TRANSPOWER

Te Kanapu

Future Grid Blueprint

INSIGHTS PAPER

Fuelling growth by enabling a diverse mix of generation.

Identifying the lowest cost pathway to a secure and sustainable future.

Overview

As part of our Te Kanapu initiative to develop a future grid blueprint, it is important we understand New Zealand's future and how our electricity system can support economic growth.

Changes in the generation mix and an increasing volume of distributed energy resources, such as solar and wind generation, will have a material impact on costs, reliability, emissions and our electricity networks - the infrastructure that carries electricity from where it is generated, to where it is used.

Our work is focused on identifying the pathway to the lowest cost, reliable and sustainable electricity system that enables New Zealand to leverage its renewable resources for growth.

We need to understand these changes and the impacts they have on the energy system. Only then can we identify the best approach to meeting an increasing demand for electricity at the lowest overall cost to everyone in New Zealand - industry, businesses, communities, households and individuals – while continuing to ensure a secure and sustainable electricity system.

In this insights paper, we've taken a deep dive into how New Zealand could meet increasing demand for electricity in a growing economy through different generation choices and what the impact of each choice might be on cost, reliability and sustainability.

By identifying the lowest per-unit cost of generation and storage, we can begin to understand the generation and technology mix that will deliver the most affordable electricity, and enable new industries and the electrification of existing activities into the future.

To date, we have not explored in any detail how different generation choices may impact the existing or future electricity network, although, as the owner and operator of New Zealand's high-voltage transmission infrastructure, we will need to do so.

The role of networks is at the heart of our work to develop a grid blueprint for New Zealand to determine the overall lowest cost pathway to a secure and reliable power system. Over roughly the past 100 years, this infrastructure has served the country well. As our nation grows and more generation is needed to meet demand, we believe it is critical to also explore the future role of New Zealand's existing networks, along with what additional capacity may be needed, to answer the question around their ongoing role in enabling the lowest-cost pathway to New Zealand's energy future.

We welcome your thoughts and feedback.

The approach we are taking in developing the grid blueprint is collaborative. We are interested in all views on this work and how New Zealand can achieve its ambitions. You can email us on **feedback@transpower.co.nz**.

Our approach

Over the past 12 months, we've been asking individuals and organisations across the country about the future of Aotearoa: what 2050 will look like, what new and existing industries are likely to drive the economy, and what are people's priorities for the electricity system. Based on the feedback we've heard, we've published five potential future scenarios for New Zealand and what each would mean for electricity demand and generation. We've also published a suite of documents outlining the technical approach we will use to create the future grid blueprint. Our thinking continues to evolve to match what we are hearing from a wide range of people across the country.

In this paper, we outline six possible ways New Zealand could meet increasing demand for electricity through different combinations of new generation and consider how each case performs against the three competing priorities of the energy trilemma: affordability (cost), security (reliability) and sustainability (emissions). We assume existing generation meets existing demand, so this paper is an exploration around how to meet new demand through new generation.

Our hypothetical cases of generation and storage present only some of the options available although we believe they broadly capture the spectrum of choices that could be made and allow us to explore what the different generation mix could cost, and how it might affect the overall performance of the electricity system.

For each case, we also outline the potential high-level impact of this new generation on networks. However, we have not done the analytical work required to optimise the generation and storage with the required network build to determine the total power system cost. That work is happening now as part of our development of the Grid Blueprint. Additionally, this work does not account for low hydro inflows.

Explainer: Our use of the term *per-unit cost* of generation and storage, specifically means the cost per megawatt hour (MWh) of the combination of generation and storage that is needed to supply the last MWh of additional electricity demand. By focusing on the per-unit cost of generation and storage to meet additional future demand, we avoid the need to explicitly model the scale of demand growth. Expressing the result as a costs per-unit of electricity allows comparison between our cases.

The term *total power system cost* is the full, optimised cost of running the electricity system, including building and operating generation, storage, and existing and new networks. It is usually expressed as net present value over a period of years. It enables comparisons between different investment solutions.

Net present value is a way of comparing costs and benefits over time by converting them into today's dollars, recognising that money in the future is worth less than money today. We have assumed a 7% p.a. discount rate for future cashflows.

Data presented. Where we have stated a single value for per-unit cost, emissions and reliability this refers to the baseline result for that case. Where we use a range, this is the lowest and highest value identified from sensitivity testing. Both are used in the document. In the next section, we describe the sensitivities applied and quote the full range of results for each case.

Other definitions are contained in our technical appendix.

Mix of new generation to meet incremental demand

Trilemma key

$ Affordability
🟢 Sustainability
🛡 Reliability

Case 1

1. Local rooftop solar
2. Batteries

Case 2

1. Local rooftop solar
2. Batteries
3. Local utility-scale wind

Case 3

1. Local rooftop solar
2. Batteries
3. Local utility-scale wind
4. Thermal peakers

Case 4

1. Local rooftop solar
2. Batteries
3. Local utility-scale wind
4. Thermal peakers
5. Geothermal

Case 5

1. Local rooftop solar
2. Batteries
3. Local utility-scale wind
4. Thermal peakers
5. Geothermal
6. Hydro

Case 6

1. Nationwide distributed solar
2. Batteries
3. Nationwide utility-scale wind
4. Thermal peakers
5. Geothermal
6. Hydro

What we found

Figure 1 shows the per-unit cost for generation and storage varies significantly from as high as $728/MWh (baseline value) in Case 1, where local demand growth is met entirely by new, local solar and battery installation, to as low as $117/MWh (baseline value) in Case 6, where demand is met through a mix of diverse generation sources, shared nationwide though electricity networks.

Figure 2 shows the emissions for each of the six cases. New Zealand's existing low emissions profile is already a strategic advantage for the country, as international businesses consider sustainability when choosing where to invest.

Figure 3 shows reliability as a percentage of demand served, which means how consistently the generation mix could supply the amount of electricity customers want, when they want it. It does not include network reliability but shows that the more diverse the portfolio of generation, the greater system reliability.

Figure 1. The per-unit cost of generation and storage in each case.

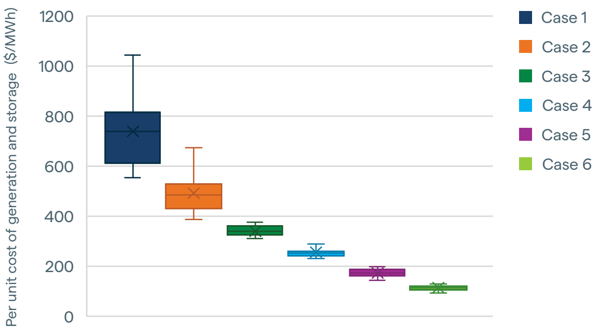


Figure 2. Carbon intensity in each case.

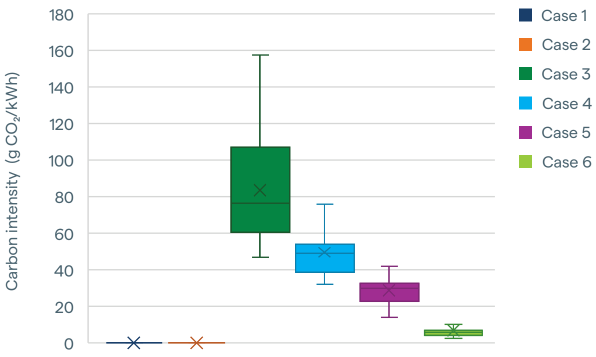
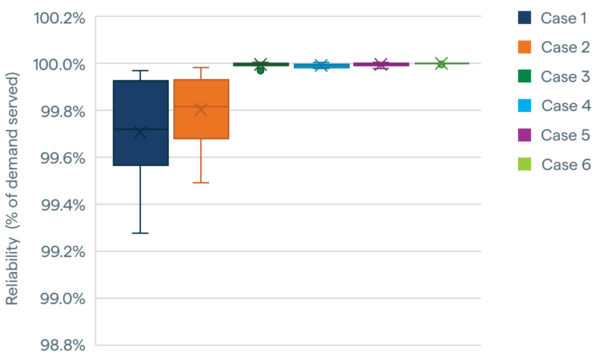


Figure 3. Reliability of the electricity system in each case.



This early work indicates that to meet the growing demand for electricity, the Case 6 approach – a mix of generation that includes wind, solar and batteries, geothermal, hydro and thermal peakers, shared nationally through electricity networks – could potentially deliver the greatest benefit to everyone.

There is further work to do to understand what network investments would be needed to enable this diverse mix of generation, as this case potentially requires the most from existing and new networks to achieve the lowest cost generation mix. Subject to the detailed analysis in our Grid Blueprint, this diversified mix may still be the pathway to the lowest overall *total power system* cost in enabling growth.

Our reasoning is outlined in this paper with results and technical detail provided in the technical appendix.

Why this matters to New Zealand

The choices we make around how to meet new electricity demand and enable economic growth will impact the cost and performance of our electricity system: that matters to everyone using electricity and paying the bill – industry, businesses, households and individuals.

Our work is focused on identifying the pathway to the least cost, reliable and sustainable electricity system that enables New Zealand to leverage its renewable resources for growth.

Even small differences in the per-unit cost of electricity translate into very large costs when scaled across the whole system. Our recent work on electricity demand, outlined in our **potential future scenarios consultation**, showed demand is projected to increase from around 40 terawatt hours (TWh) today to 56 TWh by 2050 in the low growth scenario (Patchwork Nation), and to 97 TWh in the high growth scenario (Made in Aotearoa).

In 2050, Case 1's total annual generation and storage costs are $10 billion higher than in Case 6 under the low growth scenario, and $35 billion higher under the high growth scenario. Across the full forecast horizon out to 2050, the net present value of the cost differences between the two cases is $42 billion in the low scenario and $128 billion in the high scenario.

This suggests that a fully distributed supply, with local demand met solely by local generation, despite not requiring any significant investment in networks, is unlikely to be the least-cost solution.

Electricity future hedge contracts have recently traded at around $135/MWh, down from $180-200/MWh a year ago[1]. A review of recent New Zealand gentailer investor presentations from **Meridian**[2], **Contact**[3], **Genesis**[4], and **Mercury**[5], shows they expect per-unit costs to be in the same range as Case 6. This provides us with some confidence that Case 6 is a viable option for the future.

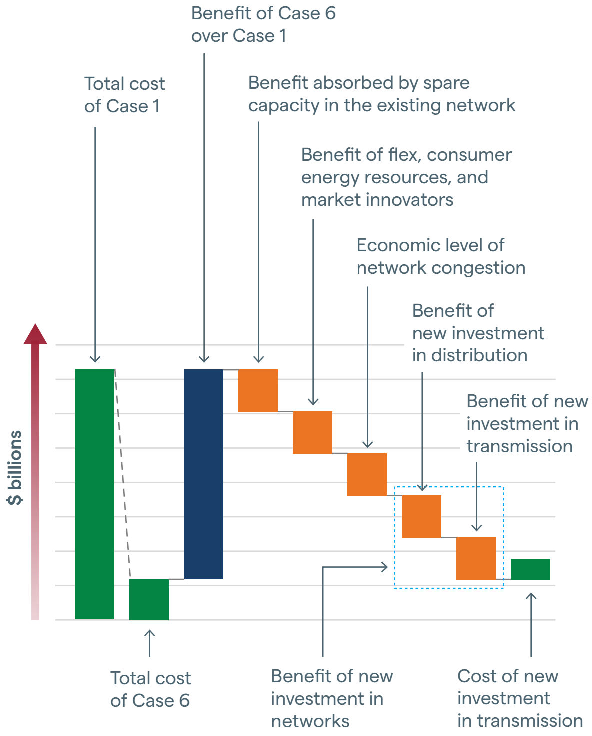
However, there is still considerable work to do to fully understand how the different cases here affect distribution and transmission networks. As we develop the future grid blueprint, we need to understand where existing network capacity is already available and can meet future growth needs. That includes where at times it may be better to rely on local generation and storage as it's more cost efficient than adding extra network capacity that remains under-utilised.

Just like having diversity in generation mix, there is diversity in the approach to network solutions. The range of options available within distribution networks include microgrids for remote communities where the cost of a network connection is significant, and reliance on distributed energy resources to help deliver reliability without more lines. On the transmission grid, new technologies and non-transmission solutions will enable different options to be used over traditional grid-scale solutions.

Figure 4 provides a qualitative illustration of the value chain, spanning existing networks, flexibility providers, market innovators, and new network investment, that needs to be in place to realise the benefits of Case 6. Network congestion is when there's more power available than the lines can carry which can result in local generation being used despite coming at a higher cost. In some places however this still comes in at a lower cost overall, than adding new transmission or distribution capacity.

The figure is indicative and should not be viewed as a presentation of actual costs or fractions.

Figure 4. Schematic illustration of costs and benefits to achieve the lowest total power system cost. Actual numbers and breakdown fractions are indicative only.



Te Kanapu – Grid Blueprint

As part of our analysis, we are working through a more detailed and rigorous version of the analysis summarised here. It includes for our five Te Kanapu demand scenarios, detailed power flow, market, and resiliency studies, to optimise the addition of new generation and storage with network capacity to establish the total power system cost and the justification (or not) for new lines or additional capacity.

With plenty more work to be done, this initial piece of analysis is helping to guide our collaborative approach to researching, modelling, engaging on and developing a future grid blueprint that must deliver the best possible outcome for everyone in New Zealand in an environment where our economy is thriving and growing.

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[1] Electricity Authority EMI data

[2] Meridian, Investor Day presentation, 2025

[3] Contact Energy, Accelerating Contact31+ Strategy and equity raise, 2026

[4] Genesis Energy, Investor Day presentation, 2025

[5] Mercury Energy, Investor Day presentation, 2025

> Our conclusion is that using a geographically spread, diverse range of generation technologies shared via electricity networks to meet new demand, could deliver the most affordable outcome for everyone. It could also balance the energy trilemma delivering a low-emissions, reliable electricity system that enables growth. Confirming this by determining the cost of network capacity needed is the core focus of the work underway on our first Grid Blueprint.

Transpower wishes to acknowledge and thank Signature Consulting's John Hancock and Aurecon's Danielle Manners for their contribution to the early stages of this work, and Jc2's John Culy for his critique and detailed review of our technical work.

Diving into the detail

Why this, why now?

New Zealand's electricity system is changing rapidly.

Demand for electricity is increasing, there is a strong pipeline of new renewable generation connecting to the grid and distributed energy resources, such as solar and wind generation combined with battery storage, are becoming an increasing part of the generation mix. This is partly because, unlike conventional hydro and geothermal sources, both distributed and grid connected solar and wind can be located almost anywhere, although some locations have their own unique challenges.

With this in mind, we also need to start thinking about whether we are going to need additional network capacity alongside new generation.

Networks play a role in our system by moving electricity from where it is generated, to where it is used. Our current network enables electricity to flow from hydro dams in the south and geothermal plants in the centre of the North Island to large cities and industries across the country.

Given new transmission lines can take 7-10 years to consent and build, we need to start thinking about the potential need for new networks, now.

In a decentralised, distributed renewable system, is there a benefit from networks and will we need more network capacity?

What did we examine?

We outline six possible ways New Zealand could meet increasing demand for electricity through differing mixes of generation types. The approach and cases were chosen to leverage New Zealand's exceptional renewable resources. Each are defined by carefully chosen assumptions.

For each case, we assume existing generation meets existing needs with new generation required to meet new demand. We then outline what the impact of this new generation would be on networks.

We provide an indication of what it might cost to deliver the new generation and storage mix, (excluding the cost of any potential investment in networks) and we have calculated the carbon intensity of each case.

Finally, we have calculated the reliability of each system as a percentage of demand served which means how consistently the generation mix could supply the amount of electricity customers want, when they want it. This does not include the reliability of the networks connecting this generation to demand.

With these three considerations, we see how each case performs against the three competing priorities of the energy trilemma: affordability, security and sustainability.

Per-unit costing of additional generation

Our aim is to identify the upper and lower limits of the per-unit (MWh) costs of the additional generation and storage needed to meet future demand, considering how new demand varies across a typical day and throughout the year. This per-unit cost includes what is needed to firm each generation type considering the constraints they have such as intermittency for wind and solar, resource limits of hydro and geothermal, and the storage limit and round-trip efficiency for batteries.

Finally, it assumes this cost remains the same irrespective of the additional demand served. In this way, we avoid the need to explicitly model the scale of demand growth.

By identifying the lowest per-unit cost of generation and storage, we can begin to understand the generation and technology mix that will be most affordable, enable new industries and electrification of existing activities into the future.

Identifying the network investment needed to enable future generation is the next phase of our work in the Te Kanapu work programme.

You'll find more detail around our calculations in the technical appendix at the end of this document.

Defining our cases

The six cases are summarised in Table 1 and described in detail from page 15 onwards. The key defining feature of each case is the generation mix used to meet new demand, which is progressively broadened as we move from Case 1 through to Case 6.

The reliance on networks to share these resources also increases as we move through the cases and the generation mix diversifies. We also outline the sensitivities that impact on the per-unit cost of generation and storage in the six cases.

Generation options for meeting new demand

Case 1 is where additional electricity demand is met locally by new solar and batteries alone, and it assumes there is no need for added network capacity. Subsequent cases retain solar and batteries and add progressively more generation. As a result, they have a growing reliance on networks. In each instance, batteries are considered as a source of firming.

Case 2 considers local rooftop solar and batteries combined with utility-scale wind resources. Case 3 adds thermal peakers to improve supply reliability; Case 4 introduces new geothermal generation; Case 5 includes the flexibility of existing hydro generation. Finally, Case 6 uses an optimised mix of multiple generation sources located across the country.

The hydro generation included in Cases 5 and 6 is not new, rather we are modelling how existing hydro can be dispatched more flexibly to lower the overall per-unit cost of generation by firming wind and solar. When wind and solar is generating, hydro can reduce output; when wind and solar are not generating, hydro can flex to increase output. This demonstrates how New Zealand's hydro generation will support higher levels of wind and solar on the system.

Case 6 captures the benefit of using resources across New Zealand because the use of purely local intermittent resources in earlier cases presents the risk there won't be enough generation to cover those times when it is not sunny or windy, which would otherwise require more local battery storage. Conversely, in earlier cases, sometimes more electricity than is needed locally is being generated this way, leading to 'spill'. Using a mix of sources across the country improves reliability and the reliance on thermal peakers is reduced, lowering the cost of firming and the likelihood of spill.

Sensitivities and the impact on our results

Within each case, the per-unit cost of generation and storage, CO_2 emissions and reliability will vary according to factors such as:

- regional differences in average wind speed and solar irradiance (from renewable resource profiles),
- the time-dependent profile of new electricity demand,
- the cost of being without power due to a shortage of generation or lack of battery storage (known in the industry as value of lost load or VoLL),
- technology and fuel costs,
- differences in weather years, and
- physical limitations of geothermal and hydro resource.

To capture these factors, we have applied a sensitivity assessment across all cases. As a result, we also express per-unit cost, emissions and reliability as a range, with an upper and lower limit therefore avoiding the potential for false precision.

Impact on the electricity network

As the generation mix changes, the network that supports this new generation is impacted to differing levels. We have not attempted to quantify these impacts rather we aim to demonstrate some of the key factors to consider when it comes to choices around generation.

One key element we don't consider is whether our existing networks can accommodate the additional generation or whether any significant new network capacity would be required. This is the work of our Te Kanapu programme to develop a Grid Blueprint and is outlined in our **technical approach**. For this work we'll be using the five future scenarios that were published in **Future Direction - Our Energy Scenarios**, assessing the need for new transmission lines within each of them.

Table 1. The Cases 1 to 6 that we consider in our analysis.

Mix of generation to meet incremental demand		Impact on the transmission and distribution network	Sensitivities
Case 1 	1. Local rooftop solar 2. Batteries	No impact.	• Regional differences • Demand shape • Value of lost load • Technology costs • Weather years
Case 2 	1. Local rooftop solar 2. Batteries 3. Local utility-scale wind	Minor impact with utility-scale wind requiring a connection.	• Regional differences • Demand shape • Value of lost load • Technology costs • Weather years
Case 3 	1. Local rooftop solar 2. Batteries 3. Local utility-scale wind 4. Thermal peakers	Some impact. Thermal generation is likely to connect in either Taranaki, Waikato, or Marsden Point, which would impact power flows into and out of those regions.	• Regional differences • Demand shape • Value of lost load • Fuel cost • Weather years
Case 4 	1. Local rooftop solar 2. Batteries 3. Local utility-scale wind 4. Thermal peakers 5. Geothermal	Some impact. Geothermal generation is located almost exclusively around the central North Island volcanic plateau, which would impact power flows into and out of that region.	• Demand shape • Fuel cost • Weather years • Geothermal limitations
Case 5 	1. Local rooftop solar 2. Batteries 3. Local utility-scale wind 4. Thermal peakers 5. Geothermal 6. Hydro	Material impact. Hydro is dispatched to firm wind and solar, which would impact power flows on the grid backbone.	• Demand shape • Fuel cost • Weather years • Hydro limitations
Case 6 	1. Nationwide distributed solar 2. Batteries 3. Nationwide utility-scale wind 4. Thermal peakers 5. Geothermal 6. Hydro	Material impact. A nationwide mix of utility scale wind and solar will impact power flows on the grid backbone.	• Demand shape • Fuel cost • Weather years • Geothermal limitations • Hydro limitations

Why the focus on networks?

Of course, Transpower has a material interest in networks: we own and operate New Zealand's transmission network.

Additionally, our purpose is to empower the energy future for New Zealand, and everyone living here. We already know networks play a key role in delivering on this purpose today, the question is, will they continue to do so into the future and in a growing economy?

We have identified five key reasons why networks are especially important in New Zealand's unique electricity system.

1. **Networks provide access to additional geothermal generation.**

   New Zealand aims to double its geothermal generation by 2040[6]. Geothermal is a great resource because it is base load, which means it keeps running continually as opposed to wind and solar which are intermittent. However, geothermal is primarily only available in the central North Island plateau (with some resource located in Northland), so networks enable this resource to be accessed outside of where it's located.

2. **Networks provide access to New Zealand's best locations for wind and solar generation**.

   We all know how some regions have higher long-term average sunshine hours or average wind speeds. It makes sense to build solar and wind generation in these regions, provided an affordable network connection can enable generation to be shared with other regions.

3. **Networks provide greater access to hydro generation schemes.**

   If we plan to use our hydro generation flexibility to firm wind and solar, then networks will need to be able to accommodate the changes in timing and amount of hydro in the generation mix, as the percentage of wind and solar increase. We will almost certainly need more network capacity to cope with the higher peak generation dispatched into the network at some locations.

4. **Networks enable technological and regional diversity.**

   The intermittency of wind and solar generation is a recognised issue. If this generation is located across many regions (capturing the regional diversity of good quality wind and sun resources), it reduces the level of overbuild and storage needed compared to if only local generation is used to serve demand. The overall delivered reliability is materially improved if these forms of intermittent generation are supported by other forms of generation located elsewhere.

5. **Networks provide greater security, reliability, and resilience.**

   The electricity system is complex and finely balanced. Connecting to a network provides a stable supply of electricity, at a consistent quality; essential in applications such as industrial machinery, advanced electronics, and healthcare. With more of the economy running on electricity, the value placed on a stable and reliable supply of electricity increases.

[6] Geothermal Strategy | Ministry of Business, Innovation & Employment.

Results

Comparing costs across our cases

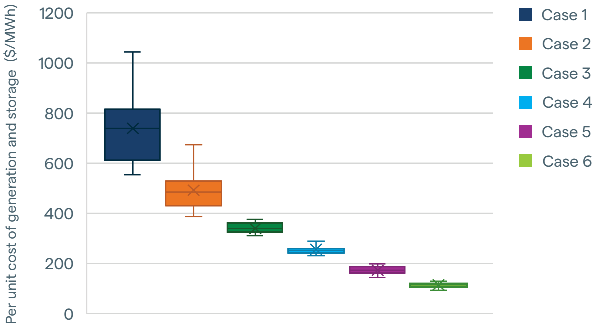
Costs are expressed as the per-unit cost of generation and storage ($/MWh).

Figure 1 (reproduced from page 4) shows the per-unit cost of generation and storage, expressed as a range determined by the different sensitivities considered within each case. The result shows a material reduction in cost as new technologies are enabled to enter the system, and we move from Case 1 to Case 6.

In Case 1, where new generation is restricted to rooftop solar and batteries, the cost sits in the range from $554/MWh to $1044/MWh. Including new utility-scale wind generation in the mix (Case 2) reduces this to a range of $390/MWh to $675/MWh. Introducing thermal peakers, then new geothermal, and finally hydro flex (Case 5) combine to reduce the cost further to a range of $148/MWh to $202/MWh.

Subject to further analysis on the network costs required to enable it, Case 6 provides a view of what is possible with a diverse range of generation and storage, shared nationally. The per-unit cost in this case sits in the range from $96/MWh to $171/MWh.

Figure 1. The per-unit cost of generation and storage in each case.

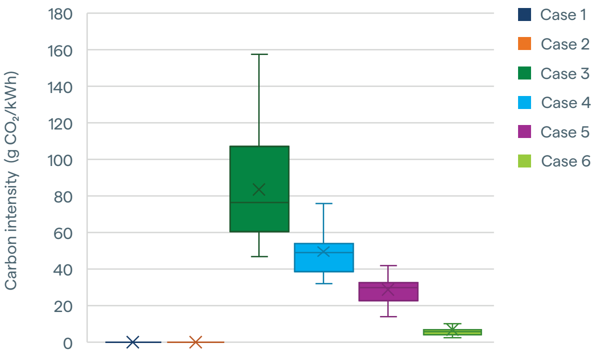


Comparing emissions

The carbon intensity of each case expressed as gCO_2/kWh, can also be assessed and is shown in Figure 2 (reproduced from page 4). No thermal peakers in Cases 1 and 2 means zero carbon intensity. Cases 3 to 6 have reducing levels of emissions as reliance on thermal peakers is progressively mitigated by new geothermal and hydro flex.

In Case 6, this reliance on peakers is limited to providing firm supply during only the most difficult hours during the year, leading to a very low carbon intensity of between 2.5 and 18 gCO_2/kWh, for serving additional demand.

Figure 2. The carbon intensity of generation and storage in each case.



Assessing reliability

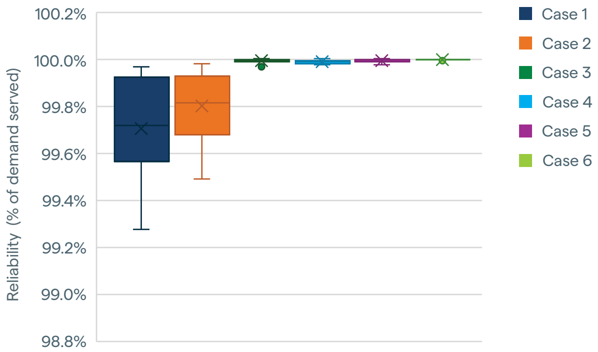
Finally, we have assessed the reliability of each case by measuring the percentage of electricity demand that is served over time. Reliability is also driven by the performance and availability of network connections which are not accounted for in this work.

In practical terms, it reflects how often households and businesses would have access to the electricity they want, when they want it, without shortfalls due to insufficient or poorly timed generation. For example, if generation can fully meet future additional demand for 99.9% of the year, this equates to around nine hours a year when demand is not fully supplied. This does not include hours when supply is disrupted by outages on the network.

Our analysis here provides an indication of how consistently each generation mix can meet customer demand, not just on average but across different weather conditions that affect generation, and different times of the day and year as demand varies.

The reliability in each case is shown in Figure 3 (reproduced from page 4).

Figure 3. The reliability in each case.

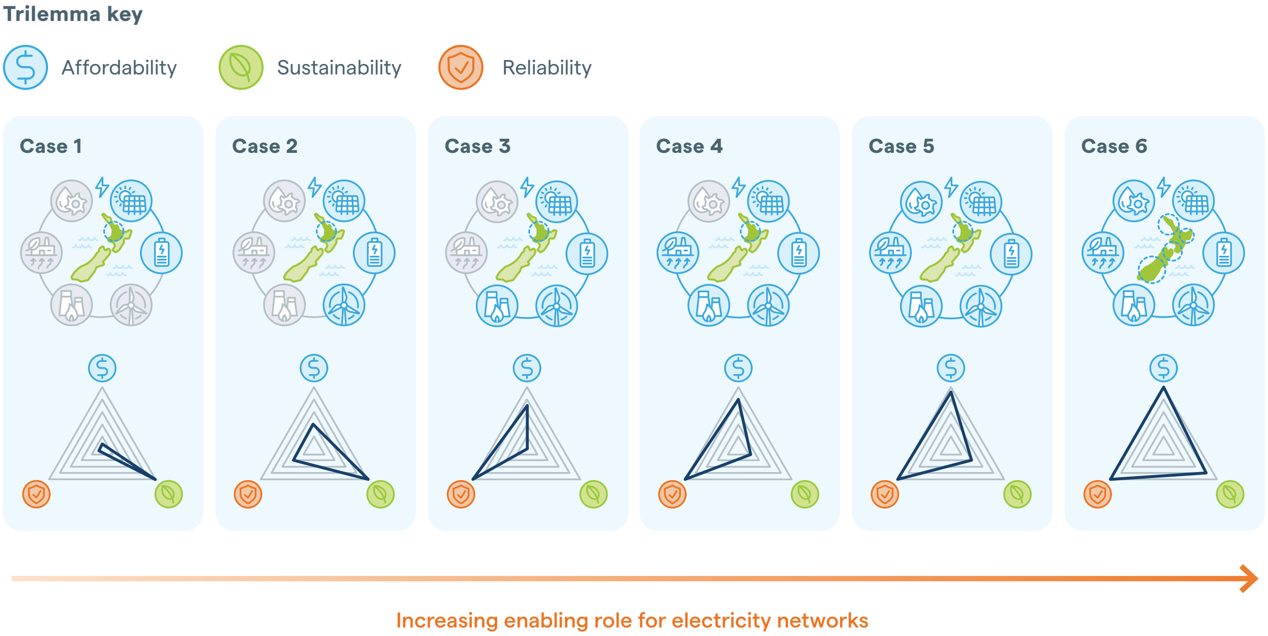


In Case 1, 99.71% (baseline value) of demand is served which is a much lower level of reliability than most people are accustomed to. It equates to approximately 26 hours of the year without electricity and from our modelling there is a high likelihood of that occurring during winter nights. Case 2 shows a slight improvement on Case 1.

The use of thermal peakers in Case 3 materially improves reliability to 99.986%, or 1.2 hrs without electricity. Cases 4, 5, and 6 use geothermal, hydro, and a nationwide mix of wind and solar to incrementally improve reliability to 99.997% or 15 minutes without electricity due to insufficient generation.

Balancing the energy trilemma

The following figure shows indicatively how in progressing from Case 1 to Case 6 we better balance the energy trilemma of affordability (cost in regard to generation and storage), sustainability (emissions) and security (reliability). We see that a more technologically and regionally diverse generation mix, enabled by networks, delivers the best balance and a positive outcome for the people of New Zealand.



Network investment

Despite the strong showing of Case 6 across the energy trilemma using the per-unit cost of generation and storage, we still need to understand how much network investment is needed to realise these benefits.

To establish that number, you also need a forecast for how much demand will grow. Our five Te Kanapu demand scenarios outlined in our **potential future scenarios consultation**, showed demand is projected to increase from around 40 terawatt hours (TWh) today to 56 TWh by 2050 in the low growth scenario (Patchwork Nation), and to 97 TWh in the high growth scenario (Made in Aotearoa).

In 2050, Case 1's total additional generation and storage costs are $10 billion higher than in Case 6 under the low growth scenario, and $35 billion higher under the high scenario. Across all years out to 2050, the net present value of the cost differences between the two cases is $42 billion in the low scenario and $128 billion in the high scenario.

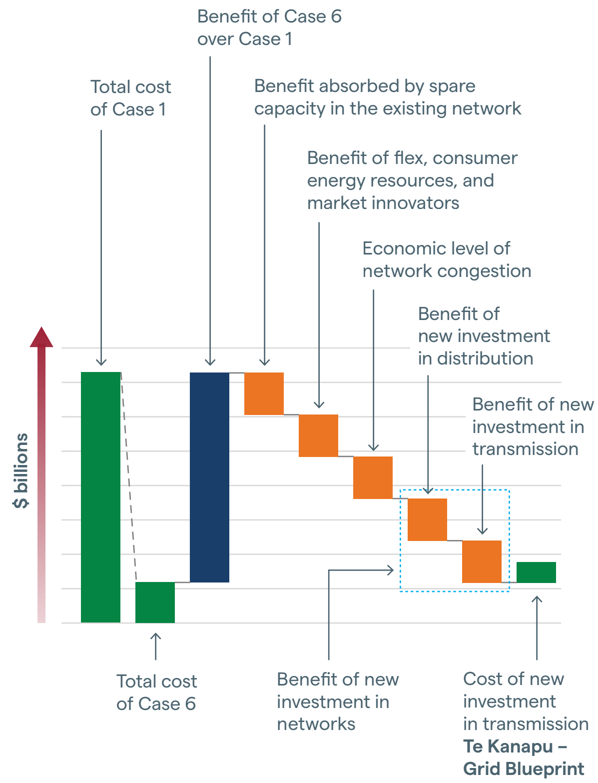
The question is could we invest significantly in networks to enable the lowest cost generation mix in Case 6 and maintain a total power system cost lower than the overall cost of Case 1, the highest cost generation mix but without any network investment?

To answer that we need to establish what network investment is required. There are several factors to consider. We need to understand where existing network capacity is already available and can meet all future growth needs. We also need to understand where and when it is better to occasionally rely on higher cost local generation and batteries than add additional poorly utilised network capacity, even when this comes in at a lower overall cost than adding new capacity. (As listed in Figure 4, economic level of network congestion).

There is a diverse range of network and non-network solutions to consider. For distribution networks these include microgrids for remote communities where the cost of a network connection is significant, or the reliance on distributed energy resources in homes and on farms to help deliver reliability without more lines. On the transmission grid, new technologies and non-transmission solutions – where alternatives are used to defer or avoid investment - will enable different options to be used over traditional grid-scale solutions.

Figure 4 (reproduced from page 5) provides a qualitative illustration of the value chain, spanning existing networks, flexibility providers, market innovators, and new network investment, that needs to be in place to realise the benefits of Case 6. The figure is indicative and should not be viewed as a presentation of actual costs or fractions.

Figure 4. Schematic illustration of costs and benefits to achieve the lowest total power system cost. Actual numbers and breakdown fractions are indicative only.



What's next?

When it comes to any actual investment, much more analysis is required. Decisions need to be evidence-based and must deliver the lowest total power system cost, including the cost of network investment.

These findings mean we anticipate that an enhanced electricity network will be needed to enable future growth and lower the total power system cost.

Under our programme to deliver our first Grid Blueprint we are working through a more detailed and rigorous version of the analysis summarised here using the five Te Kanapu demand scenarios, including detailed power flow, market, and resiliency studies, to outline where there is justification for new lines or additional capacity. **You can explore this work here on our website.**

With plenty more work to be done, this initial piece of analysis is helping to guide our collaborative approach to researching, modelling, and engaging on the Grid Blueprint that must deliver the best possible outcome for everyone in New Zealand in an environment where our economy is thriving and growing.

Analysis has shown there is a significant opportunity available to the nation, if we plan carefully and make the right choices for our electricity system; choices that maximise our diverse range of generation resources supported by transmission and distribution networks.

We must be mindful that most new electricity infrastructure takes time to deliver, especially new lines. Where they offer the opportunity to lower costs we are better to start long term planning now, so the opportunity is not missed.

In doing so we can support a growing economy by delivering the lowest cost, low emissions, reliable electricity system.

Results by case

Case 1

Generation and storage in Case 1 is restricted to a mix of rooftop solar and batteries. The demand profile and solar resource are based on Auckland conditions as it is our largest population centre. The per-unit cost of generation and storage in this case is $730/MWh, (baseline value), broken down in Figure 5 across generation, spill, storage, and residual unserved demand. The amount of installed generation and storage to optimally meet that demand is shown in Table 2. Figure 6 shows the dispatch of generation and storage across (a) an average week, (b) a week of high renewable spill, and (c) a week of high unserved demand.

The outcome of sensitivity assessment across the different input assumptions is shown in Figure 7. The range of per-unit cost of generation and storage in this case is between $554/MWh (which occurs in the '*daytime only*' demand shape sensitivity) and $1044/MWh (which occurs in the *'Invercargill'* regional sensitivity).

Figure 5. Breakdown of the per-unit cost of generation in Case 1.

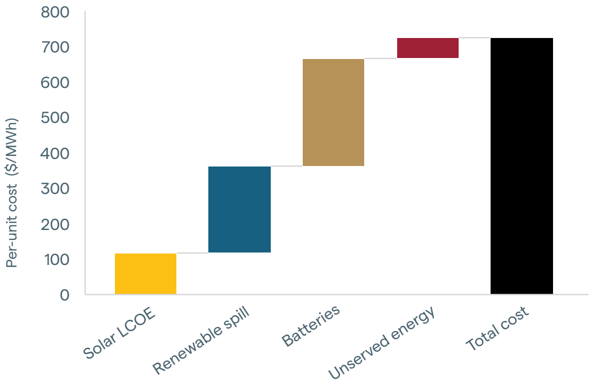
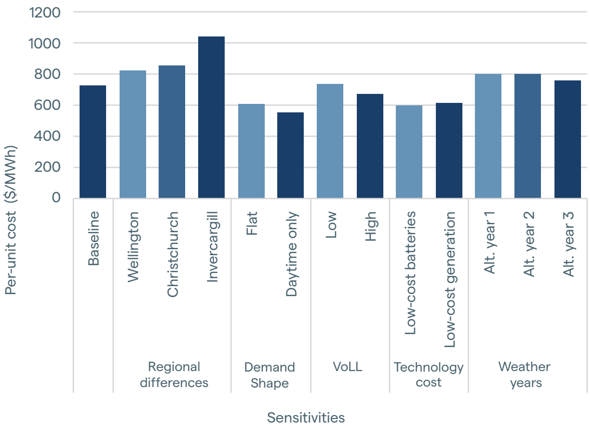


Table 2. Optimised generation and storage mix in Case 1.

Technology	Units	Baseline value	Low	High
Solar	MW	14	12	24
Battery (duration)	hrs	7.7	6.7	10
Battery (power)	MW	5.5	3.8	6.9

Figure 6. Weekly dispatch patterns in Case 1.

Figure 7. Outcome of the sensitivity assessment in Case 1.



You can view all the data for our LCOE, dispatch and case sensitivities in the associated data book.

Case 2

Generation and storage in Case 2 is a mix of rooftop solar, utility-scale wind and batteries. The demand profile and solar and wind resource are based on Auckland conditions as it is our largest population centre. The per-unit cost of generation and storage in this case is $516/MWh (baseline value), broken down in Figure 8 across generation, spill, storage, and residual unserved demand. The amount of installed generation and storage to optimally meet that demand is shown in Table 3. Figure 9 shows the dispatch of generation and storage across (a) an average week, (b) a week of high renewable spill, and (c) a week of high unserved demand.

The outcome of sensitivity assessment across the different input assumptions is shown in Figure 10. The range of per-unit cost of generation and storage in this case is between $390/MWh (which occurs in the '*daytime only*' demand shape sensitivity) and $675/MWh (which occurs in the '*Invercargill*' regional sensitivity).

Figure 8. Breakdown of the per-unit cost of generation in Case 2.

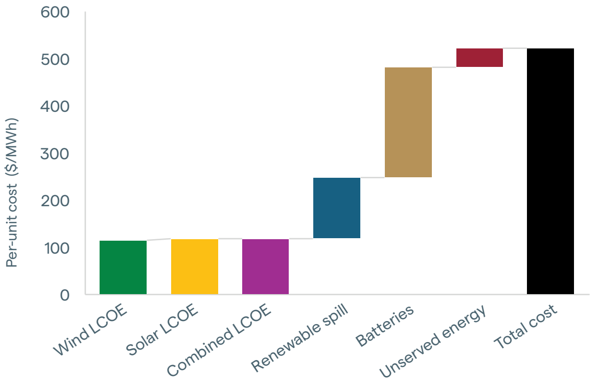


Table 3. Optimised generation and storage mix in Case 2.

Technology	Units	Baseline value	Low	High
Wind	MW	2	1.6	5.1
Solar	MW	6.3	3.4	6.9
Battery (duration)	hrs	10	7.5	20.7
Battery (power)	MW	3.3	1.7	3.5

Figure 9. Weekly dispatch patterns in Case 2.

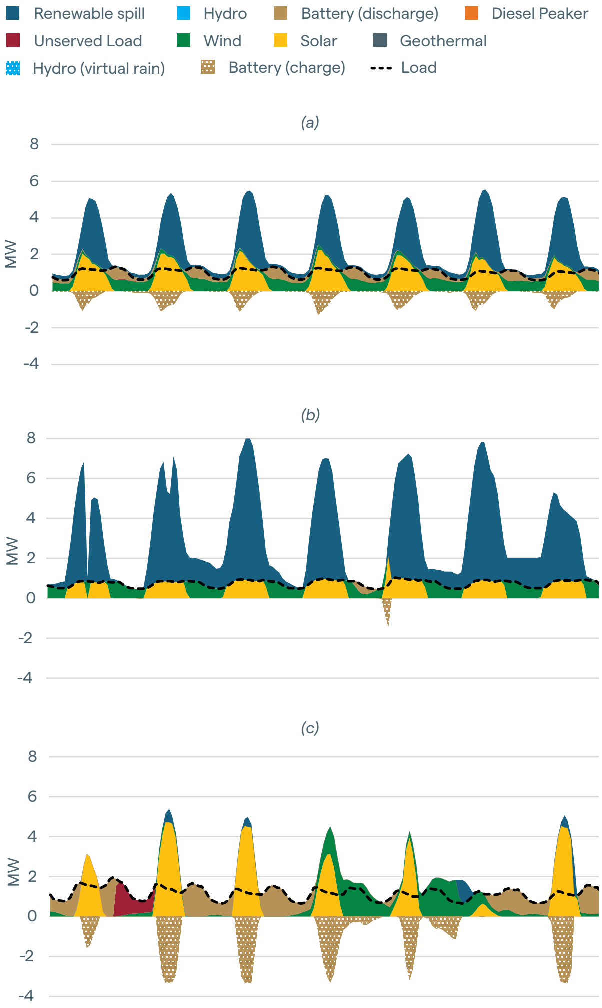
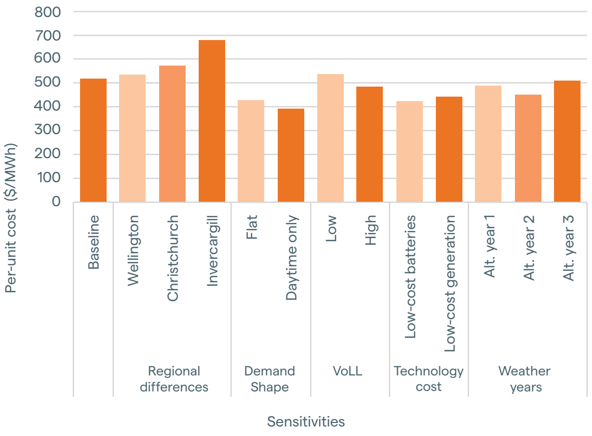


Figure 10. Outcome of the sensitivity assessment in Case 2.



You can view all the data for our LCOE, dispatch and case sensitivities in the associated data book.

Case 3

Generation and storage in Case 3 is a mix of rooftop solar, utility-scale wind, thermal peakers, and batteries. The demand profile and solar and wind resource are based on Auckland conditions as it is our largest population centre. The per-unit cost of generation and storage in this case is $344/MWh (baseline value), which is broken down in Figure 11 across generation, spill, storage, and residual unserved demand. The amount of installed generation and storage to optimally meet that demand is shown in Table 4. Figure 12 shows the dispatch of generation and storage across (a) an average week, (b) a week of high renewable spill, and (c) a week of high unserved demand.

The outcome of sensitivity assessment across the different input assumptions is shown in Figure 13. The range of per-unit cost of generation and storage in this case is between $312/MWh (which occurs in the '*low*' fuel cost sensitivity) and $380/MWh (which occurs in the '*high*' fuel cost sensitivity).

Figure 11. Breakdown of the per-unit cost of generation in Case 3.

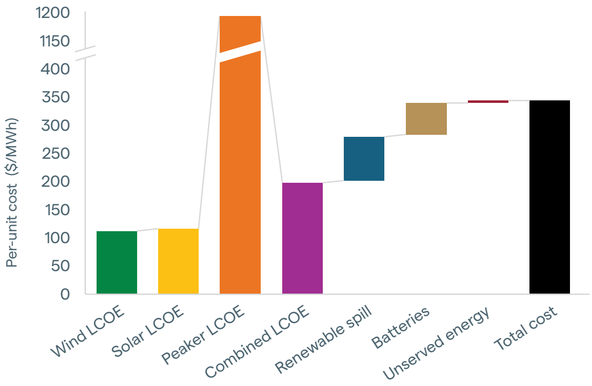


Table 4. Optimised generation and storage mix in Case 3.

Technology	Units	Baseline Value	Low	High
Wind	MW	1.7	1.3	3.1
Solar	MW	3.1	1.4	3.8
Battery (duration)	hrs	6.2	0.1	9.4
Battery (power)	MW	1.3	0.4	3.4
Thermal peakers	MW	1.6	1	1.9

Figure 12. Weekly dispatch patterns in Case 3.

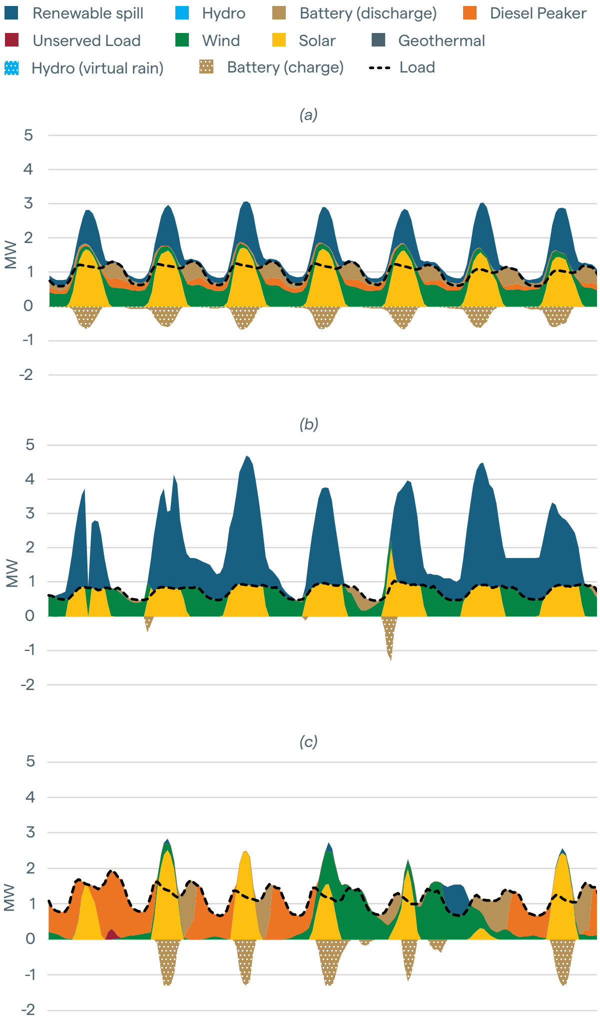
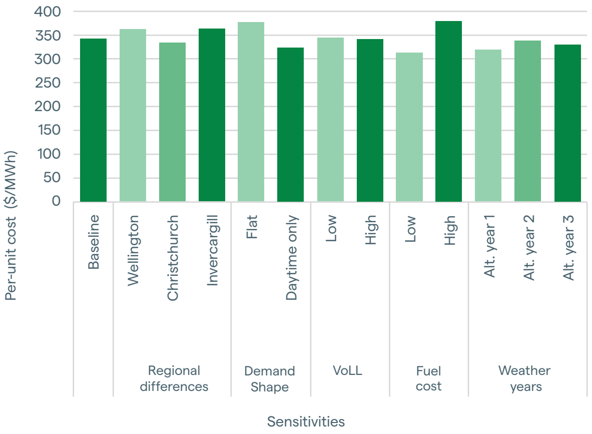


Figure 13. Outcome of the sensitivity assessment in Case 3.



You can view all the data for our LCOE, dispatch and case sensitivities in the associated data book.

Case 4

Generation and storage in Case 4 is a mix of rooftop solar, utility-scale wind, thermal peakers, geothermal, and batteries. The demand profile and solar and wind resource are based on Auckland conditions as it is our largest population centre. The per-unit cost of generation and storage in this case is $263/MWh (baseline value), which is broken down in Figure 14 across generation, spill, storage, and residual unserved demand. The amount of installed generation and storage to optimally meet that demand is shown in Table 5. Figure 15 shows the dispatch of generation and storage across; (a) an average week, (b) a week of high renewable spill, and (c) a week of high unserved demand.

The outcome of sensitivity assessment across the different input assumptions is shown in Figure 16. The range of per-unit cost of generation and storage in this case is between $233/MWh (which occurs in the *'flat'* demand shape sensitivity) and $293/MWh (which occurs in the *'low'* geothermal limit sensitivity).

Figure 14. Breakdown of the per-unit cost of generation in Case 4.

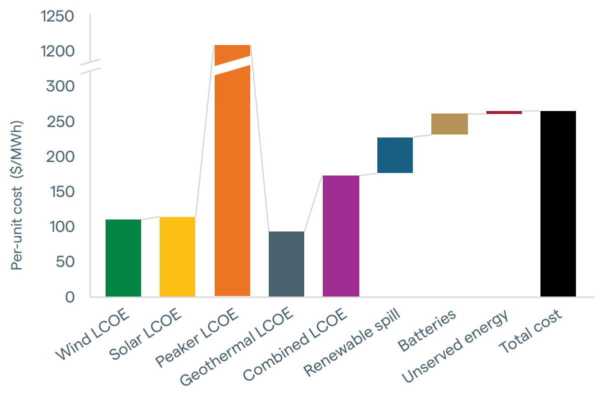


Table 5. Optimised generation and storage mix in Case 4.

Technology	Units	Baseline Value	Low	High
Wind	MW	1.2	0.7	1.4
Solar	MW	1.9	1.5	2.8
Battery (duration)	hrs	6	4.3	6.8
Battery (power)	MW	0.7	0.5	1.4
Thermal peakers	MW	1.3	0.6	1.5
Geothermal	MW	0.4	0.3	0.5

Figure 15. Weekly dispatch patterns in Case 4.

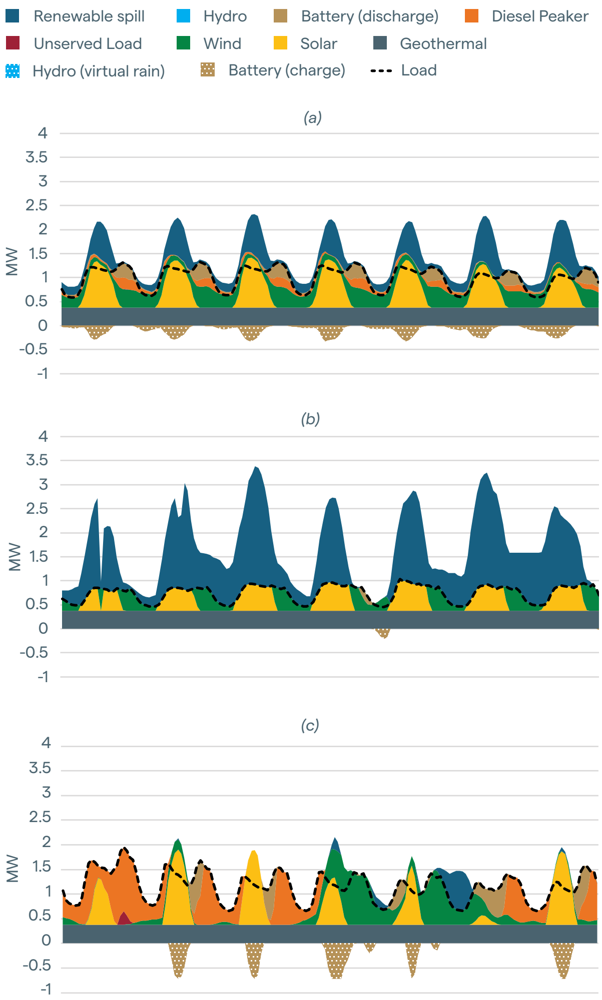
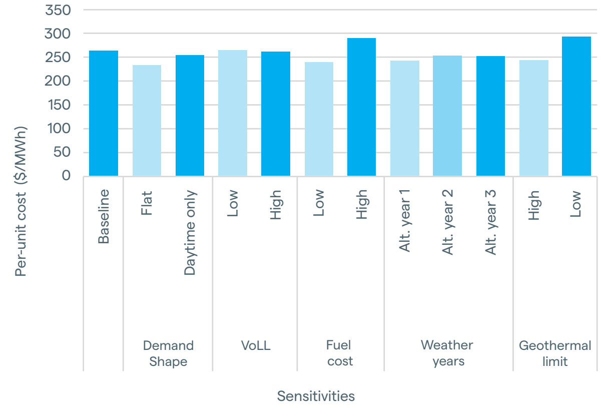


Figure 16. Outcome of the sensitivity assessment in Case 4.



You can view all the data for our LCOE, dispatch and case sensitivities in the associated data book.

Case 5

The generation and storage in Case 5 is a mix of rooftop solar, utility-scale wind, thermal peakers, geothermal, hydro and batteries. The demand profile and solar and wind resource are based on Auckland conditions as it is our largest population centre. The per-unit cost of generation and storage in this case is $180/MWh (baseline value), which is broken down in Figure 17 across generation, spill, storage, and residual unserved demand. The amount of installed generation and storage to optimally meet that demand is shown in Table 6. Figure 18 shows the dispatch of generation and storage across; (a) an average week, (b) a week of high renewable spill, and (c) a week of high unserved demand.

The outcome of sensitivity assessment across the different input assumptions is shown in Figure 19. The range of per-unit cost of generation and storage in this case is between $148/MWh (which occurs in the '*flat*' demand shape sensitivity) and $202/MWh (which occurs in the '*daytime only*' demand shape sensitivity).

Figure 17. Breakdown of the per-unit cost of generation in Case 5.

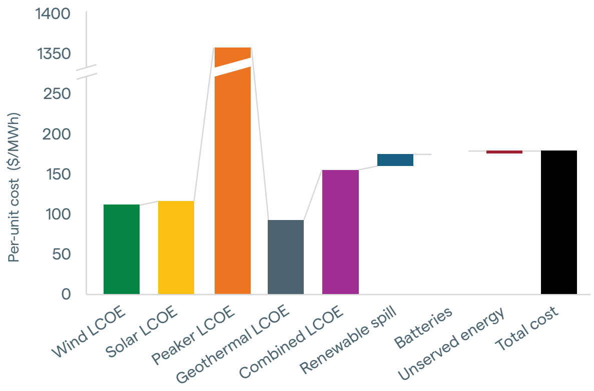


Table 6: Optimised generation and storage mix in Case 5.

Technology	Units	Baseline Value	Low	High
Wind	MW	1.7	0.6	1.7
Solar	MW	0.9	0.8	2.7
Battery (duration)	hrs	0	0	4.6
Battery (power)	MW	0	0	0.9
Thermal peakers	MW	1.1	0.6	1.1
Geothermal	MW	0.4	0.4	0.5
Hydro	MW	0.4	0.25	0.5

Figure 18: Weekly dispatch patterns in Case 5.

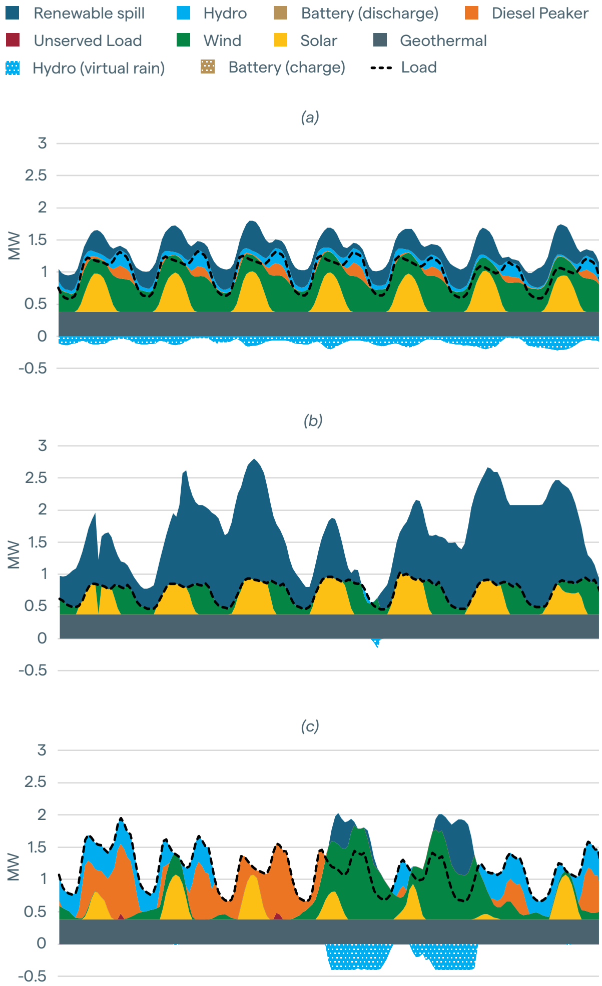
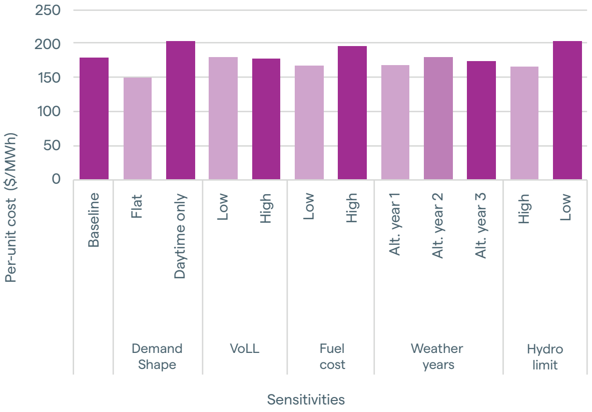


Figure 19: Outcome of the sensitivity assessment in Case 5.



You can view all the data for our LCOE, dispatch and case sensitivities in the associated data book.

Case 6

Generation and storage in Case 6 is a mix of utility-scale solar, wind, thermal peakers, geothermal, hydro and batteries. The demand profile follows a local (grid-exit-point level) historical pattern. The solar and wind resource is spread out around the country. The per-unit cost of generation and storage in this case is $117/MWh, which is broken down in Figure 20 across generation, spill, storage, and residual unserved demand. The amount of installed generation and storage to optimally meet that demand is shown in Table 7. Figure 21 shows the dispatch of generation and storage across (a) an average week, (b) a week of high renewable spill, and (c) a week of high unserved demand.

The outcome of sensitivity assessment across the different input assumptions is shown in Figure 22. The range of per-unit cost of generation and storage in this case is between $96/MWh (which occurs in the '*low*' technology cost sensitivity) and $171/MWh (which occurs in the '*daytime only*' demand shape sensitivity).

Figure 20: Breakdown of the per-unit cost of generation in Case 6.

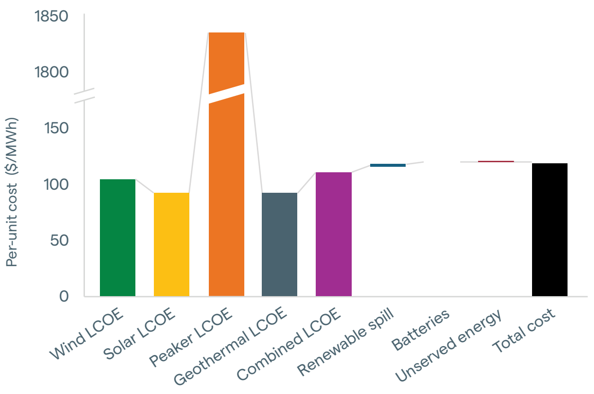


Table 7: Optimised generation and storage mix in Case 5.

Technology	Units	Baseline Value	Low	High
Wind	MW	1.8	1.5	2.1
Solar	MW	0.1	0	1.5
Battery (duration)	hrs	0	0	59.9
Battery (power)	MW	0	0	0.7
Thermal peakers	MW	0.4	0.2	1
Geothermal	MW	0.4	0.3	0.5
Hydro	MW	0.4	0.3	0.5

Figure 21: Weekly dispatch patterns in Case 6.

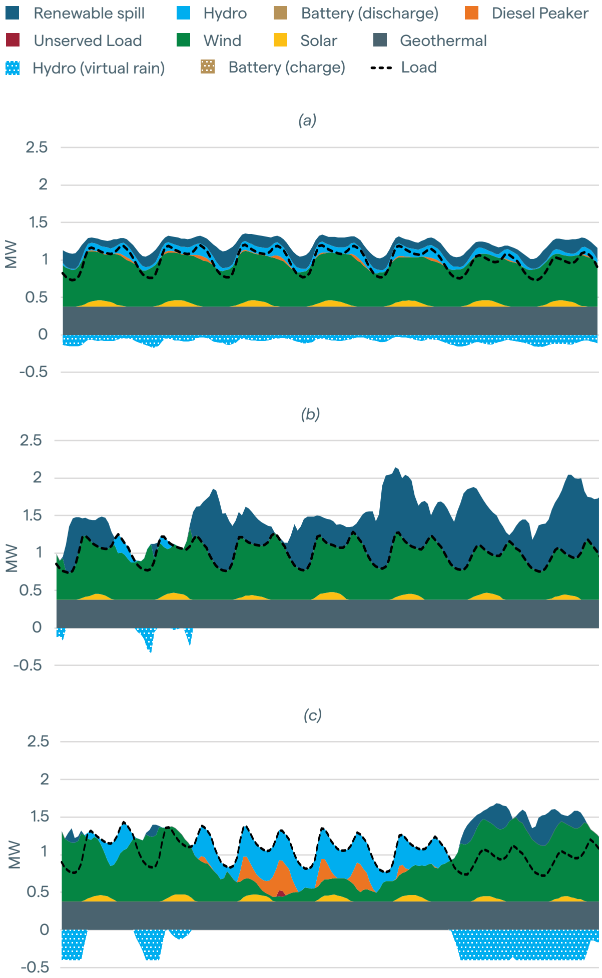
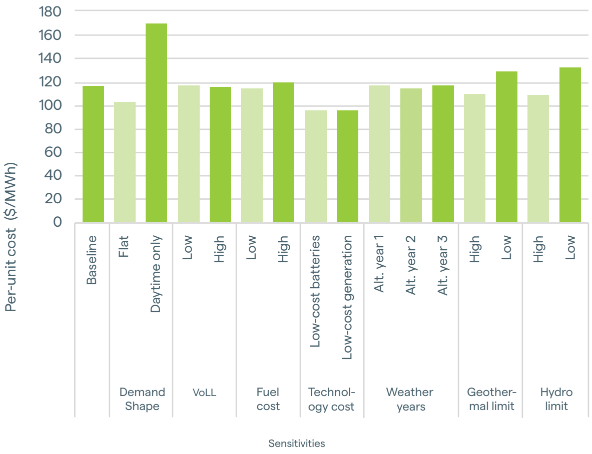


Figure 22: Outcome of the sensitivity assessment in Case 6.



You can view all the data for our LCOE, dispatch and case sensitivities in the associated data book.

Technical appendix

Definitions

Levelised cost of energy

The levelised cost of energy (LCOE) is a commonly used metric for assessing and comparing different methods of energy generation. While it is simple to calculate, it provides a relatively simplified view of real-world costs. A key limitation is that it does not account for the need to continuously balance supply and demand[7].

LCOE is the net present value of the total cost of the installed generation capacity divided by the total electricity generated over the lifetime of the generation.

The resource variability (intermittency) of wind and solar means this technology must be used together with firming technology, such as battery energy storage systems (BESS), to balance supply and demand. Geothermal is similarly inflexible, except its output is generally fixed at, or close to, its rated capacity meaning it cannot flex up or down. For these reasons, the LCOE is unsuitable for assessing the cost of an electricity system supplied by these technologies.

Levelised cost of delivered energy

In this analysis, we calculate the levelised cost of delivered energy[8, 9] (LCODE). LCODE is an advancement on the LCOE and incorporates whole-of-system costs associated with balancing supply and demand. The key distinction is that LCODE assesses the cost of the generation portfolio against its ability to meet a demand profile. The flowchart below outlines the key steps involved in calculating LCODE.

LCODE is the net present value of the total cost of the installed generation capacity, dispatched or spilled, to meet a demand profile plus the cost of any unserved energy, divided by the total demand over the lifetime of the generation.

LCODE takes the actual or assumed time-dependent output of generation assets and assesses its ability to meet a demand profile. This requires two additional inputs: 1) a demand profile $D(t)$ and 2) a dispatch algorithm for flexible generation. Any period where demand is not met receives a penalty cost set by the value of unserved energy. Computing LCODE is more challenging than computing LCOE but produces a more realistic result. LCODE has also been referred as a 'system LCOE' or a 'levelised cost of shaped energy'.

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[7] Rethinking the "Levelized Cost of Energy": A critical review and evaluation of the concept - ScienceDirect

[8] https://www.sciencedirect.com/science/article/pii/S2542435119303009

[9] https://www.tandfonline.com/doi/pdf/10.1080/14786451.2020.1753742

Figure 23: Flowchart outlining the calculation of LCODE in a system where BESS provides firming.

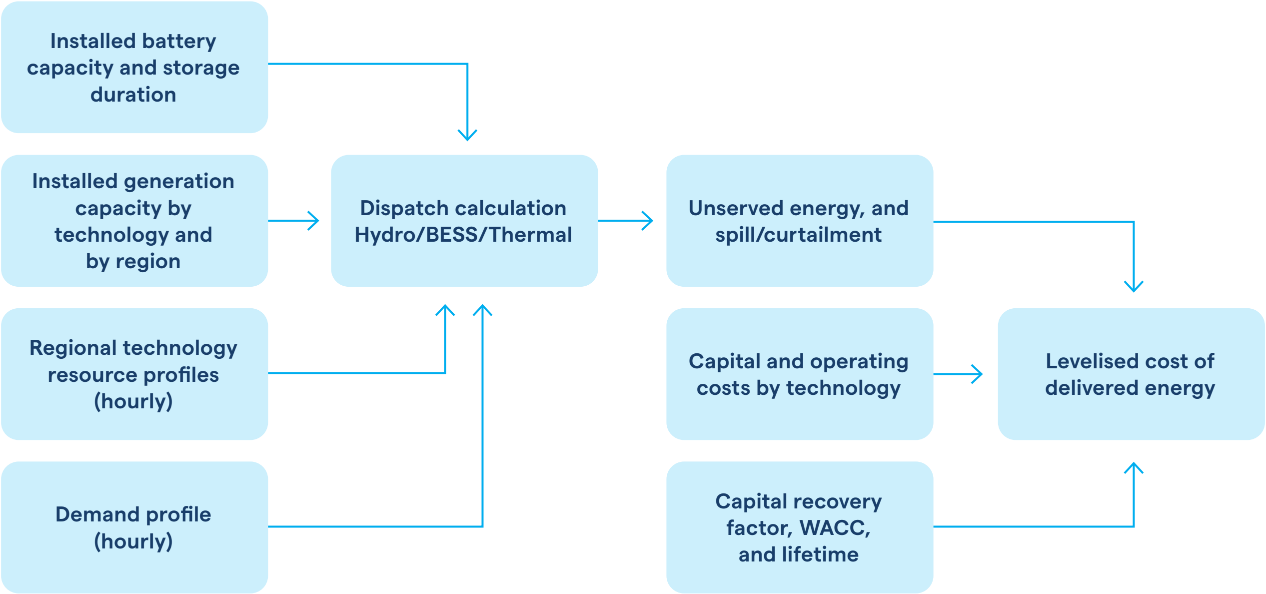
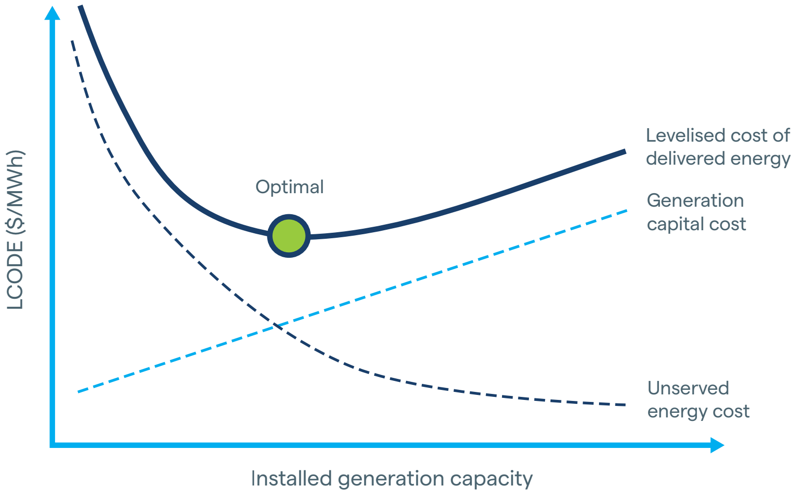


Figure 24 below illustrates how LCODE changes with installed generation capacity for a fixed demand profile. As more generation is added, capital costs increase, while unserved energy decreases. When the system is undersupplied, adding generation reduces LCODE. However, as the system moves from undersupply to oversupply, the cost of unserved energy begins to level off and LCODE starts to rise again. This means that, for a given demand profile, there is an optimal level of generation that minimises LCODE.

Figure 24: Thematic presentation of how LCODE varies with installed generation capacity.



The LCODE can be expressed mathematically as:

$$LCODE[P_{tech}] = \frac{\sum_{tech}[CRF \times C_{tech}P_{tech} + FOM_{tech}P_{tech} + F_{tech}] + VoLL \times USE}{E_{yr}}$$

In this study, we consider technologies $tech \in \{wind, solar, BESS, thermal, geothermal\}$. The denominator, $E_{yr} = \int_0^{yr} dt\ D(t)$, is the total demand (energy) across the whole year, t is time. CRF is the annual capital recovery factor. C_{tech} and FOM_{tech} are the capital and fixed operations and maintenance cost of the technology (in units: *$/kW* and *$/kW/yr*), respectively. P_{tech} is the total installed capacity of the technology (in units: *kW*). F_{tech} is the total annual fuel cost (in units: *$/yr*) which depends on the amount of thermal generation dispatched. *VoLL* is the value of unserved energy (in units: *$/kWh*) and *USE* is the unserved energy (in units: *kWh*). *USE* needs to be calculated for a given installed capacity and demand profile, $D(t)$.

$$USE = \int_0^{yr} dt \max\left[0, D(t) - \sum\nolimits_{tech} S_{tech}(t)\right]$$

$S_{tech}(t)$ is the generation profile of technology which depends on the renewable resource profiles and the BESS dispatch. In the case of wind and solar, the generation profile is set by the product of the renewable resource profile $R_{tech}(t)$ and the total installed capacity: $S_{tech}(t) = P_{tech}R_{tech}(t)$. Note that $R_{tech}(t)$ depends on the regions in which the tech is built. The BESS dispatch can be charging [when $S_{BESS}(t) < 0$] or discharging [when $S_{BESS}(t) > 0$]. The total annual fuel cost is $F_{thermal} = \int_0^{yr} dt\ \ S_{thermal}(t)\ f_{thermal}$ where $f_{thermal}$ is the per *kWh* fuel cost. The optimal dispatch of BESS, thermal and hydro are determined through a simplified dispatch algorithm, which we describe later.

Under suitable assumptions, mathematical optimisation techniques can be used to find the **optimal supply portfolio** to meet demand (the least-cost technology mix). In the next section we outline our optimisation approach.

Methodology

Overview

Assuming demand is fixed, the LCODE is a function of the total amount of supply that gets built and how that supply is dispatched. The objective is to find the values of installed capacity, P_{tech}, and battery storage duration, $\mathrm{duration}_{BESS}$, that minimise the LCODE, for a fixed demand profile $D(t)$, renewable resource profiles $R_{tech}(t)$, technology costs C_{tech}, capital recovery factor, and *VoLL*.

The nonlinear objective function is:

$$LCODE[P_{tech}, \mathrm{duration}_{BESS}]$$

A key feature in the analysis is that each region has its own renewable resource profile, meaning the mix of wind and solar capacity varies across locations. As the number of technologies and regions increases, the situation can quickly become complex. To keep it manageable, we break the analysis into three steps:

1. Optimise the regional build fractions of solar
2. Optimise the regional build fractions of wind
3. Optimise the total generation mix across both regional and technological dimensions (including BESS dispatch) using the regional breakdowns calculated in steps 1 and 2.

Because capital costs differ by technology, but not by region, steps 1 and 2 can be solved independently. Step 3 can be solved using regional build fractions found in steps 1 and 2. This reduces the analysis down to an optimisation across only the technologies, rather than the regions and technologies, which keeps the analysis tractable.

Optimising the regional build fractions

The renewable resource profile for a technology is a function of the regional build fractions, $\tilde{a}_{tech,region}$:

$$\tilde{R}_{tech}(t) = \sum_{region} \tilde{a}_{tech,region} \, R_{tech,region}(t)$$

The final regional build fractions are normalised such that $a_{tech,region} = \frac{\tilde{a}_{tech,region}}{\sum_{region} \tilde{a}_{tech,region}}$, and $R_{tech}(t) = \frac{\tilde{R}_{tech}}{\sum_{region} \tilde{a}_{tech,region}}$. With this normalisation, the generation profile is set by $S_{tech}(t) = P_{tech} R_{tech}(t)$. Finding the regional build fractions is reduced to finding the renewable resource profile that most closely matches the demand profile. That is, we look for values $\tilde{a}_{tech,region}$ that minimise the objective function below:

$$O\left[\tilde{a}_{tech,region}\right] = \int_0^{yr} dt \, [\tilde{R}_{tech}(t) - D(t)]^2$$

The least-squares minimisation is trivial. This heuristic approach is applied to both wind and solar technology, across all regions included in the case definition.

Dispatch algorithm

Dispatchable generation technologies include thermal, hydro and batteries. These technologies require an algorithm to determine how they get dispatched. Here, we assume these technologies are dispatched according to a hierarchy where hydro is dispatched first, batteries second, and thermal third. Any residual unserved energy is treated as such. The dispatch algorithm is deterministic; it does not consider trade-offs between present and future costs.

Hydro dispatch

The hydro dispatch is modelled using a simplified 'perturbation' approach. The starting point is the existing hydro dispatch pattern, which is assumed to meet current demand. We then consider how this pattern adjusts to firm wind and solar generation and to meet peaks in additional demand. When wind, solar and geothermal generation create a surplus, hydro output is reduced, effectively converting this excess energy into 'virtual rain' stored in hydro lakes. When demand exceeds available generation, hydro output increases to support the system.

The focus is on how the system responds to the marginal unit of additional demand. We consider only the existing hydro fleet, whose ability to meet this marginal demand declines as overall demand grows. In the baseline case, we assume that hydro can meet 40% of the marginal load, with an effective storage capacity equivalent to 100 hours of full output. These assumptions are represented as an equivalent 'battery', using the dispatch algorithm described in the 'Battery dispatch' subsection, but without round-trip efficiency losses.

To give a sense of scale, an additional 20 TWh of demand corresponds to an average increase of around 2.3 GW over the year. Under our assumptions, this equates to roughly 900 MW of additional capacity and 100 GWh of storage available from existing hydro for short-term (intra-day and intra-week) firming.

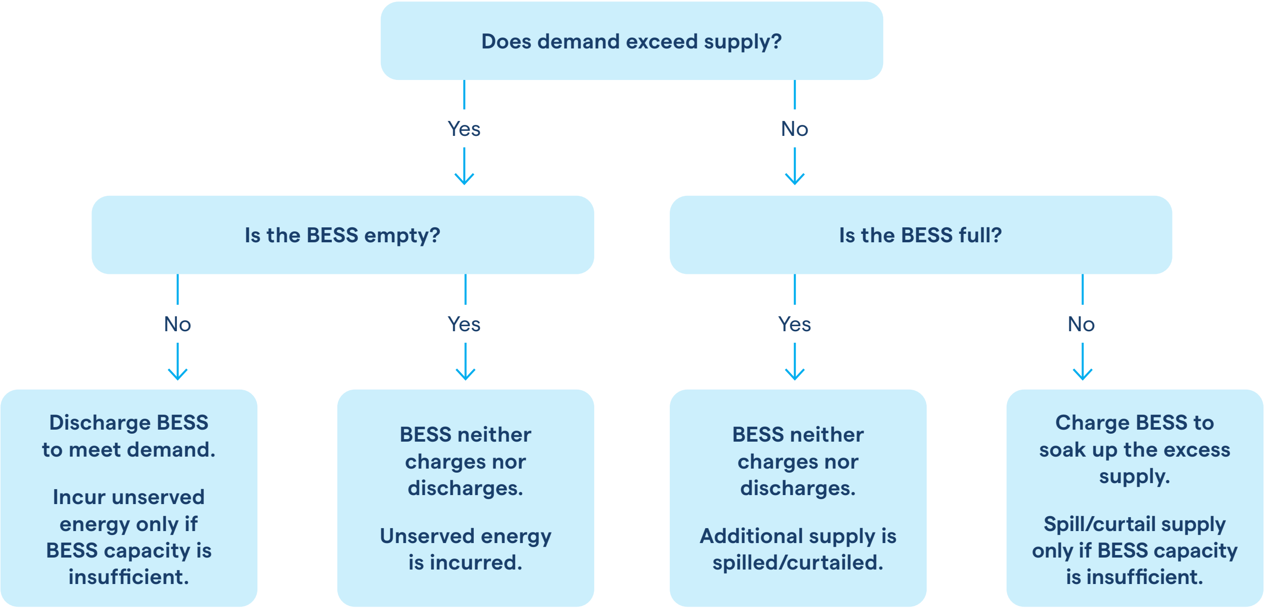
This approach relies on averages and simplifying assumptions, and is not intended to inform investment or policy decisions. Instead, it provides a conceptual illustration of how surplus renewable energy can be converted into 'virtual rain' in hydro storage. In practice, the outcomes would depend on detailed inflows and operational constraints, which are beyond the scope of this analysis. To account for this, we use sensitivity analysis to test the impact of our assumptions and present results as a range. We have also compared these results with those from more detailed modelling.

Battery dispatch

The battery dispatch is a decision variable in the system operation. This depends on three triggers:

1. Whether supply from wind, solar and geothermal exceeds, or falls short of, demand.
2. The state of charge, x_{soc}, places a limit on the amount of energy that can be stored $0 \leq x_{soc}(t) \leq 1$. When $x_{soc} = 0$ the battery is empty and when $x_{soc} = 1$ the battery is full. The normalisation links back to the product of the capacity and duration of the battery. The state of charge is determined by the dispatch $x_{soc}(t) = x_{soc}(0) + \int_0^t dt' S_{BESS}(t') / (P_{BESS} \times \mathrm{duration}_{BESS})$. The initial state of charge is set to 1.
3. The round-trip efficiency of the battery means that 10% of the energy used to charge it is lost.

The dispatch occurs according to the decision tree set out below:



Thermal dispatch

The thermal dispatch of the system is set by the minimum of the thermal capacity, $P_{thermal}$, and the difference between load and supply. In this way, thermal generation catches all unserved demand (up to its maximum capacity) after hydro and batteries have exhausted their ability to firm the system.

Optimising the total generation mix

To optimise the overall generation mix, we use MATLAB's built-in fminsearch function, which is well suited to multi-dimensional problems. To reduce the risk of converging on local minima or suboptimal solutions, we initialise the algorithm with a range of random and strategically chosen starting points.

$$LCODE[P_{tech}, \mathrm{duration}_{BESS}]$$

This becomes difficult to solve if regional build fractions are included directly within the optimisation. To simplify, we assume that the regional allocation of wind and solar capacity has already been determined through a separate optimisation step, and we treat these proportions as fixed.

We use a combination of random and strategically selected initial conditions, including technology-biased starting points, to improve robustness. In general, the algorithm converges reliably and is not highly sensitive to the initial conditions. While convergence to local minima can occur in some edge cases, this is rare and can be managed through the choice of initial conditions.

Data sources and assumptions

Geothermal, wind and solar resource data

The geothermal resource is assumed to be a constant supply at 95% of $P_{geothermal}$.

The wind and solar resource come from the MERRA-2 global reanalysis database[10] (the output from global atmospheric simulations). Hourly time series data has been created for wind speed and solar irradiation across 18 regions defined in the wind generation stack report[11]. The 'baseline' calculations for Cases 1-5 use Auckland solar and wind resource data.

To correct systematic errors[12] known to exist when inferring wind speed observations from reanalysis data, we have used a constant capacity factor value that came from regional wind data (120m hub height measurements)[13].

The capacity factors are shown in the table below.

Table 8: Capacity factors for wind and solar

Region	Wind	Rooftop solar	Utility solar
Eastland	39%	22%	25%
Northland	38%	22%	26%
Far North	38%	23%	26%
Auckland	37%	22%	25%
Waikato	35%	21%	24%
Bay of Plenty	33%	20%	23%
Central Plateau	39%	20%	22%
Hawkes Bay	37%	22%	26%
Taranaki	37%	21%	24%
Manawatu	40%	21%	23%
Wairarapa	46%	21%	24%
South Wairarapa	42%	21%	25%
Wellington	44%	21%	24%
Marlborough	34%	22%	25%
West Coast	22%	18%	19%
Canterbury	41%	21%	24%
Southland	39%	18%	20%
Otago	39%	19%	22%

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[10] https://gmao.gsfc.nasa.gov/gmao-products/merra-2/
[11] https://www.mbie.govt.nz/assets/wind-generation-stack-update.pdf
[12] https://www.sciencedirect.com/science/article/pii/S0360544216311811?via%3Dihub
[13] https://www.mbie.govt.nz/assets/wind-generation-stack-update.pdf

Technology cost data

We considered New Zealand-specific technology costs, set out in the 2025 generation stack report[14]. The relevant estimates are listed in the table below.

Table 9: Estimated costs for New Zealand-specific technologies

TE	Capital costs C_{tech}	Fixed O&M cost FOM_{tech}
Wind	\$3,400/kW	\$43/kW/yr
Solar (utility)	\$1,900/kW(AC)	\$27/kW/yr
Solar (rooftop)	\$2,100/kW(AC)	\$27/kW/yr
BESS (power)	\$771/kW	\$7.8/kW/yr
BESS (storage)	\$465/kWh	\$8.6/kWh/yr
Geothermal	\$6,700/kW	\$160/kW/yr
Reciprocating thermal	\$1,700/kW	\$25/kW/yr

The full cost of a BESS is determined by the combination of capacity and storage duration (*d*):

$$C_{BESS}(d) = C_{BESS,capacity} + d\ C_{BESS,storage}$$

For example, this sets the cost of a two-hour battery at \$1,700/kW and a 10-hour battery at \$4,700/kW. The round-trip efficiency of BESS is assumed to be 90%.

Value of unserved energy

We define the value of unserved energy (VoLL) using the value specified in Schedule 12.2 of the Electricity Industry Participation Code 2010. This value is set at \$20/kWh. We also test sensitivities using values of \$10/kWh and \$30/kWh. While this estimate is based on a study from 2004 and may be somewhat dated, subsequent analyses have broadly supported its order of magnitude[15, 16].

Capital recovery, plant lifetime, and WACC

We assume capital recovery occurs through equal annual payments (annuities) over a 20-year period, approximately the plant lifetime. The weighted average cost of capital (WACC) is 7%. The capital recovery factor is determined by:

$$CRF = WACC\ \frac{(1 + WACC)^n}{(1 + WACC)^n - 1}$$

In this equation, *n* denotes the plant lifetime.

Demand profile

The baseline calculations have used historical demand patterns aggregated to a local (substation) level in Cases 1-5 and a national level in Case 6.

The sensitivity analysis uses 1) a ‘flat’ demand pattern with no daily or seasonal pattern and 2) a ‘daytime only’ demand pattern which has demand between 7:00am and 8:00pm with no seasonal pattern.

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[14] 2025 Generation Stack Report

[15] Value of Lost Load (VoLL) Study - June 2018.pdf

[16] Estimating the value of lost load in New Zealand