MEETING NZ’S WINTER ELECTRICITY NEEDS:

Research Priorities

Introduction

NERI has published an Energy Research Strategy for NZ [1]. One of the themes within it relates to better understanding the options for meeting peak and winter/dry year electricity demand. Since the publication of the Strategy the Government has asked the newly established Interim Climate Change Commission (ICCC) to make recommendations on *Planning for the transition to 100% renewable electricity by 2035 (which includes geothermal) in a normal hydrological year* [2].

The main issue for achieving 100% renewable electricity in NZ lies in managing the mismatch between the relatively low availability of hydro, wind and solar in winter, and the relatively higher demand for electricity at that time. While not within the terms of reference for the ICCC this problem is even more acute in in dry years.

Based on the current state of knowledge it appears that an affordable approach to this issue is not obvious. Further research in the NZ context will therefore usefully increase the range of options and our understanding of them.

This note seeks to identify the relevant areas for attention.

Summary

- Any solution will consist of a portfolio of responses reflecting the range of social and environmental acceptability, technical feasibility and affordability.
- The options for affordable inter-seasonal storage of fuels for renewable electricity generation are limited by high capital cost and once-a-year use.
  - Only pumped hydro appears able to make a contribution, particularly so where it can use existing infrastructure that would be otherwise underused (e.g. hydro turbines).
- Over-provision of wind generation represents the base case for using generation to cover winters, and this will be expensive. Bioenergy fuelled generation for just the winter months appears more competitive, and where it can be configured to supply combined heat and power (CHP) might compete with the existing solution of Natural Gas (NG) but with Carbon Capture and Storage (CCS) added.

- Options to use surplus summer generation appear limited because, unless the industry involved is itself seasonal, production will need to be cut during the winter months. Fuel production for export in summer and to reduce winter electricity demand could avoid this problem.
- Reducing the winter/summer load differential will reduce the level of surplus generation required within the electricity system. Domestic and commercial building-related thermal loads represent the bulk of this differential.
    - Better understanding of the interactions between electricity supply and demand and thermal supply and demand is required. Consideration of the electricity system alone will be sub-optimal.
    - Under-researched areas here include the impact on winter electricity demand of appliance efficiency, building performance and non-electric thermal generation (i.e. biomass, geothermal). Initial results suggest it will be possible to materially flatten winter electricity demand.

Each of these areas is an area warranting further research in the NZ context.

The issue

The winter/dry year shortfall is widely discussed in a number of reports and papers reviewing NZ's future electricity needs. For convenience this note uses *Te Mauri Hiko – Energy Futures* [3] as a useful recent summary of the issues.

This mismatch isn't the only issue facing a shift to 100% renewable electricity, but the others (increasing renewable supply to accommodate both growth and the shift away from fossil fuel; managing increasing levels of short-term storage; managing short-term variability) appear much more tractable using existing or emerging technologies along with demand side management (DSM)[1].

Te Mauri Hiko summarises the issue:

> *"In the base case scenario, New Zealand's exposure to supply shortages in winter and/or a dry year is expected to grow from 4 TWh today, which is covered by 7 TWh of current thermal generation capacity, to 9 TWh by 2030 and 12 TWh by 2050, partially driven by the reliance on solar.* [page 29]

It goes on to say:

> *"Several potential technical solutions for managing New Zealand's unique winter and dry-year energy issue have been identified but none appears definitely feasible and economically attractive. Nonetheless, there are emerging alternative options worthy of early consideration."* [page 31]

The emphasis in *Te Mauri Hiko* is mainly on emerging technologies that might be used within the electricity system to meet a given demand. Scenarios are used to describe what happens outside the electricity network (i.e. demand) so the corresponding assumptions implicitly constrain the analysis.

[1] See for example Mason et al (2013) [2] that shows that using a generation mix of existing technologies - 49% hydro, 23% wind, 13% geothermal, 14% pumped hydro energy storage peaking plant, and 1% biomass-fuelled generation on an installed capacity basis - was capable of ensuring security of supply over an historic 6-year period.

The weakness in this is that supply and demand are not modelled interactively. This is a significant issue if the supply side is increasingly unable to cost effectively meet some aspects of assumed demand.

Instead under these circumstances it is essential to include in any optimisation the options available from outside the electricity system to meet the winter shortfall. This is an area where more research is required and we discuss this in more detail below, but note here that adding this dimension should suggest a much richer and lower cost portfolio of responses.

But first we follow the approach in *Te Mauri Hiko* and review the feasibility of the potential options available within the electricity system to supply renewable electricity to meet an assumed winter demand, and where further research in NZ is indicated to support those that appear viable.

Options within the electricity system

To meet the winter shortfall from within the electricity system requires additional renewable electricity supply for 3-4 months of the year.

There are two broad non-exclusive approaches:

1. Technologies that allow renewable electricity to be shifted inter-seasonally, and/or
2. Renewable generation of electricity limited to the winter months.

Both are challenging from an economic standpoint because they imply capital is being significantly under-used. In the first case the storage gets used only once a year[2] in a very deep cycle (i.e. high capital cost) and specialist generation assets may possibly be required for only a third of the year. In the second the generation assets will only get used for a third of the year and long-term fuel storage may also be required.

Battery storage

Of battery technologies only flow batteries have any prospect of low cost long-term storage. These will be in market over the next decade but those technologies suitable for utility scale deployment are rather more suited to intra-day storage timeframes than inter-seasonal [4]. For this reason research into the technology is important, but not for this application.

Hydrogen or hydrogen carriers for storage

Hydrogen could be produced using electrolysis at times of surplus electricity and then later used to generate electricity either by direct combustion in gas turbines[3] or electrochemically in fuel cells.

It can be stored in a variety of ways, but bulk storage in the volumes required for inter-seasonal energy shifting is generally anticipated to require pressurised

[2] Potentially much longer for dry year cover.
[3] Currently gas turbines are limited to around 50:50 mix of hydrogen and NG.

underground storage or transformation to a more energy dense form. Liquid ammonia is one of the simpler options, but even here conversion still face technical challenges [5] and adds cost and increase losses [6].

Internationally investigation of underground storage of hydrogen has by-and-large focused on shorter timeframes than would be required for winter cover in NZ, and has typically used hydrogen sourced from lower cost NG reforming with CCS or gasification of coal with CCS, e.g. [7]. In the NZ context we could require a bit over 30M m^3 of hydrogen storage[4], well within the potential capacity of fields studied in the UK [8], but the availability of suitable geology at the required scale in NZ seems unlikely[5] [6].

The basis for investigating electrolytic hydrogen in NZ is the perception that there will be significant periods in a 100% renewable system where there is surplus generation capacity (e.g. *Te Mauri Hiko* Exhibit 15[6]). In theory this could allow hydrogen production using zero variable cost electricity. This could reduce the cost of hydrogen from large scale electrolysis at those times to ~2/3[rds] of the cost at average electricity prices [9].

Unfortunately, three factors make electrolytic hydrogen relatively expensive and therefore uneconomic compared with other options:

- The round trip efficiency of electricity to hydrogen to electricity is under 50% [6].
- The periods of cheap electricity will be limited, targeting these periods means low utilization of the electrolyser, and there will be others looking to exploit this low cost electricity. Each then works to increase the price of hydrogen generated at these times [9]. Significant hydrogen price reductions overall are unlikely [6].
- Hydrogen storage is expensive even when it is cycled numerous times during the year[7]. Storage for winter involves a single deep cycle per year, and extraction rates are constrained unless the storage is also used for shorter term load balancing [8].

To summarise from the UK in respect of the less challenging short-term storage of hydrogen, where suitable under-ground storage is available: "in most cases, [electricity storage and regeneration] will be very challenging in the short to medium term due to the low roundtrip efficiency and high CAPEX compared to alternatives such as pumped hydro or battery storage." [9]

Consequently inter-seasonal hydrogen storage is unlikely to be feasible in NZ.

[4] [44] reports: "Very large amounts of hydrogen can be stored in man-made underground salt caverns of up to 500,000 m3 at 200 bar (2,900 psi), corresponding to a storage capacity of 167 GWh hydrogen (100 GWh electricity)."

[5] Purpose building, if practical, would increase the costs even further.

[6] The surplus and shortfall of electricity shown in Te Mauri Hiko arise from a static analysis with artificial constraints. More dynamic less constrained modelling (e.g. [43]) should find more balanced solutions. This will impact on the availability of low cost electricity in more realistic scenarios.

[7] At "an annuitised cost of around £200/MWh/annum", much higher than for NG [19].

There are other “Power-to-Fuel” technologies that could emerge (see e.g. [10]). Synthetic methane, for example, could help address the hydrogen storage issues and is mentioned later. These options should be investigated because of NZ’s significant supply of renewable electricity generation relative to other countries.

Hydro storage

Hydro storage is extensively used in NZ, although the system has been designed with intra-seasonal storage rather than inter-seasonal storage in mind. Only Waitaki has significant storage capacity, e.g. [11]. The current total hydro system storage is around 3,600 GWh, a bit more than half the additional projected by Transpower to be required to cover for a normal year in 2050 [3].

The potential to expand the hydro generation capacity has been estimated at 11,700 GWh [12], a bit under half the current capacity. But this estimate is dated so is likely to be significantly overstated particularly having regard to changing social and environmental concerns.

Proposals to increase storage capacity by altering minimum and maximum lake levels would be similarly constrained as *Te Mauri Hiko* notes.

Pumped storage allows energy to be shifted in time. The International Hydropower Association estimates the 2017 globally installed capacity was 161 GW and storage capacity 9,000 GWh [13]. However large scale inter-seasonal storage, as with hydrogen, becomes expensive because of the low utilisation of the storage capacity (i.e. one full cycle a year). This also adds to environmental impacts. NZ would require ~2/3rds of the current global pumped storage capacity to meet the Transpower projected 2050 winter needs.

As *Te Mauri Hiko* notes: “One possibility that has been explored by Professor WE Bardsley and others is a pumped hydro scheme in the Onslow-Manorburn depression”. This would provide more than sufficient energy storage for a dry year [14], but as others [15] have noted “the [Electricity Commission] reported that the proposal did not appear to be economically viable (~NZ$3 billion at 75% efficiency with $50 million y^{-1} O&M)” and “that the barriers associated with obtaining resource consent could be significant”.

The relative costs and benefits are unclear, with the Productivity Commission [16], its advisors and submitters expressing a range of views. Of the storage options it appears the most viable in this application (“might be comparable to those of variable generation geothermal”) but it “would have challenging environmental impacts” and impact on “the economic viability of existing hydro-generators”, and “the risks for a single project of such a magnitude would make it unattractive to private investors”.

Pumped hydro would therefore appear to be a solution in NZ for lower risk smaller schemes targeting shorter-term load management.

Compressed air storage

For completeness, compressed-air energy storage is in use for shorter-term energy storage, and has also been studied for inter-seasonal load shifting in at least one study [17]. This reports the potential for storage in the UK and that would go beyond NZ's dry year demand and have the ability to release it over the required period. Where associated with offshore wind it calculates a levelised cost of US$0.87 - US$1.88/kWh. This is much higher than CSIRO's fuelled alternatives, and as *Te Mauri Hiko* notes the technology has not been tested at the scale that would be required[8].

Overbuild renewable generation assets

NZ's main renewable generation (hydro, geothermal, wind and solar) have a high capital cost with low operating cost. Using them for a third of the year (or even less to provide dry year cover) increases the cost of generation approximately in proportion. This is more so for hydro, wind and solar all of which have generation profiles that are skewed against the winter months.

For this reason low utilisation generation has been typically fuelled [18] (traditionally in NZ coal and NG) but the removal of these options opens up the possibility that over-building renewables will have to be the fall-back option. Because it is feasible, if expensive, it provides a base case to compare other options like biomass generation (see below) and demand side options against.

Natural Gas (NG) Generation with Carbon Capture and Storage (CCS)

While currently this is not a renewable solution it is included for the sake of completeness as the most technically feasible solution from within the electricity system, and because there are potential options to produce methane synthetically or from biological sources[9].

Internationally the addition of CCS to NG turbines is seen a potential solution to inter-seasonal short-falls[10] in the electricity system, e.g. [19]. NG already performs this role in many electricity systems (including NZ's). Gas turbine technology is mature, NG is widely reticulated for a range of markets, is relatively easy to buffer (e.g. Ahuroa Gas Storage Facility) and the technology is also used as dispatchable generation throughout the year. This increases its utilisation and lowers the cost per unit of generation[11].

However the addition of CCS involves a number of technical processes at various levels of maturity. The recently published Review *Carbon capture and storage (CCS): the way forward* [20] provides a useful review:

> *Carbon capture and storage (CCS) … has not yet been deployed on the scale understood to be required [for climate change mitigation], owing to a variety of technical, economic and commercial challenges. This paper provides a state-of-the-art update of each of these areas, and provides a perspective on how*

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[8] Reinforcing this, the study on storage associated with offshore wind reports "no data was found for projects capable of providing inter-seasonal storage with a production of 60 days equivalent to the one in this study".

[9] In which case CCS may not be required.

[10] The addition of CCS may limit the ability to ramp the NG generation to allow peaking services, but the winter short-fall calls for more base load generation where this won't be a constraint.

[11] However in a system where short-term variability is being reduced the opportunities for gas peakers will decline in the face of competition from other technologies and DSM.

to [move] the discipline forward, highlighting key research challenges that should be addressed over the course of the next decade. Importantly, this perspective balances scientific, policy and commercial priorities.

In summary it sees a significant number of challenges in each domain, but states that these could be overcome by aggressive policy support. In most aspects NZ will be a technology taker, but the ability to sequester underground is a domestic issue and NZ has capability in this area [21][12].

A recent proposal associated with 8 Rivers Capital LLC is to scale up their Allam cycle NG generator pilot plant in NZ. The Allam cycle simplifies the carbon capture stage in NG generators [22], but still faces scale-up risks although this should be lower than that faced by full CCS. There are other technologies in various stages of development that pyrolizes the methane to produce hydrogen and carbon without CO_2 [23] [24], but these are still some way off commercialisation.

However with the passing of the Crown Minerals (Petroleum) Amendment Act 2018[13] the ongoing supply of NG in NZ is reported to be unclear beyond 2030. Importation had been considered over a decade ago by a Genesis and Contact Energy JV ("GasBridge"), but it was not pursued when local supply improved, and is yet to be revisited in the current circumstances [25].

This limits the options for using NG in NZ, unless biogas or synthetic methane[14] can be made economically competitive for this application. Based on the German experience the economics of biogas are similar to direct biomass use [26] with anaerobic digestion offering somewhat lower levelised cost of energy (LCOE). However there are limits on the supply of potential feedstock.

Technically then non-fossil fuel methane (with effective CCS if required) could contribute to the winter/dry year shortfall, and research into this in the NZ context is needed to contribute to developing this as an option or eliminate it.

Biomass Generation

Beyond biogas, electricity generation from biomass is a mature technology. It is complex to analyse because there are multiple potential pathways from feedstock source, to fuel type, to conversion technology, e.g. [27]. Evaluation depends upon considering the whole supply chain.

Apart from generation from wastes, it is generally seen as a high cost fuel for electricity generation [28] even when compared with low use dispatchable alternatives. CSIRO has recently updated projections for electricity generation costs [18] and this reports LCOE separately for flexible 40-80% load, low emissions generation (Figs 4-2 – 4.5). This shows the high and wide cost range associated with biomass in this category.

[12] Incorporating CCS with renewable NG would provide a source of GHG credits.

[13] This prohibits the issuance of new petroleum exploration permits outside of onshore Taranaki.

[14] Other synthetic fuels could potentially technically meet the need, but methane has the attractive characteristic of being a drop-in fuel within existing distribution and generation infrastructure.

However the winter/dry year electricity supply market will be difficult to service in other ways, particularly if NG isn't available. Three factors could work to make biomass comparatively attractive:

1. The CSIRO analysis assumes:
   i. A 20% absolute lower capacity factor for biomass than the competing generation technologies in this category. This is based on NG generators being able to opportunistically provide short-term support throughout the year. Pressure on NG supplies and greater competition in the short-term variability market (including DSM) means this gap will close in NZ.
   ii. A small scale[15], low efficiency (23%), pulverised fuel, steam biomass plant. However the electricity being generated for winter/dry year demand is, at the margin, servicing thermal loads. So biomass CHP (85% - 90% efficient) could provide perhaps twice the effective thermal energy[16] although at higher capital cost.
2. With uncertainty over the future of NG and coal in NZ, even with CCS, none of the competing fuelled technologies in the CSIRO analysis will be available long-term to meet this need. If correct this leaves only biomass, overbuilding renewables and storage options remaining within the electricity system.
3. While energy crops are a relatively small proportion of the final biomass electricity cost their availability could be managed on an annual cycle to be counter-cyclic to wind and hydro e.g. harvest in winter; dry through summer; and be available next winter.

Based on the above biomass generation could get close to matching the cost of NG in this market and therefore provide a renewable alternative requiring more limited price increases.

The limitation on biomass as a fuel is land use. Short rotation willow yields ~172 GJ/ha, e.g. [29], [30], and assuming 60% conversion efficiency of biomass to the required electricity and heat this would require around ¼ million ha of arable land (~4% of the 6.1M ha available in NZ [31]) to meet the total demand. Biomass CHP would not be able to meet the total winter shortfall, but this indicates land should not be a constraint for the proportion that it can. Better understanding of potential energy crops in NZ could reduce this constraint.

This option appears to have potential, is not well developed in the NZ context, and therefore warrants further research. However it does open up the use of fuels outside the electricity system to cover thermal demand, and this is discussed further in the next section.

Summary

In the main the inter-seasonal storage options are not technically feasible in NZ, or where they are (e.g. pumped hydro), too economically risky. Of the generation options only overbuilding renewables and the use of synthetic and bio based fuels appear competitive if the supply of NG is curtailed.

[15] Because of the cost of transporting feedstocks.
[16] Adjusted to take account of the better performance of heat pumps.

More research is required to better understand these options and to reduce the costs and risks around their implementation in NZ.

Options external to the electricity system

The summer/winter electricity demand differential can be reduced by selectively increasing summer demand, selectively reducing winter demand, or doing both.

Increasing summer demand

Cooling, irrigation and summer industrial processing are the kinds of loads that naturally selectively increase summer demand. In the face of surplus summer generation capacity electricity prices fall and these activities will be more attractive, but whether there are large scale opportunities that will be triggered by electricity prices alone is unclear. The electrification of dairy processing would be significant.

On the other hand introducing around-the-year industrial processes but close them for 3-4 month of the year will make those industries uncompetitive unless the lower cost of electricity compensates for the lost production[17]. This suggests a very limited pool of prospects where the electricity is a high proportion of their costs.

A potential example would be using electricity to produce a low cost fuel for export in summer while retaining it to displace electricity in winter. This is a role that has been suggested for hydrogen [32] although the economics are not proven [6].

Further research into the options that might emerge to selectively increase summer electricity demand is warranted, however on the face of it targeting winter demand appears more fruitful.

Reducing winter demand

Thermal and lighting loads from residential and commercial buildings are the primary driver of NZ's marginal electricity load in winter. This suggests three main strategies for reducing this:

1. Meet these winter loads more efficiently; and/or
2. Meet these winter loads from other fuels; and/or
3. Reduce the winter demand.

Efficiency

More efficient use of electricity for winter heating (e.g. heat pumps in various applications) and lighting (e.g. LEDs) will reduce the winter load. Opportunities to reduce peak loads are being researched in both commercial and residential buildings in NZ using datasets built up through the BEES [33] and Green Grid [34] research programmes. Work analysing these datasets suggest that more efficient appliances could also potentially make a material impact on inter-seasonal variability.

This is an area where further research would be beneficial.

[17] This is where proposals to use the Aluminium smelter and other electricity intensive industrial processes in this way fail.

Servicing winter thermal loads in other ways

The discussion so far points to the need to take an integrated look at how NZ could best meet its thermal loads. At present in NZ there is a significant body of work looking at specific sectors (e.g. process heat), particularly at a firm level and from an energy efficiency perspective[18]. There are also a number of energy models that include high level estimates of NZ's thermal energy futures (e.g. [35], [36], [37]), but these are not based on detailed interactions between fuel uses and demand. Simply projecting current fuel use is a common approach used in energy models. This sits in contrast to the much more detailed modelling used within the electricity system, and to a lesser extent in transport energy supply and demand projections.

More detailed analysis of NZ's thermal energy requirements, sitting between the current firm level analysis and high level sector modelling, is indicated, particularly given the importance of the winter and dry year issue.

An example of what could usefully be undertaken the European Commission has recently published a study [38] that reviews large scale district heating technologies and systems across Europe, and models 2030 impacts[19].

The NZ context is significantly different. But an analogous approach could usefully be undertaken focussing on smaller scale standalone building heat loads[20,21] with the targeted technologies and fuel sources adjusted accordingly. Even if joint optimisation with electricity demand and prices is not possible, iterative coupled modelling would give a better idea of the options for investment to reduce the winter and dry year electricity risks[22].

The European study gives some indication of what this might show. The higher capital cost but higher efficiency systems (e.g. heat pumps[23], CHP) get used to maximise their use, while lower cost, lower efficiency systems (e.g. boilers) that become relatively cheaper with low utilization get used to cover the residual.

Focusing on NZ's smaller scale standalone systems running through winter and early spring may well find opportunities for district building heating schemes to replace existing (or prospective) electricity use, but heating (new and retrofitting) for individual buildings will probably be more significant given our low urban density.

Biogas (including using existing residential networks in the North Island) could play a role, but small low-emissions low-cost biomass heaters and CHP are likely to be more cost competitive, particularly in the South Island that has colder winter

[18] EECA has multiple policy initiatives in this area, and with MBIE has recently consulted on policy options for industrial process heat.

[19] It uses METIS https://ec.europa.eu/energy/en/data-analysis/energy-modelling/metis a model of the European energy system, and more particularly its heat module.

[20] Domestic loads could be incorporated in summary form.

[21] A number of studies have been undertaken in NZ e.g. Otago Energy Research Centre Energy Living Labs has looked at conversion of Dunedin Energy Centre from coal to biomass https://www.otago.ac.nz/oerc/lab/index.html and a wider study of the Otago potential [45], but these focus on direct fossil fuel substitution rather than targeting existing winter electricity use.

[22] This particularly so if it dynamically modelled investment decisions over time.

[23] Including geothermal.

temperatures. Biomass (e.g. wood pellets) is an example of where around the year production for export could be undertaken to give a stable industry with some production diverted to service winter domestic loads.

There is considerable literature on options here[24] and on the future of residential energy more generally. The latter also reminds of the role of reducing energy loads from buildings e.g. [39].

<u>Reducing winter building thermal loads</u>

Reducing the energy demands of buildings (both new and retrofits) is receiving increasing attention internationally and in NZ where there are a number of building ratings systems that include energy performance[25].

NZ also participates in the IEA Energy in Buildings and Communities Programme [40] that has a variety of projects looking at energy use. By way of example of the potential of “deep energy refits” it suggests “a significant number of commercial and public buildings have reduced their energy consumption by more than 50% after renovation” [41].

While the value of this has been questioned in NZ in terms of net environmental impact [42] suggesting the reported global warming impacts from lower electricity only achieve payback periods of around a decade. However, this analysis assumes the building consumes the average annual mix of electricity generation, rather the marginal mix taking into account seasonal variations. Adjusting for this would considerable improve the pay back periods.

Overall it appears new and retrofitted buildings offer good opportunities to help address the winter and electricity dry year issue. To avoid adverse environmental impacts care will need to be taken over the specific construction technologies.

More research is indicated here.

Conclusion

Overall this analysis suggests:

- Viable options for addressing winter and dry year mismatch between renewable electricity supply and demand are limited, but there are some areas warranting further research;
- Modelling of the electricity system with the demand side only expressed through scenarios limits the capacity to explore overall optimal energy solutions.
    - Use of thermal energy sources and demand reduction appears to offer the lowest marginal cost options for addressing the renewable electricity winter and dry year issue;
    - A more systematic modelling of NZ’s building thermal energy supply and demand, where electricity is just one of the fuels, would help analyse the options;

[24] Including in NZ on the Bioenergy Association’s website (www.bioenergy.org.nz).
[25] Green Star, Homestar, Living Building Challenge, and Passive House.

    - Biomass, building performance and appliance efficiency are likely to play a more significant role than currently assumed by electricity system modelling scenarios.
- Each of the above areas also warrants further research.

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About NERI

The National Energy Research Institute (NERI) is a Charitable Trust incorporated in New Zealand. Its primary purpose is to enhance New Zealand's sustainability and to benefit the New Zealand community by stimulating, promoting, co-ordinating and supporting high-quality energy research and education within New Zealand.

Its research members are Victoria University of Wellington, Auckland University of Technology, GNS Science, Scion, University of Canterbury and the University of Otago, and its industry association members are the Bioenergy Association, BusinessNZ Energy Council, the Energy Management Association of New Zealand and Tourism Industry Aotearoa.

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