The New Zealand Electricity Market: challenges of a renewable energy system

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Introduction

Trading in the New Zealand Wholesale Electricity Market pool began on October 1, 1996. This article reflects on 20 years of experience of the 1996 market design, assesses its points of difference from other jurisdictions, and speculates on some possible future directions. The New Zealand pool market was the first market to use two elements of what has since become the North American "standard" market design with locational marginal pricing and ancillary service co-optimization, but it was implemented in a physical and regulatory environment that differs markedly from that pertaining in North America. Being based on a high penetration of renewable electricity, and two islands subject to the vagaries of a South Pacific climate and with no imports or exports of power, key considerations include promoting the most economical use of stored water and ensuring security of supply. Unlike most North American markets, the New Zealand market design currently does not include any form of capacity market or payment, or day-ahead market, and, at least initially, the market did not provide any financial transmission rights, and was not overseen by any sector-specific regulator.

The article is laid out as follows. In the next section we discuss the historical and physical context of the market evolution up to 1996. We then review the peculiar features of the New Zealand market design in this historical context, and contrast them with market design features in other countries. The next section is devoted to studying the impact of small-scale local generation and storage on the operation of distribution networks. Finally we describe the evolution of the governance of the market, and speculate on what form this might take as we move into the future.

Historical and physical context of NZEM

Geographically, New Zealand is comparable in size and shape with the British Isles, or Japan. But it is much less densely populated, and too remote to allow interconnection with any other country. So New Zealand must be self-sufficient for both electricity and gas supply. The layout of the country's transmission grid is shown in Figure 1, and the evolution of its generation mix is shown in Figure 2.

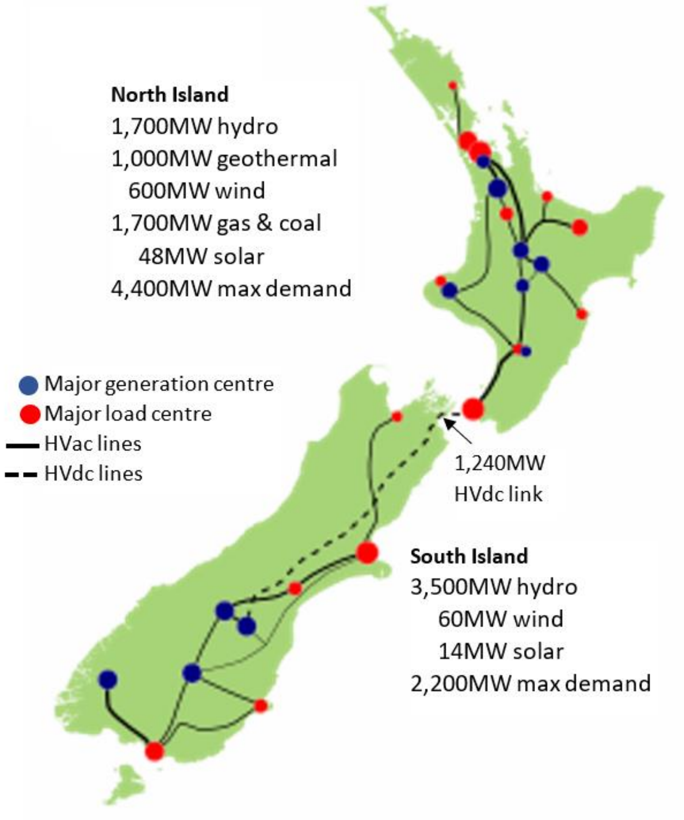


Figure 1: Map of New Zealand showing main generators, largest lines in the transmission network, and maximum loads over the year ended November 30, 2017. Over this period North Island consumption was 24,724 GWh and South Island consumption was 14,467 GWh.

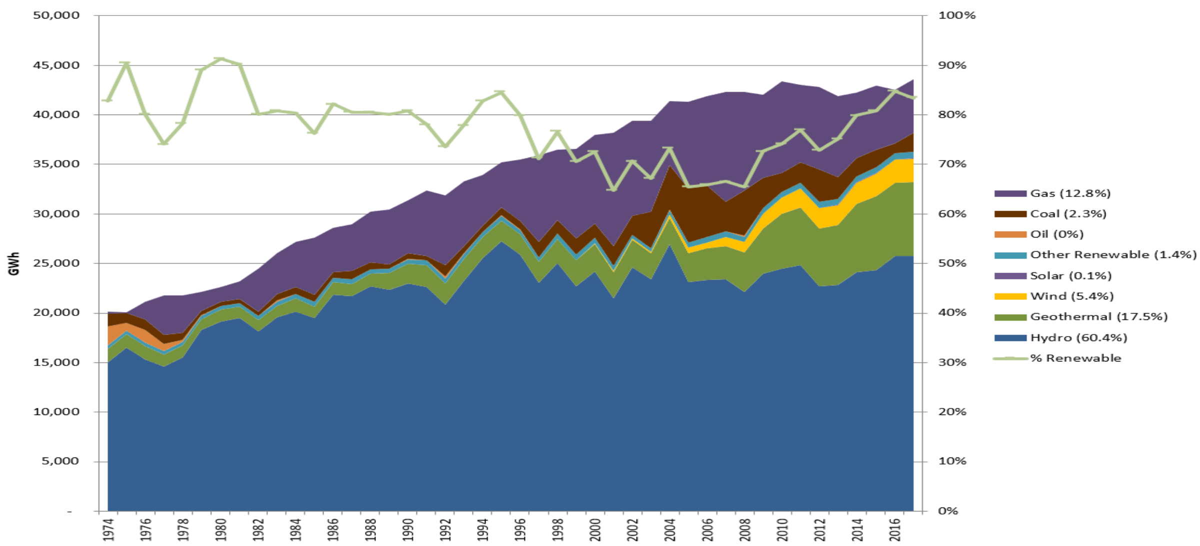


Figure 2: New Zealand generation by type, with renewable generation. 2017 is estimated from the June quarter and quarterly seasonal adjustments based on 2013 to 2016 generation, and 2016 gas plant withdrawals from the market. Figures given beside each generation type give the proportion of generation in 2016. Data is from the New Zealand Energy Quarterly, MBIE, June 2017 quarter, 5 October 2017.

Culy et al (1996) describe the history of electricity in New Zealand, starting with developments by private companies in the 1880s. From the early part of the 20th Century, however, all significant power stations were government built and owned. From 1945 to 1978 electricity was supplied to local distribution authorities by a government department, which was able to develop the system in ways the private sector probably could not have. Large-scale hydro schemes were developed, with associated new canals, roads and towns, despite gradually increasing environmental opposition. New Zealand pioneered the development of large-scale geothermal generation, from 1960. And the backbone of the national transmission system was built, with New Zealand pioneering the use of long distance underwater HVDC transmission to link the two islands in 1965.

Until the construction of a small coal-fired firming station in 1958, almost all developments were hydro. That reflected a philosophical commitment to exploiting free renewable resources, which were relatively abundant but, given the constant threat of shortages during the earlier part of this period, it is suggested by Culy et al (1996) that optimal development might actually have involved more thermal plant, closer to major loads. In the late 1960s and 1970s, the direction of development was changed by two major events. The perception of hydro as being environmentally benign, if not beneficial, was permanently changed when the Government over-rode public opinion to build the Manapouri hydro scheme, in a National Park, in order to supply an aluminum smelter. Then, the discovery of natural gas at Kapuni and Maui made gas-fired electricity generation economic. Coal and oil-fired stations were also built, in order to cope with wet/dry year output variations in an isolated hydro system, where reservoirs large enough to store water from year to year were (and still are) considered to be environmentally unacceptable.

In the 1970s New Zealand experienced declining terms of trade for primary exports, while being susceptible to fuel price shocks. An increasingly authoritarian government instituted regulatory controls and made large-scale investment decisions driven by dubious commercial incentives. Oil-fired stations were built then moth-balled, while employment was maintained by continuing work on increasingly expensive hydro developments, the power from which was supposed to have been sold at a discount to new smelters.

In 1979, the Electricity Department was integrated into a Ministry of Energy, which not only controlled planning, production and pricing of electricity at the wholesale level, but also that of fuels supplying and competing with electricity, and of demand-side management programs. This was supposed to facilitate a more consistent economic approach, and significant progress was made in trimming back the most extreme development proposals, re-balancing hydro and thermal investment, consistent shadow pricing of thermal fuels across sectoral development plans, and optimizing reservoir management strategy. But the thermal fuel costs assumed for operational purposes were quite different from those used for planning purposes, so plant was not necessarily used in the way it was planned.

End-user pricing also remained inconsistent throughout the period of government control. Prices to the voting public were held artificially low, for obvious reasons, while even lower prices were occasionally offered to a few major industries, to boost national development. But prices for most commercial and industrial users were much higher. Interestingly, so long as the system remained 100% renewable, the *Bulk Supply Tariff* (BST) charged to distribution authorities was based solely on peak load, reflecting the economics of a system most often constrained by transmission capacity limits. As thermal power became more important , an equal weighting was introduced on energy and peak demand, but no attempt was made to reflect the wide variation in marginal cost from year-to-year due to hydrological variations, or even changing economic conditions. During the early 1980s, BST was allowed to decline in real terms over a period of high inflation, and then, when the Government needed the revenue, it was suddenly raised by 60% and 40% in consecutive years.

By 1984, though, it was becoming increasingly clear that the Ministry of Energy's approach to electricity production and pricing was failing, and a new government instituted sweeping reforms, liberalizing all aspects of the economy, and corporatizing most productive activities previously undertaken by government departments. In order to avoid political incentives to boost employment by over-manning and over-building uneconomic projects to match over-optimistic growth projections, the Electricity Corporation of New Zealand (ECNZ) was formed, and expected to act in a normal commercial manner, with a view to privatisation, if possible.

The BST was replaced by a new regime under which all wholesale electricity was bought and sold using hedge contracts written against a half-hourly pseudo-spot price, calculated a week in advance using ECNZ's operational optimization model. Internal generation groups were formed, given incentives to improve efficiency, and experiments were conducted with a form of internal market coordination.

The transmission system was also separated out into a separate state owned corporation (Transpower), which was intended to recover its costs under a pricing regime combining nodal spot pricing and "beneficiary pays" funding of new projects, with costs already sunk at the establishment date being allocated using a flow tracing algorithm. This proposed regime was controversial, and not implemented as planned. Methodologies for recovering the costs of transmission continues to be a contentious issue, and has undergone continual review since the 1990s.

The institutional arrangements described above were all intended to lay the foundations for development of an electricity market, the design of which was debated at great length in the early 1990's, with eventual implementation in 1996. At that time, a collection of ECNZ assets was formed into a new company, and privatized, competing with the rest of ECNZ as a duopoly at the wholesale level. Distributors still acted as the primary retailers in each local network, but were required to accommodate competitive entry. Full retail competition, including the forced separation of distribution and retail, followed in 1999, at which point the remainder of ECNZ's assets were formed into three separate companies, although all still under Government ownership. These companies were partially privatized in 2012 and, from that point on, these four major companies, along with a fifth controlling a collection of smaller hydro plant have accounted for most of the market.

Market developments and features

The New Zealand market pioneered the implementation of nodal pricing concepts developed in North America, motivated by the fact that in a relatively long and sparsely developed transmission system, even marginal losses can create significant marginal cost variations across the network. The details of the pricing and dispatch system are described by Alvey et al (1998). The New Zealand dispatch model included the novel concept of ancillary service co-optimization which was seen to be equally important because, in this small system, even loss of a 250MW unit requires significant contingency response, in the 6 and 60 second time frame. This ancillary-service requirement is actually also a major driver of locational price differences, because inter-island transfers are often more limited by the need to provide reserve support against link failure than they are by power flow congestion. In part, this explains why US-style congestion-based financial transmission rights, which had originally been part of the market design concept, were only recently introduced into the New Zealand market.

Regulation

Given its long history of direct Government control, New Zealand had no institutional history of sectoral regulation similar to that in the US, for example, and initially the market was implemented without any sectoral regulator at all. This was a deliberate decision, partly motivated by a perhaps excessively pure economic view that the electricity sector should not be treated differently from others, and partly by a more pragmatic assessment of the overheads involved in maintaining a full-blown regulatory function for a relatively small part of the economy. This approach has since been abandoned, with the formation of the Electricity Commission in 2003, then the establishment in 2010 of the Electricity Authority (EA), which performs the role of an independent market regulator.

Regulatory market oversight of the New Zealand wholesale market by the EA is light-handed by international standards. Short-term unilateral exercise of market power by generators is not illegal in New Zealand, and widely regarded in the industry as a tolerated mechanism for recovering the long-run marginal costs of generation. This view is not inconsistent with the doctrine of workable competition espoused by the Electricity Authority, in which competition is encouraged by focusing on low barriers to entry, so that market power is curbed by potential new entrants rather than explicit market oversight. With no formal price cap and capacity market the New Zealand system relies on prices (either spot prices or those of derivatives) rising enough from scarce situations to yield the required rents to cover long-run costs.

Regulatory oversight of hydro-dominated systems is also extremely challenging, in contrast to purely thermal markets. In hydro-dominated systems, electricity prices reflect the marginal value that agents place on stored water, a number that depends on their predictions of future inflows, and their assessment of shortage risks that could be caused by dry winters, outages or thermal fuel shortages from small isolated networks with little flexibility to trade, or adjust supply. When a potential water shortage looms, price increases are typically an opportunity-cost response to a perceived risk of future energy limitations, and interactions in an almost completely closed system rather than to capacity limits, or fuel prices from liquid markets. Although perfectly competitive outcomes become difficult to determine with any certainty, let alone regulate, the Electricity Authority have constructed a historical market database, and is developing an understanding of the effects of uncertainty on wholesale prices, but there is some way to go before reliable market monitoring tools for the New Zealand system are available.

Shortage Risk

Although New Zealand's electricity system is dominated by renewable energy, where geothermal is base-loaded while stored hydro can easily accommodate short term variations in demand and wind, it remains susceptible to periods of sustained low inflows, meaning that the challenges for system operation are more about variations in fuel over seasons, rather than minutes and hours, as is the case for most other countries contemplating high-renewable ambitions. This fuel risk is compounded by the fact that inflows tend to be at their lowest when national demand is highest as shown in Figure 3.

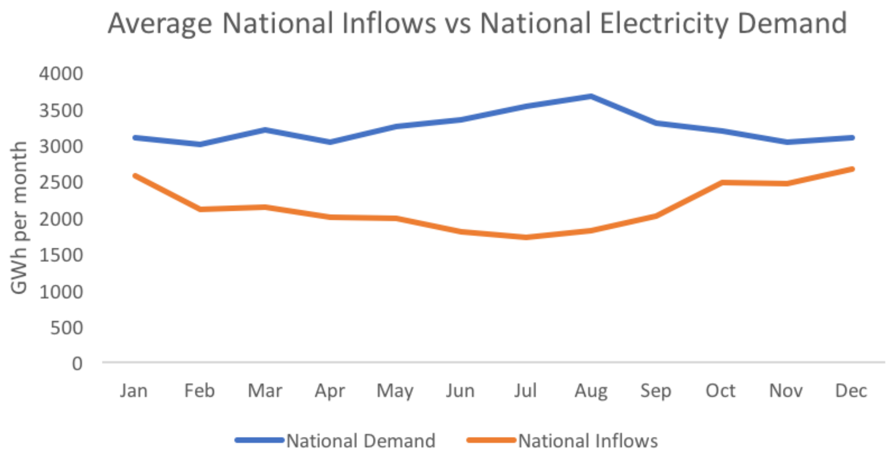
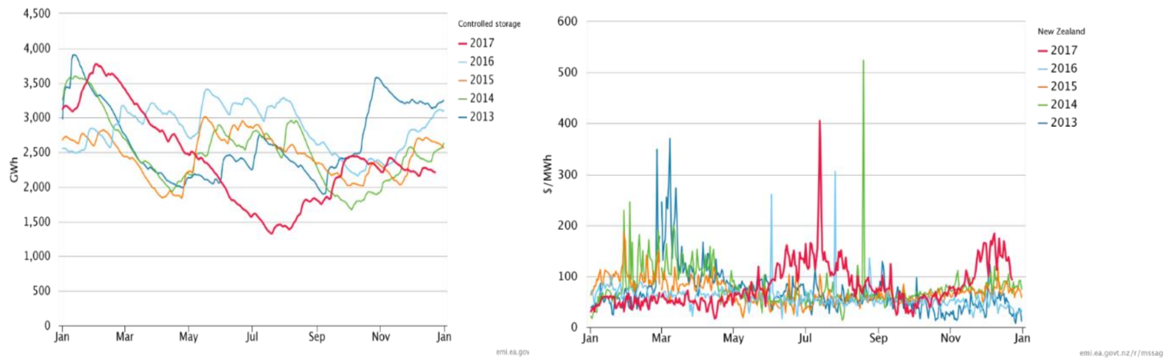


Figure 3: Average demand and average reservoir inflows. Demand is highest in midwinter when reservoir inflows tend to be at their minimum level.

There are no mandatory contractual arrangements for hedging the risk of shortage. As originally conceived in 1992, the New Zealand market was to have included a firm-energy mechanism similar to that subsequently implemented in Colombia, under which retailers were required to hold call options with a strike price set around the marginal operating cost of an OCGT unit. Thus, while the market price was to be uncapped, consumers would effectively be protected against exposure to price spikes above the OCGT level. The scheme was rejected, though, partly because it proved difficult to define exactly what capacity measure should be used in each region, but also because consumers resisted the idea of paying an insurance premium which might have to recover a potentially substantial proportion of the entire market value.

That leaves New Zealand with no market price cap, and participants potentially exposed to prolonged periods of very high prices under dry-year conditions of the kind that might be expected perhaps once every 20 years or so. In theory, participants in the wholesale market should expect to encounter very high prices when energy shortages loom. One can see this behavior happening in recent years in Figures 4a and 4b where national reservoir storage and generation-weighted electricity price are plotted.



(a) (b)

Figure 4: New Zealand historical controlled reservoir storage (a) and generation-weighted electricity price (b).

The risks of energy shortage are monitored by Transpower in its role as System Operator and the EA who publish risk curves as shown for 2016 and 2017 in Figure 5. These show the actual storage trajectory, and a set of storage levels that indicate increasing levels of risk at that time of year.

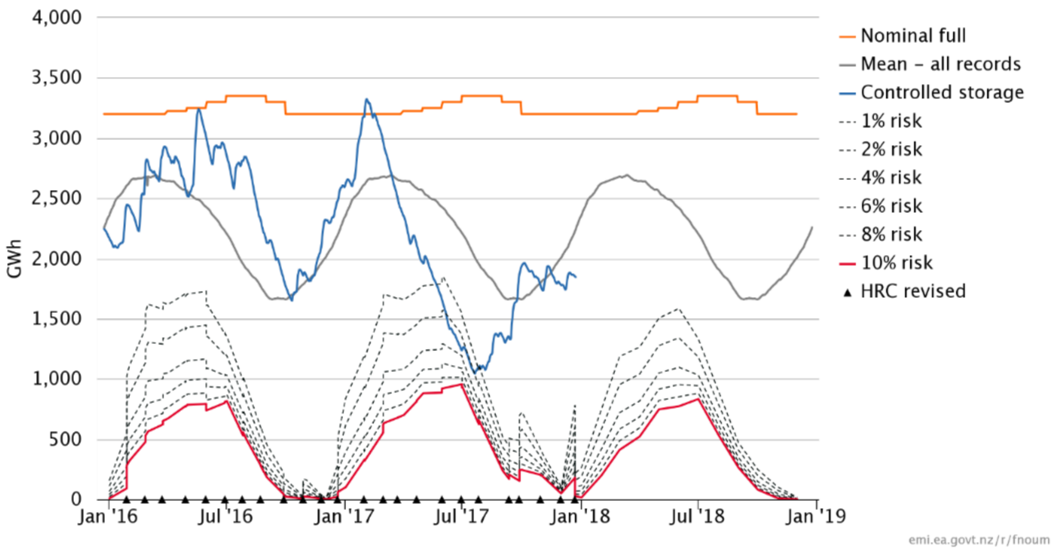


Figure 5: Historical hydro risk curves. Available controlled storage is plotted in blue. Dotted curves indicate storage levels that would incur the displayed probability of controlled storage falling to zero if all thermal plant were fully dispatched. If the controlled storage meets the 10% risk curve (red), the EA and the System Operator will launch an official conservation campaign, in which consumers will be asked to conserve electricity.

Vertical integration

The wholesale electricity market for New Zealand is *vertically integrated*. By this we mean that all of the five main generation companies are also retailers of electricity (called *gentailers* to distinguish them from several small stand-alone retailers). This is in contrast to the typical definition of vertical integration that combines generation, transmission and distribution. Participants in the market also trade various contracts to reduce exposure to risk. The most popular are *contracts for differences*: these have a fixed volume with a payout per MWh to the purchaser equal to the difference of the observed spot price and the contract price. These contracts are traded both bilaterally (over-the-counter) and via a futures exchange. The

Electricity Authority monitors the futures exchange and strongly encourages gentailers to offer contracts to it.

Both contracts and vertical integration are useful mechanisms to hedge risk, but when generation and retail load are correlated, vertical integration provides more protection, as it reduces volume risk as well as price risk. There is also some evidence that the improved risk hedging from vertical integration yields investments that are closer to socially optimal outcomes, at least under the assumption of perfect competition.

Originally, it was planned to enforce a strict vertical separation, with generators banned from retailing, and vice versa. Thus they would all be required to interact by arms-length trading in contracts. As discussed above there are strong incentives for vertical integration to hedge risk, which were even more compelling in 1996 in a small illiquid contract market. So in the early days of the market, vertical integration was regarded benignly.

On the other hand, vertical integration means that stand-alone retailers and large industrial plant must compete in a less liquid contract market. The risks of illiquidity in contracts were highlighted in 2001, when a major retailer competing solely on the basis of bilateral contracting, was forced by substantial financial losses to exit the market after failing to purchase enough forward cover in a dry year. More recently, the EA has encouraged the development of more liquid markets in both energy and transmission hedges, and a range of smaller retailers have emerged, but vertical integration is still the dominant paradigm. Indeed, in lieu of a capacity market, the EA relies on the prospect of high prices, reinforced through a regulated stress-testing regime which highlights the financial risks associated with dry years, to provide both gentailers and stand-alone retailers the incentives to invest in, or contract for dry-year capacity to meet their wholesale purchase obligations for customers. A further penalty regime applies in the event that the 10% risk storage levels occur (see Figure 5), whereby all retailers are required to compensate their customers for savings. The EA sets a minimum default rate for this compensation.

Day-ahead markets

Nearly every spot-market pool in North America and Europe consists of two markets with a two-settlement system. Committed generation is cleared in a day-ahead market on the day prior to dispatch and then flexible plant is dispatched in a balancing market on the day of operation. This process enables operators of large thermal plant to plan their unit commitment subject to start-up and ramping constraints. The day-ahead market is typically dispatched using a mixed integer program (MIP) that accounts for these indivisibilities. In contrast the Australian and New Zealand wholesale markets are single-settlement systems. The fixed costs and constraints of thermal plant are internalized in the prices of their energy offers that are then dispatched in real time in merit order. The merits of a single-dispatch unit commitment have been debated in the literature, but is generally accepted that a day-ahead market as part of a two-settlement system will yield a more efficient dispatch.

In New Zealand, with very few large thermal plant, the advantages of using a MIP for unit commitment are minimal, so a single-settlement market seems sensible. On the other hand the dispatch of hydro-stations down a river chain over a day involves a dynamic element. There is some empirical evidence that a rolling horizon price-directed approach to scheduling this dispatch using agents' offers that vary over the day gives a more expensive dispatch than a resource-directed plan that could be specified using a day-ahead optimization. Although the original design proposal for the New Zealand wholesale market included a day-ahead market, this was regarded as unnecessarily complicated by participants and abandoned.

Retail market competition

Since its establishment in 2010, the Electricity Authority has been especially active in promoting retail competition. The most significant development here was possibly the establishment of an electricity futures exchange, which enabled small, independent retailers to hedge the significant medium-term price volatility characteristic of New Zealand's hydro-driven market. Since 2010, the number of retail brands in the market has increased from 10 to over 30, with the market share of the five largest gentailers declining from 97% to around 90% currently.

Until recently, the tariff structure for a domestic electricity consumer (as well as many mass-market business customers) was almost exclusively a fixed price, variable volume (FPVV) contract. With the rollout of smart meters, new tariff structures are emerging, though, most notably a spot-based tariff offered by two retailers. One of these retailers – Flick Energy – acquired over 20,000 customers (~1% of the market) in little over three years. However, 2017 was the first high wholesale price year since Flick's entry, and it remains to be seen how durable their customer base is in the face of temporary high prices at the meter, or whether the insulation from wholesale signals (via an FPVV contract) is ultimately preferred by customers, albeit at a higher average price.

Investment and entry

As discussed above, investment in New Zealand is at the discretion of market participants, and is solely incentivized by the electricity price in an energy-only market setting. Market participants form views on the future electricity price, and revenue may be underwritten by contracts with other market participants or retail customers, or some reliance on the wholesale price.

While investment is largely price-driven, it must be cognizant of electricity demand and the investment intentions of all market participants. While some participants probably inherited unrealistically low expectations of the long-run cost of investment in the years following deregulation, investment accelerated after 2004. This investment was dominated by wind and geothermal, but also the construction of a large CCGT in 2006, bringing the total fleet of CCGTs to four. Although several hydro projects have been extensively investigated, environmental opposition has been significant, and no significant hydro project has actually proceeded since the market commenced in 1996.

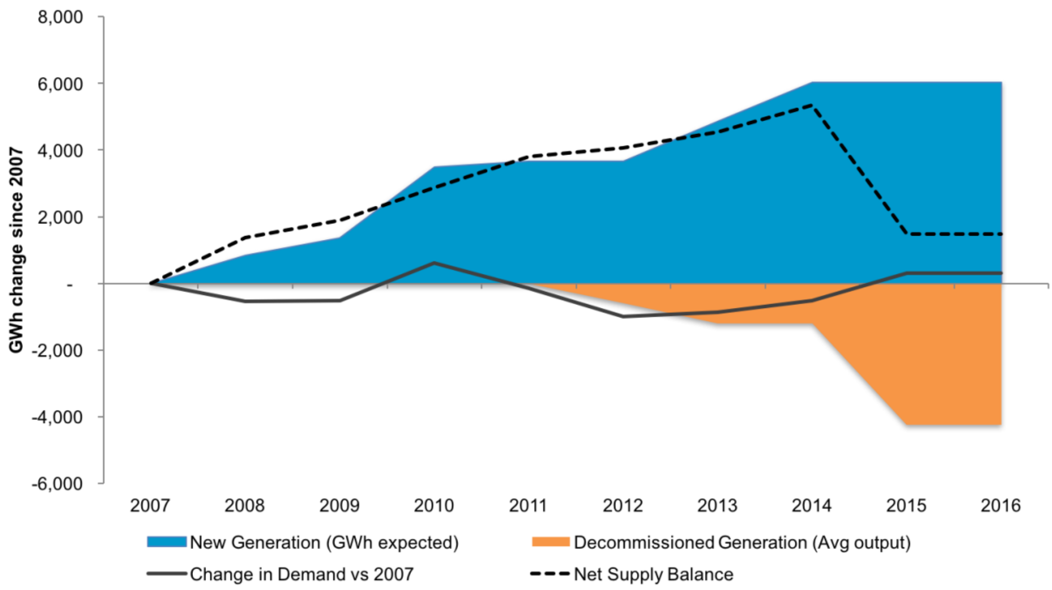


Figure 6 : New generation and decommissioned plant 2008-2015 (Source: Whiteboard Energy, Electricity Authority.)

Figure 6 shows the relative changes in both net supply and demand (again, in terms of annual expected production) since 2007. Over this period, electricity demand has remained largely flat – an unprecedented 10-year trend. While there have been some industrial closures during that period, we believe this trend is largely driven by energy efficiency. Over this period participants continued to invest in renewables, perhaps expecting demand to eventually recover. The lack of demand growth led to thermal plant being increasingly substituted by renewables. Over 2013-2015 a number of thermal plants were decommissioned by market participants, reducing available supply by over 1,000MW (over 10% of total capacity), and a further 480MW threatened with imminent closure. A bilateral contracting arrangement between market participants delayed the mothballing of this latter capacity (two units at a 30-year old coal/gas Rankine plant) until the end of 2022, amidst concerns about security of supply. It remains to be seen whether these ad-hoc contracting arrangements can continue to deal with any missing money associated with thermal plant facing decreasing utilization as a result of renewable investment.

Looking forward, the major risk to further investment in the medium term continues to be lack of demand growth. This is compounded by some degree of uncertainty of the future of a large aluminium smelter, which makes up 12% of the country's total demand. On the other hand, the electrification of transport and heat may, in the long term, put upward pressure on demand. Given New Zealand's present and potential renewable resources, it is in an enviable position to fuel this electrification while contributing to its international commitments regarding carbon emissions. However, the expansion of renewables implied by some future scenarios will have to deal with public concern about the visual and environmental effects of wind and hydro.

New developments in the distribution sector

During the reform process the number of distribution authorities was substantially reduced, but New Zealand still has nearly 30 electricity distribution businesses (EDBs) serving a total population of only 4.5 million people. There is a range of ownership models for EDBs, including: local government; private investor; community owned trust; or a combination of private investor and community trust. Being considered monopolies, EDBs are subject to price-quality and information-disclosure regulation, with strict limits on generation or retail activities. The Commerce Commission determines a default price-quality path, but EDBs determine their own pricing structures and access arrangements, within limits. This proliferation has proved to be unhelpful, and it seems clear that retail competition and innovation are inhibited by the fact that national retailers must create package offerings that deal with many different cost structures.

Rooftop photovoltaic solar

Figure 7 shows the historical uptake of PV solar, which is relatively low in New Zealand, at about 13.5 Wp per person. About 90% of the PV solar capacity is small-scale residential rooftop. Unlike many other countries, the New Zealand Government has never provided explicit subsidies for rooftop PV solar. However, some gentailers provided buy-back rates of around 17 c/kWh prior to November 2014, after which they reduced their rates to 8 c/kWh (equal to the average wholesale price). Solar uptake is indirectly encouraged, though, by a "low-user tariff" regulation, which requires EDBs to charge residential consumers with low consumption a lower daily fixed charge and a higher variable charge for each unit of electricity used. This is supposed to encourage energy efficiency and assist in energy procurement for low-income families, but many wealthier households have low usage because their homes have better insulation and use non-electric heating, and thus these users have artificially high incentives to install rooftop PV solar.

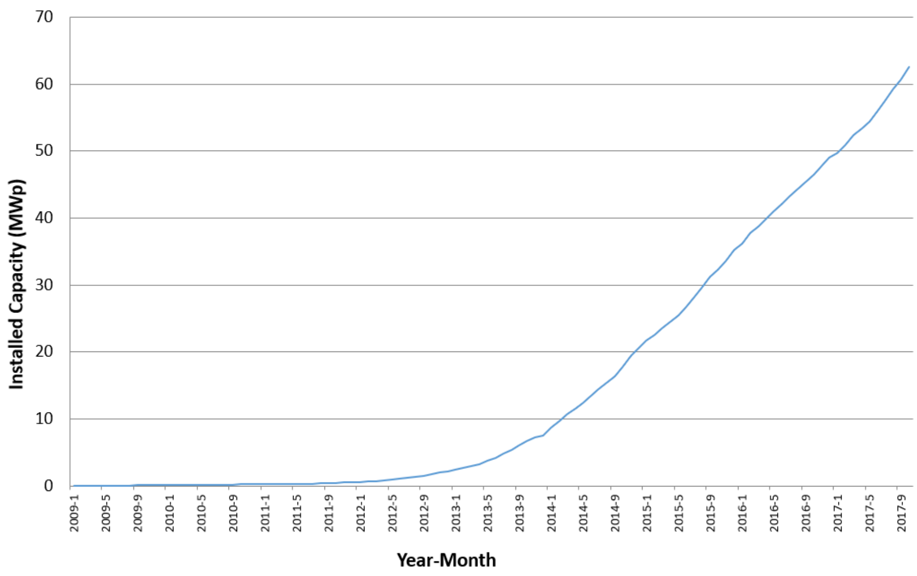


Figure 7: Photovoltaic solar installed capacity in New Zealand. Capacity reached 62MWp (13.5 Wp per person) in October 2017. Data to September 2013 collated by the GREEN Grid project, and post 2013 by the Electricity Authority. Graph supplied by the University of Canterbury.

Studies such as Miller et al (2016) show that PV solar is already commercially attractive for some households, and some commercial customers, even though they typically have a much lower variable price and higher fixed price then residential consumers. In fact, with current distribution pricing arrangements, and falling PV prices, New Zealand seems close to a very rapid uptake of PV solar by residential customers, especially in those regions with high irradiation. So the real issue is whether PV solar can actually make a positive economic contribution, given New Zealand's relatively cloudy climate, and demand pattern dominated by heating, rather than cooling requirements.

PV solar capacity factors can be as high as 18% at the top of the North and South Islands, where uptake is highest, but only around 12% at the bottom of the South Island, and that is mainly during summer, whereas load peaks on long dark cold winter nights. This contrasts with capacity factors well above 20% in parts of Australia and North America, in regions where demand also tends to peak on hot sunny days. Nor does solar hedge low hydro reservoir inflows, which fall to their lowest level around June/July, when PV solar output is also lowest. Thus, if the New Zealand Government follows the recommendations from New Zealand's Smart Grid Forum, it will not be directly supporting PV solar in the near term. Arguably, it should be more concerned that initial attempts to introduce higher fixed charges for high users installing PV solar have stalled in the face of public and solar industry outcry.

Electric vehicles

New Zealand has no automotive industry, and only accounts for a very small proportion of global demand. In fact the majority of New Zealand households buy used vehicles from Japan, and thus choose from whatever was sold there about a decade earlier. Thus New Zealand Government policies have no discernible impact on global R&D priorities, or even manufacturing strategies, so there is little economic incentive to foster experimentation with new automotive technologies. Still, the Government has provided a fund for innovative marketing and support of electric vehicles. Electric vehicles still only account for 0.16% of all light vehicles, but Figure 8 shows that uptake has grown strongly in the last two years, as more models become available internationally, range increases, and marketing ramps up.

It will be interesting to see how policy settings evolve as some environmentally conscious households who are low users currently enjoying a high weighting on variable charges to encourage solar penetration, turn into high users seeking a low weighting on variable charges to charge electric vehicles. We expect increasing political pressure to subsidize both activities. The problem of determining the most efficient policy regime is complex, and depends heavily on correlations between PV contributions, charging requirements, and other loads and generation sources, across daily, weekly and annual cycles, under a wide variety of meteorological combinations. The economics of a system approaching 100% renewable capacity with a sparse transmission/distribution network seem likely to favor a relatively high reliance on capacity-based charging mechanisms.

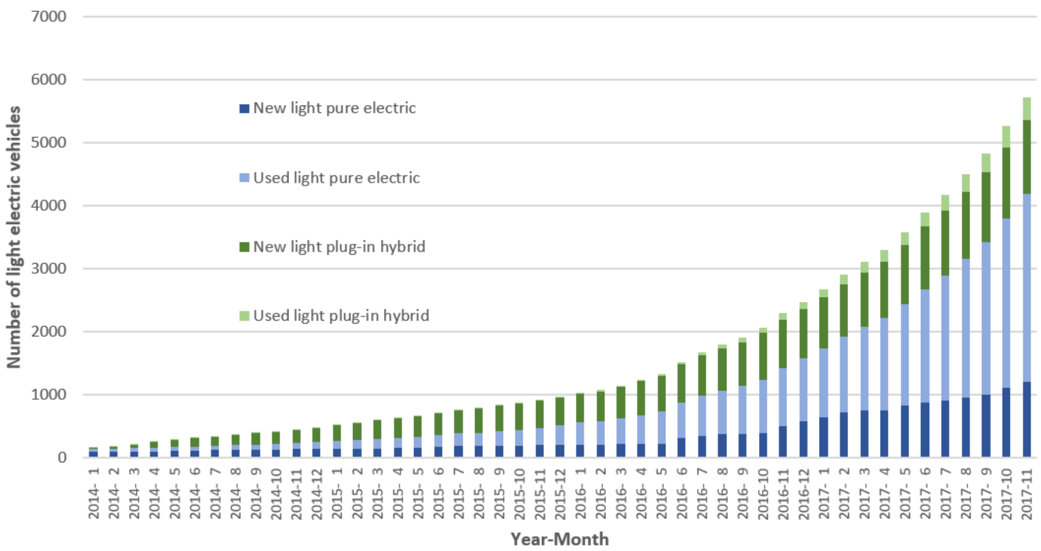


Figure 8: Light electric vehicles in the New Zealand vehicle fleet. To November 2017, the total number was 5,728 vehicles, a small fraction of the c. 3.6 million light vehicles in the fleet. Data from the Ministry of Transport, New Zealand Vehicle Fleet Statistics.

Battery storage

Batteries seem unlikely to ever contribute much to New Zealand's main supply security issue: storing enough excess production in wet years to cover dry conditions occurring perhaps every 20 years, or less. And they face stiff competition with existing hydro storage as a way of dealing with supply/demand fluctuations over minutes, hours or days. At a system level they will not make much contribution until solar and/or wind output becomes so high that hydro cannot be backed off any further, and energy must be spilled. At a household level, storage batteries can make PV solar more attractive by maximizing self-consumption. But the cost for this use alone is prohibitive, adding at least 40 c/kWh to the average cost of energy to a PV solar system. Greater benefit can be gained by situating batteries 'behind the meter', thereby enabling one battery to deliver a bundle of network, PV solar, demand response, and ancillary service potential benefits. Even so, studies suggest that it will be some time before batteries become economic in New Zealand. Nevertheless, some EDBs are experimenting with in-home and larger scale batteries to manage specific constraints in their networks. As with interruptible load systems though, the regulators may find it difficult to ensure equal access to the many benefits that batteries may bring, while also allowing them to be bundled effectively. And household installation may be inhibited if new regulations require lithium-ion batteries to be installed in separate enclosures outside homes for fire safety reasons.

Smart metering

When full retail competition was introduced in 1999, smart meters were only required for larger, typically industrial/commercial consumers. Studies suggested that the costs of mandatory smart meter installation exceeded the benefits, for most households. So this was left up to the market, except for a regulation requiring re-certification of all meters by 2015. Smart metering rollout is relatively high now, at around 70%, but this seems to have been driven more by the opportunity for retailers to reduce meter-reading costs than by a strong desire by consumers to actively manage their consumption patterns. While recent growth has been strong, only a small proportion of households actually face half-hourly spot prices and, while they receive real-time alerts of looming price spikes, they actually only see their own data about two days after real time. There has been some consolidation in the smart meter market to two main service providers, and two main meter types.

The future

The Electricity Authority's statutory objective is "*to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.*" Consistent with this, the Electricity Authority's current priorities are reviewing distribution pricing, to ensure greater efficiency and competition, pursuing multiple-trading relationships to encourage more retail competition and more participants in the market, and more fluid data exchange, including access to retail data such as smart metering data, to provide more efficiency and competition. The Electricity Authority is also pursuing, through new advisory groups, open access to distribution networks to encourage greater efficiency and competition, alternatives to traditional electricity distribution, to also further competition, and more diverse sources of electricity supply, and uses of demand response. A recent development under investigation is a proposal by the EA to move the spot market to real-time pricing to provide more timely signals for market participants.

Some electricity distribution business are evolving from low-voltage network owners towards system operators, as they seek to integrate the numerous new devices connecting to the network, and make economic tradeoffs with the new services to manage system peaks to avoid the need to continually upgrade their networks. Challenges abound for low-voltage networks in optimizing the use of storage batteries, smart electric vehicles, and increased demand-response, especially where this needs to integrate with price signals emanating from the wholesale market. Presently, the trend towards distribution system operators is occurring within existing network owners; it remains to be seen whether the separation between asset ownership and system operation, which is largely adopted for the high-voltage grid market, will also eventuate for distribution-level markets.

These developments are largely positive, but we have to ask whether they will suffice to deal with the demands likely to be placed on the electricity sector over coming decades. Although the renewable generation share is currently at around 85%, a Government goal to reach 100% renewable generation in an average hydrological year by 2035 means that the New Zealand electricity market now faces a significant developmental and operating challenge. Moreover, New Zealand has ratified the Paris agreement, with its nationally determined contribution (NDC) requiring a reduction in equivalent CO_2 emissions of just over 30MT from current levels by 2030. While New Zealand's greenhouse gas emissions are small on a global scale (about 0.15%), its per capita emissions are comparatively high, mainly due to the high level of methane and nitrous oxide emissions from agriculture. Studies have shown that electrification of private vehicle transport and most stationary heating, and conversion of the remainder of electricity generation to renewable sources, would almost reach New Zealand's NDC. The required increase in renewable generation to achieve this would be about 130%.

The question is what sources will be used to deliver an increased renewable penetration. New Zealand has to date incorporated 800MW of wind generation (about 9% of installed capacity) with no adverse effects on the power system. This is primarily because flexible (predominantly hydro) generation has so far been able to manage the variations in generation supply brought about by wind generation. But further hydro development faces very stiff environmental opposition, and would increase the need for hydro-firming plant which can flexibly respond to the medium-term variations in hydro inflows, given New Zealand's limited reservoir storage capacity. Unfortunately, New Zealand's highest demand tends to occur on winter evenings, where there is no solar resource, and a prospect of cold, windless conditions. And there has been significant opposition to the impact of wind farms on landscape values, too. Still, with about 3,000MW already consented for development, wind can be expected to play a major role in achieving the 100% renewable target, along with geothermal, of which there is about 300MW consented for development.

Studies by the GREEN Grid project have investigated the technical impact on the power system of adding up to 4,000MW more wind generation (about 50% of installed capacity). The results show an increased need for frequency keeping, instantaneous reserves to deal with the reduction in inertia, and droop response to deal with increased system frequency variations brought about by increased wind variability and reduced inertia. Demand-side involvement in the market shows some promise to provide ancillary services, thereby increasing the supply of instantaneous reserves, droop response, and frequency keeping. But, without some substantial reductions in peak demand, flexible peaking plant will also need to remain, albeit operating at low load factors. For the near future, these roles are likely to be filled by thermal plant, but may eventually be provided by partially-dispatched geothermal to manage seasonal variations, noting the commercial impacts for investors, who typically assume geothermal is base loaded.

Increasing renewable contributions will also increase the proportion of the time for which plant with near zero marginal cost are on the margin. Offering more generation from this plant to the wholesale market will depress the market clearing price, providing lower market returns for most generation, most of the time. To recover generators' fixed costs in an energy-only market will then require more periods with higher scarcity prices. And that must surely increase the pressure to introduce some form of firm-energy market to provide the missing money.

Arguably, this trend may be so extreme as to pose an existential challenge to the whole market design, and its governance arrangements. It is possible to calculate the average annual level of scarcity prices required to incentivize a reasonable level of capacity investment. In theory, we may argue that there is little difference from suppliers collecting this revenue during occasional price spikes, or the Government collecting it via capacity charges, as was done when New Zealand last had a 100% renewable power system, before 1958. But there may be very significant differences in the way those two regimes are perceived by risk-averse investors, the regulator, and by the general public. And those perceptions may ultimately determine the durability of the regime.

Perhaps the EA's current approach will endure if the sector continues to be dominated by substantial vertically integrated firms, with strong incentives to stay in business for the long term. But that may change if the sector evolves toward a purer version of the competitive market paradigm, with a large number of less substantial firms relying on supply from and to a highly volatile spot market. The situation in New Zealand is quite different from that in

Australia, for example, where both investors and the general public expect a fairly predictable number of short sharp spikes on hot days, every summer. In New Zealand, a future generation, having experienced maybe 20 years of low renewable energy prices, may find it very hard to accept that the accumulated cost of backup generation must be paid for in a single dry winter of very high prices. Presented with such an event, a future government may also find it very hard not to respond by intervening, either changing the market design, over-ruling the regulator, and perhaps even reversing privatization. And risk-averse investors are likely to commit to significantly less than the optimal capacity requirement on the basis of such an irregular and unpredictable income stream, and even less if they believe the regime itself may be changed so as to specifically prevent them from collecting the revenue required to pay for that capacity when a really dry year finally occurs.

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