Energy Efficiency First

The Electricity Story

Technical Report

JULY 2019

Energy Efficiency and
Conservation Authority
Te Tari Tiaki Pūngao

Contents

Table of figures

Abstract

This work explores the potential for energy efficiency measures to contribute to achieving very high (>95%) renewable percentages in New Zealand's electricity system. A set of scenarios for New Zealand's future electricity system are developed and modelled using detailed market simulation software. These include a range of generation only scenarios, plus two scenarios that include accelerated energy efficiency investment. The results demonstrate that targeted deployment of economic energy efficient technology has the potential to deliver high percentages of renewable electricity and reductions in greenhouse gas emissions (GHG) at a lower cost than other approaches. The main conclusion is that energy efficiency investment opportunities should be evaluated and appropriately prioritised alongside investment in new generating capacity when seeking to increase renewable electricity percentages and reduce GHG.

Trigger

New Zealand's electricity system is around 80–85% renewable at present, depending on hydro inflows and other system factors.

In late 2017, the Government stated its goal of having 100% renewable electricity by 2035, primarily on the basis of demonstrating international leadership towards decarbonisation of energy supply, along with assisting New Zealand to meet commitments made under the Paris Agreement.

Simultaneously, electrification of energy demand using renewable electricity has been put forward by a number of researchers as a potential pathway to decarbonising the wider energy system. In particular, a widely reported study from a group based at Stanford University developed renewable electricity-based energy decarbonisation pathways for 139 countries, including New Zealand[1].

However, the role of electrical energy efficiency has, at times, been viewed as less important than other actions, on the basis that New Zealand's electricity supply is already 'low-carbon' and 'highly renewable' and that future supplies of electricity are also likely to be renewable.

Because of these apparently conflicting narratives, EECA undertook work to explore and demonstrate the role of energy efficiency and electricity efficiency in a future low-carbon energy system.

1 cee.stanford.edu/news/road-map-100-percent-renewable-energy-139-countries-2050

Context

New Zealand's electricity system is relatively unusual in a global context, having a large percentage of existing controlled hydro supply, with comparatively little storage[2]. At the same time, demand is seasonally shaped toward winter periods, with daily demand dominated by a sharply peaked evening residential demand. New Zealand has a relatively low overall population density with demand concentrated in a few large main centres and industrial sites, most of which are distant from the majority of generation sources.

As a result, the electricity system faces a number of challenges in order to meet demand and maintain a secure and stable supply, and any substantial changes to the system come with risks and potential downsides. It also means that assessing any such changes requires detailed simulation of the system, in particular the variability and timing of hydro inflows.

A specific challenge is the need for seasonal storage or 'dry year cover' to meet demand during periods when hydro inflows fall below expected levels. These dry periods can last for several months, and can occur at any time of year, although they are generally most difficult to manage when occurring in autumn or winter. The absence of a known and cost-effective low-emissions alternative makes this a particularly difficult problem with respect to the 100% renewable target.

Most observers expect that attempting to remove thermal generators from the New Zealand electricity system will make managing the 'dry year cover' problem more difficult, with views variously ranging from 'challenging'[3] or 'very challenging'[4] to 'prohibitively expensive'[5].

2 www.niwa.co.nz/sites/niwa.co.nz/files/import/attachments/hydropower.pdf

3 www.productivity.govt.nz/sites/default/files/Productivity%20Commission_Low-emissions%20economy_Final%20Report_FINAL_2.pdf p.385

4 www.srgexpert.com/publications/transitioning-to-zero-net-emissions-by-2050-moving-to-a-very-low-emissions-electricity-system-in-new-zealand/ p.79

5 ibid p.xvi

Hypothesis

Our hypothesis is based on the assumption that the supply of flexible hydro and baseload geothermal generation is finite and has the capacity to efficiently integrate a finite capacity of other (intermittent) renewables while meeting demand and maintaining a secure supply. As such, reaching higher levels of renewables may become increasingly difficult and expensive, especially if demand continues to increase.

Figure 1 shows recent electricity data for New Zealand. Total renewable supply reaches approximately 36,000 GWh[6], with total generation (made up of demand plus losses) at around 43,000 GWh, leaving a 7,000 GWh 'gap' between the current system and a 100% renewable one. This gap is currently filled by fossil-fuelled thermal generators.

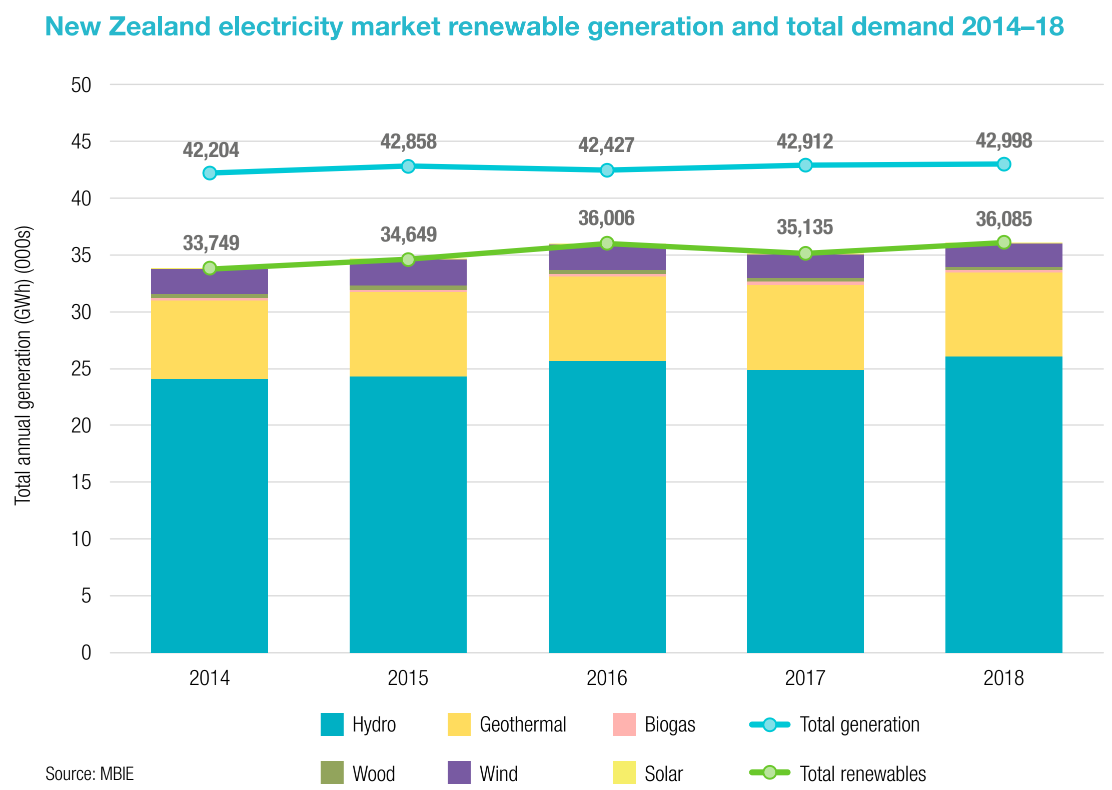

Figure 1. Average annual renewable supply by source; annual demand; renewable shortfall

6 www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/electricity-statistics

In order to reach very high levels of renewables with current demand for electricity, one or both of two things must occur:

- usage must become more efficient to reduce demand; and/or
- more renewables must be built to increase supply.

Many approaches[7,8] to modelling investigate these as entirely separate factors, with energy efficiency usually incorporated as a mild reduction in demand growth[9] for future scenarios.

This may be because:

- energy efficiency opportunities and costs are **not widely known and are therefore poorly understood**
- energy efficiency opportunities are **assumed to be more expensive** than new generation
- **only a narrow range** of potential energy efficiency opportunities is considered.

Simply adding more renewables increases costs, especially as increasingly larger amounts of intermittent renewables are needed to maintain security of supply.

Our hypothesis is that a highly renewable system can be achieved more easily and at a lower cost by incorporating a mixture of new renewables and energy efficiency investments.

7 For example, Concept (2017) www.concept.co.nz/uploads/2/5/5/4/25542442/summary_report_-_energy_related_carbon_abatement_.pdf has separate chapters for electricity generation (ch.3) and consumer energy savings (ch.4)

8 See, for example, Table 1, p.67 www.srgexpert.com/publications/transitioning-to-zero-net-emissions-by-2050-moving-to-a-very-low-emissions-electricity-system-in-new-zealand

9 Ibid Section 6.1.3 p.96.

Methodology

To complete this work, EECA acquired a proprietary modelling tool known as EMarket from a notable energy services supplier, Energy Link. This tool is used for a number of different applications through the electricity industry, and is purpose built for the type of long-range simulations needed tocomplete the project.

General modelling approach

The EMarket tool is highly flexible in terms of time resolution and other parameters.

Time step

For this work, a time step of three hours was chosen as a good balance between accurate representation of within-day variability (important for wind, solar and demand impacts) and processing time and data volumes. Half-hourly or hourly would have provided higher accuracy but much longer run-times and more difficult data processing.

Modelled time period

For each scenario, a single year of time was modelled, representing the state of the market in that nominal year. While this does not give a pathway to a future state, this pathway can be readily interpolated for future years and, if necessary, could be the focus of future work.

The model contains demand and generation data for out-years, which affects the optimisation process to ensure that reservoirs are not drawn down at the end of the modelling period.

Inflow sequences and start levels

Each model run is repeated for each of the available 86 inflow sequences. For this work, the start level is the same for each run, reflecting an ‘average’ starting condition. The model run start date is 20 December, which provides a small amount of variability between hydro start levels on 1 January (the first day of data included in the results).

Transmission network

The EMarket model is capable of modelling transmission constraints; however, this feature was not used to allow faster run times. To detect transmission shortfalls we have used the circuit overload detection feature in the tool, which can create a report detailing the transmission asset, time and quantity of transmission shortfall occurring for each run.

Generation build

Generation build was done exogenously, using a semi-manual process. Additional generation plant was added to give a target GWh figure based on expected load factors. The model was run and results examined for residual thermal volumes and any demand met by shortage stations[10]. Generation was then added or removed to correct the imbalance. Core scenarios were adjusted on average three times to converge on the final generation configuration. For a single modelled year, this is a workable approach as the specific timing of built plant is less important than for a price path or multi-year time series.

Water values

The EMarket model uses a separate optimisation routine to develop water values for the hydro reservoirs. These water values determine the offer prices and volumes for each hydro scheme when the market simulation is run.

Under current system conditions, water values are mainly set relative to offer prices on existing thermal generation. New renewable generation is likely to have generally low marginal costs, which can lead to a lack of pricing information from which to form water value curves.

This situation was addressed in this project by applying very high offer prices to the shortage stations, between $2,200 and $3,000 for the purposes of determining water values.

Offer prices/short range marginal cost (SRMC)

When the model is run to replicate existing market conditions, the offer prices used should reflect the behaviour of participants. This means that wind and geothermal is offered at prices close to $0, while hydro may be modelled as allowing spill below a certain price in order to prevent price collapse or degenerate solutions.

When exploring a future or alternate system, it was considered more useful to use prices reflective of short run marginal cost. On this basis, the spill price for hydro schemes was lowered, and the offer prices for wind and geothermal were increased to reflect estimated SRMC for each.

This has the effect of reducing hydro spill, and transferring any curtailment onto newer wind and geothermal. This provides a useful signal when refining build schedules, as new plant that is underutilised may be 'overbuilt'. Without ordering offer prices in this way, overbuild could be masked by increased hydro spill.

System costs

The measure chosen for this study was total system cost, which includes estimated generation, transmission and distribution costs. Total system cost is a measure of the overall economic cost of generating and supplying electricity and, as such, changes in total system cost are a better measure of the national benefit or cost than alternative measures.

Existing and new generation plant and energy efficiency investments are treated on a long run cost basis, with the exception of thermal generation which is treated as a sunk asset and valued on a short run cost (variable costs only) basis.

10 A shortage station is a 'dummy' station used to enable to model to solve even if there is not enough supply to meet demand.

Key assumptions are given in the table below:

Item	Value
Carbon price	NZD \$25 /tCO_2e
Cost of capital/finance cost	5% per year
Transmission cost	NZD \$990 million per year
Distribution cost	NZD \$2,521 million per year

Note that for each of these factors it is assumed that costs are fully recovered from consumers. This assumption is needed to ensure that estimates of cost are sustainable. If costs are not fully recovered then the system may not be sustainable in that configuration, and parties may retire assets or change business models, leading to a new equilibrium. Using a fully recovered cost allows us to shortcut the process of seeking a full market equilibrium price using, for example, Nash-Cournot methods, which are computationally intensive and subject to input assumption errors.

Solar PV

Solar PV was implemented using a demand adjustment feature, allowing a total solar area for a region to be converted to a total regional solar output which is then spread across a number of different demand nodes.

Wind generation

Wind generation is modelled using a mean reversion jump diffusion equation, where the wind speed for a region is generated in a semi-random fashion. This was then converted into generation output parameters.

Geothermal

Geothermal generation is something of a special case, in that it produces GHG emissions in normal operation, and steam reservoirs may not last forever. As such, it is technically neither renewable nor zero emissions. However, geothermal is generally lower emissions than fossil fuel alternatives, and reservoirs are usually managed sustainably. As such, in this paper, geothermal is treated as renewable.

Co-generation

Co-generation represents a relatively small but significant residual fraction of thermal generation, around 2.5% of current demand. In order to reach 100% renewables in our scenarios, it was decided to phase out existing gas-fired co-generation in the model runs. This approach is supported by research from the University of Waikato[11] that suggests co-generation using gas is less effective from an emissions viewpoint than direct use of gas for heat and grid offtake of electricity. One of the three existing facilities was retained in the model and converted to renewable supply, nominally fired on biogas.

11 core.ac.uk/download/pdf/132284639.pdf

2017 modelling

Our first stage of modelling utilised a present-day base case model of the current New Zealand electricity system, including actual demand from 2017. This was chosen to remove a key uncertainty, which is demand growth between now and any future modelled date. Estimates of future demand growth may include or exclude energy efficient technology uptake, and can therefore be hard to separate out from business as usual (BAU). This carries a risk of double counting or other mis-estimation.

Scenario development

Six scenarios were developed:

1) Base case

   Existing generation. Some modifications applied to the Energy Link base case to reflect observed market behaviour were removed to provide a 'cleaner' reference case.

Generation only scenarios

2) No thermal

   All existing and potential thermal generators were removed from the model. This left a significant shortfall in the supply and demand balance. Sufficient additional renewable generation was added to reduce average annual supply shortage over all 86 years of inflows to less than 5 GWh per year.

3) Thermal restricted to peaking only

   Instead of removing thermal plant entirely, in this scenario, offer prices for existing thermal plant were increased to a multiple of SRMC, to reflect a 'peaking only' operating mode. Sufficient new renewable generation was added to limit thermal generation to less than 50 GWh per year on average. (Note that an average annual thermal generation of zero is not achievable using this approach, as the thermal generation does not go negative during wet years to balance out the dry years.)

4) 99% renewable

   Starting with the build parameters from scenario 3, some of the additional renewable generation capacity was reduced to allow average annual thermal generation of ~400 GWh, reflecting 1% of average demand to achieve the 99% scenario target.

Energy efficiency scenarios

5) Energy efficiency only

   This scenario seeks to evaluate if the 100% renewable target is achievable using energy efficient technology alone. The demand volume parameters in the model were reduced to 80% of their original value, reflecting extensive investment in energy efficiency measures. See Appendix 1 for the data used to estimate available energy efficiency and resulting costs.

6) Hybrid – energy efficiency plus new generation

   This scenario seeks to find the optimum balance between new renewable generation and energy efficiency to achieve close to 100% renewable electricity. Starting with the '99% renewable' scenario we reduced the modelled demand by the total volume of energy efficiency that appears to be more cost effective than generation, which totalled 4,100 GWh. This reduction in demand was then offset by reducing new generation in the scenario by 4,100 GWh.

Results

Renewable percentage

The renewable percentage figures achieved for the six scenarios are shown in Figure 2. Both the No thermal and Peak thermal only are very close to 100%, which is by design, while the 99% result of the 99% renewable and Hybrid scenarios is also by design. The 96.7% renewable figure for the Energy efficiency only scenario is perhaps lower than might be expected given the size of the demand reduction modelled.

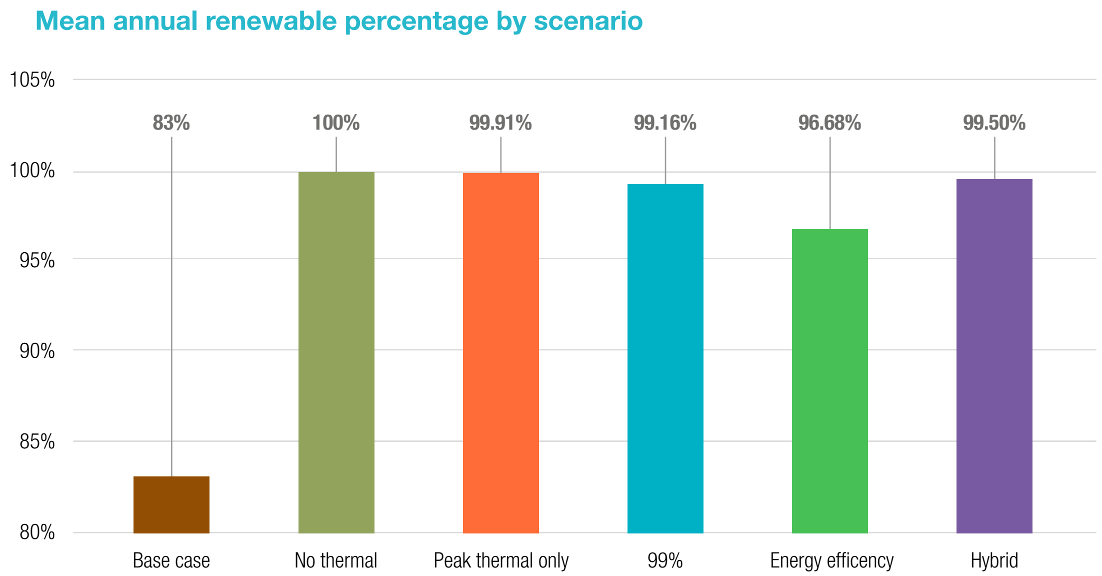

Figure 2. Mean annual renewable percentage for the six scenarios – note non-zero x axis

Installed capacity

Achieving a 100% renewable system in all years (the No thermal scenario) requires the greatest increase in renewable capacity, around 2,600 MW.

Retaining thermal generation for dry periods requires substantially less generation build, just under 2,000 MW.

A 99% renewable target requires an even lower level of generation build (around 1500 MW).

Applying energy efficiency to remove 20% of demand results in a 97% renewable system (on average) with no additional generation build (the small increase in renewables in Figure 3 is the conversion of a co-generation plant to biogas).

The Hybrid scenario gives us a >99% renewable figure with 700 MW of new generation, about half as much as the '99% renewable' scenario.

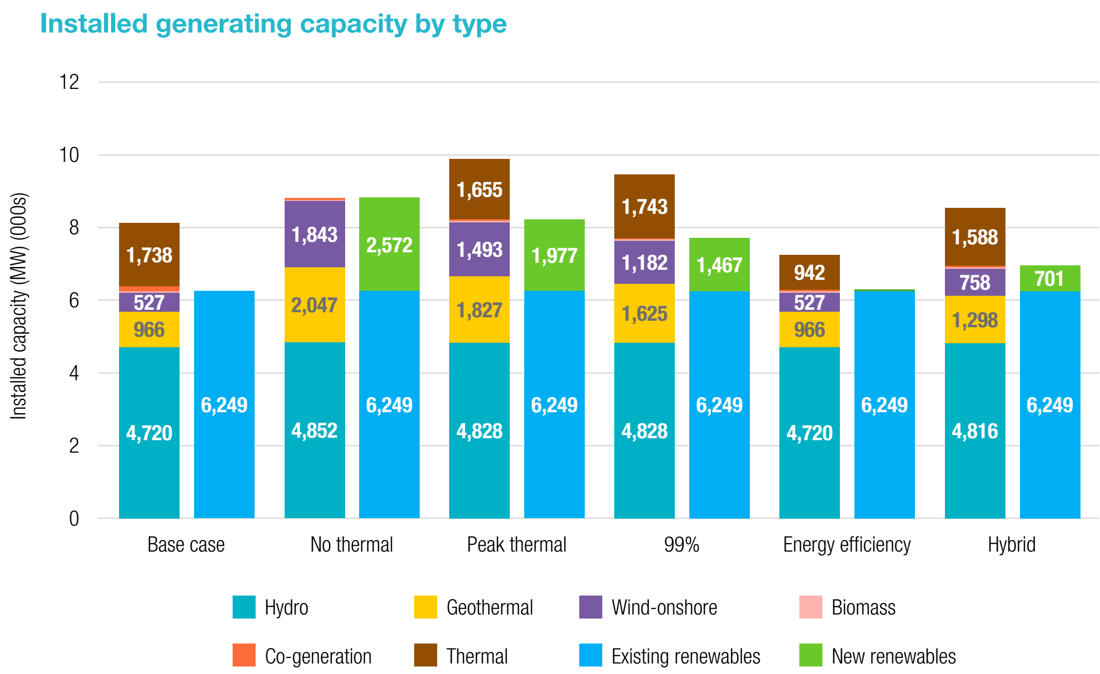

Figure 3. Installed generating capacity (MW) by type

Generation mix

Annual average generation figures shown in Figure 4 are, to a large extent, a result of the modelling choices. Hydro generation is largely static, as prices within the model were adjusted to prioritise the use of existing hydro resource, partly to reflect good practice and partly to avoid unnecessary overbuild of other sources. The exception to this is the Energy efficiency only scenario, which saw levels of spill increase for both hydro and wind. It may be possible to optimise the scenario further to decrease both hydro spill and thermal generation, as demonstrated by the result from the Hybrid scenario.

Wind and geothermal volumes reflect the relative build volumes and availabilities[12]. Utilisation factors (not shown) for the No thermal scenario are substantially lower for both wind and geothermal, reflecting higher levels of curtailment or spill with cost and efficiency implications. This means that plant that has been built and paid for will sit idle at times, as there is not enough demand to use up the available supply.

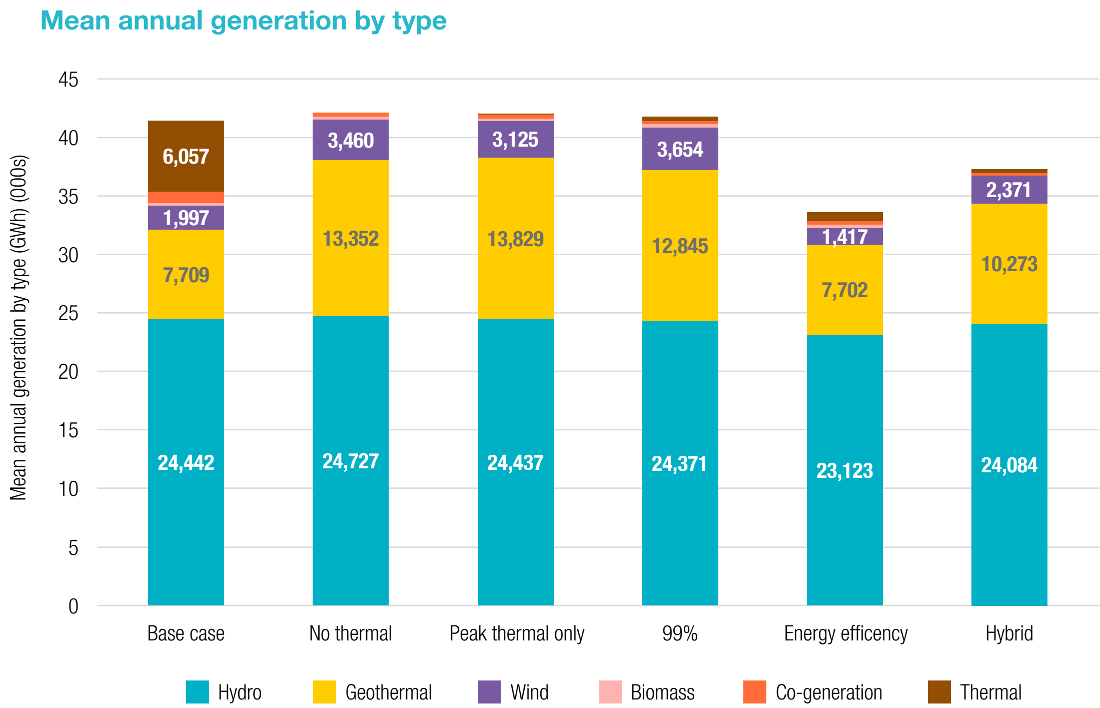

Figure 4. Mean hydro year annual generation volumes by type

12 Availability is the expected generation from a plant as a percentage of the maximum power rating times the number of hours in a year. For geothermal plant, availability is very high, 90% or greater, whereas for wind plant it tends to be much lower, around 40%, and for solar around 16%.

GHG emissions

GHG emissions (Figure 5) decrease sharply across all scenarios, and to roughly comparable levels, set primarily by emissions from geothermal generation. Thermal emissions are highest in the Energy efficiency only scenario, which probably indicates the scenario is not fully optimised. In other words, the model dispatched more thermal than was actually needed. The Hybrid scenario has the lowest level of GHG emissions.

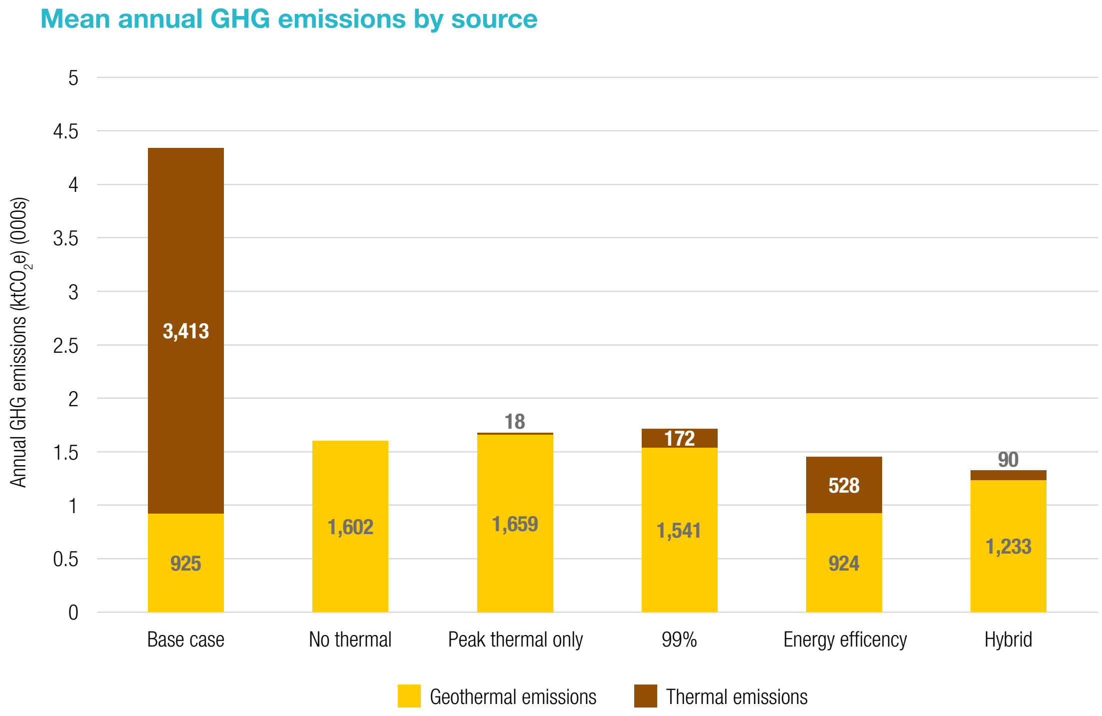

Figure 5. Mean annual GHG emissions by source

Wholesale prices

Modelled wholesale prices are lower than the base case in all scenarios. Figure 6 shows average prices along with 95th (dry) and 99th (extreme dry) percentile prices for each run. Percentiles are based on the full set of 86 inflow years and three-hour time steps for a full year.

In the No thermal scenario, collapsing prices reflect the need to overbuild to maintain supply during dry periods. This is less noticeable in the Peak thermal only and 99% renewable scenarios, although still present.

In the Energy efficiency only scenario, the fall in wholesale prices reflects an overhang of existing generation competing to supply a smaller demand.

The Hybrid scenario results in wholesale prices similar to those in the 99% scenario.

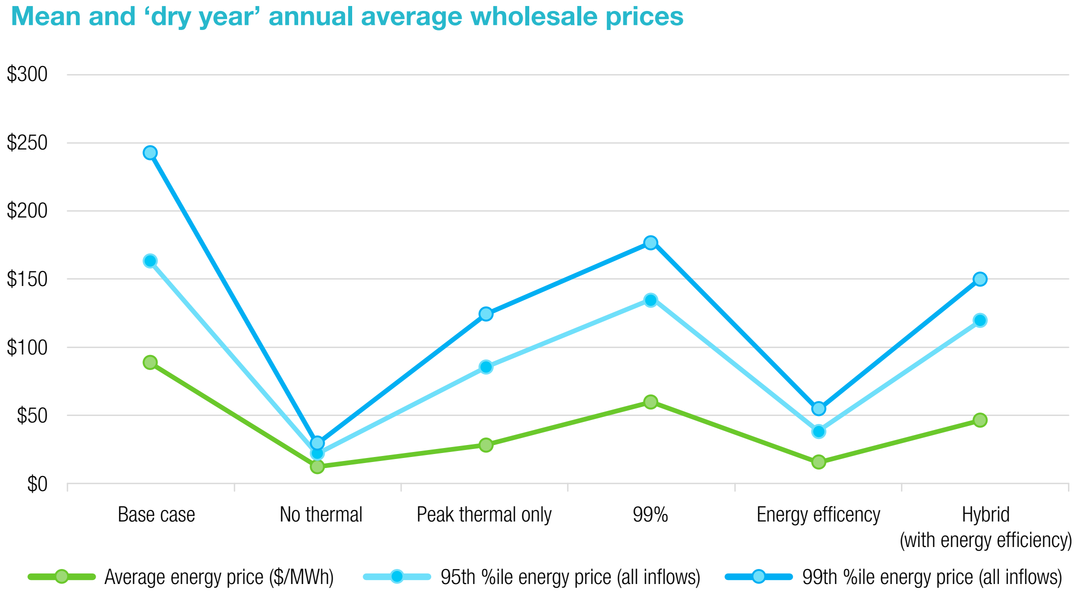

Figure 6. Modelled mean and extreme dry wholesale prices

Figure 7 shows a comparison between estimated generation costs and total wholesale revenues across the six scenarios. Those scenarios with low wholesale prices fall well short of covering generation costs.

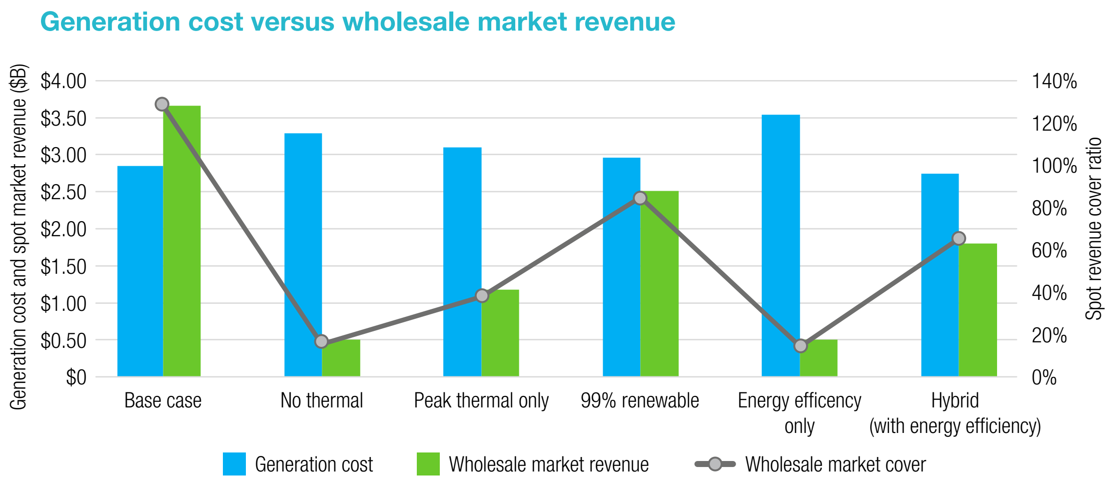

Figure 7. Generation cost versus wholesale market revenue, wholesale market revenue as a percentage of cost (secondary axis)

Capital cost

A potential barrier to achieving a highly renewable system will be the availability of capital. Figure 8 shows the estimated capital cost for each of the six scenarios, covering both new generation and energy efficiency investment where applicable. The Hybrid and 99% renewable scenarios have similar capital investment requirements, which are substantially lower than other approaches modelled.

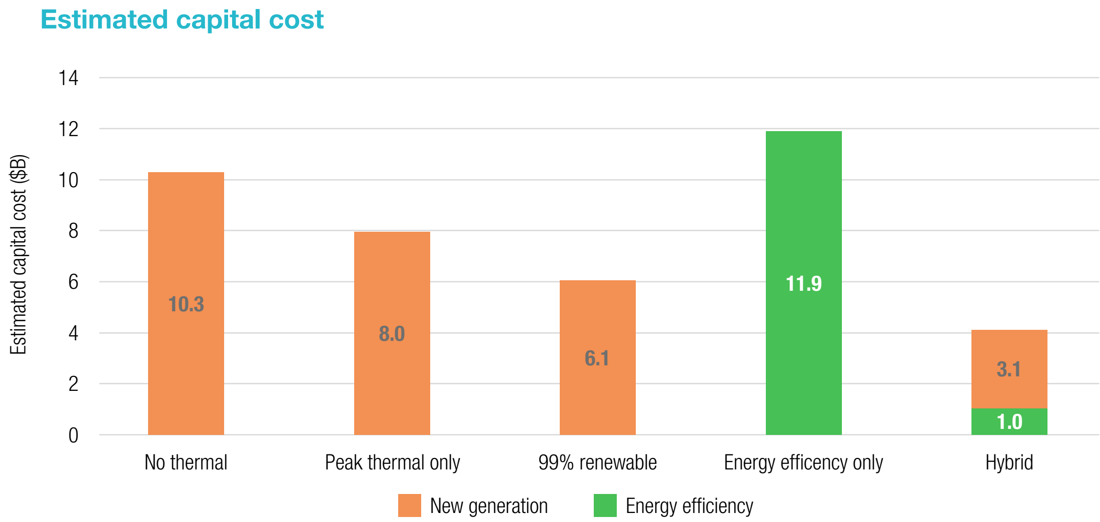

Figure 8. Estimated capital cost for new generation and energy efficiency investment

System cost

Wholesale prices are one component of electricity cost; it is important to consider the overall system cost. However, defining the system cost is highly sensitive to assumptions and methodology. For this reason, we have used multiple approaches to estimating system cost to avoid the influence of any particular assumption.

All scenarios included current transmission and distribution costs (data from the Commerce Commission). The Energy efficiency only scenario assumed these would both fall by 10% due to reduced system and peak demand, while the Hybrid scenario assumed a reduction of 5% for both transmission and distribution costs.

GHG emission costs were calculated directly for each scenario using the current New Zealand Emissions Trading Scheme (NZETS) price of $25 per tonne of carbon dioxide equivalent.

The three approaches used were:

1) Accounting cost

   Generating assets valued at cost, with generation costs made up of short-run costs (fuel and maintenance) and a capital charge (based on an interest cost plus a depreciation charge). This approach allows valuation of the existing asset base alongside new capacity.

2) Levelised cost of energy

   Changes in generation volume (positive or negative) are valued at levelised cost of energy for new generation and short-run marginal cost for existing plant. This approach provides a lower bound cost estimate that effectively assumes that exactly the right volume of new generation is built.

3) Levelised cost of capacity

   Changes in capacity are valued at the levelised cost of energy for the full utilisation of that capacity. This approach reflects the cost of overbuilt capacity.

The results of this analysis are shown in Figure 9. The No thermal scenario is the most expensive due to substantially higher levels of generation build. The cheapest low-carbon scenario is the Hybrid scenario, and the next best is the 99% renewable scenario. Peak thermal and Energy efficiency only are roughly equivalent and sit in the middle range.

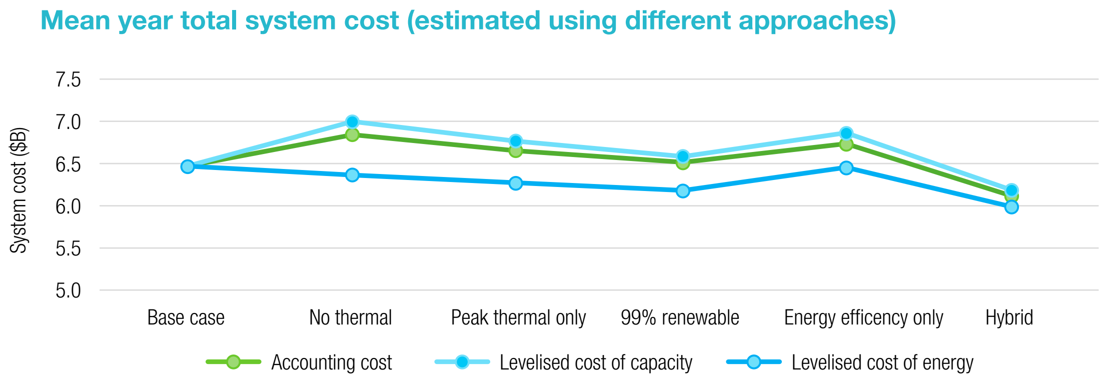

Figure 9. Mean year total system cost using three different approaches

Using the system cost estimates above, we can derive a 'fully recovered' cost per MWh (that is, the estimated system cost divided by the number of MWh delivered). These are shown in Figure 10.

For the Energy efficiency only and Hybrid scenarios, a much smaller volume of electricity is supplied. If we use the same calculation approach, this gives a disproportionately high cost per

MWh. The types of energy efficiency technologies used in these scenarios provide the same end-use output but for less energy input[13]; hence for the Energy efficiency and Hybrid scenarios, the base case demand is used as the denominator to allow a fair comparison.

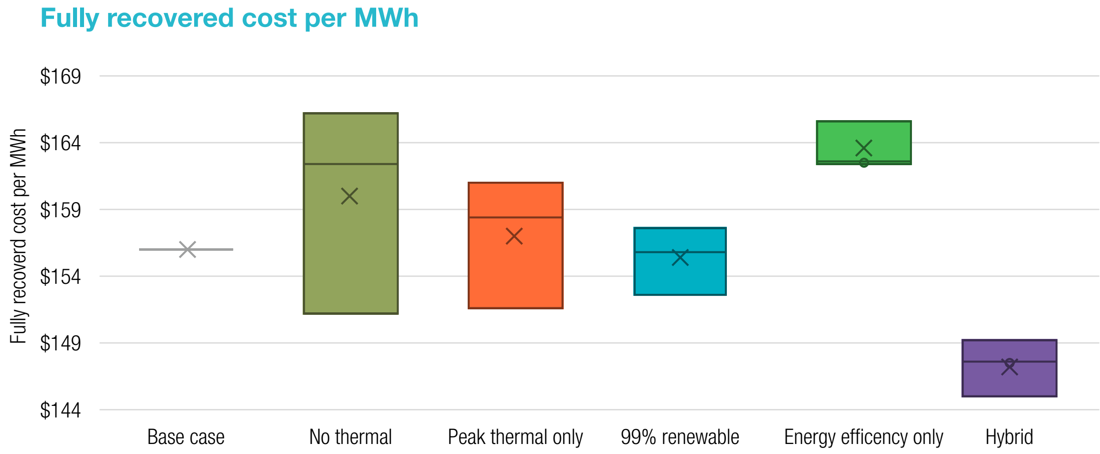

Figure 10. Mean year fully recovered cost per MWh

GHG abatement costs

Combining the system cost estimates with the GHG emissions results, we can calculate an effective cost of abatement for each scenario. The results are provided in Figure 11. The range of price estimates is quite wide due to the different cost estimation approaches.

The Hybrid scenario is the most cost-effective delivering GHG reductions at negative costs. This arises because system costs have fallen at the same time as GHG emissions, hence the 'cost' is negative.

The 99% scenario suggests modest abatement costs in the range of $5–$45, or comparable with current NZETS prices.

Other scenarios have higher abatement costs, reflecting a degree of over-reach and over-spend and highlighting the potential for cheaper abatement to occur in other energy types or in other sectors of the economy without a fully optimised approach.

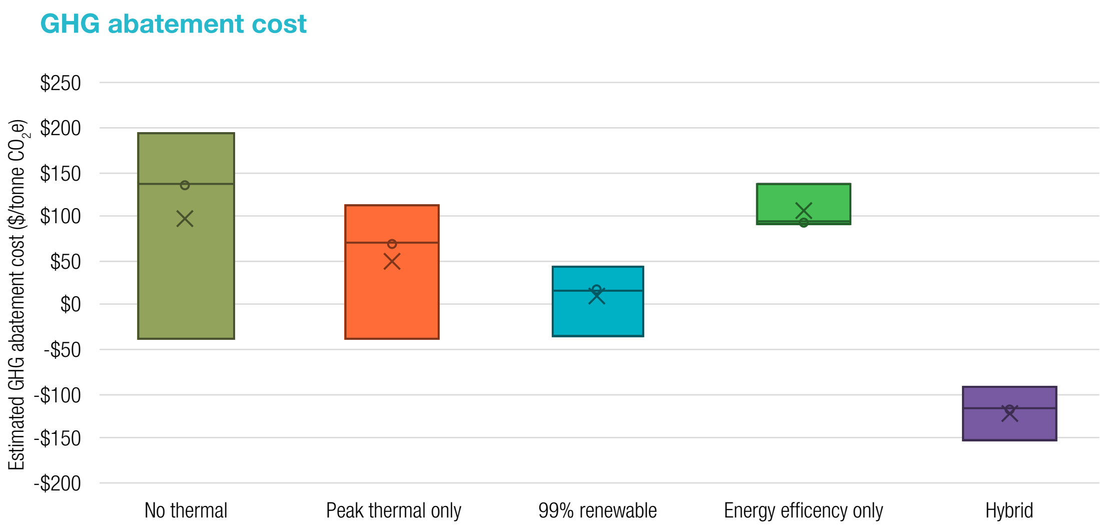

Figure 11. Estimate mean year costs of GHG abatement relative to base case

13 For example, an LED light provides the same number of lumens for a much smaller energy consumption.

Discussion

GHG emissions level out at a similar level in all scenarios due to geothermal emissions

This finding suggests that addressing emissions from geothermal plants, particularly those yet to be built, may be a valuable future focus area for addressing electricity sector emissions as we reduce emissions from other sources.

Low prices

Modelling approach

The modelling used a short-run marginal cost approach to determine offer prices, meaning that modelled wholesale prices may not reflect those expected in reality.

Real-world prices would be lower if owners of plant were to push generation into the market in order to maintain output volumes and seek to recover capital costs; similarly, prices would be higher if plant owners were to withhold or price up plant strategically to maintain short-term returns. While both situations are possible, neither is sustainable in the long term, hence the short-run cost approach is potentially more informative of likely long-term outcomes.

Likelihood of overbuild

In the case that short-term returns are lower than long-run costs, it becomes implausible to expect generation build to continue. As such, those scenarios with very low wholesale prices may require further testing to ensure plausibility from a generation build perspective, unless we assume an alternative market structure.

Overhang in the energy efficiency scenario

This overhang could be addressed via existing market mechanisms and orderly retirement of plant. We expect this could readily be modelled in future work.

System costs

Analysis of system costs shows that, for most scenarios, achieving very high renewable percentages will incur additional costs of less than $10 per MWh, or 6% of the current cost, with many scenarios incurring substantially lower incremental costs. The model results suggest the Hybrid scenario delivers the desired outcomes while also lowering overall electricity costs.

A different approach

Our Energy efficiency only and Hybrid scenarios highlight several key issues.

Energy efficiency definition

Firstly, the term 'energy efficiency' does not have a shared meaning across all parties.

Observations of other modelling work shows energy efficiency usually only includes behavioural, incremental and conservation measures, such as turning off lights and reducing temperature set points, along with BAU improvements to appliance efficiency etc.

In our scenario above we include much more direct energy efficiency measures, such as switching out entire technologies for particular end-uses (for example, LEDs for lighting, heat pumps for space heating). These measures have much more durable and direct impacts on the system by permanently changing the efficiency of electricity conversion and, as such, may be considered equivalent to a new generating station.

The cost estimates are derived from the actual capital cost of this investment; however, actual costs of change may be higher or lower (higher if rapid change causes a supply shortage and prices rise, or if very large incentives or administratively expensive programmes are needed, lower if a rapid large-scale change results in cheaper purchase costs or more efficient installation).

Achieving energy efficiency investment at scale

A consideration for assessing energy efficiency investment alongside new generation is that, to achieve energy efficiency investment at the scale presented here, many thousands of individual consumers or businesses need to make investment decisions. This may be difficult to achieve compared to a single company deciding to build a new generating station. This issue highlights a potentially key role for government, which in general is the only party holding the necessary levers to achieve co-ordination on this scale.

An optimal solution is a hybrid one

The results presented here lead us to suggest that an optimal system can only be modelled by quantifying and iterating supply- and demand-side interventions alongside one another, or to combine them.

To illustrate this point, we present three charts, representing indicative build curves from a generation expansion model of the sort used to estimate future supply requirements, costs and sources.

Figure 12 shows a typical[14] long run marginal cost (LRMC) cost curve for renewable generation projects. From these cost curves it is possible to estimate total and marginal LRMC for new generation, and derive a build schedule for more detailed system modelling.

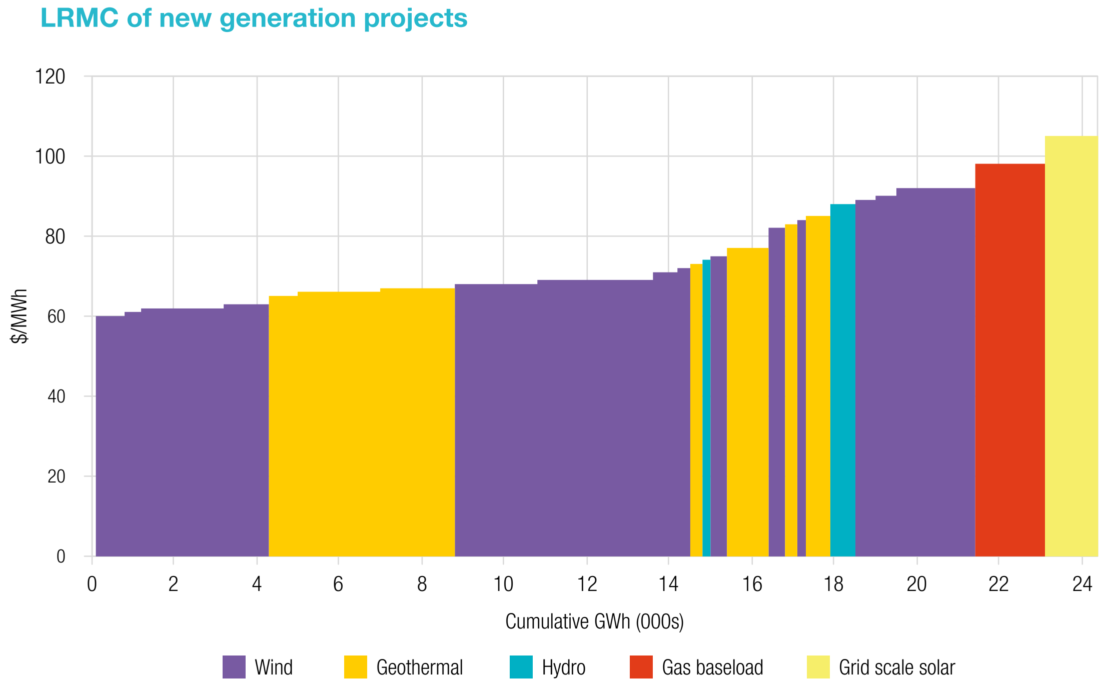

Figure 12. Estimated generation cost curve for supply side only

Figure 13 shows an indicative energy efficiency supply curve on the same basis, reflecting the assumptions that went into the Energy efficiency scenario presented in this paper. While energy efficiency investment is lower cost than new generation initially, this curve rises more steeply than the generation curve, and spans a smaller energy supply range, reflecting the inherent limits of energy efficiency as a resource. This steepness also explains the overall cost performance of the Energy efficiency scenario, in that to reach the desired 8,000 GWh, we are calling on a resource that is more expensive than its generation equivalent (not shown in Figure 13).

14 This one is derived from Lazard LCOE V12.0.

Levelised Cost of Energy Efficient Technologies

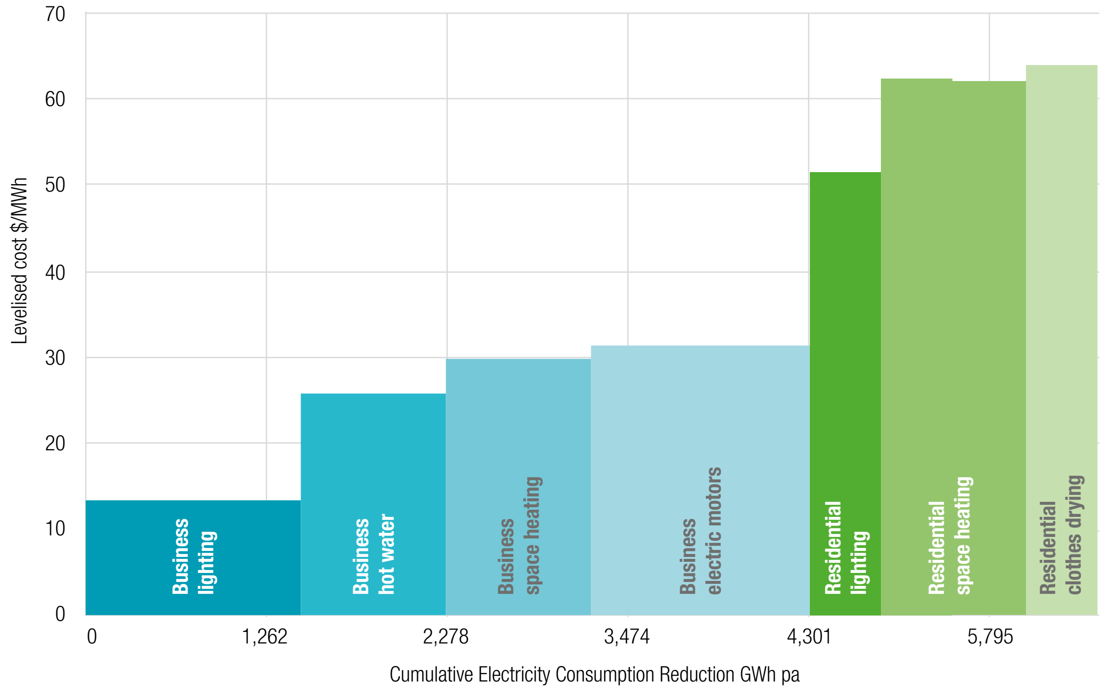

Figure 13. Illustrative cost curve for demand-side interventions

In order to illustrate the concept of co-optimisation embodied in the Hybrid scenario, we combine the two sets of resources into a single curve as shown in Figure 14. Here we can see that a mixture of generation and energy efficiency resources can be deployed to achieve a target GWh figure at a lower overall cost than either approach alone.

LRMC of combined energy efficiency and generation projects

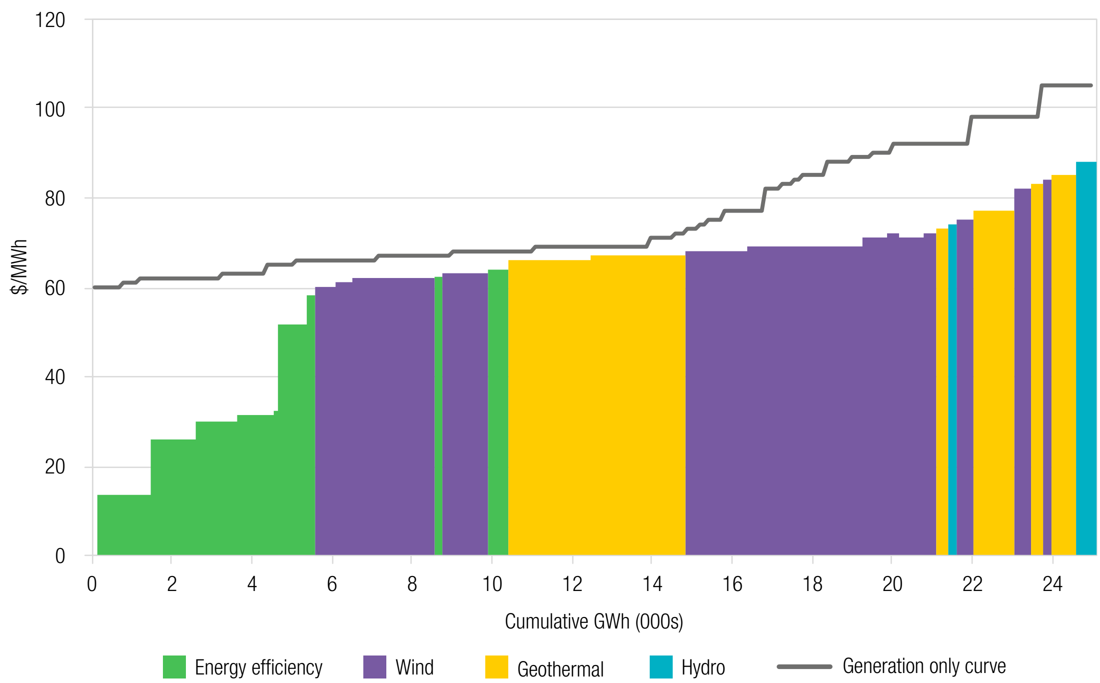

Figure 14. Combined cost curve for generation and demand reduction projects

Supply curves are made up of smaller increments at different prices

The above charts are simplifications, particularly with regard to the energy efficiency investment blocks.

While the efficiency and cost of a particular technology are easily defined, the equivalent per MWh cost for a range of given uses and users can be highly variable. This is readily illustrated using LED lighting. A 10 W LED costing $8 can replace a 100 W incandescent bulb, but the size of energy saving and the resulting costs depend on whether this bulb was used for several hours per day in a living room or warehouse or only occasionally in a garage or utility room.

The figures presented here are based on EECA's approach to estimating economic energy efficiency potential which uses a rational choice architecture to model the uptake of technologies based on the relative economics of each technology. Some constraints are applied within the model to limit the rate of change of technology to realistic levels.

For each end use and subsector, current energy service demand forms the baseline. This energy service demand is then modelled as being met by the most efficient economic technology available. Modelled technology uptake can then be used to derive total capital costs and energy savings figures. Sector technology capital costs ($M) are determined using a per unit capex value multiplied by the overall uptake figure.

Annual energy volume savings (GWh) are calculated by multiplying the technology uptake by the percentage efficiency improvement and the usage factor over a year. Generation equivalent cost is calculated by dividing the upfront capital cost by the discounted energy savings over the expected life of the technology to give a cost in $/MWh. These estimates are shown in Appendix 1.

These figures are averages for each end use and sector. There may be a case for a more granular approach to try to understand the impact of targeting specific subsectors or applications that may have higher load factors, greater efficiency impacts or lower capex costs, all of which could lead to lower generation equivalent costs.

Conclusions

- The most optimal and cost-effective highly renewable electricity system will require a combination of additional renewable build and investment in energy efficient technologies.
- A ~100% renewable electricity system is potentially achievable with current demand and available generation resources. However, a system that is 99% renewable achieves a very large proportion of the GHG reduction at a much lower cost.
- The highly renewable electricity systems modelled do not recover generation costs through wholesale prices alone. Further investigation is required to establish whether this result is due to the modelling approach or indicates a fundamental issue.
- Geothermal emissions are likely to dominate the emissions profile of a highly renewable future electricity system, creating an incentive to look more closely at geothermal technologies and potential emissions reduction strategies.
- Reducing demand through investment in energy efficient technology can be a highly cost-effective means of reducing GHG emissions.

Further work for EECA

1) EECA should develop and distribute information about energy efficiency technology that supports the evaluation of investment in energy efficiency alongside new renewable generation.
2) Future scenarios and energy strategies for the New Zealand electricity system should include consideration of energy efficiency investments alongside new generation, in a similar way to the Hybrid scenario presented here.
3) EECA should consider how the approach presented here can be translated to a 2035 timeframe to complement the ICCC modelling work.
4) EECA should extend the approach presented here to look at high levels of electrification.

Appendix 1:
Table of electricity efficiency savings

The table below gives details of the different technologies and sectors that were applied to scenarios 5 and 6, and form the basis of the supply curves in Figure 13 and Figure 14.

Table A1: Estimated economic electrical energy efficiency potentials (Source: EECA EEPT analysis, 2019)

Sector	End Use	Efficient technology	Capacity factor	Capex ($/kW input)	2016 Consumption (TJ) (EEUD)	Savings %	Uptake of efficient technology (TJ)	Capex ($M)	Cumulative capex ($M)	GWh saved	GWh saved cumulative	Levelised cost ($/MWh)
Commercial	Lighting	LED lights	50%	500	8,024	46%	4,256	135	135	1,035	1,035	13.4
Primary	Lighting	LED lights	50%	500	579	46%	307	10	145	75	1,110	13.4
Industrial	Lighting	LED lights	50%	500	1,178	46%	625	20	165	152	1,262	13.4
Commercial	Water heating	Heat pump	50%	3,750	3,256	70%	793	189	353	637	1,899	25.8
Primary	Water heating	Heat pump	50%	3,750	1,837	74%	472	112	466	379	2,278	25.8
Commercial	Space heating	Heat pump	50%	3,750	6,549	51%	1,324	315	780	920	3,197	29.8
Industrial	Space heating	Heat pump	50%	3,750	436	71%	125	30	810	87	3,284	29.8
Commercial	Motive power, stationary	Electric motor with VSD	50%	336	2,731	25%	2,048	44	854	190	3,474	31.3
Industrial	Motive power, stationary	Electric motor with VSD	50%	336	11,130	25%	8,347	178	1,031	773	4,246	31.3
Primary	Motive power, stationary	Electric motor with VSD	50%	336	801	24%	606	13	1,044	54	4,301	32.2
Residential	Lighting	LED lights	8%	500	5,679	47%	1,874	371	1,416	741	5,042	51.6
Residential	Space heating – peripheral	Heat pump	17%	1,718	1,383	59%	292	97	1,512	226	5,268	58.1
Residential	Clothes drying	Clothes dryer	4%	167	1,157	58%	489	65	1,577	186	5,454	62.3
Residential	Space heating	Heat pump	15%	1,718	5,075	37%	682	248	1,825	527	5,981	63.9
Residential	Water heating	Solar hot water cylinder (electric backup)	3%	3,167	12,165	70%	3,270	11,937	13,762	2,370	8,350	811.2