. New renewable electricity capacity grew at its fastest pace in 2015, supported by policies driven by energy security, local pollution concerns and climate benefits. With the momentum of the United Nations Framework Convention on Climate Change (UNFCCC) 21st Conference of the Parties (COP21) and recent policy changes, the outlook for renewable power is even more optimistic. However, policy uncertainties, non-economic barriers and grid integration challenges persist, preventing renewables from being fully on track with the IEA’s 2025 2DS target. (IEA 2016)

A total of 175 countries have primary and final renewable energy or electricity targets, or capacity targets for various renewable energy systems. A number of countries are now projecting dates when they plan to achieve 100% renewable electricity, most are like New Zealand; they have a choice of suitable renewable energy resources or are island nations. (REN21 2016)

In New Zealand stable demand levels might slow investment, but MBIE project that New Zealand electricity sector emissions will revert to 1990 levels by the mid-2020s. (MBIE Insight 2016).

2. Low sector emissions relative to some other sectors

Coal and gas for electricity production made up 12% of New Zealand’s GHG emissions in 2014. Fugitive emissions from geothermal applications (CO₂ released from geothermal steam) made up 3% of national GHG emissions.

**Figure 7: Sector GHG emissions in New Zealand.**

3. New Zealand retail electricity prices

One of the key objectives in any power system is to maintain economic costs for a given resource base. Historical prices (in real terms) were lower than current prices for a range of reasons. The Electricity Authority’s 2013 review of pricing explores these in some detail. Figure 8 shows the total prices and costs averaged for all consumers in real 2013 dollars. (Real dollars normalise out inflation changes).
Rises in electricity prices since 1985 include removal of cross-subsidies and more recently, higher costs to generate and distribute electricity. The residual in the graph is a mix of implied taxpayer subsidy and under-recovery of generator margins. Although average costs reduced slightly in the 1990s, they increased quite sharply from the early 2000s as a result of increasing fuel costs, the increase to GST in 2010 and more recently increases in transmission and distribution charges. (Electricity Authority 2013) The analysis includes sector analysis of prices and cost structures.

Comparison of country costs to other similar countries is a common and relevant perspective on a sector’s performance. Figure 9 compares New Zealand’s residential electricity cost to other OECD nations.
Figure 9: New Zealand retail residential power costs relative to OECD nations.

Residential Electricity Costs in OECD Countries for 2014

<table>
<thead>
<tr>
<th>Country</th>
<th>USD per MWh (PPP)</th>
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<tbody>
<tr>
<td>Portugal</td>
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<tr>
<td>Germany</td>
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<tr>
<td>Poland</td>
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<td>Norway</td>
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<tr>
<td>OECD Average</td>
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Source: MBIE 2016

Price reflects many aspects of a power system’s available resources, technology mix and system reliability. It’s interesting to compare New Zealand prices to:

- Norway with the lowest prices in the OECD, has 98% renewable electricity from a system with one year’s worth of storage capacity and a similar dynamic electricity market system to New Zealand.
- Portugal and Germany with the highest prices, (twice the New Zealand price) and significant renewables feed-in-tariff costs.
- France – similar costs to New Zealand, but from an aging nuclear generation base.

New Zealand enjoys high reliability from the third highest renewables power system in the IEA member countries (after Norway - high storage hydro, and Iceland – high geothermal) despite the significant hydro resource variability in New Zealand.

Part of that reliability has been due to the firm capacity of coal and gas power stations. Huntly (CCGT and Coal), Otahuhu and the Glenbrook kilns waste heat power plant have all contributed to peak demand management and provide power quality services (voltage, frequency and power factor stability) largely because of their proximity to major upper North Island load centres. The need for that supply side management is changing as increasing demand response capability starts to offer economic alternatives to supply side peak management.
The potential for increasing renewable electricity is multi-faceted

A strong sense however that higher levels of renewable electricity are possible.

The 2016 Royal Society report; Transition to a Low Carbon Economy for New Zealand, states “Technically renewables in the mix could achieve close to 100% without reducing the reliability and security of the power grid. However, very high penetration that includes high shares of variable renewable energy systems would need a more flexible grid, energy storage, and back-up generation (possibly thermal plant) to meet seasonal peaks, especially in dry years when hydro is constrained.”

Even 100% renewable electricity would not be zero-carbon since some subterranean CO₂ is released during geothermal generation. To achieve this, the report argues the electricity grid needs to be more flexible with more energy storage and found an even higher percentage could be reached if back-up generation could be put in place to meet seasonal peaks, particularly when water flows were low in the hydro-electric dams.

- Distributed generation systems and ‘smart grids’ are expected to become more common, overcoming technology integration issues, though the rate of deployment could be faster.
- The co-benefits from installation and operation of renewable energy plants are often significant and should be included in decision making alongside the energy cost evaluation.

The report also suggested it could be possible to get to near zero net carbon emissions for electricity generation by including some coal or gas fired power plants linked with carbon dioxide capture and storage, and an increased uptake of renewable energy projects would probably be the outcome of an increased carbon price being placed on emissions from thermal generation of heat and electricity (Royal Society 2016).

Industry perceptions about extended renewable electricity: “achievable but...”

In the 2016 Energy News and ABB Annual New Zealand Electricity Survey of power industry respondents:

- 29% claimed a 100% renewable electricity sector was achievable and realistic. A further 52% felt it was technically achievable but financially unrealistic.
- 45% claimed that encouraging uptake of electric vehicles was the best opportunity for the power industry to reduce transport emissions. A further 28% believed working towards a 90% renewable generation target was the best option for the industry to address GHG reductions, and a further 10% believed that working to a 100% renewable generation target was the best option for the industry. (Energy News 2016)

There is analysis that New Zealand could have a 98% renewable electricity system...

In their New Zealand Energy Scenarios, Navigating Energy Futures to 2050, the New Zealand Business Energy Council ‘Waka’ scenario describes renewables reaching 98% by 2050. (BEC 2016) The scenario points to an overall decline in energy use from under 600PJ to 500 PJ and a substantive shift to electric vehicles, a halving of CO₂ emissions, while GDP nearly doubles to NZD416Bn.

And analysis that shows New Zealand could have 100% renewable electricity with system stability.

There are few publically available studies on the New Zealand electricity system’s resilience under higher levels of renewables. Such analysis requires modeling of interactions of all parts of the system, including detailed resource variability unique to each generator, transmission characteristics and half hourly demand with regional resolution.
One published study set out to test combinations of wind and geothermal generation in a 100% renewable generation mix against ‘minzone’ hydro requirements. (Mason et al 2010)

Balancing wind, base-load geothermal and hydro storage for 100% renewable electricity. Three different generation mixes were found to be capable of providing a 100% renewable electricity system for New Zealand, whilst meeting existing “minzone” criteria for ensuring security of supply.

As wind penetration decreased from 29.5% to 18.7% to 4.9%, and new base-load was added accordingly, the magnitude and frequency of supply deficits needing to be met by peaking plant and/or demand-side measures decreased substantially. Hydro spillage also decreased with lower levels of wind penetration. Since wind resources are plentiful and relatively cheap in New Zealand, new geothermal reserves are limited and new hydro generation has potential development constraints, transitional planning must consider the appropriate balance between the amount of wind generation in the system and the implications for peaking measures.

The role of hydro storage was found to be significant, but further research is required to determine whether building additional capacity is justified. Demand-side measures offer potential to minimise peak power requirements at low cost, but further investigation is needed to ascertain the potential to deal with the 450-1430 MW peaks identified in this study.

(Mason, Page and Williamson 2010)

3. Demand for electricity is an important driver – both sides of the meter matter.

a. The persisting demand for electrification

Developed societies have a strong trend of replacing less efficient and less clean fuels with electricity. Societies that struggle to grow their electricity resources struggle to develop modern social and economic outcomes. Examples include the global trend of displacing coal and diesel powered rail transport with electricity, increasing delivery of end-user services with electricity, and the growth of electronic appliances. The general demand for electricity, trend for electrification and increasing efficiency of end-use technologies, continues in all societies, and looks set to transform transport systems as adoption of electric vehicles takes off.

b. Supply responds to a demand for electricity derived from society’s activities.

Economic and societal activity creates a derived demand for energy supply and this derived demand will have an on-going underlying impact on supply options. Analysis undertaken for the 2001 NEECS, highlighted that growing the share of renewables, and indeed growing generation capacity at all, is driven by demand for energy. In the analysis it was highlighted that growth in renewable supply beyond that required to meet demand could come at a high cost. There is a cost to artificially growing renewable supply beyond organic demand for electricity. Figure 10 shows the impact on underlying electricity costs as a permit price climbs to the point at which higher cost additional demand is required to drive renewable supply.
With the advent of electric vehicles and other changes in the system, the price values change considerably but the principle that there are real limits to growing renewable supply beyond normal demand remains.

c. Demand sensitivity to climate perturbations.

The future impact of climate change on the New Zealand hydro and energy resource base is highlighted by a NIWA study on climate impacts on New Zealand hydrology and wind resources. “A rise of 2.5°C of warming by the end of the century with a rise in mean snow line of 200-300m and a 30-50% reduction in snowpack” would be offset to some degree by “winter heating demand reducing significantly, with no frosts likely in major population centres by the end of the century.” The net effect would seem to be “a changing seasonality of electricity generation capacity. Generation capacity is likely to be higher in winter and spring with increased rainfall, river flows and windiness, while capacity is likely to be lower in summer and autumn with reduced snow melt.” (Renwick et al. 2010)

d. Options for significant growth in demand.

Despite the likely trend of lower demand growth, the possibility of significant growth in demand is always possible. While an extension to a large industrial plant is more likely than a new large energy intensive industrial development in a developed economy, the existing high level of electrification suggests demand for power is mature.

The main opportunity for demand growth is electric vehicles. Transport has yet to achieve the level of electrification seen in other sectors, but there are good economic reasons for a shift to electric vehicles in New Zealand. Substantial market transformation is needed to transform what currently looks like a slow growth adoption path in New Zealand.

New Zealand transport emissions have grown faster than in other sectors in New Zealand; up 69% since 1990. (65% light duty petrol vehicles; 21% heavy duty vehicles; 16% light duty commercial vehicles). Electric vehicles will initially substitute for relatively modern vehicles, but replacement of older higher polluting vehicles from the vehicle stock will take time to realise GHG reductions. Other mobility options are also changing transport demand for electricity; electric bikes, increasing public transport, and changing perceptions about vehicle ownership. Oil prices are currently low, so is New
Zealand’s currency, but repatriating our fuel expenditure with a shift from imported oil to local power is a valid path.

Electric vehicle purchase price is the biggest issue to consumers, but battery costs are falling fast. Lower GHG, local pollution, and substantially lower operating costs are less well recognised. The current target to double EVs (from a base of 1000 EVs in 2016) each year to 64,000 in 2021 (2% of vehicle fleet) is what MoT identified as autonomous growth (MOT 2015). With more supportive policies and market development, electric vehicle growth could accelerate.

### Global supply dynamics for electric vehicles
- Global electric (and hybrid) vehicles exceeded 1m in 2015.
- Renault-Nissan, the global EV sales leader committed to 20% of EV sales by 2020, has a 200-mile-range Leaf on the way.
- Volkswagen will sell 2-3M EVs by 2025,
- Volvo is aiming for 10% electric sales by 2020.
- BMW’s plans on electrifying its whole line-up with plug-in hybrid options and all-electric “i” line.
- Tesla plans to sell 500,000 electric vehicles a year by 2020, ten times current production.
- BYD, the leading China manufacturer, will sell 0.5m EVs by 2020.

[http://www.theicct.org/electric-vehicles](http://www.theicct.org/electric-vehicles)

Electric mobility options could grow disruptively and create a potential demand for an extra 4% of new base load electricity demand by 2030, but a more moderate 1.5% is likely with current policies. This can be easily met by already consented new renewable electricity investments.

e. Loss or gain of significant ‘parcels’ of demand.

The possibility that a large element of demand (such as the NZAS Tiwai Point smelter, which makes up 13% of electricity demand, or a central North Island pulp mill) could be lost from the system over a relatively short time period is quite different from a more gradual adjustment in demand from population growth or increasing energy efficiency. New plant expansion could be commissioned, the recent growth in dairying adds up to significant new processing plant capacity.

Large energy intensive plants are typically long term investments, their prospects driven by global commodity prices and global technology innovations. Location, the type of load, and transmission pricing structure are important factors in determining the implications on power price, system performance, future investment and system GHG implications.

Modeling by Auckland University suggests that if the Tiwai Point left the system “lower prices reduce the total wholesale cost of the country’s electricity by over $140 million, 9.9% of the wholesale electricity bill. At the Tiwai node where the smelter is located the price of electricity falls by 18.4% over the course of the year. Whilst at the main population centers in Auckland, Wellington and Christchurch prices fall by 5.4%, 9.0% and 15.0% respectively. These price reductions occur despite the extra line losses that would occur from having to transmit energy further up the country”. (Browne et al 2010)

How this lower power price is resolved into changes in economic output is unclear. Increasingly the economy’s structure is developing activity from less electricity intensive services, marginal gains would have to exceeded the loss of export sales, regional jobs etc. before the economy recovered the loss of output.
“Wholesale electricity prices constitutes around 38% of the retail price of electricity (Bertram, 2013). Lower wholesale prices may ultimately lead to lower retail prices as competition forces electricity companies to pass through the reduced costs. The impact on the market is likely to be most significant in the short to medium term. In the long term firms may hold off building new generation if prices are too low, this and growing demand would offset the lower prices” (Browne et al)

A key consideration when looking at renewable developments in the power system is that the loss of a large parcel of demand outside the main load centers at Auckland - Central North Island may not significantly alter the power security drivers for thermal peaking and power quality plants at the upper North Island. The impact depends on the coincidence of the load with demand peaks.

The implications extend beyond New Zealand’s power system. While New Zealand might lower its net emissions as direct emissions from a site like the smelter cease, baseload electricity emissions are low in New Zealand and the carbon intensity of our exported products reflect the low carbon intensity of our electricity. As an example, global emissions will grow substantially if Tiwai Point’s very low carbon intensity aluminium (1.97 tCO₂/tAl) is replaced by increased production from Middle East gas powered smelters (12.6 tCO₂/tAl) or Chinese coal-fueled smelters (17 tCO₂/tAl). (UK Carbon Trust)

f. Improvements in energy efficiency and demand side management; reducing peak demand and lowering supply costs.

Minimum Energy Performance Standards and labeling. The energy efficiency impact on the electricity system is significant. This programme (Mandatory Energy Performance Labeling, Minimum Energy Performance Standards and the complementary ENERGY STAR programme) offers substantial reductions in base load energy demand for a healthy net benefit to consumers.

Since 2002 appliance and equipment energy performance regulations (MEPS 2016) mandatory labelling, and importantly voluntary endorsement labelling (ENERGY STAR), have been reducing the energy intensity of key energy using products in New Zealand. The changes in energy use have been substantial and continue to develop as; existing appliance stocks are replaced, energy efficiency Standards are improved, technologies develop, consumer awareness and understanding of energy efficiency benefits improves, retailers and suppliers change behaviours, and sales trends evolve.

Key trends in MEPS projections evaluation (E3 2016) and the evolution of sales of regulated products (EECA 2016) offer good measurement of progress to date. Cumulative energy demand reductions from 2002 are 22.9 PJ, worth $560M, and associated GHG reduction of 879kt CO₂. In 2015, electricity consumption was reduced by 4.7PJ or 1305 GWh from its 2002 baseline. (EECA 2016). The programme cost NZD 4.0Mn to run in 2015 delivering 183GWh of energy demand reductions at a cost to government of 0.37 c/kWh. (EECA 2015)

Existing energy efficiency programmes already offer significant electricity use and peak demand reductions. In the Electricity Authority’s 2015/16 consultation on it’s programme of work, the scale of electricity use and peak demand reduction to 2015 is provided by EECA:

EECA states that by the end of 2015/16, EECA’s levy-funded activities will have delivered:

- cumulative annual savings of 2195 GWh,
- 742 MW reduction in peak demand,
- present value of energy reductions of around $1278 million at a cost to the levy of about 0.6c per kWh avoided energy demand. (Electricity Authority 2015)

Levy funded electricity efficiency delivered an additional 371GWh of energy demand reduction in 2015/16.
The EECA evaluation of MEPS is included in the electricity demand reductions.

### Table 1: Evaluated electricity efficiency impacts.

<table>
<thead>
<tr>
<th>Activity</th>
<th>2015 Annual demand reduction in 2015/16</th>
<th>Peak demand reduction in 2015/16</th>
<th>Cumulative to 2015/16</th>
<th>Cumulative peak demand reduction 2015/16</th>
<th>Cost of avoided demand</th>
</tr>
</thead>
<tbody>
<tr>
<td>MEPS</td>
<td>183 GWh</td>
<td>NA</td>
<td>1305 GWh</td>
<td>NA</td>
<td>0.37c/kWh</td>
</tr>
<tr>
<td>MEPS &amp; Levy</td>
<td>371 GWh</td>
<td>371 MW</td>
<td>2195 GWh</td>
<td>742 MW</td>
<td>0.6c/kWh</td>
</tr>
</tbody>
</table>

A simple projection assuming medium term decline in electricity use reduction improvement due to saturation, and no further improvements in Standards, suggests annual energy use reductions could expand to 1500 GWh for MEPS in 2030, while levy funded demand reductions could expand to a further 800MW or more. The demand side peak demand reduction – cost dynamics deserve further exploration as they make such a large low cost contribution to system value.

The upstream impact of energy efficiency results on the power system are not dissimilar to those from other countries and reduce the need for transmission, distribution and reserve generation as well as the direct electricity use reductions. Most power system analysis focuses on supply side issues and options, but power sector impacts from demand side efficiency are explored in the Energy Delivery chapter of Capturing the Multiple Benefits of Energy Efficiency. (IEA 2014)

Examples include:

- Modeling of the German power sector, including T&D costs, as it moves to 80% renewables shows 2035 system costs dropping from a BAU case of EUR65Bn with increasing levels of energy
efficiency. Energy efficiency (driven reductions in demand) at 16% below current levels offers EUR55Bn system costs, 20% offers EUR52Bn and 40% offers EUR44Bn (all in 2012 currency). This defines a potential system cost reduction of 30% despite increasing renewables over the long term. Cost per MWh are about the same in each scenario, the key issue being that despite increased renewables costs being the biggest element in scenarios, costs can be offset by energy efficiency. (Wunsch et al 2014 reported in IEA 2014)

- Efficiency Vermont energy efficiency programmes reduced energy demand by 110GWh over a 10 year average measure life at a total cost of USD33Mn and at a levelised energy cost of USD39/MWh. The energy efficiency measures in turn provided measured benefits 2.4 times greater, over USD104/MWh, comprising: avoided generation costs worth USD57/MWh, avoided distribution costs of USD20/MWh, avoided lines losses of USD10/MWh, avoided CO₂ of USD9.4/MWh at USD20/tCO₂, as shown in Figure 11. (IEA 2014)

Figure 12: Power system upstream multiple benefits - example.

Similar analysis for the New Zealand power system highlights that future changes in electricity demand are expected to create a substantial economic case for the smart grid opportunity in New Zealand. The benefits available from using demand flexibly could reduce New Zealand’s required electricity system investment by up to $3.5 billion in 2030 and up to $10.6 billion in 2050. (Meridian Energy 2012)

A key issue is the degree that energy efficiency or demand response options contribute to system stability by reducing winter / dry year peak demand. A wide range of winter base load / dry year energy efficiency demand reducing options span the entire economy and are outlined in Annex 1. Recent changes are outlined:

**Household Sector.** Recent changes in sector electricity demand include:

- A decrease of -244GWh in electric water heating between 2012 and 2014 as electric storage water heater sales drop. Gas water heater sales increased by 6442 units or 33% and electric water cylinder sales dropped by 5371 or 10% over 2012 to 2014 (EECA 2016).

- A decrease in electric resistance heating of -105 GWh offset by an increase of 50 GWh in heat pumps from 2012 to 2014. This reflects the ongoing application of heat pumps and offers an indication of the net efficiency gain of over 200% after changes in heating patterns. While wood


heaters remain a cost-effective non-electric heating option (10-12c/kWh delivered heat), air quality issues in built up areas are a concern and they tend to be used in peri-urban and rural areas, close to low cost wood supplies. Heat pumps (5-7c/kWh delivered heat) continue to dominate urban areas. Given that heat pumps deliver nearly twice the heat per dollar, it is unlikely that wood fuel will grow significantly in urban areas.

- An increase in household electric cooking energy of 113GWh from 2012 to 2014. (EEUDB 2016)

The wellbeing outcomes from improved insulation in New Zealand homes are well documented. Studies in other countries have also identified low levels of energy demand reduction as consumers maximized their utility from new insulation by choosing increased comfort and health outcomes rather than reduced use of energy for heat. This is entirely understandable; New Zealand has the lowest residential heating intensity of IEA member countries; a function of both under-heating and a fairly benign climate. (IEA 2012) There is a growing body of analysis in New Zealand of energy poverty and worsening household affordability. New Zealand isn’t alone – most temperate climate countries have an energy poverty challenge and historically under-insulated housing stock.

The scope for improved insulation and heating system efficiency to reduce winter / dry year electricity consumption remains significant. It’s far easier and cheaper to address energy efficiency and future energy and operating cost implications of houses at design suggest scope to further increase sustainable energy in new buildings. Some aspects of home retrofit programmes deserve further exploration: The Warm Up New Zealand (WUNZ) offering was a set of low-cost, high-benefit retrofits. Addressing home energy efficiency from a lifecycle perspective should enable a greater winter - dry year energy demand response. The WUNZ retrofits can be developed to get an older home closer to current standards (which aren’t retrospective) given the now identified health gains for occupants and scope for further social outcomes.

Lighting. Lighting demand peaks in winter evenings. Residential annual lighting energy has grown slightly from 1498GWh in 2012 to 1512GWh in 2014.

LED lighting is cost effective and reduces both evening peaks in street lighting, residential and commercial buildings and reduces base load energy use in commercial buildings. Currently LED lighting is economic in commercial buildings, and fluorescent lighting sales are declining as LEDs take over. (EECA 2016). Two issues are relevant;

Network companies that have traditionally included distribution and street lighting capital, operating and maintenance costs in a metered or assessed kWh charge, and are now having lower capacity charges as well as energy charges as street lighting energy and capacity drops. LED lighting offers little demand or energy use improvement over good quality T5 commercial lighting practice, so the main opportunity lies in residential lighting.

The scope for LED / high efficiency lighting potential lies in displacing remaining incandescent lighting, poor quality CFL, or older fluorescent lighting mainly in households. Lighting consumption in households is estimated at 1,500 GWh per year, (EEUDB 2016). In 2011, OPENZ assessed the residential lighting energy reduction potential at about 1.5PJ or 400GWh. “Incandescent lighting provides 34% of the lighting by 2025/26, down from 77% in 2006/07. Compact fluorescent lighting provided 25% of the lighting in 2025/26, increasing from 19% in 2006/07. The remainder of the lighting in 2025/26, was provided by long-tube fluorescent (13%), halogen lights (13%) and LED lights (13%).” (EEUDB 2011) In 2010, the economics for LED lighting and the role that LED lighting is now playing was not obvious.

Commercial Sector. Recent changes include

- An increase of 116GWh (+8.%) in refrigeration electricity consumption from 2012 -2014.
- A drop of -82GWh (-3.5%) in water heating electricity consumption from 2012 -2014.
• An increase in resistance heating of 48GWh (+3.4%) and Heat pump heating 23GWh (+3.8%) from 2012-2014

Commercial building electric heating and reheat in air conditioning systems is 1,400 GWh / ann. consumption (5.1PJ EEUDB). Direct use of gas could displace commercial winter electric heating by replacing morning / evening electricity peak with gas heating. The experience in Christchurch shows that combination of commercial heat pumps and LPG fresh air duct heaters for cold morning boost works well, and can be retrofitted economically if part of a “continuous commissioning” (systematic ongoing energy efficiency upgrade) process.

There are barriers however. Electric heating and reheat is often wired into tenant boards but should be building base load wired. Gas supply is quite invariable. Gas is often an associated output from oil extraction, so there is limited supply side value in peak pricing. Gas storage is also now part of the system with the Contact Energy owned Ahuroa field able to inject 27 TJ per day and release 45 TJ per day. Commercial consumers already have a gas – electricity price differential. It is more difficult for energy managers to manage gas use in any meaningful way as all but industrial scale sites have gas meters that are still manually read on an ex-post monthly basis. Modern clamp-on time of use ultrasonic gas meters might help improve efficiency of gas use and there are a number of examples where they have identified leaks and opportunities to achieve up to 50% reduction in gas use, however the upfront installed costs of around $8,000 per meter are a barrier to accurate time of use commercial gas prices and improved management of gas use.

**Distributed generation - Demand side renewable options**

Distributed generation has been a small but useful part of New Zealand electricity scene for many years, the systems have been installed in industrial or commercial applications, typically receiving a time of use tariff or installed in response to demand or capacity charges. New Zealand’s distributed generators ‘just got on with the job’ and adapted generators, installed small hydro plants, and installed wind generators and more recently PVs, to offset peak supply costs and improve reliability. Larger distributed generators included synchronisation capability enabling them to start on a price signal and synchronise with grid-supplied power to export when supplier price signals made exporting power economic for the end user. Not intended as base load generators (their operating costs are typically above sector LRMC and they often aren’t designed for continuous operation) they have however usefully contributed to peak demand reduction, avoided network expansion costs, and helped their communities through diverse power supply constraints. Most hospitals and public facilities with a need for on-site generation (e.g. for lift power back up) will have synchronised generating capability.

**Photo-voltaic (PV) solar power - The new kid on the distributed generation block.**

Photovoltaic solar power systems generated 7GWh in 2013 (MBIE 2016) (almost 1/800th of 6,053 GWh of geothermal generation).

The recent growth in residential scale PV systems is a new potential in New Zealand’s power market. Prices have fallen in an inverse logarithmic trend since the 1970’s and the supply has increased logarithmically. The two trends together are expressed as Swanson’s law (figure 12) and represents an accelerating growth in availability and supply of this technology that saw 200GW of PV module capacity produced globally in 2014 at a module price of USD0.6/Watt.
Swanson’s law shows a 20% decrease in price for every doubling of cumulative shipped photovoltaics. The blue line shows actual worldwide module shipments vs. average module price, from 1976 to 2014. Prices are in 2011 dollars. (ITRPV 2015)

Transpowers’ forecast of solar photovoltaic costs graph from Transmission Tomorrow (Transpower 2016) translates the declining capacity costs of photovoltaics into a levelised cost of electricity for New Zealand (figure 14). For many consumers this is already below their retail cost of electrical energy, and for commercial consumers offers an opportunity to lower capacity charges. Currently central generation plant remains a lower cost option for the system as a whole; Geothermal energy currently appears to be the cheapest new baseload generation technology in New Zealand, at around 9 c/kWh, followed by wind and then natural gas. (MBIE 2016)
This future potential for distributed photovoltaic generators offers a new and potentially large demand-side sub-market of photovoltaic renewable generation, which can contribute substantially to managing winter / dry year demand if it is effectively integrated to market electricity demand and capacity drivers. In 2014 distributed solar generation capacity in New Zealand grew by 12MW, in 2015 by 14MW. (EA 2016)

MBIE projections show a range of photovoltaic scenarios in figure 15: For the mid case, it was assumed 30% of new households and 15% of existing households install solar PV once it is economic. Commercial solar PV is included in the total and was assumed to be 16% of total residential uptake. The purple line below is the mid case and shows solar PV capacity over time in all scenarios except GS3 and GS4. In GS4 uses the high case while in GS3 the low case. (MBIE 2015)
In New Zealand photovoltaic generators were first installed by niche operators (microwave links and remote applications including rural intersection lighting were the first adopters of PV in New Zealand) Mainstream retailers are starting to engage in distributed renewable energy. Mercury bought ‘What Power Crisis’ in 2016. A market of pro-sumers (producer-consumers) has evolved as householders and small businesses keen to develop their own generation invest in PV. The distribution and orientation of these systems is somewhat arbitrary, while they are generally oriented to the north, there is no effective relationship between these systems and the drivers for value and demand in the electricity system, and their current installation is all but arbitrary.

Commercial building air conditioning and cold storage demand is an interesting opportunity for photovoltaic generation. Electricity demand for these end uses is highest in summer, rather than during winter / dry year demand, but they are only partially driven by external climatic conditions\(^1\), they are primarily a function of internal cooling loads, and therefore can make effective winter / dry year demand management options.


Installing photovoltaics on these buildings offers commercial building and cold store operators, and distribution companies a cost-effective reduction in peak demand costs. Photovoltaic generators can be oriented to be more coincident with peak cooling demand, and it makes sense to be integrated with these end-uses and their peak capacity charges rather than arbitrarily oriented or distributed.

**Supply Side Options**

New Zealand has an extraordinary renewables resource endowment. While a range of base-load generation options such as new hydro could be utilised, two supply side options stand out for New Zealand in a medium-term transition to higher renewable electricity generation: Geothermal and Wind generators.

Most renewables have distinct variability characteristics - and most correlate positively with hydro variability. Geothermal however offers genuine ‘baseload’ availability, with plants achieving 80% availability (operating at rated load 80% of the year)

**Geothermal generators.**

New Zealand’s geothermal resources are large. Geothermal generation can be run to provide base-load, at higher capacity factors than most other renewables. Most of New Zealand’s installed geothermal generation, capacity of 1010 MW is situated in the Taupo Volcanic Zone, and about 25 MW is installed at Ngawha in Northland. In 2014, electricity generation from geothermal accounted for over 16 % of New Zealand’s total electricity supply (MBIE 2016b)

Geothermal is currently one of New Zealand’s cheapest sources of new electricity generation. However, we are unlikely to see additional new geothermal power stations in the next five year or so, due to slow growth in electricity demand and the recent completion of geothermal generating capacity. Nevertheless, additional new capacity is expected in the medium term to meet any demand growth or to replace retired fossil fuel plant. (MBIE 2016b)

Grid-connecting geothermal systems are limited to significant geothermal resources in the Taupo Volcanic Zone and Northland, but these resources are sufficiently close to major demand loads with adequate transmission capacity for geothermal electricity to make a significant contribution to New Zealand’s renewable electricity future. Geothermal plant can also be developed as combined heat and

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\(^1\) It should be noted that residential home space conditioning energy is a function of external climate and insulation resistance of external walls, while commercial building space conditioning is largely driven by internal activities.
power for any industrial heat requirements. A 300MW plant located at Kawerau produces process steam for the local pulp and paper mill.

Calculations of field capacity assume a limited amount of stored heat, allowance has to be made for past extractive use of the resource. 1200GW of geothermal plants are considered sustainably available and could eventually be developed over and above current developments, though not all of this will be economic. Over half of this potential capacity buildup would be brownfield stepouts from existing developments on proven fields. (Geothermal Association 2016)

A potentially important component of future development options has been the 102 geothermal wells (dating from the 1960s) in the Central North Island. These assets and their associated IP have been administered by the Treasury. Government has signaled its intention to develop these assets by naming Mighty River Power as its developer. In an initial step Kawerau geothermal assets were transferred to Mighty River Power in July 2005 (NZGA 2016) Following the sale of the Kawerau geothermal assets to Mighty River Power the Crown will retain ownership of around 60 residual wells (of which the majority are located in various fields throughout the central North Island and 5 are located in Northland). Included in the sale and purchase agreement between the Crown and Mighty River Power is the option for Mighty River Power to purchase the residual wells. (NZ Government 2005)

Geothermal power plants are not entirely emission free. Like hydro lakes, geothermal plants have fugitive GHG emissions. CO\textsubscript{2} entrained in the steam resource can be present and is emitted as part of the power plants operation. Tauhara Stage Two will produce about 79 tonnes of CO\textsubscript{2}e per gigawatt hour (GWh) of electricity generated, compared with about 380 tonnes of CO\textsubscript{2}e per GWh for a modern, high-efficiency gas-powered station, and about 900 tonnes of CO\textsubscript{2}e per GWh for a coal-fired station such as Huntly. (Contact 2009) Geothermal power plants are therefore low-carbon power plants.

Consented and prospective geothermal power plants are listed in table A2 in an annex.

**Wind generators** offer a large-scale resource of renewable electricity, distributed around the country, but subject to wind variability. This variability needs to be managed in the New Zealand electricity market.

New Zealand is fortunate to possess one of the best wind resources in the world, with capacity factors typically around 40%, and up to 50% in the case of the Brooklyn turbine in Wellington. In contrast, Denmark, a world leader in wind energy implementation, experiences 25-30%. Wind is also considered to be one of the cheapest forms of generation in New Zealand at present (Smales, 2010) and the potential is considerable, with up to 6600 MW projected to be available in a recent study (EECA, 2009). Thus it seems appropriate to make good use of this resource. (NIWA 2009)

New Zealand’s wind resource is predominantly from westerly winds. For example, Te Apiti windfarm receives 66% of its wind from the west. Strong westerly winds tend to be associated with rainfall. “The correlation between estimated wind generation capacity for 12 monitored wind sites, and current installed hydro–generation inflows for New Zealand as a whole is 80% on an annual basis. South Island hydro inflows correlate strongly positively to most New Zealand wind sites, but North Island hydro inflows relate slightly negatively to Southland wind sites (data from Meridian Energy Ltd). The New Zealand electricity system has been assessed at being capable of managing up to 20% wind generation capacity but the needs for further capacity flexibility is also noted. (Strbac et. al. 2008)

Consented wind power project proposals are listed in Table A3 in an annex.

Total identified and consented capacity is 2.2GW, equivalent to 7,700GWh/year or 18% of 2014 generated output, at current wind availabilities.

**Photovoltaics** Photovoltaic output varies annually (more sunshine in summer – less in winter) and diurnally (more sunshine at midday – none at midnight).
There is a large scope for micro-scale distributed wind generation in low-density settlements, but consumers will need to manage the variability of small system to their demand characteristics with interruptible load, load controllers and/or battery systems.
4. Plotting renewable electricity and demand side change options.

The challenge of measuring change.

At best only scenarios can be developed on future system resilience and renewables proportion. For a number of reasons, New Zealanders will only know the renewables percentage after the event - and then could still debate the meaning and significance of the achievement:

- The basis for measurement of a percentage renewables target is not straightforward. The 90% renewables target is based on an ‘average hydrological year’. This is not easily defined. An average is defined as “A number expressing the central or typical value in a set of data, in particular the mode, median, or (most commonly) the mean, which is calculated by dividing the sum of the values in the set by their number”. (Oxford Dictionaries 2016) How the ‘set’ is defined is crucial to defining the average. Any average based on less than 10 years data would not represent the perturbations in the hydro system hydrology by the “IPO (which) acts as a longer-term modulator of ENSO activity and is associated with decadal-scale variations of mean inflows of about 10-15%.” (Renwick et al) Probably at least two decadal cycles need to be covered.

- With changing climate dynamics it’s unlikely that the past 20 years will be a representation for the next 20 years.

- There is little public information on long-term power system hydrology, and the data sets are complex.

- There is no basis offered for defining ‘not affecting security of supply’. In reality this comes down to a rationale that might be proposed by the system operator.

The above uncertainties defy simple analysis – and are one of the underlying reasons why a dynamic market that reflects system perturbations through to all system actors including consumers is necessary in New Zealand.

Capacity options, scenarios.

Figures 16 -18 show scenarios that outline future potentials of generation types and capacities in an unfolding 15-year forward view. The potential plants in the scenarios are based on public information in MBIE supply side generation build mixes (MBIE 2015) (See Annex 2) and include a range of assumed contextual and build costs that enable an implied build order. Note these are always scenarios – a wide range of global financial and technical supply issues, domestic economic and electricity market issues shape what actually gets built, and these do not express the commercial plans and /or commitments of would be investors. They do however allow a picture of what can evolve over the next 10 -15 years.

These scenarios focus in on the marginal changes in generation capacity at decommissioning and – investment in new options. It should be remembered that this is played out on top of an existing dynamic fleet with a capacity of producing 37TWh electricity in a year in a 9GW capacity generation system.

Low demand base case; scenario 1

Figure 16 shows a low-demand scenario where a least-cost investment response with no external drivers for carbon emissions management and forms a base case for considering electricity system future scenarios. The orange line shows flat demand from the current base of fossil fuel capacity.
Coal should be displaced from the market in 2022 with the announced decommissioning of Huntly 3 and 4. MBIE’s build mix shows Taranaki Combined Cycle being decommissioned in the following year, and Huntly 6 (P40) in 2029. Actual decommissioning decisions are driven by many factors and these are expectations not commitments as external and market conditions at the time will shape actual commercial decommissioning decisions. Huntly E3P is anticipated to continue operation though the period.

With negligible demand growth, replacement power plant capacity would be a mix of about 40% gas and 60% renewable plants. However if demand grows substantially, and there are no carbon management policies, the next tranche of generation could include 2 more gas generators – a total of 800MW of new plants. Whether these are denoted as peaking plants or base load plants is something of a moot point, once build, the plant operators are incentivized to maximize the utilisation of the plants. Again actual investment decisions and the actual functional roles played by the plants are complex and made with the prevailing signals at the time of decision. Annex 2 shows the estimated timings from MBIE build mix data, but any actual build times could be later, MBIE suggests no need for new plant till 2020. (MBIE 2015) The mix of E3P and likely new gas generators in this scenario indicates the scale of gas plant at over 1GW.

In this scenario with a high turnout of gas power plants, 90% renewables could be met ahead of the 2025 government policy target if unexpected plant failure decommissions older thermal plant early, and would hold at that level until 2030. The actual renewable percentage is dependent on the hydrology, plant operating mix and demand during the year relative to an average year.

**Low carbon scenario**

Figure 17 shows a low-carbon / high renewables option, where national policy objectives for GHG reduction (necessary after the 4 October 2016 ratification of the COP21 Climate Agreement) set an overarching low carbon operating environment for the electricity market and the rest of the economy.
The scenario is a hybrid drawn from both MBIE’s Global low Carbon and High Geothermal access build mixes, a national GHG reduction policy will be needed to drive both the supply and demand side carbon reducing actions.

**Figure 17: Low carbon future. Scenario 2.**

In this scenario the brown line shows flat demand, the red line potential growth in demand. E3P stays in the generation fleet scenario (as it does in the low demand base case). A mix of wind, geothermal and limited scale hydro investments make up the replacement generation fleet, including responding to any future growth in demand. The only gas plant option is a comparatively small cogeneration plant, a generation option driven by a demand for heat, not power demand. The difference between the demand stasis and demand growth scenarios alters the timing of plants entry but doesn’t substantially alter the future generation mix. This is the type and mix of new plants that would be seen in a 100% renewable generation mix, the lowest cost plants would be picked up first, and there are a lot of renewables that will still be waiting to be built.

In order to achieve this scenario both the demand and supply sides of the market need to improve their ability to manage system security. Both (EECA DR 2004) and (MBIE 2015) point to a need to develop something like an additional 500MW of demand side management capability, to support variance in renewable generation capacity but also to provide power quality support for the grid, but it’s not clear how this is affected by the identified reduction in peak demand identified in (Electricity Authority 2015). The adaptations that underpin system resilience and enable higher renewables take time as multiple decision makers learn to adapt and respond to a richer set of power price signals and market and potential demand resource information becomes more widely available.
The challenge with any scenario is the difference between the rates at which older fossil fueled plants decommission, the rate at which both potential demand response develops and the rate of investment in new renewable plants in the face of a demand stasis. All of these are of course unfolding within a +/- 1GW capacity margins of plant decommissioning and commissioning over 10-20 years in a 9GW existing system, with something like 40% excess capacity in a typical year. There are a lot of variables. Importantly the market is becoming increasingly adept at signaling and managing risks.

**Increasing system resilience and 100% renewable electricity – Scenario 3.**

A third scenario – outlines an option where a historical supply security paradigm (suppliers manage risks) is replaced by a system resilience paradigm (demand and supply side contribute to risk management). This shift is key to achieving higher renewables while managing system security, and points to a more resilient system overall, than one reliant on a limited number of peaking power plants.

- Three key factors enable a transition to a fully renewable electricity system outlined above.
  - Active demand management – both daily and winter/dry year peak risks are moderated by cost effective demand side and energy efficiency actions that reduce the need for peak plant.
  - An overarching policy that shifts new generation and demand for electricity to low carbon options in support of New Zealand’s global climate commitments
  - A resilient path scenario where all the above are motivated by increasing cost reflectivity with time of use pricing of energy and capacity.

Figure 18 brings the demand and supply side options together into a single plot, to show planned fossil fuel plant retirements from the existing supply-side generation base and the stepping up of renewable electricity percentage as retirements occur. It extends out to 2035. Renewable percentages change as existing fossil fueled plants are retired according to MBIE estimates. Allocating current coal and gas consumption across the remaining fossil plants, as Huntly coal units are retired the percentage renewables grows from the current 82% to 84% to 86%. The next step occurs as Taranaki Combined Cycle is retired when the percentage of renewable electricity steps to around 93%. Projected retirement of the two remaining Huntly plants brings the percentage of renewable electricity to around 98% while the 2013 100MW peaker remains in economic operation for the foreseeable future, not necessarily because a peaking plant might be required, but because it currently exists with an economic operating life. Of course any additional fossil fueled plants will reduce the renewable electricity percentage, and 100% renewable electricity would be achieved when the final fossil fuel plant is retired.

On-going demand side actions extend the 740MW demand reduction from electricity efficiency policies in 2015 at 0.6c.kWh to with a further 800MW by 2035. Potential future solar photovoltaic, geothermal, hydro and wind developments from 2016 are shown.

The graph superimposes potential new renewables potentials over this existing plant mix as a way of showing the identified potential for further supply side renewables is at a similar scale to existing capacity. Only one tenth of this potential may to be required to 2030. When these new renewables might be required depends on the actual retirement of existing plants. The variability of these options needs to be considered, including. their coincidence with hydro variability.

Existing electricity efficiency peak demand reduction is the pink wedge above the system capacity line. In 2015/16 this was measured at 740MW peak demand reduction by EECA. (EA 2015) This energy efficiency demand reduction was achieved at less than 0.6c/kWh, implying a significant potential still for cost-effective demand side capacity and energy reduction measures. Ongoing MEPS penetration of the New Zealand appliance and equipment stock, and any additional energy efficiency policies and
adoption of new energy efficiency technology innovations will grow this low cost demand side potential.

Demand growth due to electric vehicles is based on MBIE’s high growth scenario for electric vehicles. Demand response, solar photovoltaic, geothermal, hydro and wind potentials are based on MBIE Draft Electricity Demand and Generation Scenarios – New generation plants available to earliest commissioning years. The electricity efficiency peak demand reduction wedge is a simple representation of the future energy efficiency potential in continuing to explore and maximize the potential for electricity efficiency and demand side capacity management is important for minimizing system costs, reducing peak demand for system resilience, and enabling progress toward 100% renewable generation.

One of the challenges is that New Zealand is on a learning curve, and it’s impossible to state what new plant will be in the system in 10 years’ time, only to point to what should or could happen. What is obvious however is that New Zealand’s commitment to the CoP21 agreement is requiring those parts of the economy that can reduce emissions to shift to a system where many new low carbon demand and supply side measures, especially energy efficiency, will be enabled to reduce CO₂.
Figure 18: Growing electricity efficiency, demand reduction, retiring coal and gas plants and potential renewables. Scenario 3.
The evolving New Zealand electricity market and renewable electricity.

Emerging Market Instruments that could enhance progress to higher percentage renewable electricity.

Context. Something like half the world’s nations have undergone electricity market liberalisation processes of one sort or another as governments seek better ways to manage the complexity of power generation, investment, supply and demand dynamics.

At the heart of these attempts is a need to efficiently allocate limited resources, balance supply and demand, and enable investments in new power options as demand grows. Many efforts have followed models that have in turn offered limited or ineffective outcomes, or simply failed to deliver as governments have shied away from (mis)-perceived political risks of normal market dynamics.

We can accept that some products and services have costs, which vary with resource availability and demand and that it costs to harvest and transport produce to consumers. Vegetables cost more out of season, so why do we seem to struggle to accept seasonal dynamics and delivery costs in power systems?

Some developed countries like New Zealand have reached a situation where electricity demand growth has stalled, a function of many drivers including: power prices motivating a richer mix of demand side responsiveness and energy efficiency, new distributed generation options and global change dynamics including the 2008 global financial crisis and an emerging clarity on carbon management options.

Power markets are entering a new phase of development: distributed renewables are now least cost options, on-going development of demand side technology options are changing the context of power markets to one that is far more dynamic than the traditional central generator / transmission grid model that has held since the 1940s. Traditional industry structures and systems are not flexible or transparent enough to enable a potentially vast diversity of demand and supply options. Power sectors around the world are evolving rapidly, becoming more dynamic, deriving more resilience from diversity than simply building more power plants as a naïve response to growth in power demand:

- changing consumer expectations,
- new technologies on both demand and supply sides of markets,
- alternative business models,
- changing global and national drivers; the need to manage carbon,
- changing climatic dynamics (New Zealand’s 2015/16 warmest – longest summer on record - (what implications for hydrology, snow fall and snow melt?)
- changing constructs - traditional perceptions of retail, distribution, transmission and generation functions and how they interact with consumers.

The power market of the future will be more like a farmer’s market than a supermarket as increasingly diverse generators and consumers seek a richer mix of seasonal, locally generated, or renewable products, with clear provenance.

The New Zealand electricity sector was and is still a pioneer: ripple control (1950s); Geothermal power, Wairakei was the first wet steam power plant in the world (1958); HVDC transmission (1965); market reform, (1995 onwards); and wind generation (2000s); and the learning process continues.
The rise, fall and re-incarnation of the pro-sumer.

The pro-sumer tends to be a residential consumer with a PV array on the roof enabled by the recent drop in prices and growth in availability of PV modules.

Pro-sumers typically rely on a connection to the local power network to provide back up power supply when their systems aren’t generating. The immediate profitability has been a function of what have been to date quite averaged retail energy price signals, and they have not had to face the costs of:

- Actual cost of generation during the period when they demand back up power. If this is during a winter energy peak the real cost of peak power from peaking plants can be many times higher than the average retail process faced over a year.
- The real cost of network and transmission supply during the periods when they require power. Real costs are variable and rise as demand peaks. Peak capacity at point of supply to consumers can cost up to $150/kW in some networks.
- The cost or benefit of their systems impact on system stability

Getting individual power plants and distributed generators to effectively complement other power plants and enable a stable renewable power system is a challenge. Mainstream generators, network and transmission companies face these variable costs and reflect them in tariffs, but these are averaged by retailers and blunt the time of use price implications of variable distributed load and generation.

Mainstream generators, network companies and transmission operators around the world can easily deal with a limited number of these ‘arbitrary’ generators, but at a certain stage their presence and their future growth requires improved price signals and stability controls at a network level.

Pro-sumers are developing their own informal markets. Peer to peer networks (for example P2Power.co.nz) provide a platform for off-market trades of surplus electricity. Like ‘farmers markets’ local produce is available for sale to local buyers. Network companies and the transmission system are however expected to still provide peak demand and capacity services at peak demand, and the pro-sumer network capacity costs can end up being unfairly borne by a shrinking set of consumers if time of use and capacity tariffs aren’t used.

PV is ‘naively cost-effective’ for consumers that seek to produce their own power, minimise their GHG footprint, or improve the sustainability of their household of business. But while on an average retail price tariff, pro-sumers are missing out on an opportunity to maximise returns by exporting when the system needs extra capacity and is prepared to pay a premium for generation capacity at the right time and place.

The evolution of pro-sumers is a shift from a central grid supply market paradigm to distributed supply paradigm. It is analogous to a shift from supermarkets, to growing your own food. Many consumers welcome the experience of ‘growing’ their own power, and want alternatives and capacity backup choices. Few would expect to sell their own home grown surplus cabbages to a supermarket at the prevailing retail prices, but they might be happy to swap them with a neighbour.

PV systems are installed in a rather arbitrary manner. The location, sizing, orientation etc are shaped by exogenous factors, like the north-most face of a roof, not by the reality of New Zealand’s or the household’s supply and demand characteristics or real variable supply and capacity costs.

There is a strong likelihood that pro-sumer PV will deliver increased renewable generation and lower average GHG emissions in the long run, but also a likelihood that they could increase the need for thermal winter peak capacity in the short term without clearer market signals. The winter demand impact of PV systems that deliver peak output in mid-day summer is highlighted in Figure 21.
Figure 19: Peak demand of arbitrary PV.

There is a risk that on-going arbitrary PV installations will contribute to increased demand for winter peaking support, likely to be provided by gas power plants. (Concept Consulting 2016) While this is true, the need for this support could be much reduced as solar can be oversized, aligned for winter peaks, and battery storage costs reduce and increase local storage resources. At present photovoltaic investors typically receive limited signals to enable better targeted responses to time of use peak or capacity challenges.

Shaping a more productive load contribution from PVs.

Ideally pro-sumers will receive real-time price signals that motivate a more economic investment of PV with a higher price for systems that better meet the real time capacity and energy demands of the system. Smart meters are required, but they are already being rolled out. The functionality of these meters has yet to be fully exploited, and meter technology has continued to evolve since the technology was first deployed in New Zealand to meet the current regulations.

Orienting photovoltaics for maximum winter peak reduction and investment returns.

Winter peak or congestion charges make up 20 to 70% of total commercial electricity costs depending on weather and site load characteristics in commercial facilities. Peak or Congestion charges of up to $250 per kW are incurred in specific congestion/control periods often when network load peaks. Residential line and distribution pricing is generally around 40% of retail costs but is hidden in averaged retail pricing. Peak or congestion charges can be reduced with simple control mechanisms. Businesses can manage these dynamic charges using a range of demand management options, including PVs. Figure 20 shows how the energy output and economic output can be optimised by altering panel orientation.
At a 63 degree angle the photovoltaic panels produce a more balanced annual output, and for a May – September capacity peak tariff, between 48 and 69 degrees makes sense. A frosty year would make steeper north facing panels more economic. East & west facing panels are not very beneficial for winter peaks as the sun is below the horizon. If a site cannot use or export electricity then closer to 65 degrees starts becoming much more economic, and for solar hot water 65 degrees or more becomes desirable, but demands a larger storage tank.

An electricity market evolving to meet dynamic challenges
Figure 21 compares current and future paradigms of electricity markets moving their focus towards the consumer end of the electricity market value chain.

Figure 21. A shift to consumer focused power markets

Source WEF Future of Electricity 2015.

One of the common challenges to change is that the power system is a technically determined system that requires a centrally designed planning system to operate effectively. There is no doubt that the physics of power systems are both real and unequivocal in their response to changes in demand and supply. The reality is however that as our ability to measure and understand system dynamics in real time has evolved in the past 30 years, and options have evolved away from a central plant investment
model to distributed systems that we need to also shift from a central to distributed accountability model. A key issue here is that industry protocols, particularly those that allow interaction between consumers and the market, need to keep pace with these technological developments. (WEF 2015)

### Power systems still run on the laws of physics, and still run on economics.

Electrical transmission and distribution networks are remarkably effective at allocating electrical energy from multiple generators to the millions of appliances and equipment that run our economy. Electrons are allocated at close to the speed of light in direct inverse proportion to the impedances (complex alternating current resistances) in the network. When you flip a switch you immediately add load to a generator – somewhere. *The physics of power demand is instantaneous – but very little else is.*

All generators take time to respond to an increase in load. Generators are mechanical systems with mechanical inertia; it takes time to accelerate the rotating mass of a wind, thermal or hydro generator in response to changing demand. Thermal and geothermal power plants have thermal inertia – it takes time to increase the flow of fuel, and for the heat to flow through steam boilers and heat exchangers to gas or steam turbines, so these tend to be base load plants. *The physics of generators is not instantaneous.*

Wind and PV generators are variable generators; they generate less when the wind drops or sun clouds over. *The physics of renewables is reliable, but output is variable in the short term.*

Power markets use price signals (cents per kWh, $/kW) to express the dynamics of the physics of power systems to the generators and consumers of power. Until recently most consumers only received a price for energy (c/kWh). But there are significant costs in additional system capacity, extra lines and generators that often are only utilised during demand peaks. From the 1970’s larger industrial and commercial consumers started to face charges for the capacity they demanded from networks, reflecting the costs of their decisions to flip a switch and add demand. This shift from charging for averaged energy and demand prices, to charging for marginal energy and demand impacts better reflects the instantaneous nature of demand impacts on a complex power system.

Globally power sectors are adapting to increasing complexity of demand, new time of use and intelligent metering technologies, and novel distributed generation options by shifting to marginal pricing of both energy and capacity. *The physics of practical power management systems is improving and the economics of marginal power supply and demand is catching up.*

New Zealand, along with Norway, was one of the first adapters to marginal pricing – our hydro system variability demanded a pricing system that reflected that resource variability back to other system actors and importantly to consumers, in order to develop system resilience and stability.

Consumers will increasingly face the real costs of the implications of their choices to add instantaneous demand. They will also receive price rewards for withdrawing demand during periods of peak demand. Generators will increasingly face the real costs of unreliable variability and receive price rewards for generating in response to peak demand. Technology options like batteries, more efficient appliances, PV generation, etc. will receive more accurate price signals. *The better physics of new power technologies will be better rewarded by better economic prices.*

### Transmission and Networks: Changing capacity and system stability.

The New Zealand grid operator Transpower is also the system operator, responsible for balancing supply and demand and ensuring system security. Transpower already sees its role as a central grid
operating morphing to one where it transports electrical energy from a set of central generator to consumer power loads, to one where its role will be to make capacity available and manage system resilience in the face of many more demand and supply actors. Ultimately, the power system of tomorrow will be radically different to what it is today. In the long-term, battery or other storage technologies installed within homes and businesses, vehicles, distribution networks, and grid substations could fundamentally alter how the power system is operated by covering short-term power imbalances in supply and demand. Given the makeup of New Zealand’s power system however, where much of our low-cost renewable generation is located far from where the major load centers are, there will always be a need for a strong transmission grid. Transmission Tomorrow. (Transpower)

Distribution Networks

The medium term challenge for New Zealand’s 28 networks is perhaps greater than for any other part of the electricity system. Their capacity to develop and pass to consumers a more dynamic set of cost-reflective time or use energy and capacity prices is key to progressing to a more resilient system with improved economic signals and rewards for pro-sumers, effective management of daily and winter/dry year risk, and in turn effectively enabling increasing renewables.

As natural monopoly service providers their role is simply to provide economically efficient network services at least cost to consumers. While the network role was perceived as a lines capacity delivery function it will change rapidly as distributed generation and pro-sumers expand and increasingly demand local and regional real time capacity support and backup services. There are few instruments they can use to achieve that public objective, the main one is how they price for efficient service delivery in their pricing strategies, a difficult task as their pricing strategies are bundled into retailer prices, and their activities are closely regulated by Part 4 of the Commerce Act.

Current network regulatory controls focus on the value of lines and charges for those lines. But this is a narrow perspective on the investment and pricing challenges faced by network operators making long term investments in the face of a growth stasis and emergent disruptive technologies. In an interview on the challenges faced by lines companies Vector CE Simon MacKenzie "We do not want to invest in traditional network assets that in 15 or 20 years may no longer be needed at the capacity that is currently in place, and we don't want that cost to be a burden on consumers and we do not want it to be an issue that we are not earning a return on." (RNZ 28 February 2016).

Unison altered their network charges to pro-sumers to maintain recovery of capacity charges in response to lower energy revenues from pro-sumers. Unison claim it costs $900 to provide lines services each residential customer and distributed generator connections were avoiding approximately $300 of these costs, which were then cross-subsidized across other users. http://www.unison.co.nz/ At first glance this is a reasonable attempt by a lines company at meeting their ‘efficient provider of network services’ role by balancing out a change in the cost and benefits to different users of connecting to the network and wider power system,. The solution is however only partially effective, it focusses on a single technology (solar) to address an underlying and long term need for accurate pricing of capacity services. What is needed is technology agnostic real-time pricing of capacity and energy to provide consumers, pro-sumers and supply side participants with the best signals for smarter investments.

Looking forward.

Networks are currently operating within an optimised deprival valuation mandate (network operators can price network services based on replacement cost up to the level at which an optimised line of the same capacity would be cheaper). This works for a network model of operation based on supplying
energy at a capacity in a context of on-going demand growth, but doesn’t motivate an efficient real-time capacity management service system.

Among other parties, the Electricity Networks Association is looking at this issue and has established a group “considering a number of options including time of use consumption pricing – that is different charges for peak, off-peak and possibly shoulder periods; capacity pricing including fuse based and anytime maximum demand pricing; peak demand pricing and critical peak pricing to reflect network congestion. The group’s recent publication; New Pricing options for Electricity Distributors, is exploring these issues (ENA 2016).

Meridians Energy’s 2012 report into demand participation highlighted two findings: “Encourage demand participation. The benefits of demand response (and other smart grid technologies, such as storage) may be shared among several industry participants along the energy value chain. Achieving active demand side participation is internationally considered to be a barrier to achieving the full economic benefits that a smarter grid could deliver. The industry has a key role to play to raise awareness, put appropriate systems and processes in place and create incentives for greater demand side participation in the energy market.” “At the network level, New Zealand’s regulatory framework may need to evolve to recognise investment in efficiency. Network operators need to be able to make choices between investing in innovative demand response and investing in network assets. Incentives to adopt technically effective and cost efficient non-network solutions need to be considered as part of the regulatory design framework. Such incentives could be complemented with a review and update of network design standards in order to accommodate the contribution that flexible demand initiatives may be able to make as a substitution for building network infrastructure.” (Meridian 2012).

Adaptations already underway in the New Zealand Electricity Market.
The electricity sector is exploring the need for change, driven by new technologies and business models, and changing consumer expectations. The Electricity Authority, working with Transpower and other market participants is actively exploring options to develop the needed innovations to improve market signals and enable an economically efficiency basis for progressing power demand and supply options in New Zealand. The Authority decided to orientate the advisory groups around key industry challenges and issues, rather than along the traditional industry structure lines. Existing advisory groups are being replaced by two new groups, structured as follows;
• Innovation and Participation Advisory Group (IPAG) - this group would focus on issues specifically inhibiting the entry and participation of evolving technologies and new business models in the electricity industry. It would also focus on enhancing consumer participation and choice.
• Market Development Advisory Group (MDAG) - this group would focus on further evolving the ‘machinery’ of the electricity markets that are not specific to the requirements of new technologies and business models. This would include issues such as improving price signals, and enhancing risk management markets including the ancillary service markets. (Electricity Authority)

2. Future Renewables: Beyond LCOE to System Value
New Zealand isn’t the only country where an electricity market is adapting to significant shifts towards renewables. “Wind and solar photovoltaics (PV) are currently the fastest-growing sources of electricity globally. A “next generation” phase of deployment is emerging, (IEA-CEM 2016).

Getting the right cost reflective signals is key to ensuring economic investments as well as balancing capacity and ensuring resilience. Significant feed in tariffs in Europe in a less than fully functional power market have distorted recent investments in renewable power plants to sub-optimal locations and inefficient costs.
A challenge in all energy markets is integrating variable resources when market participants place a value on system stability. Traditionally system security has been seen as a supply side issue—a steady flow of new generation and transmission capacity was seen as the best way to keep ahead of demand or address system reliability.

A range of novel electricity options exist already and new innovations regularly surface. One of the challenges is ensuring that the outcomes are well understood and that investors receive signals that encourage desired environmental outcomes as well as economic outcomes. The GHG environmental outcomes from three current choices highlight how only one of the three delivers significant GHG reductions. Growing the right type of demand (electric vehicles) reduces country emissions significantly, while the two ‘renewable enhancing’ electricity options PV’s and batteries may offer local benefits to the purchaser, they offer little improvement in emissions in a significantly renewable New Zealand’s power market.

**Figure 22 GHG reductions from 3 emerging options.**

Unlocking the contribution of system-friendly deployment calls for a paradigm shift in the economic assessment of wind and solar power. The following outline some of the international thinking on the changing objectives for the power sector.

The IEA is starting to explore how a shift from traditional least cost generation perspectives to one that seeks to develop value from the system. "The traditional focus on the levelised cost of electricity (LCOE) is no longer sufficient. Next-generation approaches need to factor in the system value of electricity from wind and solar power. System value (SV) is defined as the overall benefit arising from the addition of a wind or solar power generation source to the power system; it is determined by the interplay of positives and negatives. Positive effects can include reduced fuel costs, reduced carbon dioxide (CO2) and other pollutant emissions costs, reduced need for other generation capacity and possibly grid infrastructure, and reduced losses. (IEA –CEM 2016)"

It proposes actions in three areas:
• System-friendly deployment, which aims to maximise the net benefit of wind and solar power for the entire system.

• Improved operating strategies, such as advanced renewable energy forecasting and enhanced scheduling of power plants.

• Investment in additional flexible resources, comprising demand-side resources, electricity storage, grid infrastructure and flexible generation.
**Tail winds and Head winds. What will get New Zealand to higher levels of renewable electricity?**

<table>
<thead>
<tr>
<th>Tail winds</th>
<th>Head winds</th>
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<tbody>
<tr>
<td><em>high levels of renewable electricity will be enabled by:</em></td>
<td><em>high levels of renewable electricity will be retarded by:</em></td>
</tr>
<tr>
<td>Policy coherence on climate change and energy policy: the NPS on Renewable Electricity Generation has already helped consent 3.2GW of non-hydro renewables, but after COP21 more is required.</td>
<td>Relying on single policy interventions and neglecting the role of complementary measures</td>
</tr>
<tr>
<td>A policy framework that prioritises low-carbon options across the economy, with relevant complementary measure such as accelerating energy efficiency in sectors.</td>
<td>On-going lack of clarity in how COP21 objectives will play out in New Zealand delay investments, add risk and cost.</td>
</tr>
<tr>
<td>Growth in non-hydro renewable electricity generators displacing higher run cost non-renewables (gas and coal) ‘down the merit order’.</td>
<td>Existing non-renewable generators staying ‘high in the merit order’ rather than reverting to peaking or power quality roles.</td>
</tr>
<tr>
<td>A level playing field – transparent time of use energy and network capacity charges provide balanced incentives for all demand and supply side options.</td>
<td>Continued aggregation of network and transmission capacity costs into retail energy prices blunts rewards for energy efficiency and demand-coincident renewable electricity.</td>
</tr>
<tr>
<td>Improved exposure of actual network and transmission capacity costs to consumers improves investment decisions for energy efficiency and renewables investments.</td>
<td>On-going retail bundling and cost averaging in retail energy prices blunts rewards for energy efficiency and demand-coincident renewable electricity.</td>
</tr>
<tr>
<td>Increasing time of use energy prices that prompt reliable base load and winter/dry year capacity while improving the reward for energy efficiency and generators.</td>
<td>Removing the Avoided Cost of Transmission (ACOT) fees from current transmission pricing and not replacing it with a more accurate reflection of the actual costs and benefits of locally based generation.</td>
</tr>
<tr>
<td>Developing PV so it coincides with peak demand in commercial and industrial facilities.</td>
<td>On-going random orientation of PVs prompts a need for winter peak generation and keeps non-renewable generators down in the merit order.</td>
</tr>
<tr>
<td>Aligning PV systems for winter peak output increases value from their winter renewable electricity supply.</td>
<td>Assuming energy efficiency is ancillary to progress rather than central to minimising system costs and increasing productivity.</td>
</tr>
<tr>
<td>Continuing to develop electricity efficiency, especially where it offers reductions in peak and winter demand. Explore the potential beyond the current 0.6 cent/kWh levelised cost of avoided electricity.</td>
<td>Rethinking the role of networks to enable local capacity services and stability services for prosumers with clear real-time pricing.</td>
</tr>
<tr>
<td>Rethinking the role of networks to enable local capacity services and stability services for prosumers with clear real-time pricing.</td>
<td>Bundled network services and pricing, investments in distracting non-core services</td>
</tr>
<tr>
<td>Enabling regional development projects that deliver low carbon value added activities, jobs and regional low carbon energy resources</td>
<td>Continuing a central supply paradigm</td>
</tr>
<tr>
<td>Ensuring wide distribution of low carbon and non-hydro coincident generators, e.g. east cost wind, geothermal/wind north of Auckland</td>
<td>Continuing a central supply paradigm</td>
</tr>
</tbody>
</table>
Annex 1. Demand and Supply side options.

Demand Side Options.

A vast range of demand side and supply side options that deliver low-cost energy efficiency and renewable energy exists. Table A1 canvases these with some of their key characteristics, in some cases the picture is incomplete and insights into the available capacity impacts have yet to emerge.

Table A1. Demand Side Options that might increase renewable share of generation

<table>
<thead>
<tr>
<th>Key</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Green</td>
<td>Option offers contribution to increasing % renewable electricity by mitigating winter / dry year demand response</td>
</tr>
<tr>
<td>Olive</td>
<td>Option offers improved short term (day &lt; week or emergency) reduction in electricity use or emissions, but not a significant contribution to increasing % renewable electricity by mitigating winter / dry year risk</td>
</tr>
<tr>
<td>Orange</td>
<td>Possible contribution to increasing % renewable electricity by possibly mitigating winter / dry year demand response</td>
</tr>
<tr>
<td>Yellow</td>
<td>Emerging actions likely to enhance NZEM ability to increase renewable electricity and reduce emissions</td>
</tr>
<tr>
<td>Grey</td>
<td>Demand side option that emits CO₂. May enhance renewable generation, but without obviously reducing net emissions. May increase net emissions.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Demand Response (DR) Options</th>
<th>Short run DR (24hr diurnal peak reduction)</th>
<th>Medium term DR (Winter peak electricity reduction)</th>
<th>Does this efficiently improve net emissions and system reliability. Challenges</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand side</td>
<td>Many diurnal DR options make little change to winter peaking plant</td>
<td>Offsetting winter peak reduces annual exposure to a dry year event.</td>
<td>Decision makers may not see opportunities. Have all options been quantified</td>
<td></td>
</tr>
<tr>
<td>Demand response – Industrial</td>
<td>Large industrials already moderate load in response to high spot prices</td>
<td>Hard to see that extended loss of production is cost effective beyond very short-term</td>
<td>Large industrial consumers already balance prevailing spot price to marginal production cost – product value</td>
<td>Limited scope over extended periods. Limited by the impact of regular load shedding on productivity and profit. Industrial processes use electricity where process needs require electricity.</td>
</tr>
<tr>
<td>Industrial</td>
<td>Gas supplementary firing could offset day electricity peaks</td>
<td>Biomass is typically displacing coal for heat, not electricity.</td>
<td>Gas, Oil or Coal may shift emissions from supply side to demand side. There may be a role for industrial scale heat pumps should the cost and performance of this technology (in particular Coefficients of Performance) continue to improve</td>
<td>Limits to fuel shifting; Industrial processes typically based around particular fuels. Industrial processes use electricity where process needs require electricity. Industrial heat facilitated by resizing updating old inefficient plants</td>
</tr>
</tbody>
</table>
### Transport

**Increasing Electric Vehicles (EV’s)**  
New Zealand Govt EV policy  
64,000 EVs by 2021  
5 May 2016 (NBR 2016)

- EVs are not obviously peaky. Demand impact unclear as consumers will charge when required, day or night.
- New EVs are baseline annual demand, not obviously peaky. Could create demand for new RE generation.
- EV economics good, but fleet turnover slow without enabling infrastructure.
- High transport fuel GHG reduction potential.

**Vehicle to Grid (VTG) EV’s**  
including electrification of PT and MT rail  
Also assume batteries could contribute to peak reduction / shifting

- Nominal 40kWh storage per car, possible extra batteries in garage with charger, off significant diurnal peak demand shifting. But can this be relied on by market seeking rapid DR?
- EV’s will change winter / dry year risks, by adding to baseload, but its unclear how short term battery storage will contribute to managing winter/dry year demand.
- Economics depend on future battery costs and EV adoption rate  
Future battery costs could drop below USD100/MWH vs New Zealand LRMC around NZD85/MWh and real time price signals that motivate off peak charging.

### Commercial

**Commercial tariff Demand Response**

- Successful DR already achieved how much more can be motivated?
- Contributes if distribution system peaks are coincident with winter peaks / dry year scarcity period
- High capacity charges for limited periods can enable lower overall distribution system costs.
- Probably not happening because building owners struggle to get functionality out of smart meters. Also incentives on generators and distributors to install peak lopping are not there, not allowed, or they don’t want to risk write downs if demand shrinks.

**Distributed PV coincident with Air Con and cool store, reefer, peak demand (rather than random)**

- How much cool store DR already?
- Reduce capacity and electricity during winter / dry risk if oriented to winter sun
- AC and cold storage load is highest in summer, not during winter / dry year demand

**Gas heaters could displace electric heat and reheat in commercial buildings.**

- Cut morning / evening peak
- Reduce electric heat and reheat through winter 1,400 GWh consumption (5.1PJ EEUDB)
- Chch experience shows combination of commercial heat pumps and LPG duct heaters works. Most economic if part of continuous commissioning process.
- Reheat is often wired into tenant boards but should be building base load wired
<table>
<thead>
<tr>
<th><strong>Commercial and Industrial Market for (Winter) Direct Use of Gas</strong></th>
<th><strong>Develop the commercial and industrial market for (winter) direct use of gas</strong></th>
<th>Replaces electricity peak with gas peak</th>
<th>Gas supply is quite flat – often an associated output, so limited supply side need for peak pricing.</th>
<th>Commercial consumers already have a gas – electricity price differential. Increasing GHG rebound possible.</th>
<th>Clamp-on ultrasonic gas meters, ($7k up front per meter + $1k paper work) can provide accurate Time of use commercial gas price Better meters enable a potential of up to 50% reduction in gas use in some instances, from better metering information.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Commercial Lighting – LED &amp; T5</strong></td>
<td>Little difference in energy intensity of commercial T5 fluorescent and LED luminaires.</td>
<td>Little difference in energy intensity of commercial T5 fluorescent and LED luminaires.</td>
<td>LED are now the only choice in commercial buildings</td>
<td>Fluorescent tube sales falling as LED take over.</td>
<td></td>
</tr>
<tr>
<td><strong>Electric Water Heating to Direct Gas Water Heating</strong></td>
<td>Replaces electricity peak with gas peak</td>
<td>Shifts usage to alternative higher CO₂ emission source on demand side. 830 GWh consumption (3PJ EEUDB)</td>
<td>Marginal change in net emissions if not increase.</td>
<td>Similar to residential case; Poor economics for consumers and increased GHG emissions (CRA 2006)</td>
<td></td>
</tr>
<tr>
<td><strong>How Much More Can We Expect from MEPS?</strong></td>
<td>Reduces peaks as well as energy at 300% return on investment</td>
<td>MEPS still changing the fleet of end-use appliances and equipment</td>
<td>Electricity efficiency contributing over 700MW of peak demand response</td>
<td>1,300GWh (4.7PJ) avoided consumption in year ending 31 March 2015. (EECA 2016)</td>
<td></td>
</tr>
<tr>
<td><strong>Advanced Wood Burners</strong></td>
<td>Coincident with evening peak demand</td>
<td>‘the 500MW power station in the woodshed’ (HEEP) and advanced burners vs reality of air shed limits, and health risks of emissions.</td>
<td>Health risks and PM2.5 local emissions also matter. Existing emission testing standard doesn’t adequately test advanced wood burners.</td>
<td>Potential may not exist anymore as HPs may have displaced previous direct electric heating load. Cost of supplied heat is an issue: ENERGY STAR heat pumps 5-7c/kWh vs modern Wood burners 10-11c/kWh. (BRANZ 2015).</td>
<td></td>
</tr>
<tr>
<td><strong>More Insulation Double Glazing etc?</strong></td>
<td>Reduce evening peaks, reduce winter / dry year electricity consumption</td>
<td>Reduces winter electricity demand Also significant positive rebounds in improved heating, comfort &amp; health</td>
<td>Slow upgrade / new build rate. Has DR benefit been included in insulation analysis?</td>
<td>Capacity reduction role should be revisited</td>
<td></td>
</tr>
<tr>
<td><strong>Residential LED / Efficient Lighting</strong></td>
<td>Reduce evening peak</td>
<td>Reduces baseload at peak time</td>
<td>Has DR benefit been included in analysis?</td>
<td>EECA lighting energy efficiency analysis in annual report</td>
<td></td>
</tr>
<tr>
<td><strong>ENERGY STAR Heat Pumps</strong></td>
<td>Spread peaks during day / night</td>
<td>COP of 3.5 vs COP of 3.2 = 10% more heat for less electricity demand</td>
<td></td>
<td>BRANZ heat pump survey.</td>
<td></td>
</tr>
<tr>
<td>Solar water heaters</td>
<td>Reduced day peaks and reduced electricity consumption</td>
<td>Should reduce electricity demand during dry risk if oriented for winter peak output</td>
<td>Longer ROI on SWH. Have DR benefits been included in SWH analysis?</td>
<td>Capacity reduction role should be revisited</td>
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<tr>
<td>Shift residential electric water (12PJ EEUDB) and space heating (4.0PJ EEUDB) to direct gas heating.</td>
<td>Replaces electricity peak 3.334GWh Electric water heating, (12PJ EEUDB) and 1,111GWh space heating (4.0PJ EEUDB) Autonomous growth in gas already exists.</td>
<td>High cost to consumers for appliance change over, revenue transfer from power to gas sector, net increase in emissions. (CRA 2004)</td>
<td>The current balance of residential electricity – gas usage may be optimal: Winter/Summer electricity ratio (W/S) is 174%, Shift to max gas use W/S = 155% with increased emissions, shift to max electricity W/S = 209%. (BRANZ 2016)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hot water heat pumps</td>
<td>Should spread peaks</td>
<td>Heats water faster, rapid recovery</td>
<td>Ecoenergy heat pump has connection for direct PV input</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Non-market customer generators</td>
<td>Standby generators are generally designed for short term operation</td>
<td>Some mid-sized plants can increase operation</td>
<td>Suitable plants already responsive to market price and DR signals</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Synchronisation of Non-market customer generators</td>
<td>Improved – automated response to demand peaks</td>
<td>Suitable plants already responsive to market price and DR signals. 1-2 yr payback on sync gear.</td>
<td></td>
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</tr>
<tr>
<td>Water heater DR tariffs</td>
<td>Good experience in shifting daily peaks to night, lower consumer prices.</td>
<td>Unlikely to deliver MT winter / dry year peak reduction</td>
<td>How much DR control from ripple - how much more scope? Daily load response only. Does ripple control have a conservation effect - reduce consumption?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>New PVs and SWH are oriented to produce winter peak output (angled to sun on winter afternoon)</td>
<td>Depends on the day. Not firm demand responsive capacity.</td>
<td>Should produce more renewable electricity / offset demand during dry risk if oriented for winter peak output</td>
<td>Integrated Solar Thermal Electric PV/SWH could fall to NZD0.04/kWh (IEA)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Smart metering</td>
<td>Still 200,000 non-compliant meters changing at 9k/month.</td>
<td>What participation has been achieved and what DR impact? What participation has been achieved and what DR impact?</td>
<td>Are there any actual examples of smart meters mitigating demand peaks. Smart meter standard not perfect: All have good functionality but doesn’t mean retailer has to use the functionality.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Innovative consumer motivations to DR</td>
<td>20% reduction in price? – how much is reduction in demand?</td>
<td>Consumers respond to incentives – how DR responsive if offered spot prices?</td>
<td>FLICK, SPARK, PULSE, Electric Kiwi, POWERSHOP…</td>
<td></td>
<td></td>
</tr>
<tr>
<td>“Future” technologies e.g. household scale batteries</td>
<td>Unclear how they will change demand / winter /dry year risks</td>
<td>Unclear how they will change demand / winter /dry year risks</td>
<td>EA consultation on evolving technologies for pricing of distribution services</td>
<td></td>
<td></td>
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<tr>
<td>Peer to peer 2 p-p websites.</td>
<td></td>
<td></td>
<td>Distribution companies can’t charge costs for unknown flows.</td>
<td></td>
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</tr>
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</table>
Supply Side Renewables Options

While a range of base-load generation options such as new hydro could be utilised, two supply side options stand out for New Zealand in a medium-term transition to higher renewable electricity generation: Geothermal and Wind generators.

Geothermal generators.

Table A2 Consented and prospective geothermal power plants.

<table>
<thead>
<tr>
<th>Station</th>
<th>Capacity (MW)</th>
<th>Operation</th>
<th>Developer</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Te Ahi O Maui</td>
<td>20</td>
<td>2017</td>
<td>Eastland Group and Kawerau A8D Ahuwhenua Trust &amp; Innovations Development Group</td>
<td>Project up to 50 MW announced but still requires consents and contracts.</td>
</tr>
<tr>
<td>Tikitere</td>
<td>&lt;45</td>
<td>2016?</td>
<td>Tikitere Trust (and partners)</td>
<td>currently in consenting and investigation stage.</td>
</tr>
<tr>
<td>Rotoma</td>
<td>35</td>
<td>2016?</td>
<td>Rotoma No 1 Inc</td>
<td>Consents under appeal.</td>
</tr>
<tr>
<td>Tauhara II</td>
<td>240</td>
<td>2018?</td>
<td>Contact</td>
<td>Consents in place through Board of Inquiry. Production drilling to follow.</td>
</tr>
<tr>
<td>Taheke</td>
<td>?</td>
<td>?</td>
<td>Contact &amp; Taheke 8C and the Adjoining Blocks Inc</td>
<td>3 Exploration wells drilled.</td>
</tr>
<tr>
<td>Te ia o Tutea</td>
<td>?</td>
<td>?</td>
<td>MRP, Okere Inc and Ruahine Kuharua Inc</td>
<td>Agreement for expansion and cooperative development</td>
</tr>
<tr>
<td>Ngawha 3</td>
<td>50</td>
<td>2020</td>
<td>Top Energy</td>
<td>Planning stage</td>
</tr>
<tr>
<td>Ngawha 4</td>
<td>50</td>
<td>later</td>
<td>Top Energy</td>
<td>Planning stage</td>
</tr>
<tr>
<td>Misc</td>
<td>400</td>
<td>By 2025</td>
<td>Various</td>
<td>Balance of unspecified projects including late stages of existing developments</td>
</tr>
</tbody>
</table>

Source: New Zealand Geothermal Association

Wind generators

New Zealand is fortunate to possess one of the best wind resources in the world, with capacity factors typically around 40%, and up to 50% in the case of the Brooklyn turbine in Wellington. In contrast, Denmark, a world leader in wind energy implementation, experiences 25-30%. Wind is also considered to be one of the cheapest forms of generation in New Zealand at present (Smales, 2010).
### Table A3a. Consented wind power project proposals.

<table>
<thead>
<tr>
<th>Site</th>
<th>Developer</th>
<th>Region</th>
<th>Capacity (MW)</th>
<th>RMA application publicly notified</th>
</tr>
</thead>
<tbody>
<tr>
<td>Awhitu</td>
<td>TrustPower</td>
<td>Franklin</td>
<td>Up to 18</td>
<td>April 2004</td>
</tr>
<tr>
<td>Titiokura</td>
<td>Meridian</td>
<td>Hastings</td>
<td>Up to 48</td>
<td>April 2005</td>
</tr>
<tr>
<td>Hawkes Bay</td>
<td>Meridian</td>
<td>Hastings</td>
<td>Up to 225</td>
<td>May 2005</td>
</tr>
<tr>
<td>Castle Hill</td>
<td>Genesis Energy</td>
<td>Northern Wairarapa</td>
<td>800</td>
<td>August 2011</td>
</tr>
<tr>
<td>Taumatatotara</td>
<td>Ventus</td>
<td>Waikato</td>
<td>Up to 27</td>
<td></td>
</tr>
<tr>
<td>Taharoa</td>
<td>Taharoa C and PowerCoast</td>
<td>Kawhia</td>
<td>Up to 54</td>
<td>December 2005</td>
</tr>
<tr>
<td>Kaiwera Downs</td>
<td>TrustPower</td>
<td>Gore</td>
<td>Up to 240</td>
<td>November 2007</td>
</tr>
<tr>
<td>Mt Cass</td>
<td>MainPower</td>
<td>Hurunui</td>
<td>Up to 78</td>
<td>June 2000</td>
</tr>
<tr>
<td>Hurunui</td>
<td>Meridian Energy</td>
<td>Hurunui</td>
<td>Up to 75.9</td>
<td></td>
</tr>
<tr>
<td>Central Wind</td>
<td>Meridian</td>
<td>Ruapehu &amp; Rangatikei</td>
<td>Up to 130</td>
<td>July 2008</td>
</tr>
<tr>
<td>Waitahora</td>
<td>Contact Energy</td>
<td>Southern Hawkes Bay</td>
<td>Up to 156</td>
<td>September 2008</td>
</tr>
<tr>
<td>Turitea</td>
<td>Mighty River Power</td>
<td>Manawatu</td>
<td>Up to 180</td>
<td>January 2009</td>
</tr>
<tr>
<td>PuketoI</td>
<td>Mighty River Power</td>
<td>East of Manawatu Gorge</td>
<td>Up to 159</td>
<td></td>
</tr>
<tr>
<td>Long Gully</td>
<td>Windflow</td>
<td>Wellington</td>
<td>Up to 12.5</td>
<td>May 2009</td>
</tr>
</tbody>
</table>

*Source: New Zealand Wind Energy Association.*

Total identified and consented capacity is 2.2GW, equivalent to 7,700GWh/year or 18% of 2014 generated output, at current wind availabilities.
**Table A3b Proposed (under research) windfarms**

<table>
<thead>
<tr>
<th>Site</th>
<th>Developer</th>
<th>Region</th>
<th>Capacity (MW)</th>
<th>Status</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Castle Hill</td>
<td>Genesis</td>
<td>Wairarapa</td>
<td>Up to 858</td>
<td>Consent granted</td>
<td>July 2013</td>
</tr>
<tr>
<td>Hurunui</td>
<td>Meridian</td>
<td>Hurunui</td>
<td>Up to 75.9</td>
<td>Consent granted</td>
<td>April 2013</td>
</tr>
<tr>
<td>Mt Munro</td>
<td>Meridian</td>
<td>Wairarapa</td>
<td>Up to 60</td>
<td>Application withdrawn</td>
<td>January 2012</td>
</tr>
<tr>
<td>Blueskin Bay</td>
<td>Local community</td>
<td>Otago</td>
<td></td>
<td>Consent applied for</td>
<td></td>
</tr>
<tr>
<td>Pouto Forest</td>
<td>Meridian</td>
<td>Northland</td>
<td></td>
<td>Site under investigation</td>
<td></td>
</tr>
<tr>
<td>Ahipara gumfields</td>
<td>Meridian</td>
<td>Northland</td>
<td></td>
<td>Site under investigation</td>
<td></td>
</tr>
<tr>
<td>Slopedown</td>
<td>Genesis Energy</td>
<td>Southland</td>
<td></td>
<td>Site under investigation</td>
<td></td>
</tr>
<tr>
<td>Cape Campbell</td>
<td>Mighty River Power</td>
<td>Marlborough</td>
<td></td>
<td>Site under investigation</td>
<td></td>
</tr>
<tr>
<td>Mt Stalker</td>
<td>Waitaki Wind</td>
<td>Otago</td>
<td></td>
<td>Site under investigation</td>
<td></td>
</tr>
</tbody>
</table>

*Source: New Zealand Wind Energy Association*

Total proposed capacity is 999MW equivalent to 3500GWh / year or 8% of 2014 generated output, at current wind availabilities.
### Table A4. Supply Side Demand Response Management Options.

<table>
<thead>
<tr>
<th>Supply Side Demand Response (DR) Options</th>
<th>Short run DR (24hr diurnal peak reduction)</th>
<th>Medium term DR (Winter peak electricity reduction)</th>
<th>Does this efficiently improve net emissions and system reliability?</th>
<th>Challenges</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>increasing Wind</td>
<td>20% wind in NZEM manageable.</td>
<td>840MW, capable of 5,887GWh/year or 14% of 2014 generated output identified projects.</td>
<td>Currently no demand growth to realise consented potential. Cost effective to LRMC if high utilisation is achieved.</td>
<td>Adding any non-SI hydro capacity improves dry year risk</td>
<td></td>
</tr>
<tr>
<td>increasing Geothermal</td>
<td>Base load at 80%+ availability</td>
<td>2,203MW, equivalent to 7,700GWh/year or 18% of 2014 generation already consented</td>
<td>Currently no demand growth to realise consented potential. Cost effective to LRMC if high utilisation is achieved</td>
<td>Adding any non-SI hydro capacity improves dry year risk</td>
<td></td>
</tr>
<tr>
<td>Whats my number? campaign</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>New retail offerings, increasing retail completion, Spot price retailing e.g, Flick</td>
<td>What participation has been achieved and what DR impact?</td>
<td>What participation has been achieved and what winter / dry year DR impact?</td>
<td>Customers point to 20% cost reduction but no sense of consumption reduction? Retail prices dropped 1% in 2016</td>
<td>15 or so new entrants to market offer increasingly diverse retail products</td>
<td></td>
</tr>
<tr>
<td>Load aggregators (like EnerNOC)</td>
<td>What participation has been achieved and what DR impact?</td>
<td>What participation has been achieved and what winter / dry year DR impact?</td>
<td>EA looking at allowing aggregators to participate in frequency services</td>
<td>Transpower and Enernoc instantaneous reserve and 5 mins response. How do we find non-traditional 30mins response DR options? DR Initiates other options that motivate energy efficiency</td>
<td></td>
</tr>
<tr>
<td>Avoided Cost of Transmission (ACOT)</td>
<td></td>
<td></td>
<td></td>
<td>Context 2006? – dry winter hedging arrangements requirements?</td>
<td></td>
</tr>
<tr>
<td>Prudent Discount Policy (PDP)</td>
<td></td>
<td></td>
<td></td>
<td>PDP announced May 2016</td>
<td></td>
</tr>
<tr>
<td>Normal dispatch spot price dynamics</td>
<td></td>
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<tr>
<td>EA dispatchable demand project</td>
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<tr>
<td>EA DR principles guideline EA DSBF project</td>
<td></td>
<td></td>
<td></td>
<td>Demand side demand framework</td>
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<tr>
<td>EA scarcity pricing project</td>
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<tr>
<td>PV buy back tariffs moderated</td>
<td>Should ameliorate PV peakiness</td>
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<tr>
<td>Distribution charges</td>
<td>Transpower’s DR programme</td>
<td>Future development of Transmission Pricing Methodology (TPM)</td>
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<tr>
<td>20% reduction in network capacity 90% of Orion’s customers have chosen DR</td>
<td>130MW from 8 large sites How well does DR transmission deferral correlate to winter / dry year peak reduction?</td>
<td>Too early to tell Too early to tell</td>
<td></td>
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<tr>
<td>Maunsell identified 900MW DR potential in EECA report in 2004</td>
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</tbody>
</table>

Build schedules by scenario

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Base Case (Mixed Renewables)</th>
<th>High Demand</th>
<th>High Low Load</th>
<th>High Low Load</th>
<th>Medium Low Load</th>
<th>Medium Low Load</th>
<th>Low Demand</th>
<th>High Demand</th>
</tr>
</thead>
<tbody>
<tr>
<td>2021</td>
<td>CCGT</td>
<td>Hunter_400MW</td>
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<td>2032</td>
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Notes:

- CCGT refers to Combined Cycle Gas Turbine.
- Hunter_400MW refers to a 400 MW Hunter power station.
- Medium Low Load refers to a medium load scenario.
- Low Demand refers to a low demand scenario.

Additional details on builds and schedules for different fuel types and capacities can be found in the detailed supply side generation build mixes.
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