Cost-benefit analysis of distributed energy resources in New Zealand

A report for the Electricity Authority

David Reeve, Toby Stevenson, Corina Comendant
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Glossary

Abbreviation	Stands for
BESS	Battery electric storage system
CBA	Cost-benefit analysis
DER	Distributed energy resources
DR	Demand response
DSM	Demand-Side Management
EDB	Electricity distribution business
EECA	Energy Efficiency and Conservation Authority
EV	Electric vehicle
FIR	Fast Instantaneous Reserve
FK	Frequency keeping
IPAG	Innovation and Participation Advisory Group (an advisory group to the Electricity Authority)
IR	Instantaneous reserve
LV	Low voltage
MFK	Multiple frequency keeping
NREL	National Renewable Energy Laboratory
O&M	Operations and maintenance
OCGT	Open cycle gas turbine
PV	Photo voltaic (solar panels)
SIR	Sustained Instantaneous Reserve
SO	System Operator
THD	Total Harmonic Distortion
TOU	Time of use
V2G	Vehicle to Grid
WUNIVM	Waikato and Upper North Island Voltage Management (project)

Executive summary

Distributed energy resources (DER) refer to any resource that provides or manages energy that is distributed. Technically, it includes the utilisation of demand response, access to vehicle batteries on charge and management of rooftop solar and battery units. However, the term also refers to harnessing the resource which is deployed in large numbers and at small scale throughout the distribution network.

For some time, the Electricity Authority has sought to release the potential contribution DER can make to a secure electricity system. This has been the main focus of the work conducted by the Authority's Innovation and Participation Advisory Group (IPAG). The challenges start with the fact that current arrangements tend to reflect wholesale supply to consumers starting with generators through transmission, distribution and retail, whereas DER can supply consumers directly or backfeed to the distribution network, and maybe even transmission. The energy can then either be traded on the wholesale market or, potentially, through peer-to-peer transactions. Reorientating the system will require a rethink of commercial arrangements and access rights.

There are many valuable services that DER can potentially provide to the electric power system. If DER is recognised for these value streams, then this can help ensure that DER is invested in and is designed to provide these services. If DER can be harnessed, it can reduce the need for thermal peaking in the electricity market and can also offset the need for new lines investments and generation. It can contribute to ancillary services including instantaneous reserves, frequency keeping, voltage support, harmonics, and inertia.

We were asked to develop a cost-benefit analysis (CBA) of DER if it were to realise its unfettered potential. In the ideal scenario, all of the DER potential is harnessed. In the baseline scenario (counterfactual), only some of DER is utilised as not all potential services are provided under existing arrangement.

In the ideal scenario, we have forecast what DER could be deployed in place of traditional ways of providing services, such as through building peaking plant, transmission, and distribution lines. Where DER could provide these services, there is an increase in value (economic surplus) through achieving at least the same level of service at cheaper cost. For DER to provide these services, all problems with access, pricing, and coordination would need to be addressed.

It is worth noting that there can be a difference between where the value of DER accrues and where costs of integration might occur. DER provides some service to distribution networks but also services not directly related to distribution. Nevertheless, DER must be connected and integrated into the distribution network.

The baseline scenario takes into account that there will be some utilisation of DER in the future. However, without all problems with access, pricing, and coordination being addressed, not all potential services will be provided and more expensive options for services will not be avoided. Our counterfactual assesses the economic surplus that could be realised by DER under existing arrangements, and, compared to the factual, identifies the services that could not be provided by DER without action from the Authority.

This allowed us to calculate the total net economic surplus achievable between what would happen anyway and the full potential of DER. This is the monetised value of the total wellbeing to NZ from DER penetration. If the difference between benefits and costs increases (i.e. benefits minus costs is greater than it was before), then there is an improvement in the net benefit or economic surplus.

The total economic surplus is the sum of consumer surplus and producer surplus. Consumer and producer surplus can be determined based on the supply and demand curve.

A demand curve approximates the consumers' willingness to pay by showing how much consumers would be willing to consume (in aggregate) if electricity were free, and then the rate at which consumers would purchase less as the price increases.

A supply curve shows that generators would not supply if electricity were free, and then the rate at which supply would increase as the price rises. The intersection of the supply and demand curves is the point of market equilibrium and demonstrates the quantity and price where consumers (in aggregate) would purchase, and the generators (in aggregate) would supply. This is known as the clearing price.

The clearing price sets the boundary between the producer surplus, who profit when they supply at a cost less than the clearing price, and the consumer surplus, who benefit when they take supply at a clearing price less than their willingness to pay. Usually, where buyers and sellers have equal information and are free to shop around and transact, a single price for product or service is discovered where the demand curve intersects with supply. However, ideal transacting conditions do not always exist in electricity markets.

Figure 1 sets out the economic surplus in the baseline scenario and Figure 2 the economic surplus in the ideal scenario.

Figure 1: Illustration of total economic surplus where DER is harnessed to a limited degree

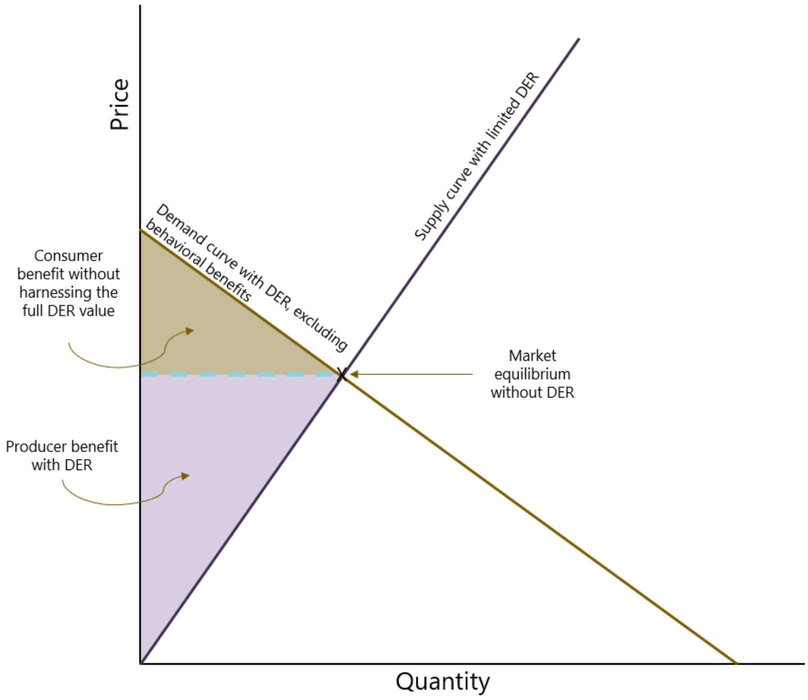
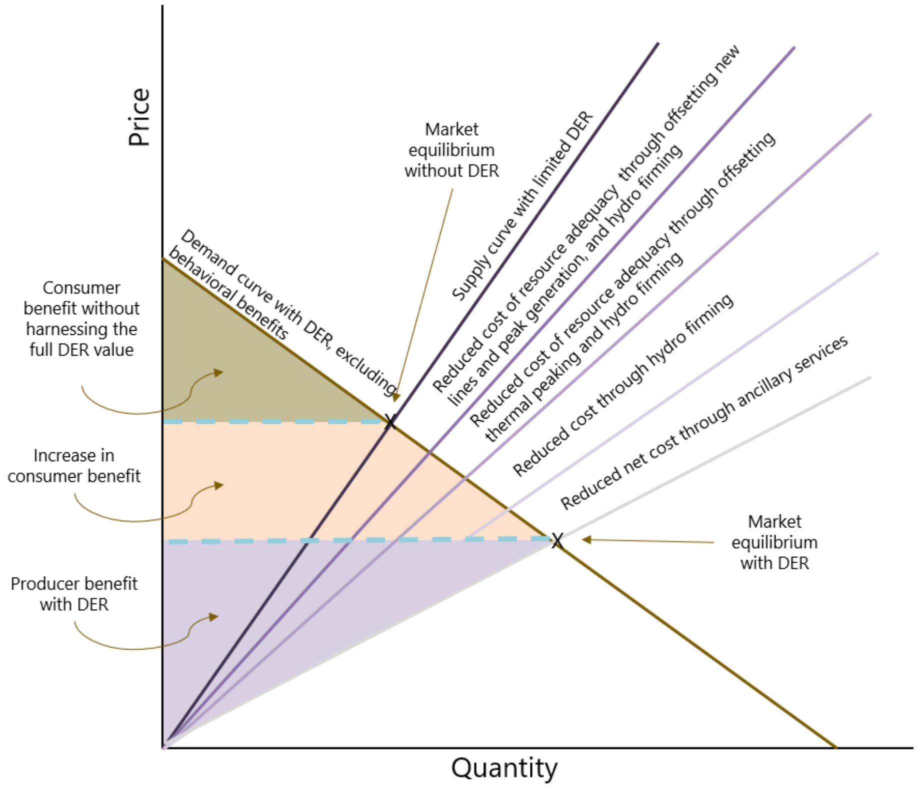


Figure 2: Illustration of total economic surplus where DER is fully harnessed



The area below the demand curve and over the market price represents the benefit to consumers, who would have been willing to pay more (on average). In the context of DER, it reflects the total wellbeing of all participants in the electricity market as a result of the DER value streams being harnessed. For a particular value stream, it reflects the difference between the value of that stream and the value of the next more expensive stream. In this case, market participants obtain the benefits from both value streams but only pay the lower cost. This creates a surplus.

The area above the supply curve up to the price represents the benefits to producers as DER owners would have been willing to sell for less (on average). Because the producers are also DER owners, these benefits are also referred to as prosumer surplus. DER services are compensated in the market based on the value streams (service) they provide. The producer surplus reflects the difference between the value of a DER stream and the cost of providing that service.

In the ideal scenario, the movement in the supply curve is due to the value streams accessed by DER. This leads to an increase in consumer and producer surplus.

In Table 1 we show our calculated consumer surplus, producer (prosumer surplus) and total net economic surplus.

Table 1: Summary estimates of economic surplus from DER uptake, net present value 2021-2050

	$ billion, net present value
Consumer surplus	$2.8
Producer (prosumer) surplus	$4.1
Total economic surplus	**$6.9**

In our estimate of the total economic surplus from DER, we have assumed DER uptake will grow with an increase in population and household growth, to the extent the market allows different DER value propositions to be harnessed. We have not considered behavioural factors that can further increase DER uptake as a result of amenity premia that DER can provide in our analysis above. We have assessed the potential value of this increased amenity value as a sensitivity. The amenity premium can manifest itself in at least three ways:

- **Increased use of smart appliances** – People are purchasing appliances where the full value of energy management control may not yet be able to be used. By enabling such services, the value of consumers' purchases in smart appliances will increase.
- **Social peer-to-peer** – Overall, peer-to-peer trading of surplus DER contributions should reduce the cost of electricity services to consumers. However, as some people would like to transact their surplus resources freely on a peer-to-peer basis, this suggests that some people value assisting friends, family, and/or social causes more than reducing their own costs. This would contribute a value add from peer-to-peer trading.
- **Increased choice and control** – Some people put a high value on self-sustainability, choice, being able to see their household system, and controlling it. Increasing the options and value sources for consumers will also increase this value.

Methodologically, these amenity premia will shift the demand curve, increasing the consumer benefit.

Based on our modelling assumptions, we have determined that for every 1% increase in the y-intercept, total net economic surplus increases by 1.15%. In other words, the estimates are sensitive to assumptions on consumer's responses to the amenity premia that DER can bring in addition to the values that can be harnessed in the electricity market. Thus, a 5% change in the y-intercept raises the present value of the total DER economic surplus from $6.9 billion to $7.3 billion. A 10% change in the y-intercept raises the present value to $7.7 billion.

1. Introduction

The Electricity Authority has actively pursued an environment for integrating DER for some years. The IPAG has had DER potential on its agenda since its inception. We actively supported the IPAG's Equal Access work.

To support this, we have been asked to develop a cost-benefit analysis of DER if it were to realise its unfettered potential against a future where it does not. There are many problems in fully realising the value of DER due to the different nature of this technology compared to the technologies and market dynamics for which the industry and the regulatory arrangements were designed.

1.1 The context for this report

Current arrangements tend to be designed around wholesale supply to consumers through transmission, distribution and retail, whereas DER can supply consumers directly or backfeed to wholesale 'backwards' through distribution, and maybe even transmission. This not only creates some commercial problems but problems with managing security of supply.

The Authority has shared with us the key themes it is using for developing its thinking on DER integration. These themes are listed below, and we have mapped the 13 issues IPAG identified that might prevent full utilisation of DER to these themes. The themes and issues do not perfectly match up and so there is some duplication of the issues:

- **Information on power flows and capacity** – investors need information to make informed business decisions and to compete on a level playing field.
    - **IPAG issues.**
    - Key network information is not collected and/or made available to DER providers.
    - Providers and procurers of DER can't see DER "market" information.
- **Connection and operation standards** – additional standards may be needed to address a range of power quality issues associated with increased competition and participation in the flexibility market.
    - **IPAG issues.**
    - Technical specifications are not consistent or in some cases adhered to.
    - Distributors may restrict technologies or network users.
    - Distributors are not confident that DER can assist with service quality or is viable as a network alternative.
    - Security and reliability at risk if DER use by transmission and distribution in conflict.
- **Market settings for equal access** – competition for contestable services can be improved by removing barriers to entry and levelling the playing field. Competitive flexibility markets can improve efficiency decreasing the overall costs for consumers.
    - **IPAG issues.**
    - Distributors may restrict technologies or network users.

  - Transaction costs for facilitating DER trade are high.
  - Distributors may favour in-house or related party solutions.
  - Distributors may favour network solutions.
  - Distributors may misallocate costs and revenues.
- **Operating agreements** – the costs of developing and negotiating contracts for flexibility services is high for both flexibility traders and distributors. Distributors also have a stronger negotiating position as a natural monopoly, which could deter flexibility traders from entering the market and reduce competition.
  - **IPAG issues.**
  - Transaction costs for facilitating DER trade are high.
  - Security and reliability at risk if DER use by transmission and distribution in conflict.
- **Capability and capacity** – some distributors may not have the capability and capacity to coordinate and integrate DER, which could lead to not all consumers benefiting from new technologies and innovation in the sector.
  - **IPAG issues.**
  - Distributors are not confident that DER can assist with service quality or is viable as a network alternative.
  - Security and reliability at risk if DER use by transmission and distribution in conflict.
- **Efficient price signals** – Distribution prices do not always reflect network conditions and costs, which prevents network users from making informed decisions.
  - **IPAG issues.**
  - Distribution pricing does not signal the cost of DER to network operation (congestion and voltage excursions for example) or its value to distributors.
  - Part 4 Incentives appear to be poorly understood.[1]
  - Distributors' DER investments are treated as regulated capital but the planning and operating services provided are contestable.

These problems suggest that interventions are required by the Authority in the form of rule changes and possibly market design. Without such interventions, DER may still be deployed in significant volumes but may not:

- be deployed in as much volume as it economically should
- provide all the value it could (mainly through offsetting other costs in the supply of electricity to consumers).

[1] Part 4 of the Commerce Act 1986. However, the intended incentives really arise from the implemented Input Methodology and are not specified in the Act. This issue is described more fully at 2420102C-Commerce-Commission-material-on-regulation-and-incentives-for-IPAG.pdf (ea.govt.nz). Essentially, an EDB's input costs can include third party service. Price-quality regulation incentivises lower costs, and the regime's settings allow an EDB to keep a greater share of savings from early cost reduction and reducing opex costs over capex. Obviously, non-financial barriers are not within the Commerce Commission's jurisdiction.

This CBA is an assessment of the potential loss of future value if such interventions are not implemented.

1.2 What is DER?

DER technically refers to any resource that provides or manages energy that is distributed. Technically, this means DER is deployed in large numbers and at small scale throughout the distribution network. Based on our previous work (Reeve, 2020), the major contribution of DER include:

1. Demand Response (DR) – smart home management and appliances that actively manage household consumption, including smart EV charging.

2. Vehicle to Grid (V2G) – the use of EV batteries to inject back into the power system when needed.

3. Residential rooftop solar and battery ($PV+B_r$) – residential-scale rooftop solar PV with an integrated battery.

4. Commercial rooftop solar and battery ($PV+B_c$) – commercial building-scale rooftop solar PV with an integrated battery.

1.3 Building on previous work

This report builds on our previous report for Transpower, which assessed the potential value of distributed energy resources in New Zealand (Reeve, 2020). For this report, we have updated assumptions on current and future costs of DER, as well as on the potential uptake (MW) of DER in the future. The key updates on potential uptake are for:

- smart appliances, using assumptions from BEC2060 Kea scenario[2]
- residential and commercial PV and battery uptake based on solar driver-tree and battery driver-tree data from (Transpower, 2020b).

[2] TIMES-NZ Data from https://www.bec2060.org.nz/downloads

2. Constructing the CBA

Our economic assessment is based on a forecasted ideal world with DER fully utilised to its capability and a forecasted baseline, or what would happen anyway if nothing fundamental were to change. We do not develop full scenarios for either forecast. Our ideal scenario is based on Transpower's Whakamana i Te Mauri Hiko work and is the assessment of what DER could be deployed in place of traditional ways of providing service, such as through building peaking plant, transmission, and distribution lines. Where DER could provide these services, then there is an increase in value (economic surplus) through achieving at least the same level of service at cheaper cost. For DER to provide these services, all problems with access, pricing, and coordination would need to be addressed.

The counterfactual (the baseline scenario) does not simply remove DER. There will be DER in the future and, even without recognising all value streams, the volumes could be large. However, without all problems with access, pricing, and coordination being addressed, then not all potential services will be provided and more expensive options for services will not be avoided. Our counterfactual assesses which services could not be provided by DER without action from the Authority and evaluates the reduced economic surplus, while keeping the economic surplus that could still be realised by DER under existing arrangements.

2.1 The value of DER in our baseline scenario

Under the baseline, the only service we have assessed that DER can provide in significant volumes is 'Resource adequacy – offset thermal peaking'. The wholesale electricity market currently provides peak energy signals, and energy companies or aggregators could coordinate DER to respond to wholesale prices. Other services could only be provided under current arrangements in limited volumes.

We note that Aurora Energy has entered an arrangement with SolarZero to provide Non-Network Services to offset distribution and transmission capacity. While this is a clear case of DER being used to also offset lines capacity, we do not think this is likely to be widespread for two reasons:

1. Lines companies currently have incentives to prefer their own investments over alternatives.
2. Lines companies are responsible for security and reliability in their distribution networks and are going to prefer solutions they know work currently.

Nevertheless, the use of DER to offset lines capacity could be more widespread than we have assessed, and so we have modelled this as an uncertainty.

Some services, such as instantaneous reserve (IR), could be relatively easily opened to suitable DER, but other services would require significantly more coordination and incentives.

In the future, with global demand and the relatively low cost of power electronics and programming, DER equipment will likely have the functionality required to provide the services described above. In the short term, however, cheaper inverters are likely to be used unless the value of services provided is allocated to the providers of the service. Getting the pricing right will incentivise DER equipment of suitable specification to provide services and will likely make more DER economic.

We have not attempted to assess how much more DER might become economic and, therefore, our cost-benefit could be understated. However, there is uncertainty about our DER volume forecasts, and so a conservative approach on increasing the forecast for an increase in the effective price paid to DER is warranted.

Much of the contribution of DER comes from DR either from smart appliances or the smart charging of EVs. Electricity pricing, at the margin, is not likely to be a key driver in the take up of EVs. We have made a conservative estimate of take-up of smart appliances and have included a sensitivity analysis if utilisation were to be higher. It is plausible that by 2035 every appliance will be a smart appliance and the pricing of DER value will not affect take-up but only utilisation.

Investment in solar PV and batteries is probably the most likely to be sensitive to DER value pricing. Again, we have not assumed that more PV and batteries will be installed in the ideal scenario (just that more of it is utilised for other value streams), but we may have overstated the level of solar and PV deployment. Most of our assessed CBA value comes from DR, where we are confident that our assessment is conservative.

2.2 The value of DER in the ideal scenario

The supply curve for DER is complicated because not all DER can meet demand across the whole demand curve. For example, solar PV without a battery cannot offset lines or peak generation because it cannot be relied on to generate during peaks. We have set up a matrix of value streams in the demand curve and configurations of DER to correlate where those configurations can add value. Only DER that can provide the services at the corresponding segments of the demand curve are used in the supply curve at those points. The value streams in the matrix are described in section 3.

Table 2: DER capability matrix for 2035

	Frequency keeping	Instantaneous reserve	Resource adequacy – offset thermal peaking	Resource adequacy – offset lines and transmission	Voltage management	Harmonic filtering	Inertia	Resource adequacy – hydro firming
EV storage	✓	✓	✓	✓	X	Cost	✓	X
EV storage + PV	✓	✓	✓	✓	✓	Cost	✓	✓
Demand response - residential	X	✓	✓	✓	X	Cost	✓	X
Battery - residential	✓	✓	✓	✓	✓	Cost	✓	X
Battery - commercial	✓	✓	✓	✓	✓	Cost	✓	X

	Frequency keeping	Instantaneous reserve	Resource adequacy – offset thermal peaking	Resource adequacy – offset lines and transmission	Voltage management	Harmonic filtering	Inertia	Resource adequacy – hydro firming
PV system - residential	Limited	Limited	X	X	✓	Cost	Limited	X
PV system - commercial	Limited	Limited	X	X	✓	Cost	Limited	X
Battery + PV system - residential	✓	✓	✓	✓	✓	Cost	✓	✓
Battery + PV system - commercial	✓	✓	✓	✓	✓	Cost	✓	✓

Source: Sapere analysis.

In Table 2 a tick means that the DER technology combination in that row can provide value to the service in that column. A cross means that it cannot. Some combinations can provide some services but only on a limited basis. Harmonic filtering is the only service for which DER probably adds net costs in all scenarios.

Just because a DER category above can provide a service does not mean that it features in our analysis. The DER must also be cheaper than the existing alternative to 'clear' and have available forecasted capacity. It should be noted that, even where a DER category can provide service, not all DER of that category can necessarily provide the service. For many services, the DER must be operationally ready, in the right place, and used at the right time. We have tried to cater for this in our assessments of the available volume.

Harmonic filtering is included in our assessment, but it is a net cost under all scenarios when DER deployment reaches high levels.

Solar PV can potentially provide IR and inertial services by partially loading but only if the sun is shining. In this way solar PV can also potentially provide an option for hydrofirming (providing energy in dry years). Solar PV can be held in dry year reserve, the same way that thermal plant is currently. However, as solar PV is not available during winter evening peaks, the use of solar for hydrofirming creates higher peak needs unless it is paired with a battery system.

3. The value DER can provide

3.1 Resource adequacy

We define resource adequacy as the electricity system's ability to incentivise the most efficient investment in solutions that can ensure that electricity demand can be reliably met at every point in time and over time, i.e. the system incentivises the most efficient investment to meet peak and dry year energy needs (hydrofirming). Historically, the peak-energy need has been substantially addressed through flexibility on the supply side (with the conspicuous exception of load control). In the future, consumers – households, commercial or industrial users – will become much more involved in the decision making around how and when their DER is utilised, and the price at which they are prepared to respond. We expect the bulk of the management of the DER will be conducted by aggregators or distributors or retailers rather than actively conducted by the consumers.

Meeting New Zealand's emissions reduction commitments will require significant electrification of the economy, particularly transport and industrial process heat. Without changing the way we generate and consume electricity, electrification will cause a significant increase in peak demand, requiring additional electricity system investment.

New Zealand has traditionally been able to meet peak demand with its flexible hydroelectric schemes. Meeting peak demand in New Zealand in the future, however, could be particularly challenging due to potential peak demand growth and the increasingly intermittent renewable generation base. This is essential for New Zealand to meet its targets for greenhouse gas emissions reductions. Therefore, more solutions will be required to respond cost-effectively to peak demand pressures.

Demand-Side Management (DSM) is the active management of demand consumption and/or the demand profile. It could be argued that all DER is DSM, but we use the term to refer to DER where its normal use is to manage demand.[3] The benefits of using DSM solutions include increased network asset utilisation, increased ability to accommodate intermittent generation, and enhanced network flexibility in the face of uncertain future development. Together, these benefits will to reduce the overall investment required in generation and network assets.

We consider the value of DSM mechanisms by estimating avoided cost of providing power during peaks through traditional supply chains. This is done through:

- management of peaks through technology such as battery storage, demand-side response (e.g. smart appliances), etc
- management of peaks through smart EV charging (and time of use (TOU))

[3] We note that long-term DSM also includes energy efficiency. We have not considered energy efficiency as a DER, but it is critical for emissions reductions.

3.1.1 Reduce the need for existing thermal peaking

We have separately considered two aspects of peak resource adequacy, which essentially break down to the value of 'peaking' DER in the existing power system and the value in the future power system.

In the current power system, the peaking role is taken first by hydroelectricity and then, at the margin, by thermal generation. As DER can be deployed to meet or offset peak demand, it can reduce the need for thermal generation in the peaking role (this, by itself, does not significantly reduce the need for thermal generation in dry years).

As DER accessing this value stream can only displace current thermal generation exclusively for the peaking role, there is limited volume that can be displaced.

Theoretically, as DER replaces remote peak capacity with local peak capacity, some transmission and distribution capacity might also be released. However, this is not certain and, even if it was, the redundant transmission and distribution capacity may be sunk costs that cannot be recovered.

3.1.2 Offset new lines investment and generation

Looking forward, as New Zealand's electricity demand grows to decarbonise transport and industrial heat, more peak capacity will be required. The more that DER can avoid the need for new peak capacity, the more there is avoided cost in new transmission, distribution, and generation.

In keeping with the Government's stated policy of 100% renewable electricity by 2030, we have assumed that the peaking generation avoided is partially loaded geothermal. However, it is increasingly likely that grid-scale batteries will be the primary competition for DER in this role.

As there is not currently a pressing need for new peaking capacity, but forecasts are for significant demand growth through to 2050, the volume available to be avoided through the deployment of DER increases over the period.

3.2 Ancillary services

3.2.1 Instantaneous reserve

Instantaneous reserve (IR) is generation that is held in reserve or load that can be interrupted in order to halt a decline in system frequency caused by an unexpected supply interruption (e.g. due to generation or transmission interruptions). In New Zealand, two distinct IR products are procured in the wholesale market for each island separately.

- The Fast Instantaneous Reserve (FIR) is intended to counter an under-frequency event,[4] and is made up of spinning reserve and interruptive load. It must be provided within six seconds after the event and sustained for 60 seconds.

[4] E.g. due to the tripping of single or multiple generating units or HVDC trips in bipole or single pole mode.

- The Sustained Instantaneous Reserve (SIR) aims to recover frequency to or above 49.25 Hz after an under-frequency event. It must be provided within 60 seconds after the event and sustained for at least 15 minutes for spinning reserve or, if it is interruptible load, until the provider is instructed by the SO to cease the provision.

In the future, smart grid technologies are expected to make demand response, such as responsive load and storage (stationary or mobile batteries), available as a source of instantaneous reserve. Smart grid communication and control should enable a continuous demand response to an under-frequency event, which is in contrast to the current binary response of interruptible load afforded by relay technology that trips load at a pre-defined frequency (Transpower, 2015).

A study by Imperial College London[5] on NZ energy futures determined that there are mainly two flexible demand technologies that would be well placed to provide frequency response services – smart refrigerators and electric vehicles (Strbac, et al., 2012). For EVs, the service can be provided by controlling the charging of EVs, e.g. interruptible charging for a short period of time. For refrigerators, the service can be provided by changing the duty cycle of appliances.[6]

In addition to flexible demand, frequency management services could be also be provided by battery storage systems. A recent study on distributed battery energy storage systems in New Zealand shows that if such systems are appropriately configured, they can respond faster than current providers of instantaneous reserve, recovering frequency faster and stabilising the system with fewer oscillations (Transpower, 2019a).

3.2.2 Frequency keeping

Frequency keeping services are required to manage short-term supply and demand imbalances to ensure that the system frequency is maintained in each island within a normal band, i.e. between 49.8 Hz and 50.2 Hz. This service is usually provided by one or more generating units capable of quickly varying their output (hydro and thermal plants) in response to instructions from the System Operator. The range over which current frequency keeping providers must be able to adjust their output is known as the frequency keeping band. From 1 May 2016, this band is 15 MW in each island.[7]

While they are both frequency management services, FK and IR are different services. FK varies continuously to balance imbalances between supply and demand to try to keep the frequency close to 50 Hz between dispatch instructions. To do this in a stable way it is either provided by a single provider or coordinated by a central control system. IR restores frequency to a level after a loss of

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5 This study was commissioned by Meridian.

6 Domestic refrigerators generally keep the refrigerator temperature between two set points. Once the internal temperature reaches a pre-set maximum point value, the compressor starts and the refrigerator starts to cool, and stops when the refrigerator's internal temperature reaches the minimum required temperature. The cycle then repeats. The compressor typically has a duty cycle of 20% to 30.%. The inclusion of smart refrigeration control changes the refrigerator's duty cycle length as the frequency changes. A frequency drop due to loss of generation decreases the refrigerator's duty cycle, which in turn means that the refrigerators can contribute to frequency stabilisation by reducing their aggregate load. The need for the refrigerator to continue to contribute system balancing means that average energy use for each appliance should reduce as the system frequency reduces.

7 Previously, there was a 20 MW and a 10 MW band in the North Island and South Island respectively.

supply event. As it is provided quickly by multiple independent providers, to function in a stable way it deliberately does not try to restore frequency to 50 Hz. The level frequency restoration that is reached is determined by the stability characteristics of the plant dispatched to react to an event.

In New Zealand, there has been a progression in the way frequency keeping services have been provided, from an island-centric to a national procurement of service. Up until 2013, frequency keeping services were purchased by the System Operator from a single provider. Subsequently, dispatching of multiple frequency keeping providers (MFK) was introduced in 2013 and 2014 in the North Island and South Island respectively. Since the introduction of the new HVDC bipole control system in 2013, it has been possible to transfer frequency keeping between islands. Trials have been done to enable frequency keeping services to be procured from available providers at a national level, rather than at an island level. This is something that could be done in the future.

At present, only four generating companies meet the System Operator's technical and access requirements for MFK.[8] It is technically feasible for currently installed DER to meet the technical requirements, but the System Operator does not currently permit access below a certain size. On this basis, we assume that by 2035 the potential opportunity for DER to provide frequency keeping service is the entire frequency keeping band of 15 MW. However, over a very long-term horizon, it is almost certain that future dispatch technologies will be able to dispatch resources in real time, significantly reducing the need for FK. On this basis, we assume that by 2050 the value of DER providing frequency keeping is likely to be zero. The dispatch technology that achieves this will include faster supply response (including from DER), better real-time supply and demand prediction (through fast information and AI prediction), and faster optimisation and dispatch automation.

3.2.3 Voltage

In distribution networks, voltage can be the main driver of capacity restrictions. In this value stream, however, we are looking at the value DER can provide in controlling voltage. Voltage control requires significant investment in New Zealand. The upper North Island, as New Zealand's largest load region with little local generation, has significant investment in static voltage control and compensation in the transmission network and more is potentially needed to manage future demand growth. The upper South Island, while a much smaller load, has weak transmission and little local generation, and also has relatively significant investment in voltage management at transmission level.

Much of New Zealand has low population densities with distribution lines often having to serve many customers over long line distances. There is significant investment in voltage management in distribution networks as well.

DER can help manage low voltage in a couple of ways. DER can provide reactive power, potentially more flexibly than a synchronous machine and as well as a statcom. The most important way in which DER can add value to low voltage management is as an active generation source. If DER is encouraged to generate when voltage is low, which is also going to be when regional demand is high, then just the provision of active voltage will help lift voltage. However, DER could export reactive power as well.

[8] Mercury, Genesis, Contact and Meridian.

DER can also help with high voltage. By incentivising batteries to charge and demand response to consume when voltage is high and regional demand is low, DER could add load to network circuits and reduce their net capacitance. DER can also consume reactive power to help.

There is significant investment in voltage management within the transmission and distribution networks. Transpower has two major projects, one currently going ahead and one planned, for managing upper North Island voltage. Based on electricity distribution businesses' (EDBs) information disclosures to the Commerce Commission, there are 649 voltage-regulating transformers and 279 capacitor installations in the New Zealand distribution network as at the end of the 2019 disclosure year (Commerce Commission of New Zealand, 2020).

In 2020 there is insufficient DER to be able to make a meaningful difference in voltage management within distribution networks. However, with the levels of penetration of DER expected, even by 2035, DER should be able to assist managing voltage. The best voltage regulation probably comes through active generation from a battery or solar panel, but their inverters could vary reactive power output at any time. To assist with managing voltage the DER output has to not only be incentivised to invest in technology that can coordinate voltage and follow a stable voltage characteristic, but it has to be coordinated in real time to set up workable voltage profiles throughout the transmission and distribution networks. When utilised in this way, DER is not only helping to manage voltage but is also optimising the import and export capacity of the power system.

3.2.4 Harmonics

The New Zealand power system is not only designed to work on Alternating Current at 50 Hz, but it also needs the AC waveform to resemble, quite closely, a sine wave. Digital switching devices – as in electronic controllers, rectifiers, and inverters – can introduce a form of interference on the AC sine wave. The combined effect of these forms of interference is called Total Harmonic Distortion (THD). If THD gets high enough, many devices and items of electrical equipment can operate incorrectly or fail.

Harmonics is probably the only value stream where, if problems occur, it will be almost entirely due to DER. Therefore, in aggregate, harmonics may be a cost to DER. However, given differences in DER equipment performance there should be benefits in creating incentives to encourage higher specification DER and recover costs from poor performing equipment. This could also encourage harmonic filtering solutions where they are required.

So far harmonic problems have not occurred in New Zealand except in relatively isolated examples. This is despite the proliferation of electronic power supplies for appliances and equipment. We are not aware of harmonics causing significant problems overseas. This is probably because the electronic equipment meets international standards of limits on THD, and diversity of equipment probably also helps. Most of these electronic power supplies have also been relatively small compared to the total flow of electricity on the power system.

The power electronics associated with DER are significantly larger and, with enough DER deployed, harmonics could become a problem. We have included harmonic filtering costs associated with the level of DER deployment forecasted for 2035 and 2050.

3.2.5 Inertia

If there was no inertia in our power system, then any mismatch between supply and demand would cause the whole system to either stop dead or speed out of control instantly. Inertia is the characteristic of mass that resists changes in movement caused when force is applied to that mass. Traditionally, machines connected to the power system are effectively linked to the frequency of the power system and provide inertia.

Power electronics completely remove the relationship between a generator's mechanical speed and frequency, e.g. in the case of many wind turbines, or connect generating sources with no mechanical rotation, e.g. in the case of solar. These types of generating capacity provide no inertia, and the concern is that the replacement of inertia-less generation for machines that provide inertia will lead to uncontrollable swings in frequency for relatively low mismatches in supply and demand, such as when a generator trips off.

Significant inertia is also provided by the demand side. There are large numbers of electrical motors in the demand side ranging from industrial motors and pumps, to commercial (predominantly in heating, ventilation and air-conditioning), and to domestic appliances (again particularly in refrigeration, heat-pumps and air-conditioning). In the past these have mostly been induction motors giving way to synchronous permanent magnet motors. However, to improve efficiency, increasingly these synchronous permanent magnet motors are using inverter speed controllers, which use power electronics, and provide no inertia.

The power electronics in DER systems can operate so quickly that they could provide a very quick response to any changes in frequency. This is technically ultrafast reserve but could be designed to simulate inertia. Therefore, some DER can assist with the potential inertia problem.

Whether inertia will become a problem is, as yet, uncertain. It has been recognised overseas, and grid-scale battery banks are now being installed that can simulate inertia. As we do not know whether inertia will be a problem in New Zealand, we have not included it in our CBA. If inertia does become a problem, then the value potential of some types of DER will increase, and so will the cost-benefit of DER.

4. Description of method

4.1 Total economic surplus

The total economic surplus is the sum of consumer surplus and producer surplus. Consumer and producer surplus can be determined based on the supply and demand curve.

A demand curve approximates the consumers' willingness to pay by showing how much consumers would be willing to consume (in aggregate) if electricity were free, and then the rate at which consumers would purchase less as the price increases.

A supply curve shows that generators would not supply if electricity were free, and then the rate at which supply would increase as the price rises. The intersection of the supply and demand curves is the point of market equilibrium and demonstrates the quantity and price where consumers (in aggregate) would purchase and the generators (in aggregate) would supply. This is known as the clearing price.

The clearing price sets the boundary between the producer surplus, who profit when they supply at a cost less than the clearing price, and the consumer surplus, who benefit when they take supply at a clearing price less than their willingness to pay. Usually, where buyers and sellers have equal information and are free to shop around and transact, a single price for product or service is discovered where the demand curve intersects with supply. However, ideal transacting conditions do not always exist in electricity markets.

Figure 3 sets out the economic surplus in the baseline scenario and Figure 4 the economic surplus in the ideal scenario.

Figure 3: Illustration of total economic surplus where DER values are harnessed to a limited degree

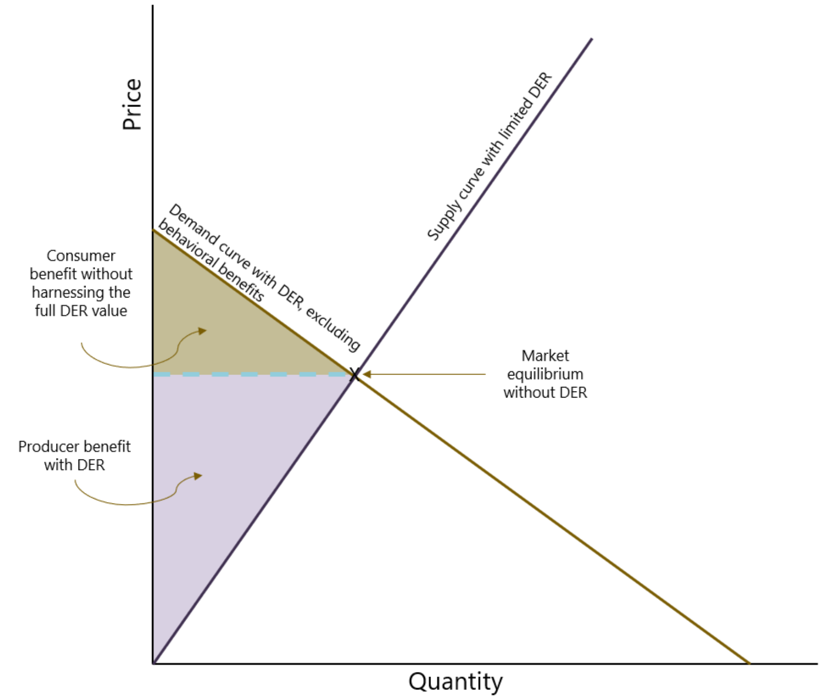
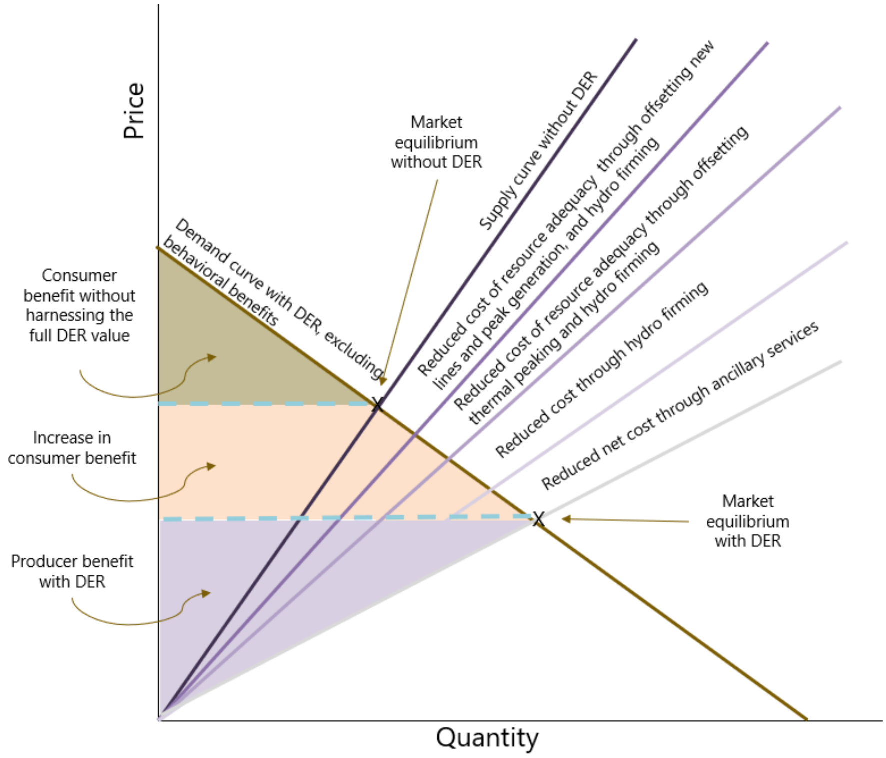


Figure 4: Illustration of total economic surplus where DER values are fully harnessed



The area below the demand curve and over the market price represents the benefit to consumers, who would have been willing to pay more (on average). In the context of DER, it reflects the total wellbeing of all participants in the electricity market as a result of the DER value streams being harnessed. For a particular value stream, it reflects the difference between the value of that stream and the value of the next more expensive stream. In this case, market participants obtain the benefits from both value streams but only pay the lower cost. This creates a surplus.

The area above the supply curve up to the price represents the benefits to producers as DER owners would have been willing to sell for less (on average). Because the producers are also DER owners, these benefits are also referred to as prosumer surplus. DER services are compensated in the market based on the value streams (service) they provide. The producer surplus reflects the difference between the value of a DER stream and the cost of providing that service.

In the ideal scenario, the movement in the supply curve is due to the value streams accessed by DER. This leads to an increase in consumer and producer surplus.

4.2 Building the demand curve

The demand curve was substantially constructed around our conclusions from the value streams. The price and potential volume of each value stream become a tranche in the demand curve. Values are stacked in the demand curve to capture all the value that could be realised by DER to meet demand at that point, i.e., value stacking where appropriate.

A problem in doing the value comparison is that some components, such as for transmission and distribution, are usefully priced in $/kW whereas energy production is usually defined in $/kWh or $/MWh. We needed to have a comparable unit. Overall $/kW was more useful but converting the variable costs of energy resources to a present value was potentially confusing on a time series analysis. In the end we landed on $/kW p.a. as a unit that was directly relevant to DER and gave an indication of the annual value that could be avoided in the year of analysis per kW.

The problem with comparing energy related services to peak demand related services is that you need to determine the after-diversity capacity factor to apply to convert one to the other. Capacity factor (also known as load factor) is the reason power systems are built larger than they seemingly need to be for a given energy demand. For example, a residential house consumes around 7,200 kWh of electricity per year. If this consumption were a flat, constant demand, then this energy could be supplied by a 0.82 kW connection. However, as a house could be running stoves, kettles, and heaters at the same time, a standard house connection is 13.8 kVA (a 60 A connection at 230 V).[9] The maximum energy a 13.8 kVA connection could supply in a year is 121,000 kWh. The capacity factor is the amount of energy that is supplied divided by the maximum energy that could be supplied, which is around 0.06 for residential houses. Residential loads tend to be the worst Commercial loads usually have better capacity factors, and large industrial loads get close to capacity factor of one, i.e., their average consumption is close to the capacity of their connection. Industrial connections tend to be highly utilised.

[9] kVA, or kilovolt-amps, is a measure of AC circuit capacity. Designed AC circuit capacity can also be higher than required for a given energy consumption due to a problem associated with alternating current called power factor. We have not explicitly considered power factor but, as we have based our assumptions where appropriate on VA (volt-amps), power factor is implicitly considered in our after-diversity capacity factor. This would also include an allowance for line losses, which therefore are also implicitly included.

If we look at distribution substation capacity, which are the connection points that supply a larger area such as a street or a few streets, then in 2020 32 TWh of electrical energy was supplied to distribution customers through 22 GVA of distribution substation capacity.[10] This gives a capacity factor of 0.17, or distribution substations are designed to provide 6 kVA of peak capacity to supply 1 kWh of annual energy on average. This capacity factor is higher than residential houses not just because the designed capacity includes commercial and industrial loads but also because of diversity. Diversity recognises that not all consumers do everything at the same time. Different patterns of behaviour and work/travel times mean that the aggregate peak of many consumers is never as high as their individual peaks.

At the national level 9.4 GW of generating capacity supplies 39 TWh of delivered energy.[11] This gives a capacity factor of 0.47, again partly due to the inclusion of large industrial loads but also because of diversity.

Generating plants also have a range of capacity factors. The national average capacity factor from above is 0.47, but this is made up of baseload plants (e.g. geothermal and some thermal) with capacity factors over 0.9, hydro-electric and wind plants with capacity factors from 0.3 to 0.7, and peaking plants with capacity factors from 0.05 to 0.2.

Picking the correct capacity factor for each of our potential value streams is problematic and would ultimately have required a number of judgements. Rather than pursue a detailed process to calculate each after-diversity capacity factor, which would have been an exercise in precision rather than accuracy, we instead chose a uniform conservative capacity factor of 0.15. This is a suitable target capacity factor for a peaking generating plant and is slightly worse than the average design after-diversity capacity factor for distribution substations.

Based on the above, the following points were identified on the value stack and added to the demand curve as appropriate to create the curve.

4.2.1 Total power system cost

The point total grid system cost was based on a high retail electricity cost of $300/MWh. Converted in to $/kW p.a., $394/kW is the price at which it is cheaper to purchase entirely from the grid rather than use DER. At any price below this, DER can start to economically offset power system costs.

4.2.2 Frequency keeping

DER is currently unable to provide frequency keeping services and so it is not added to the 2021 demand curve. We also assume that by 2050 market solvers, dispatch and control systems will be so fast that frequency keeping will no longer exist as a service. This is the logical conclusion for a frequency keeping band that is steadily reducing.

We have assumed that frequency keeping will remain as a service in 2035 at about the same level as today. Using 2019's annual frequency keeping costs of $1.1m and an operating band of 15 MW gives

[10] From the Commerce Commission's disclosures on lines companies at www.comcom.govt.nz
[11] From MBIE's energy statistics.

$77.1/kW p.a. This is the value of the service for a maximum of 15 MW of DER; however, the cost of frequency keeping is recovered over all consumption and, therefore, the price effect on the demand curve is a much smaller number, less than $0.1/kW p.a..

4.2.3 Instantaneous reserve

As with frequency keeping, DER is not currently able to provide instantaneous reserve. For 2035 and 2050 we reviewed 2019 final reserve prices and dispatched volumes. In our assessment we treated Fast Instantaneous Reserve (FIR) and Sustained Instantaneous Reserve (SIR) identically. Based on this assessment we determined that our equivalent price for both FIR and SIR in the North Island was $71.83/kW p.a. and for FIR and SIR in the South Island was $54.31/kW p.a.. We have assumed South Island reserve volumes remain consistent at around 100 MW. In the North Island, average unit sizes will reduce significantly with the removal of large thermal machines, although the HVDC will occasionally set much higher volume requirements. With the largest geothermal unit being 130 MW and allowing some uplift for potentially higher HVDC transfers with the exit of Tiwai, we have assumed 200 MW as the average level of reserve requirement in the North Island. These assumptions translate to $14.4m of cost in 2035 and 2050.

While the maximum potential value to DER is between $50-$70/kW p.a. for up to 300 MW across both islands, costs are recovered more broadly. Reserve costs are charged to the generating units that create the risk, which then try to recover these costs from the market. We have simply assumed that reserve costs are recovered from all consumption. This gives a demand cost for instantaneous reserve of $2/kW p.a., which is applied to the first 300MW of DER on the demand curve.

4.2.4 Resource adequacy – reduce the need for existing thermal peaking

The offset of existing thermal peaking plant is assessed at a price equivalent to $80/MWh, which gives $118/kW p.a. DER below this equivalent cost with discretionary capability can reduce the contribution of thermal peak generation of up to 250 MW.

4.2.5 Resource adequacy – offset new lines and generation

In 2020 the potential to offset future peak capacity has been set at a notional 100 MW. Currently, it is not obvious what volume of new generation and capacity could be offset. This number assumes that the 1,700 MW of installed distributed generation capacity has had some impact on offsetting peak needs. The volumes for 2035 and 2050 are assessed at 2,397 MW and 3,317 MW respectively, which are based on peak growth forecasts from Transpower (2020b) for 2020 to 2035 and extrapolated to 2050.

The total cost of new lines and generation is assessed as $241/kW p.a. being made up of $69/kW p.a. for transmission, $97.8/kW p.a. for distribution, and $74/kW p.a. for renewable peaking generation. The transmission costs were based off Transpower's own estimates. The distribution costs were based on an analysis done for Transpower by Stakeholder Strategies. The peaking renewable generation was based on our analysis for a partially loaded geothermal plant.

4.2.6 Offset voltage management assets

The cost of voltage management assets can be offset by DER with the capability to manage voltage (through discretionary reactive power generation or as an active voltage source) at the effective price and volumes based on avoiding some grid voltage management projects and voltage regulators and capacitors in the distribution networks.

We used Transpower's Waikato and Upper North Island voltage management project to establish a price for transmission voltage management. We assessed a similar rate using an approximate cost for the 325 voltage regulators in distribution networks, derived from the Commerce Commission's disclosure information, for distribution voltage management, although the input numbers were less certain. We used the grid voltage rate of $36/kW p.a. as our marginal rate. Arguably, we should add the transmission and distribution rates together. However, the requirement for each of these is not necessarily continuous nor concurrent. Therefore, we have used a conservative estimate that at any point in the demand curve either transmission or distribution voltage management assets are required but not both together.

These costs are only separately avoided to the extent that new lines and generation have not been avoided as we assume that the costs for new transmission and distribution includes the cost of voltage management. For this reason, offsetting voltage management costs does not appear in the 2035 demand curve as the volume of new generation and lines is greater than the volume of potential voltage management.

We could only make a rough estimate of the volume for the DER demand curve. Based on an operating power factor of 0.95, we have estimated that 960 MW of DER can offset 300 MVA_r of voltage management assets.

4.2.7 Harmonic filtering

Harmonic filtering is technically a cost of DER and would have been more correctly applied as a supply side cost. However, as the potential need for harmonic filtering increases as the total of all DER increases, it cannot be applied as a constant per kW cost. Therefore, it has been included as a negative avoided cost on the demand curve.

It is uncertain whether harmonics will be an issue. Even if harmonics did become a problem, we would not expect problems with harmonics before there was significant backfeed into the distribution network. Therefore, we have only assumed harmonics become an issue when DER reaches 1.7 GW of capacity. Based on the costs and a rough estimate of the effectiveness of harmonic filtering on the HVDC, the value of harmonic filtering is -$1/kW p.a. at 1.7 GW rising to -$2/kW p.a. at 5 GW. This has little effect on the demand curve.

4.2.8 Hydrofirming

This part of energy arbitrage, the ability to offset the contribution of thermal fuels to dry hydrological seasons, was added to form the bottom of the demand curve. It is based on the volume of PV solar panels, if the output were able to manage short-term resource adequacy, that could offset 3,100 GWh of winter energy margin even at winter load factors. The price is based on the variable costs of $90/MWh of thermal generation being avoided in 1 in 4.5 years, which gives $79/kW p.a.

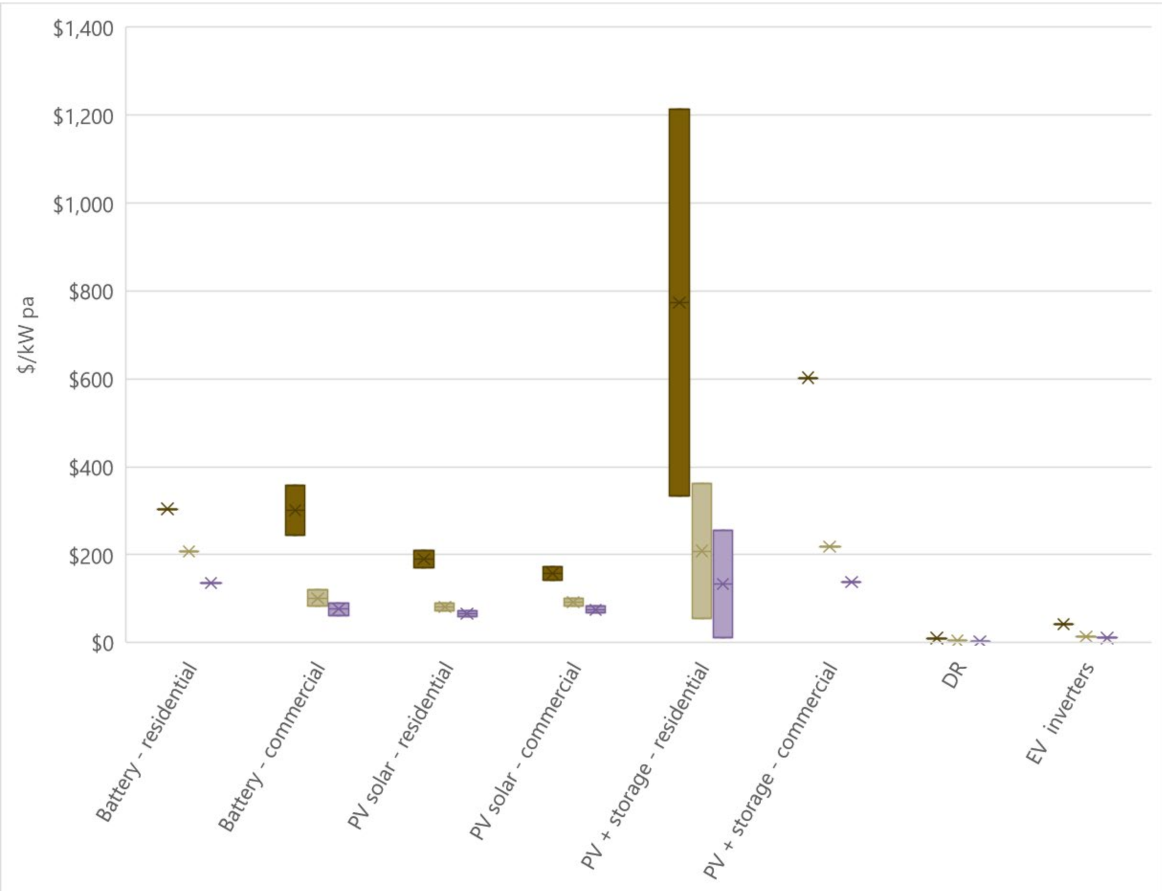
The winter energy margin is held constant over the period from 2020 to 2050 as the volume contribution of hydroelectricity is not forecast to change much over that period.

4.3 Building the supply curve

Supply curves were determined separately for different DER options in 2020, 2035 and 2050, using experience curves (i.e. annual technology cost reductions) estimated from available sources such as Lazard, US National Renewable Energy Laboratory (NREL), local NZ sales data, the Energy Efficiency and Conservation Authority (EECA) and others. The supply curves are measured in terms of annualised $/kW per available DER capacity.

The figure below illustrates the cost point or range estimates (as applicable) for different DER technologies.

Table 3: DER costs in 2021 (gold), 2035 (light brown) and 2050 (purple). Bars indicate cost ranges



Source: Sapere analysis based on data from NREL, Lazard, My Solar Quotes (NZ).

Different DER technologies can provide similar or different system services. The residual supply curve is built by mapping the service required at a certain point on the residual demand curve to the available DER technologies at that point. Where technologies provide the same system service, the residual supply curve picks up the cheapest option.

The shaded cells in the following matrix illustrate the service we assume a specific DER technology is able to provide theoretically. Note that not all of these services are necessarily provided in 2020, 2035 or 2050, either due to a specific DER technology not being available on the market yet (e.g. demand response by smart fridges in 2020), or due to some services no longer being required as a result of smart grid deployment (e.g. frequency keeping in 2050).

Appendix A includes the matrices for each of these three years in the factual and counterfactual scenarios.

Table 4: Mapping of DER technologies by system services

	Hydro firming	Offset thermal peaking	Offset lines/ transmission	Voltage management	Instant. Reserve/ Inertia	Freq. keeping
DR - residential						
EV inverters						
Battery – residential						
Battery – commercial						
PV system – residential						
PV system – commercial						
PV + storage – residential						
PV + storage – commercial						

Appendix B provides a detailed description of the assumptions used to determine the residual supply curve for the various DER technologies.

4.4 Interpreting the supply and demand curves

The supply and demand curves we have developed are not strict supply and demand curves, as they do not represent different tranches of cost and opportunity for homogeneous service. Different DER technologies have different capabilities, and different avoided power system costs require different capabilities to offset them. Our approach to this is to combine the power system avoidable costs in one demand curve despite a heterogeneous service specification for each. In determining the supply curve, we have had to construct it with two criteria being:

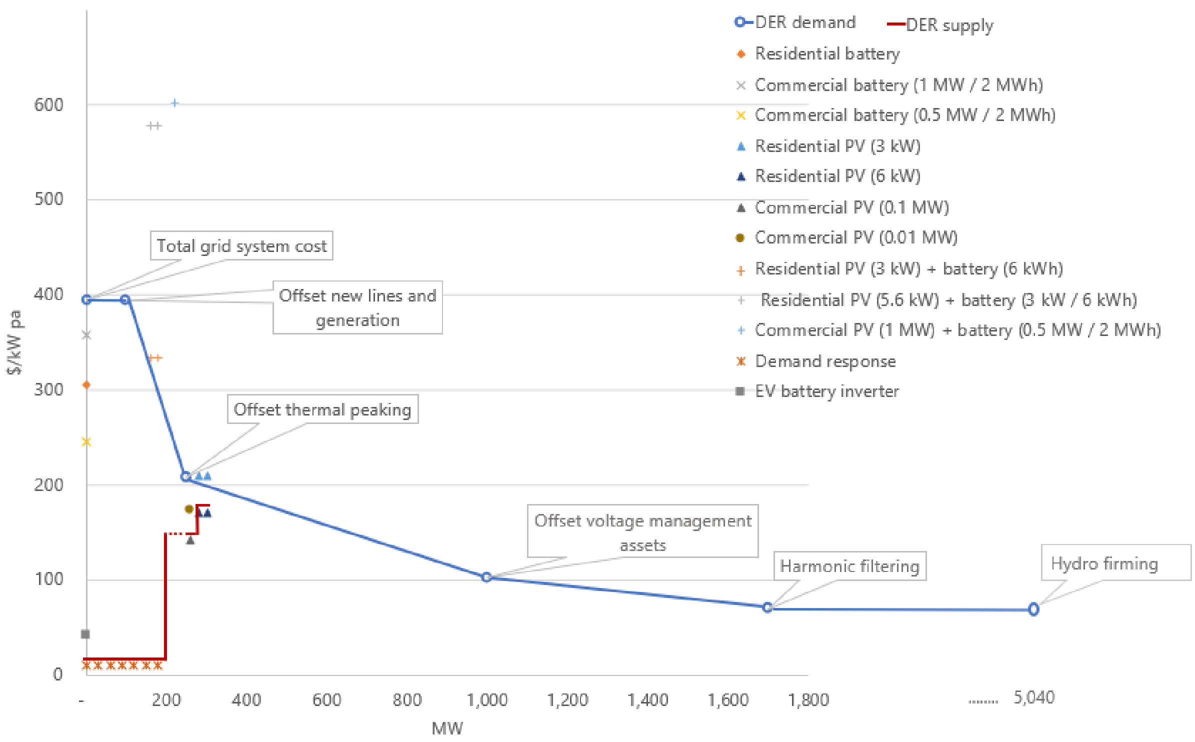
- resources that can meet the specification to avoid the costs at that part of the demand curve, and
- the cheapest resources to meet demand with progressively more expensive resources added.

Below we illustrate the supply and demand curves in 2020, 2035 and 2050 in the factual scenario. In red ellipses are the DER technologies that determine the supply curve at the margin, i.e. the technologies that provide a specific system service at least cost.

4.4.1 2021

DER demand and supply curves are illustrated in the figure below by the blue and red lines respectively.

Figure 5: DER demand and supply curves in 2021



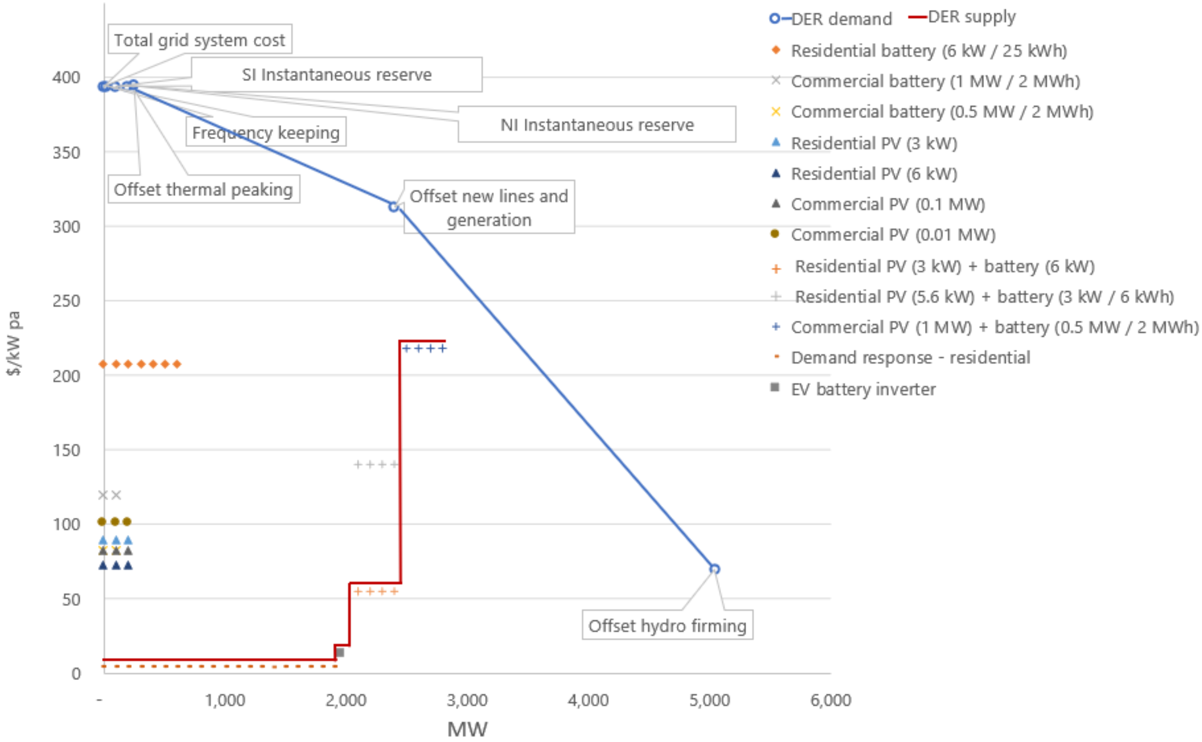
Source: Sapere analysis

In 2021, three technologies are clearly economic in avoiding power system costs and which can meet the specification at the point on the demand curve where they are potentially deployed – demand response, EV batteries and PV systems. As discussed above, other technologies like PV + storage systems are being deployed despite the seeming costs being too high, but these are unlikely to be taken up in volumes significant enough to affect our conclusions here.

Of the three technologies that are clearly economic, one is not practically available. Despite the low marginal cost of using EV batteries for electric power system service, and the potential that EV batteries are considered to have in the literature, none are yet available that can integrate with the electric power system beyond demonstration models.

4.4.2 2035

Figure 6: DER demand and supply curves in 2035



Source: Sapesomere analysis

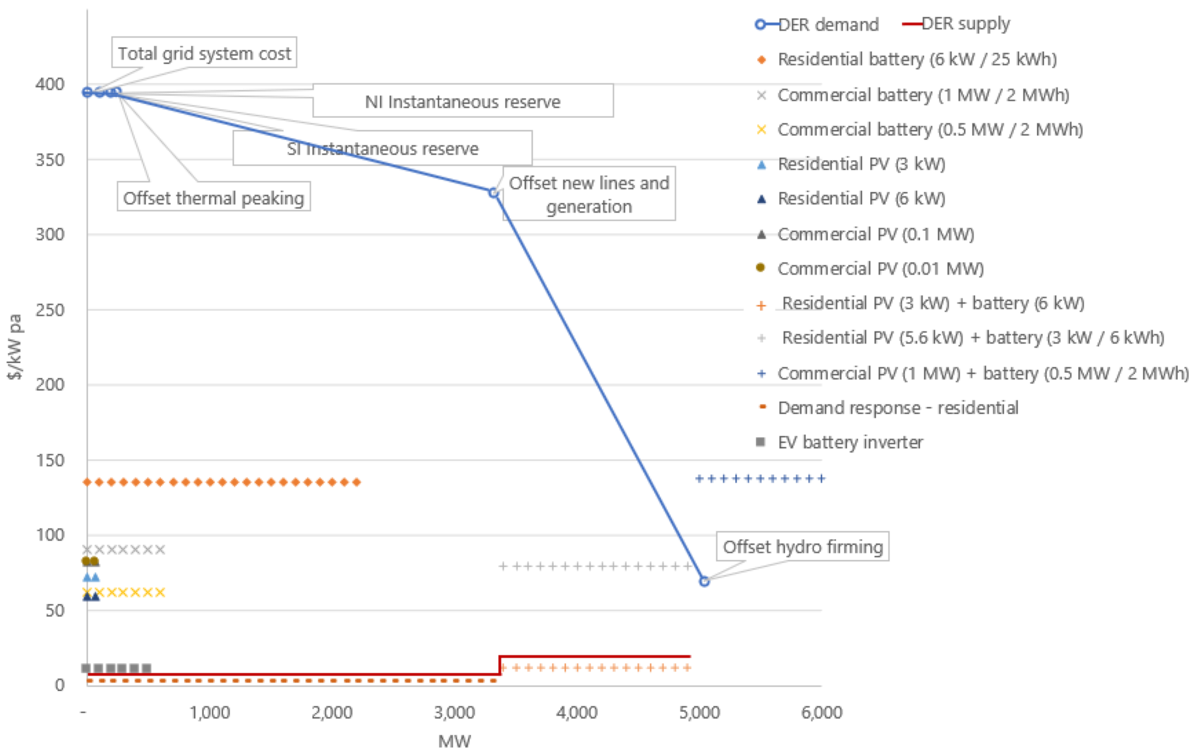
By 2035, many DER technologies are cheaper than building new lines and generation or thermal peaking. However, not many combinations can meet the specifications to add them to the supply curve. Demand response becomes the cheapest DER technology and is potentially large enough to offset the need for new lines and new peaking capacity. EV batteries remain competitive but the opportunities are relatively marginal, and the EV battery volumes are still not large. However, EV batteries are likely to be paired with PV installations. We expect a substantial contribution from residential PV systems with batteries.

We assume smart technology becomes relatively common by 2035. This is not just the automation and communication technology, but also the increasing use of inverter-controlled compressors for heating, cooling, and refrigeration. With the fine load control offered by digital inverters, increased efficiency and multiple thermal storage options (e.g. fridge/freezer, water heater, space heating), it becomes plausible that consumer preferences can be maintained at a maximum loading with a coordinating home automation system. Individual homes may exceed maximum loads at times, but large numbers of automated smart homes should lead to reliable load control in aggregate. Our assumptions for residential DR capacity are not conservative but, again, we have not considered commercial DR.

Many DER technologies are competitive for frequency keeping, reserve and offsetting thermal peaking, but not many can offset the hydrofirming problem characteristic of the NZEM. PV and battery systems in sufficient numbers, particularly in conjunction with DR, can produce significant energy even in winter, with the residual residential load then significantly lower than baseload demand. By 2035, small-scale PV and battery systems are cheap enough that, even with elevated prices only every four to five years, they are still forecast to be cheaper than maintaining large thermal power stations on standby with the associated fuel supplies or stockpiles. However, having a surplus of PV and battery capacity during periods of normal or wet hydrology has significant implications for the wholesale market.

4.4.3 2050

Figure 7: DER demand and supply curves in 2050



Source: Sapere analysis

The case in 2050 is an extension of 2035 except that, in all likelihood, new technologies will be making a difference. Nevertheless, PV and battery installations are forecast to fall in price to such an extent that they are almost economic without accessing any value except self-supply. This is reflected in the low residual cost of PV with battery shown above. DR continues to be the cheapest way of offsetting the need for new peaking generation, transmission, distribution and some hydrofirming. EV batteries are cheap DER resources, but cannot make a marginal contribution to offsetting hydrofirming unless paired with PV.

PV installations with batteries can potentially make a significant contribution to even the hydrofirming problem, as long as a method for setting wholesale and DER prices can be developed that rewards a very large renewable capacity, which is periodically required, while spot prices generally tend to zero or the variable cost of renewables operations and maintenance (O&M). However, at these levels of inverter connection, harmonics are likely to be a problem at times. By 2050, assuming the technology has not changed more dramatically than we can predict, there will need to be a price incentive for harmonics to either encourage inverters with extremely low levels of Total Harmonic Distortion, or to signal the need for harmonic filtering stations.

5. Results

5.1 Total net economic surplus

To determine the net present value of economic surpluses in 2021, 2035 and 2050, we use a 6% discount rate, based on Treasury guidance.[12] We then interpolate these results to derive total figures for the 2021-2050 time horizon.

Table 5: Estimates of net consumer and producer surpluses from DER uptake, net present value 2021-2050

	$ billion, net present value
Consumer surplus	$2.8
Producer (prosumer) surplus	$4.1
Total economic surplus	**$6.9**

Table 6: Estimates of net economic surpluses by DER value streams, net present value 2021-2050

	$ billion, NPV	**% total**
Resource adequacy – offset thermal peaking	$0.347	5.06%
Resource adequacy – offset new lines and generation	$5.9	85.86%
Hydrofirming	$0.624	9%
Instantaneous reserve	$0.0007	0.01%
Voltage management	$0.005	0.07%
Total economic surplus	**$6.9**	**100%**

5.2 Sensitivity analysis

In our estimate of the total economic surplus from DER, we have assumed DER uptake will grow with an increase in population and household growth, to the extent the market allows different DER value propositions to be harnessed. We have not considered behavioural factors that can further increase DER uptake as a result of amenity premia that DER can provide. The amenity premium can manifest itself in at least three ways:

- **Increased use of smart appliances** – People are purchasing appliances where the full value of energy management control may not yet be able to be used. By enabling such services, the value of consumer's purchases in smart appliances will increase.

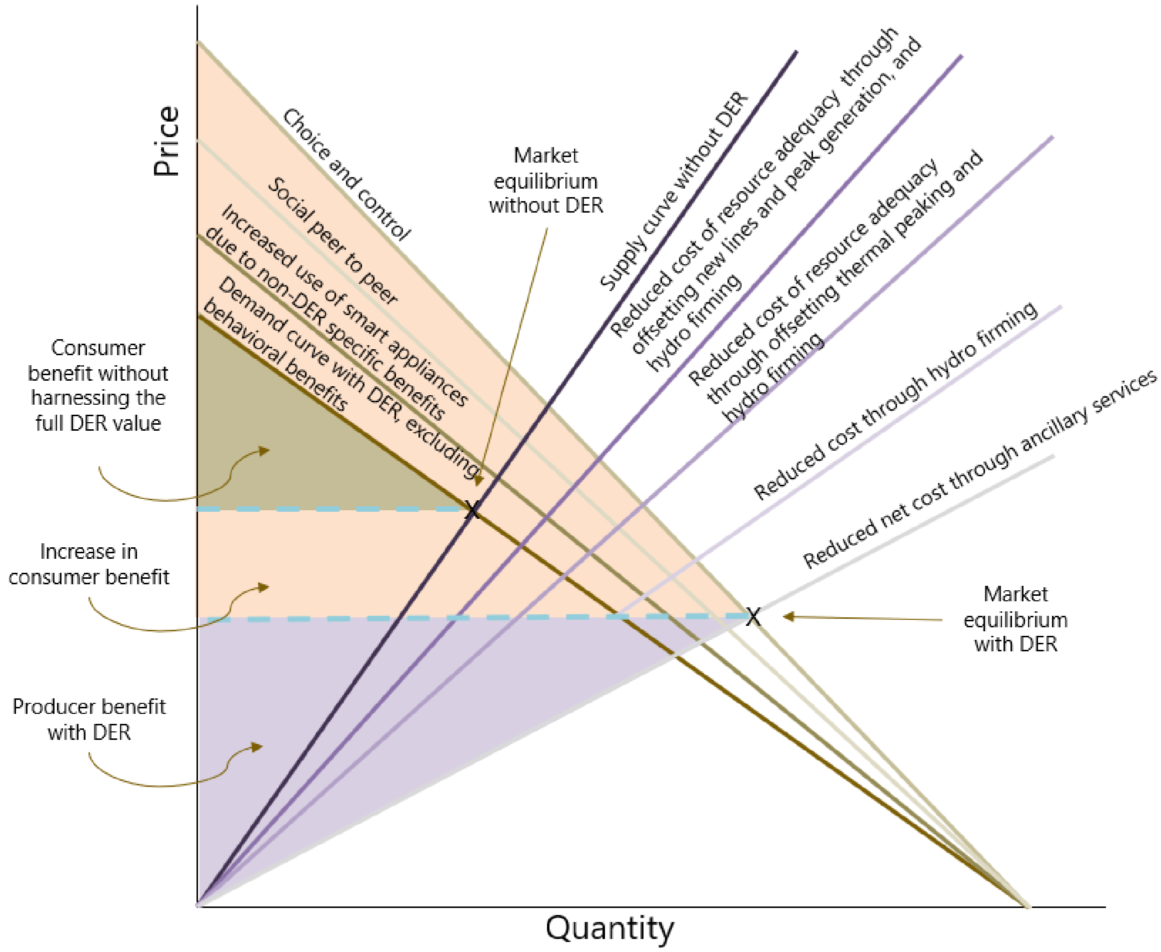
[12] https://www.treasury.govt.nz/information-and-services/state-sector-leadership/guidance/financial-reporting-policies-and-guidance/discount-rates

- **Social peer-to-peer** – Overall, peer-to-peer trading of surplus DER contributions should reduce the cost of electricity services to consumers. However, some people would like to transact their surplus resources freely on a peer-to-peer basis, which suggests that some people value assisting friends, family, and/or social causes more than reducing their own costs. This would contribute a value add from peer-to-peer trading.
- **Increased choice and control** – Some people put a high value on self-sustainability, choice, being able to see their household system, and controlling it. Increasing the options and value sources for consumers will also increase this value.

Methodologically, these amenity premia will shift the demand curve, increasing the consumer benefit. The figure below illustrates the case where the new demand curve rotates around the x-axis intercept, although other functional transformations of the demand curve may be possible. We are not aware of studies that have aimed to estimate such shifts, so our discussion here is for exposition only.

The question for us is *How sensitive are estimates of total DER economic surplus to small shifts in the demand curve, given our assumptions on DER costs, system avoided cost (DER value propositions), and DER uptake?*

Figure 8: Changes to the total net economic surplus as a result of behavioural changes that further increase DER uptake



To estimate this sensitivity, we assume the y-intercept of the demand curve shifts upwards by 5% and 10%. This rotation around the x-axis intercept reflects a decrease in the elasticity of demand. The intuition behind this is that consumers are willing to pay more (or alternatively, they are less responsive to a price increase) for a quantity of DER given their recognition of additional values it can bring over and above values strictly harnessed through services in the electricity market.

The results in the following table suggest that, given our assumptions in the modelling, for every 1% increase in the y-intercept, total net economic surplus increases by 1.15%. In other words, the estimates are sensitive to assumptions on consumers' responses to the amenity premia that DER can bring in addition to the values that can be harnessed in the electricity market.

Table 7: Sensitivity analysis of total DER economic surplus estimation

Change in y-intercept of the demand curve relative to our factual scenario	Present value of total DER economic surplus
0%	$6.9 billion
5%	$7.3 billion (5.77% increase)
10%	$7.7 billion (11.5% increase)

5.2.1 More use of DER to offset new lines and generation in the baseline

We have assumed that there will be little use of DER to offset new lines and generation in the baseline scenario. However, there could be significant use of DER for this purpose in the baseline as demonstrated by the arrangements between Aurora and SolarZero in the Upper Clutha. We still maintain that there will not be as much use of DER for this purpose as there should be in the baseline for the reasons identified by IPAG and outlined in section 1.1.

For sensitivity, we have used an assessment by (Watson, et al., 2016) that modelled a simulation of the low-voltage (LV) network to assess the impact of solar PV on the New Zealand LV system. This report found that 11.06% of the LV network currently experiences under-voltage. For the sensitivity analysis we assume that the approximately 10% of the LV network that has existing problems with voltage, as voltage is the general limit on capacity in distribution, would lead distributors to address these extant problems by using DER as Aurora has done. We also assume that this deployment also offsets 10% of potential transmission remediation and new peak generation, which is an optimistic – i.e., conservative – assumption. Then the Resource Adequacy – offset new lines and generation component in Table 6 would be reduced by 10% or $590m. This reduces the total cost benefit by 8.4%.

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Appendix A Mapping DER technologies by system services they can provide

Ideal scenario

2021

	Frequency keeping	Instantaneous reserve	Resource adequacy - offset thermal peaking	Resource adequacy - offset lines and transmission	Voltage management	Harmonic filtering	Inertia	Resource adequacy - hydro firming
EV storage	X	X	X	X	X	Cost	X	X
EV storage + PV	X	X	X	X	X	Cost	X	X
Demand response	X	X	✓	✓	X	X	X	X
Battery - residential	X	X	✓	✓	✓	Cost	X	X
Battery - commercial	X	X	✓	✓	✓	Cost	X	X
PV system - residential	X	X	X	X	✓	Cost	X	X
PV system - commercial	X	X	X	X	✓	Cost	X	X
Battery + PV system - residential	✓	✓	✓	✓	✓	Cost	X	X
Battery + PV system - commercial	✓	✓	✓	✓	✓	Cost	X	X

2035

	Frequency keeping	Instantaneous reserve	Resource adequacy - offset thermal peaking	Resource adequacy - offset lines and transmission	Voltage management	Harmonic filtering	Inertia	Resource adequacy - hydro firming
EV storage	✓	✓	✓	✓	X	Cost	✓	X
EV storage + PV	✓	✓	✓	✓	✓	Cost	✓	✓
Demand response	X	✓	✓	✓	X	Cost	✓	X

	Frequency keeping	Instantaneous reserve	Resource adequacy - offset thermal peaking	Resource adequacy - offset lines and transmission	Voltage management	Harmonic filtering	Inertia	Resource adequacy - hydro firming
Battery - residential	✓	✓	✓	✓	✓	Cost	✓	X
Battery - commercial	✓	✓	✓	✓	✓	Cost	✓	X
PV system - residential	Limited	Limited	X	X	✓	Cost	Limited	X
PV system - commercial	Limited	Limited	X	X	✓	Cost	Limited	X
Battery + PV system - residential	✓	✓	✓	✓	✓	Cost	✓	✓
Battery + PV system - commercial	✓	✓	✓	✓	✓	Cost	✓	✓

2050

	Frequency keeping	Instantaneous reserve	Resource adequacy - offset thermal peaking	Resource adequacy - offset lines and transmission	Voltage management	Harmonic filtering	Inertia	Resource adequacy - hydro firming
EV storage	X	✓	✓	✓	X	Cost	✓	X
EV storage + PV	X	✓	✓	✓	✓	Cost	✓	✓
Demand response	X	✓	✓	✓	X	Cost	✓	X
Battery - residential	X	✓	✓	✓	✓	Cost	✓	X
Battery - commercial	X	✓	✓	✓	✓	Cost	✓	X
PV system - residential	X	Limited	X	X	✓	Cost	Limited	X
PV system - commercial	X	Limited	X	X	✓	Cost	Limited	X
Battery + PV system - residential	X	✓	✓	✓	✓	Cost	✓	✓
Battery + PV system - commercial	X	✓	✓	✓	✓	Cost	✓	✓

Baseline scenario

2021

	Frequency keeping	Instantaneous reserve	Resource adequacy - offset thermal peaking	Resource adequacy - offset lines and transmission	Voltage management	Harmonic filtering	Inertia	Resource adequacy - hydro firming
EV storage	X	X	X	X	X	Cost	X	X
EV storage + PV	X	X	X	X	X	Cost	X	X
Demand response	X	X	✓	X	X	X	X	X
Battery - residential	X	X	✓	✓	✓	Cost	X	X
Battery - commercial	X	X	X	✓	✓	Cost	X	X
PV system - residential	X	X	X	X	✓	Cost	X	X
PV system - commercial	X	X	X	X	✓	Cost	X	X
Battery + PV system - residential	✓	✓	✓	✓	✓	Cost	X	X
Battery + PV system - commercial	✓	✓	✓	✓	✓	Cost	X	X

2035

	Frequency keeping	Instantaneous reserve	Resource adequacy - offset thermal peaking	Resource adequacy - offset lines and transmission	Voltage management	Harmonic filtering	Inertia	Resource adequacy - hydro firming
EV storage	X	X	✓	X	X	Cost	X	X
EV storage + PV	X	X	✓	X	X	Cost	X	X
Demand response	X	X	✓	X	X	X	X	X
Battery - residential	X	X	✓	X	X	Cost	X	X
Battery - commercial	X	X	X	X	X	Cost	X	X

	Frequency keeping	Instantaneous reserve	Resource adequacy - offset thermal peaking	Resource adequacy - offset lines and transmission	Voltage management	Harmonic filtering	Inertia	Resource adequacy - hydro firming
PV system - residential	X	X	X	X	X	Cost	X	X
PV system - commercial	X	X	X	X	X	Cost	X	X
Battery + PV system - residential	X	X	✓	X	X	Cost	X	X
Battery + PV system - commercial	X	X	✓	✓	X	Cost	X	X

2050

	Frequency keeping	Instantaneous reserve	Resource adequacy - offset thermal peaking	Resource adequacy - offset lines and transmission	Voltage management	Harmonic filtering	Inertia	Resource adequacy - hydro firming
EV storage	X	X	✓	X	X	Cost	X	X
EV storage + PV	X	X	✓	X	X	Cost	X	X
Demand response	X	X	✓	X	X	X	X	X
Battery - residential	X	X	✓	X	X	Cost	X	X
Battery - commercial	X	X	✓	X	X	Cost	X	X
PV system - residential	X	X	X	X	X	Cost	X	X
PV system - commercial	X	X	X	X	X	Cost	X	X
Battery + PV system - residential	X	X	✓	X	X	Cost	X	X
Battery + PV system - commercial	X	X	✓	X	X	Cost	X	X

Appendix B Detailed assumptions for building the demand curve

Resource adequacy – offset new lines and generation

We define resource adequacy as the electricity system's ability to incentivise most efficient investment in solutions that can ensure that electricity demand can be reliably met at every point in time and over time, i.e. the system incentivises most efficient investment to meet peak and dry year energy needs (hydrofirming). Historically, the peak energy need has been substantially addressed through flexibility on the supply side (with the conspicuous exception of load control). In the future, consumers – households, commercial or industrial users – will become much more involved in the decision making around how and when their DER is utilised, and the price at which they are prepared to respond. We expect the bulk of the management of the DER will be conducted by aggregators or distributors or retailers rather than actively conducted by the consumers.

Meeting New Zealand's emissions reduction commitments will require significant electrification of the economy, particularly transport and industrial process heat. Without changing the way we generate and consume electricity, electrification will cause a significant increase in peak demand, requiring additional electricity system investment.

Transpower estimates that in its base case scenario, peak demand will grow from 7.5 GW today to 8.9 GW in 2035 and 10 GW in 2050.[13] The base case assumes that electricity demand will increase by 68% by 2050,[14] reflecting the important role that electrification will play in meeting NZ's climate change commitments.

New Zealand has traditionally been able to meet peak demand with its flexible hydroelectric schemes. Meeting peak demand in New Zealand in the future, however, could be particularly challenging due to potential peak demand growth and the increasingly intermittent renewable generation base. Therefore, more solutions will be required to respond cost-effectively to peak demand pressures.

The benefits of using demand-side management solutions include increased network asset utilisation, increased ability to accommodate intermittent generation, and enhanced network flexibility in the face of uncertain future development. Together, these benefits will reduce the overall investment required in generation and network assets.

We look at the following demand-side management mechanisms for ensuring resource adequacy as defined above:

- Management of peaks through demand-side solutions such as battery storage, demand-side response (e.g. smart appliances) etc.

[13] Page 61 in (Transpower, 2020a)

[14] This estimate of electricity demand growth is broadly consistent with estimates by ICCC, MBIE and the Productivity Commission.

- Management of peaks through smart EV charging (and TOU).

We consider the value of demand-side management mechanism by estimating avoided cost of providing power during peaks through traditional supply chains.

In the context of DER services, the total cost of avoided peak demand when viewed across the entire load profile is made up of two components: (i) the avoided cost of peak thermal generation and associated transmission and distribution costs, less (ii) the additional baseload generation cost to provide the required energy that is shifted from peak to off-peak hours. We assume the marginal peaker to be an open cycle gas turbine (OCGT) plant, and the marginal baseload generator to be a geothermal plant (as it is cheaper than wind), with the following cost assumptions:

Table 8: Cost assumptions for an OCGT peaker

	Unit	**Value**	**Source**
OCGT capital cost	NZD	$110,000,000	Based on recent projects
OCGT plant lifetime	Years	20	
OCGT plant capacity	MW	100	
OCGT plant load factor	%	10%	(Lazard, 2018)
OCGT fixed cost	USD/kW pa	USD 12.5	(Lazard, 2018)
OCGT variable cost	USD/MWh	USD 7.35	(Lazard, 2018)
OCGT fuel price	$/kWh	USD 0.012	Based on USD 3.45/MMBTu as per (Lazard, 2018)[15]
OCGT emissions	tCO2/kW/yr		Uses a conversion factor of 528 tCO2/GWh
Carbon price	NZD/tCO2	2020 – $34 2035 - $75 2050 - $200	Based on Concept modelling as reported in (Productivity Commission, 2018)
Transmission lines lifetime	Years	100	

[15] Note that this value might be on the lower end as it reflects gas prices in the US market

Distribution lines lifetime	Years	60	
OCGT total capex + opex	**$/kW/yr**	**$143**	
Transmission cost	**$/kW/yr**	**$69.27**	Assumes $1.8 for 1,821 MW as per Transpower email on April 28
Distribution cost	**$/kW/yr**	**$97.79**	Assumes $2.5 for 1,821 MW as per Transpower email on April 28[16]

Table 9: Cost assumptions for a geothermal plant

	Unit	**Value**	**Source**
Capacity	MW	100	
Capex	NZD	$471,200,000	Sapere analysis
Connection cost	NZD	$7,500,000	Sapere analysis
Fixed cost	% capex	66%	
Variable cost	% capex	10%	
Load factor	%	97%	
Incremental load factor to offset peak	%	10.3%	
Total incremental cost	**$/kW/yr**	**$74.2**	

Note that the total incremental geothermal cost above was estimated in proportion to the energy component of generation that is shifted from peak to off-peak hours. This means that the relevant load factor is not the full 97%, but only 10.3% (=100 MW OCGT * 8,760h * 10% divided by 100 MW Geothermal * 8,760h * 97%).

[16] This is based on a prorating of relative asset base growth through time for distribution businesses compared to incremental transmission investment. Although this method is credible, we have not been able to check the actual calculations performed by Stakeholder Strategies.

On net, therefore, we estimate that the cost of 1 MW avoided peak is $240,447 p.a. in 2021. We note that this is higher than Transpower's estimate of $149,041/MW p.a.[17]

Our annualised estimate of avoided cost does not capture the ability to address the dry-year problem. We note, however, that the problem could be addressed through an overbuilt of solar generation combined with distributed battery storage. An overbuild of solar would provide energy to meet the winter energy margin even at winter load factors. Batteries ensure that this solar energy can be usefully deployed in the short run. Absent solar overbuild, the dry-year problem would require long-term back-up from batteries (which would require at least 2,700 GWh of battery storage[18] and around 1,000 MW of charge/discharge capacity). Although this would be technically possible, it is not seen to be economically viable. Operating batteries of this scale in a hydro-firming mode[19] is estimated to incur a marginal emissions abatement cost of $89,000/t CO2e (ICCC, 2019) – a figure that is prohibitively expensive.

Instantaneous reserve

Instantaneous reserve is generation that is held in reserve or load that can be interrupted in order to halt a decline in system frequency caused by an unexpected supply interruption (e.g. due to generation or transmission interruptions). In New Zealand, two distinct IR products are procured in the wholesale market for each island separately.

The Fast Instantaneous Reserve (FIR) is intended to counter an under-frequency event,[20] and is made up of spinning reserve and interruptive load. It must be provided within six seconds after the event and sustained for 60 seconds.

The Sustained Instantaneous Reserve (SIR) aims to recover frequency to or above 49.25 Hz after an under-frequency event. It must be provided within 60 seconds after the event, and sustained for at least 15 minutes for spinning reserve or, if it is interruptible load, until the provider is instructed by the SO to cease the provision.

In the future, smart grid technologies are expected to make demand response, such as responsive load and storage (stationary or mobile batteries), available as a source of instantaneous reserve. Smart grid communication and control should enable a continuous demand response to an under-frequency event, which is in contrast to the current binary response of interruptible load afforded by relay technology that trips load at a pre-defined frequency (Transpower, 2015).

[17] This is the annualised value of $1.58 billion saved for each 1GW avoided (Transpower, 2020a), assuming a rate of 7% over 20 years – note the longer lifetimes of transmission and distribution lines would further reduce this number (for a 6% rate, the annuity is $137,752). Transpower's estimates reflects avoided cost of gas-fired generation, and transmission and distribution investment costs.

[18] As indicated in (ICCC, 2019)

[19] This means that the battery would need to be charged when prices are low and discharged in a 1-in-5-year event when lake storage levels are low in winter.

[20] E.g. due to the tripping of single or multiple generating units or HVDC trips in bipole or single pole mode.

A study by Imperial College London[21] on NZ energy futures determined that there are mainly two flexible demand technologies that would be well placed to provide frequency response services – smart refrigerators and electric vehicles (Strbac, et al., 2012). For EVs, the service can be provided by controlling the charging of EVs, e.g. interruptible charging for a short period of time. For refrigerators, the service can be provided by changing the duty cycle of appliances.[22]

In addition to flexible demand, frequency management services could be also be provided by battery storage systems. A recent study on distributed battery energy storage systems in New Zealand shows that if such systems are appropriately configured, they can respond faster than current providers of instantaneous reserve, recovering frequency faster and stabilising the system with fewer oscillations (Transpower, 2019a).

Based on EMI data on cleared reserves, we estimate that the average IR capacity for the South Island is 100 MW. For the North Island, we note that in a recent report, EA suggested that the Government's target of 100% renewable generation in a year of average hydrology by 2035 would result in a significant reduction of instantaneous reserve required — from around 400 MW of SIR at times of capacity scarcity to potentially 140 MW, although the HVDC link flows could set the SIR requirement at a higher level in those cases (EA, 2018). We agree that more renewables probably means smaller units and lower risk, thus reducing the need for reserve, but this also depends on how much any reduction in inertia affects the rate of change of frequency in an event.

To recognise that sometimes the HVDC would set the risk, we adopted a 200 MW figure for 2035 and 2050. Although this is a high-level assumption, significant changes to it would not materially affect our conclusions with regards to the DER opportunities that can bring most value.For the purpose of this report, we assume that the IR capacities do not change over from 2035 through to 2050. On this basis, our estimates reflect the upper bound value of the opportunity, as we do not expect IR demand to go up from current values. We will investigate in more detail the possible trend in IR demand through 2050 in Stage 2 of the project.

We estimate the DER value from providing IR services in terms of avoided costs of needing to supply reserves in compliance with current technical requirements (e.g. SIR for 15 mins); in the future, we expect that these requirements would be reduced with an increased use of smart grids that will optimise the deployment of DER for IR purposes. Currently, IR services cannot be practically provided by existing DER sources as the Code does not allow small providers to offer IR services.

[21] This study was commissioned by Meridian.

[22] Domestic refrigerators generally keep the refrigerator temperature between two set points. Once the internal temperature reaches a pre-set maximum point value, the compressor starts and the refrigerator starts to cool, and stops when the refrigerator's internal temperature reaches the minimum required temperature. The cycle then repeats. The compressor typically has a duty cycle of 20% to 30.%. The inclusion of smart refrigeration control changes the refrigerator's duty cycle length as the frequency changes. A frequency drop due to loss of generation decreases the refrigerator's duty cycle, which in turn means that the refrigerators can contribute to frequency stabilisation by reducing their aggregate load. The need for the refrigerator to continue to contribute system balancing means that average energy use for each appliance should reduce as the system frequency reduces.

As we discuss in section 2.9, it is also possible that a market for simulated inertia/ultra-fast reserve could also at least partially displace the IR markets. Using 2019 data on final reserve prices,[23] we estimate that the cost of providing FIR and SIR were $71.83/kW and $54.31/kW in the North Island and South Island respectively. For simplicity, we assume that the capacities for FIR and SIR are even, i.e. the FIR and SIR reserve prices are added together. Although this assumption is not entirely accurate, it provides a conservative upper value assessment of the IR opportunity for DER.

We determine the potential value opportunity from DER providing IR services to be as follows:

Table 10: Instantaneous reserve value stream

	Unit	2020	2035	2050
IR capacity provided by DER – NI	MW/yr	0	200	200
IR capacity provided by DER – SI	MW/yr	0	100	100
Total value	**$/yr**	**$0**	**$19,8**	**$19.8**

Source: Sapere analysis based on Electricityinfo data

Frequency keeping

Frequency keeping (FK) services are required to manage short-term supply and demand imbalances to ensure that the system frequency is maintained in each island within a normal band, i.e. between 49.8 Hz and 50.2 Hz. This service is usually provided by one or more generating units capable of quickly varying their output (hydro and thermal plants) in response to instructions from the System Operator. The range over which current frequency keeping providers must be able to adjust their output is known as the frequency keeping band. From 1 May 2016, this band is 15 MW in each island.[24]

While they are both frequency management services, FK and IR are different services. FK varies continuously to balance imbalances between supply and demand to try to keep the frequency close to 50 Hz between dispatch instructions. To do this in a stable way it is either provided by a single provider or coordinated by a central control system. IR restores frequency to a level after a loss of supply event. As it is provided quickly by multiple independent providers, to function in a stable way it deliberately does not try to restore frequency to 50 Hz. The level frequency restoration that is reached is determined by the stability characteristics of the plant dispatched to react to an event.

We note that a higher proportion of intermittent sources of energy (generally connected to the system by power electronics) to traditional synchronous generation would result in lower system inertia, which in turn could increase the requirement for frequency keeping capacity. Normally we would also expect supply and demand imbalances to increase with higher demand. However, to

[23] From https://www.electricityinfo.co.nz/

[24] Previously, there was a 20 MW and a 10 MW band in the North Island and South Island respectively.

remain consistent with our assessment of inertia (Section 3.2.5) and the use of DER to flatten demand (Section 2.3), we assume that the rate of change of frequency in the future does not change.

Battery energy storage systems (BESS) could play an important role in providing frequency keeping services. Most commentators assess DER on the basis that active power curtailment is generally available for wind and solar-PV generation in case of over-frequencies (when they are generating), but that these sources of generation cannot guarantee a power reserve in case of under-frequencies. BESS can help overcome this issue, thanks to their ability to absorb large amounts of active and reactive power simultaneously and in a very short time (Ortega & Milano, 2016).

While BESS may be the best way to ensure FK even when there is no wind or sunshine, we disagree with the assessment that active wind and solar generation cannot provide power in the case of under-frequency. If this were true, the same could be said for the provision of frequency services from traditional generation. Partial loading of generating plant is the way in which frequency services are provided by that plant. While it is sometimes true that there is no opportunity cost in partially loading, say a hydroelectric turbine, there can be. As long as the value extracted from frequency services is at least equal to that from any other use, then partially loading wind or solar is a valid economic choice.

In New Zealand, there has been a progression in the way frequency keeping services have been provided, from an island-centric to a national procurement of service. Up until 2013, frequency keeping services were purchased by the System Operator from a single provider. Subsequently, dispatching of multiple frequency keeping providers (MFK) was introduced in 2013 and 2014 in the North Island and South Island respectively. Since the introduction of the new HVDC bipole control system in 2013, it has been possible to transfer frequency keeping between islands. Trials have been done to enable frequency keeping services to be procured from available providers at a national, rather than at an island level. This is something that could be done in the future.

At present, only four generating companies meet the System Operator's technical and access requirements for MFK.[25] It is technically feasible for currently installed DER to meet the technical requirements but the System Operator does not currently permit access below a certain size. On this basis, we assume that by 2035 the potential opportunity for DER to provide frequency keeping service is the entire frequency keeping band of 15 MW. However, over a very long-term horizon, it is almost certain that future dispatch technologies will be able to dispatch resources in real time, significantly reducing the need for FK. On this basis, we assume that by 2050 the value of DER providing frequency keeping is likely to be zero. The dispatch technology that achieves this will include faster supply response (including from DER), better real-time supply and demand prediction (through fast information and AI prediction) and faster optimisation and dispatch automation.

However, achieving this would require market development. There is currently little incentive for intermittent generators to improve their load forecasts, or for demand to improve its forecasting or for generators to improve their speed of response to dispatch instructions. Currently such incentives would probably yield little benefit, but as technology improves the speed of information and the

[25] Mercury, Genesis, Contact and Meridian.

ability to forecast, control, and respond, new market incentives would be warranted. These are not just incentives for DER, though, but are market design issues.

We determine the maximum DER value from providing frequency keeping by 2035 based on the current cost of providing the service. The maximum potential opportunity by 2035 is the total avoided cost of purchasing FK from synchronous plants. We are not saying that DER would offset current FK providers, but that is the maximum opportunity. We will look more closely at the supply and demand economics in stage 2.

Based on 2019 Transpower data on frequency keeping costs,[26] and assuming a 15 MW cap on the service provision, we determine an average cost of $77.11/kW p.a. This means that by 2035 the potential opportunity from DER providing frequency keeping services is $1,156,667 which is gradually reduced to zero by 2050 when real-time dispatch replaces centralised FK purchase. For 2020, the infrastructure and rules to enable DER to participate does not exist and, therefore, there is no opportunity for DER.

Table 11: Frequency keeping value stream

	Unit	2020	2035	2050
FK capacity provided by DER	MW/yr	0	15	0
Total value	**$m/yr**	**$0**	**$1.16**	**$0**

Voltage

In distribution networks, voltage can be the main driver of capacity restrictions. In this value stream, however, we are looking at the value DER can provide in controlling voltage. Voltage control requires significant investment in New Zealand. The upper North Island, as New Zealand's largest load region with little local generation, has significant investment in static voltage control and compensation in the transmission network. The upper South Island, while a much smaller load, has weak transmission and little local generation. The South Island also has relatively significant investment in voltage management at transmission level.

Much of New Zealand has low population densities with distribution lines often having to serve many customers over long line distances. There is significant investment in voltage management in distribution networks as well.

In Whakamana i Te Mauri Hiko, Transpower identifies that a voltage management project developed in response to the closure of the Southdown and Otahuhu power stations (in Auckland), and the prospect of closure of the Huntly Rankine units, are essential to the long-term transformation of the transmission network. Despite significant DER offsetting some transmission flows, grid-scale renewables are going to need to be transported to Auckland, and with the eventual decommissioning

[26] https://www.transpower.co.nz/system-operator/electricity-market/frequency-keeping

of the Rankines, Transpower has developed the Waikato and Upper North Island Voltage Management (WUNIVM) project – stage 1 and stage 2. Stage 1 will:

- install a ±150MVAr dynamic reactive device in Auckland
- install a ±150MVAr dynamic reactive device in Waikato
- install a post-fault demand management scheme across Waikato and the UNI
- do preparatory work for stage 2.

A Grid Upgrade Proposal has been made to the Commerce Commission for stage 1 to be completed by 2023, at a cost of $145m (Transpower, 2019b). Stage 2 would install series reactors on the two Brownhill – Whakamaru circuits. Stage 2 is required because when the significant transmission capacity into Auckland is lightly loaded it introduces large capacitance to the network and high voltages are a problem. Stage 2 is expected to cost $65m – $135m (Transpower, 2020a, p. 46).

DER can help in a couple of ways. DER can provide reactive power, potentially more flexibly than a synchronous machine and as well as a statcom. The most important way in which DER can add value to low voltage management is as an active generation source. If DER is encouraged to generate when voltage is low, which is also going to be when regional demand is high, then just the provision of active voltage will help lift voltage. However, DER could export reactive power as well.

DER can also help with high voltage. By incentivising batteries to charge and demand response to consume when voltage is high, and regional demand is low, DER could add load to the transmission circuits and reduce their net capacitance. DER can also consume reactive power to help.

The WUNIVM stage 1 project will now go ahead. However, we assume that if there had been price signals in place, then the distributed solar generation already installed in the Waikato and Upper North Island regions could have offset 50MVA$_r$ of the stage 1 project. This is a rough estimate. According to the Electricity Authority, there is 65 MW of distributed solar in the Central and Upper North Island. We do not know how many of these have batteries, which would be necessary to ensure active generation at peak times. Although the number of batteries is likely to be a small proportion of the current solar installations, there may have been more batteries installed if there had been a voltage price signal. Such a price signal could also lead to the sizing and capability of inverters to provide voltage support if it is economic to do so. To the extent that reactive power can contribute to the Upper North Island voltage issues, solar inverters could be installed to generate reactive power at any time without a battery. We will look more closely at supply and demand in our second report.

There is significant investment in voltage management within distribution networks. Based on EDBs information disclosures to the Commerce Commission there are 649 voltage regulating transformers and 279 capacitor installations in the New Zealand distribution network as at the end of the 2019 disclosure year (Commerce Commission of New Zealand, 2020). Voltage regulating installations can use one, two or three voltage regulating transformers in each installation. The most common configuration, and the one we are going to use as an average, is two per installation, which gives 325 voltage regulating installations. Collectively we have valued these assets dedicated to voltage control at around $60 million on a replacement cost basis. We assume that these distribution voltage control assets would increase proportionally with demand growth in the absence of an alternative form of control.

In 2020 there is insufficient DER to be able to make a meaningful difference in voltage management within distribution networks. However, with the levels of penetration of DER expected, even by 2035, then DER definitely could. The best voltage regulation probably comes through active generation from a battery or solar panel, but their inverters could vary reactive power output at any time. However, to assist with managing voltage the DER output has to not only be incentivised to invest in technology that can coordinate voltage and follow a stable voltage characteristic but has to be coordinated in real-time to set up workable voltage profiles throughout the transmission and distribution networks. When utilised in this way DER is not only helping to manage voltage but is also optimising the import and export capacity of the power system.

We determine the following annualised values for voltage control.

Table 12: Voltage value stream

	Unit	2021	2035	2050
DER value from voltage	$m/yr	$0	$11.3	$14.6

Source: Transpower and EDB data and Sapere analysis

Harmonics

The New Zealand power system is not only designed to work on Alternating Current at 50 Hz, but it also needs the AC waveform to resemble, quite closely, a sine wave. Digital switching devices, as in electronic controllers, rectifiers, and inverters, can introduce a form of interference on the AC sine wave. The combined effect of these forms of interference is called Total Harmonic Distortion (THD). If THD get high enough then many devices and items of electrical equipment can operate incorrectly or fail.

Harmonics is probably the only value stream where, if problems occur, it will be almost entirely due to DER. Therefore, in aggregate, harmonics may be a cost to DER. However, given differences in DER equipment performance there should be benefits in creating incentives to encourage higher specification DER and recover costs from poor performing equipment. This could also encourage harmonic filtering solutions where they are required.

So far harmonic problems have not occurred in New Zealand except in relatively isolated examples. This is despite the proliferation of electronic power supplies for appliances and equipment. We are not aware of harmonics causing significant problems overseas. This is probably because the electronic equipment meets international standards of limits on THD and diversity of equipment probably also helps. Most of these electronic power supplies have also been relatively small.

The mode under which harmonics could become problematic is where there are large amounts of DER export back-feeding through relatively small distribution networks. When DER exports back into the distribution network it offsets the electrical current that would be required to supply the load. Sufficient DER export can push the current back upstream until the point where it is supplying all local demand it can. These points where the DER export current stops being able to supply further upstream and, therefore, where the upstream current is not required to supply further downstream are called null points. The current flows around these null points is low. However, the upstream current does not necessarily offset harmonics, and if the harmonic currents are not abated by travelling through the network (known as attenuation) then the harmonic distortion could be too high compared to the light current near null points.

While this effect is theoretically possible it has not been noticed much overseas with high concentrations of DER export. However, this could be because other limits, i.e. voltage, are limiting DER export before the harmonic effects become serious. The risk is that addressing voltage limits on DER export results in exports which are then limited by THD. This risk is theoretically observed in (Sun, Harrison, & Djokic, 2012, p. 4). Or, it could be that natural attenuation in distribution networks is enough to reduce harmonics to acceptable levels even near null points.

Harmonics could also manifest in areas where they are unexpected due to unfortunate combinations of electrical characteristics of distribution and consumer equipment. The more there are larger digital switching devices in the network the more chance there is of these sporadic THD events. They are difficult to diagnose and exceedingly difficult to fix.

From section 1.1 the level of penetration of DER by 2050 would mean significant back export from DER within distribution networks. At this level of penetration (22% of generation capacity), we would expect null points associated with every DER connection with the possible concentration of harmonic distortion at these null points. However, we would expect the distribution network to attenuate the majority of the harmonic injections, we have assumed 90% attenuation. In 2035 the level of DER penetration is 12% of generation capacity and we assume at this level only about half the connected DER would contribute to null points in the distribution network. Based on filtering costs and effectiveness for the HVDC, we assess the value impact for harmonics in Table 13.

Table 13: Harmonics value stream

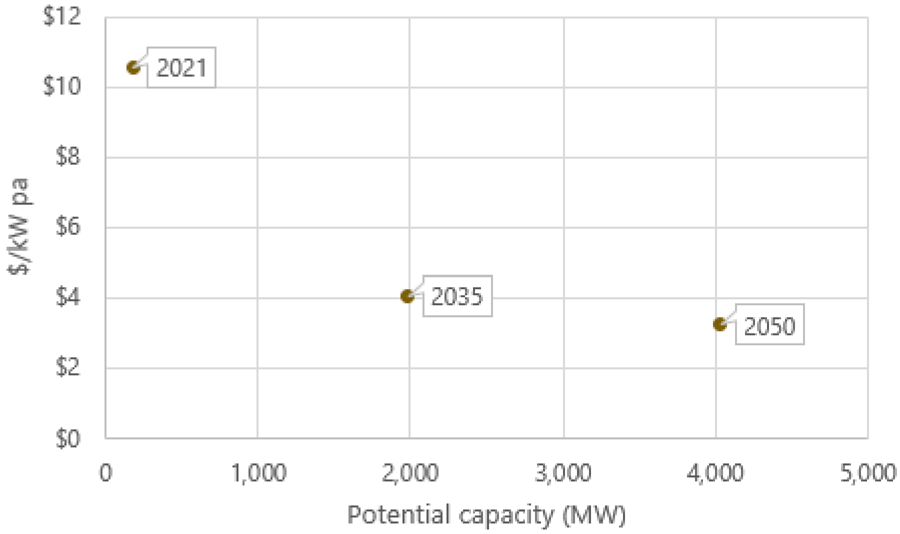
	Unit	2020	2035	2050
DER value from harmonics	$m/yr	$0	-$1	-$7

Source: Transpower data and Sapere analysis

Appendix C Detailed assumptions for building the supply curve

Demand response

Figure 9: Demand response supply curve



Demand response technologies include: EV battery charging, residential and commercial smart air conditioners, residential smart dryers and residential smart fridges. We note that this list does not include the full set of DR options. In this analysis we only look at the marginal potential compared to what is already in place.[27]

To determine available DER capacity, we assess the number of smart appliances that may be available in 2021, 2035 and 2050. However, not every smart appliance will be running at the same time even during peaks. Notwithstanding that the point of DR is to guide consumption to specific times, we assume a 13% diversity factor, based on residential peak diversity.

To determine potential capacity for different types of demand response, we use the following sources of information:

- EV charging: assumptions on light EV uptake based on (Transpower, 2020a) and (MoT, 2017).
- Residential electric dryers: EECA historical sales data and future uptake assumptions based on Kea scenario in BEC 2060 (BEC, 2020).

[27] Given that water heaters are already controlled in NZ, water heaters are not included in the supply curve, although they do and will continue to play an important role in the providing demand response capacity. However, the control of water heating will have to change to allow more flexibility and to optimise its value.

- Residential and commercial air conditioning: EECA historical sales data and future uptake assumptions based on Kea scenario in BEC 2060 (BEC, 2020).
- Residential smart fridges: EECA historical sales data and historical estimates of nr of fridges per household.

The cost assumptions are based on (i) current price differentials for EV charger hardware and software controls and smart appliances, and (ii) assumed experience curves, as per the table below:

Table 14: Demand response cost assumptions

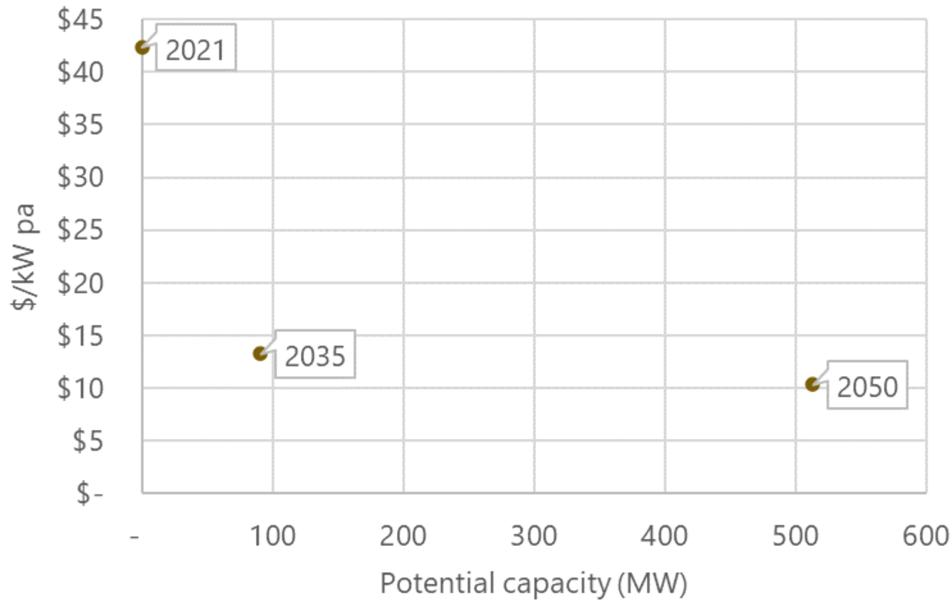
	Unit	2021	2035	2050	Source
Cost reductions	Average annual cost reduction, %	-10%	-7%	-2%	Battery cost reductions as per (Schmidt, Melchior, Hawkes, & Staffell, 2018)
EV charging unit	Incremental annualised cost, $/kW	$8	$4	$4	Assumes $155 based on USD100 in 2015 as per (Rocky Mountain Institute, 2015)
Smart air conditioning		$8	$3	$2	Assumes $327 in 2019 based on existing sales[28]
Smart dryer		$17	$6	$4	Assumes $286 in 2019 based on existing sales[29]
Smart fridge		$8	$3	$2	Assumes same incremental cost as smart AC given similarity of technologies
Weighted average cost	**Annualised cost, $/kW**	**$10.09**	**$3.87**	**$3.08**	Costs weighted in proportion to capacity shares of different smart appliances

EV inverters

Figure 10: EV inverted supply curve

[28] https://www.homedepot.com/p/Emerson-Single-Stage-5-2-Day-Programmable-Thermostat-P150/207173074 and https://store.google.com/us/product/nest_learning_thermostat_3rd_gen?hl=en-US

[29] https://www.whirlpool.com/laundry/dryers/electric.html?plp=%253Arelevance%253Acategory%253ALaundryDryersElectric%253Acategory%253ALaundryDryersElectricDryerMatchesTopLoadWasher&plpView=grid



EV inverters enable power to be injected back into the grid during peak times. If this is implemented alongside smart EV charging, whereby, for example, a 3 kW EV battery is charged during off-peak hours, a total net reduction of 6 kW in peak generation could be achieved.

The potential capacity for EV inverts is based on assumptions in (Transpower, 2020a) about EVs with V2G technology.

The cost assumptions for EV inverters are described below.

Table 15: EV inverter cost assumptions

	Unit	2021	2035	2050	Source
Cost reductions	Average annual cost reduction, %	-10%	-7%	-2%	Battery cost reductions as per (Schmidt, Melchior, Hawkes, & Staffell, 2018)
Battery inverter lifetime	Years	15	15	15	(MBIE, 2016)
Battery inverter	Incremental annualised cost	$306	$96	$74	Difference between the cost of bi-directional battery-based inverter and PV inverter (2016USD 2,739) as per (Ardani, et al., 2017)
O&M cost	% capex	1.8%	1.8%	1.8%	Assumed to equal the figure for residential battery
Battery inverter	**Annualised cost, $/kW**	**$42**	**$13**	**$10**	

Battery – residential and commercial

The total potential capacity are based on estimates of distributed battery storage from (Transpower, 2020a).

For residential batteries, we have used costs as reported in (Transpower, 2020a).

For commercial batteries, Figure 12 shows a range of battery costs, reflecting different battery sizes. The lower-end cost is for a commercial 0.5 MW/2 MWh battery, whereas the higher-end cost is for a residential 6 kW/25 kWh battery. Detailed cost assumptions are provided in the subsequent tables.

Figure 11: Battery supply curve, residential

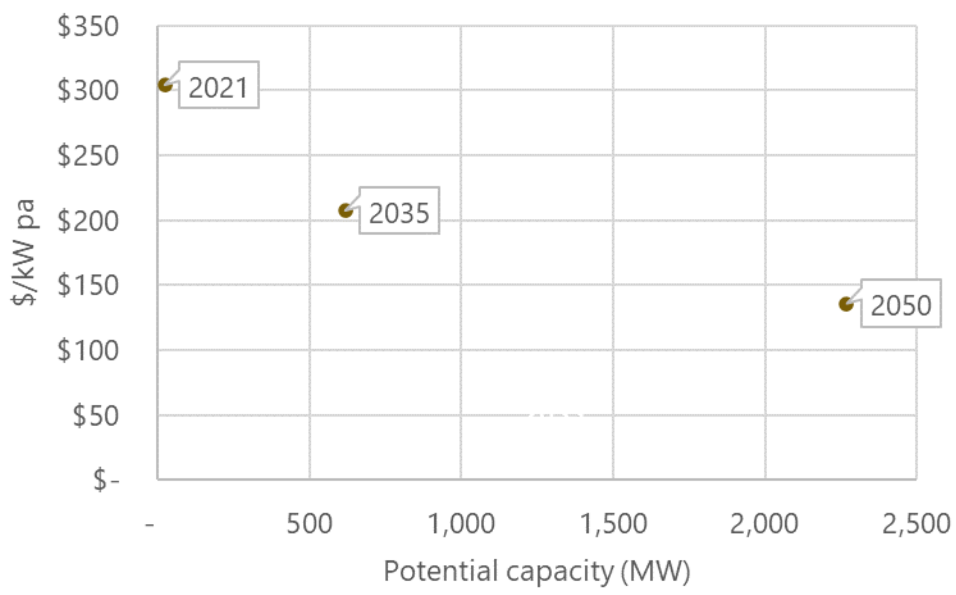


Figure 12: Battery supply curve, commercial

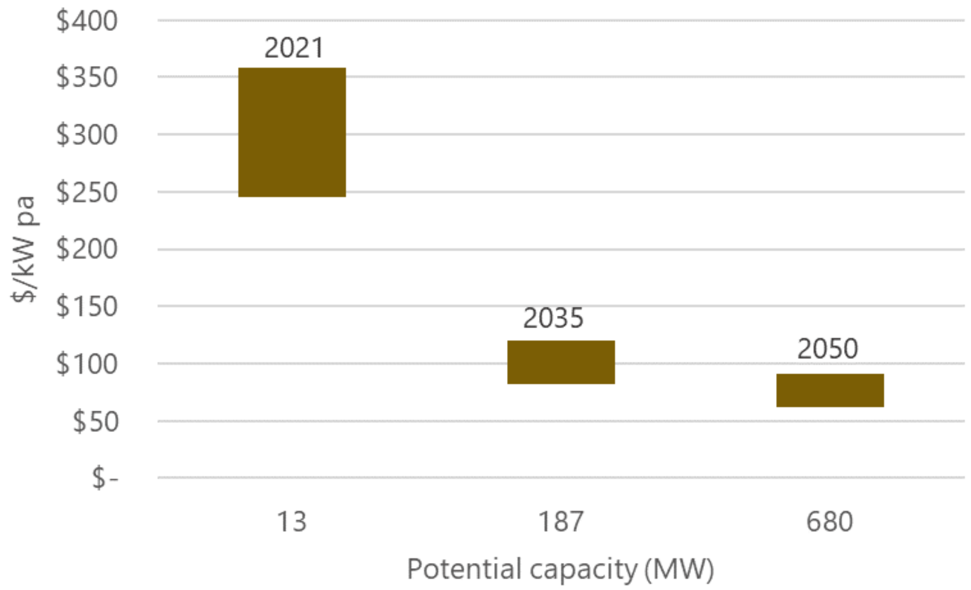


Table 16: Residential battery cost assumptions

	Unit	2021	2035	2050	Source
Battery cost	$/kW	2,200	1,500	1,000	(Transpower, 2020a)
Battery lifetime	Years	10	10	10	(Lazard, 2019)
O&M costs	% capex	1.8%	1.8%	1.8%	(Lazard, 2019)
Residential battery cost	**Annualised cost, $/kW**	**$304**	**$207.5**	**$136**	

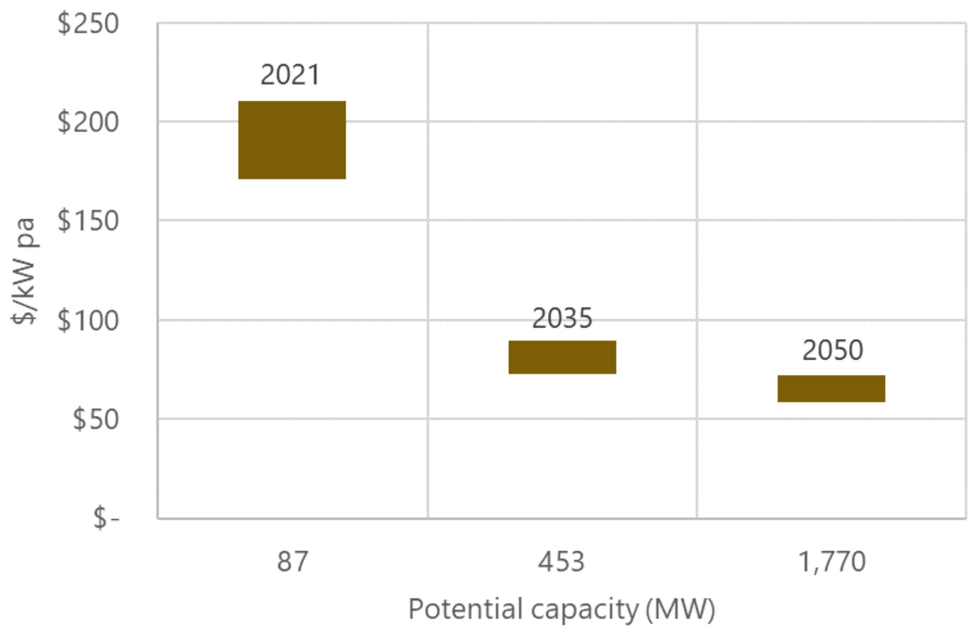
Table 17: Commercial battery cost assumptions

	Unit	2021		2035	2050	Source
Cost reductions	Average annual cost reduction, %	-10%		-7%	-2%	Based on (Schmidt, Melchior, Hawkes, & Staffell, 2018)
Battery lifetime	Years	10		10	10	(Lazard, 2019)
O&M costs	% capex	1.4%		1.4%	1.4%	(Lazard, 2019)
Battery cost (1 MW/ 2 MWh)	**Annualised cost, $/kW**	**$358**		**$120**	**$91**	Assumes a total cost of 2019 USD 1,905,700 for a

	Unit	2021		2035	2050	Source
						1 MW / 2 MWh battery, as per CAISO standalone battery case study in (Lazard, 2019)
Battery cost (0.5 MW/ 2 MWh)		**$245**		**$82**	**$62**	Assumes a total cost of 2019 USD 1,306,600 as per CAISO PV + storage case study in (Lazard, 2019)

Solar PV – residential

Figure 13: Residential PV supply curve



PV system costs show a range of values depending on system size. We estimated costs for system sizes of 3 kW and 6 kW as per the table below.

Table 18: Residential PV cost assumptions

	Unit	2021	2035	2050	Source
Experience curve	Average annual cost reduction, %	-6%	-6%	-1%	Based on residential capex estimates from (NREL, 2020),

	Unit	2021	2035	2050	Source
					including installation costs, excluding financing costs.
PV system lifetime	Years	25	25	25	(MBIE, 2016)
O&M cost	% capex	0.8%	0.8%	0.8%	Estimated based on data from (NREL, 2020)
PV system cost (3 kW)	**Annualised cost, $/kW**	**$210**	**$89**	**$72**	Assumes a total cost of $8,000 in 2021[30]
PV system cost (6 kW)		**$171**	**$72.5**	**$59**	Assumes a total cost of $13,000 in 2021[31]

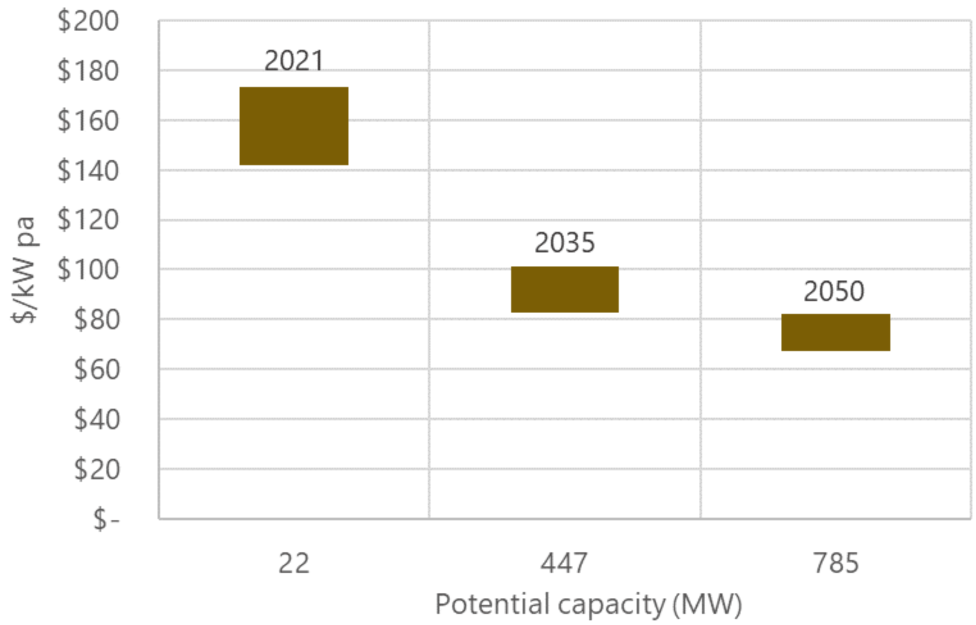
Residential PV capacity was estimated based on (Transpower, 2020a) projections of residential distributed accelerated capacity, excluding dwellings with systems that have both PV and batteries. We determine that the proportion of households with solar that have PV systems without batteries is 86%, 52% and 52% in 2020, 2035, 2050 respectively. The 2035 and 2050 figures are based on assumptions of the number of households with solar and solar + batteries as per (Transpower, 2020b).

Solar PV – commercial

Figure 14: Commercial solar PV supply curve

[30] https://www.mysolarquotes.co.nz/about-solar-power/residential/how-much-does-a-solar-power-system-cost/

[31] Ibid



Commercial PV capacity was estimated based on (Transpower, 2020a) projections of commercial distributed capacity, excluding dwellings with systems that have both PV and batteries. . Similar to residential PV, costs for commercial PV depend on the system size. We estimated costs for commercial systems of 10 and 100 kW as per the table below.

Table 19: Commercial PV cost assumptions

	Unit	2021	2035	2050	Source
Experience curve	Average annual cost reduction, %	-4%	-4%	-1%	Based on commercial capex estimates from (NREL, 2020)
PV system lifetime	Years	25	25	25	(MBIE, 2016)
O&M cost	% capex	1%	1%	1%	Estimated based on data from (NREL, 2020)
PV system cost (0.01 MW)	**Annualised cost, $/kW pa**	**$173**	**$101**	**$83**	Assumes a total capex cost of $22,000 in 2021[32]
PV system cost (0.1 MW)		**$142**	**$83**	**$68**	Assumes a total capex cost of $180,000 in 2021[33]

[32] https://www.mysolarquotes.co.nz/about-solar-power/commercial/about-commercial-grid-connect/
[33] Ibid

Solar PV + storage – residential

Residential PV + storage capacity was estimated based on projections on distributed solar generation and battery install capacity from (Transpower, 2020a), and assuming. Based on these numbers, we determined that the proportion of households with solar that also have batteries installed is 30%, 48% and 48% in 2021, 2035 and 2050 respectively. The range of costs in the figure above reflects different PV + storage configurations and reflect the annualised $/kW technology costs less electricity cost savings from being able to inject power back into the grid.

We have used our own estimates of wholesale electricity prices, reflecting an increasingly decarbonised electricity system. These prices are $271, $155 and $154 $/kW in 2021, 2035 and 2050 respectively. The cost assumptions are summarised below.

Figure 15: Residential PV + storage battery supply curve

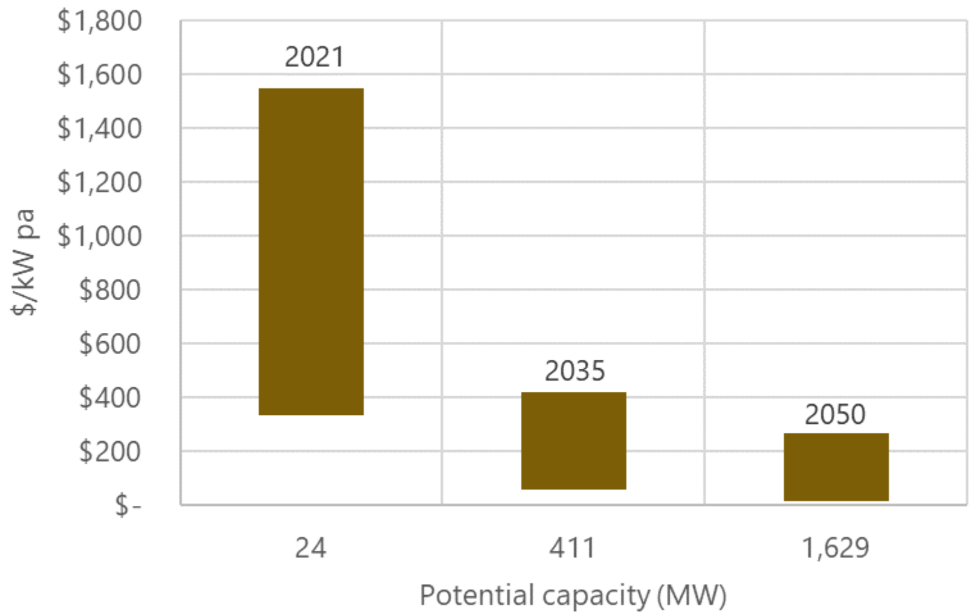


Table 20: Residential PV + battery storage cost assumptions

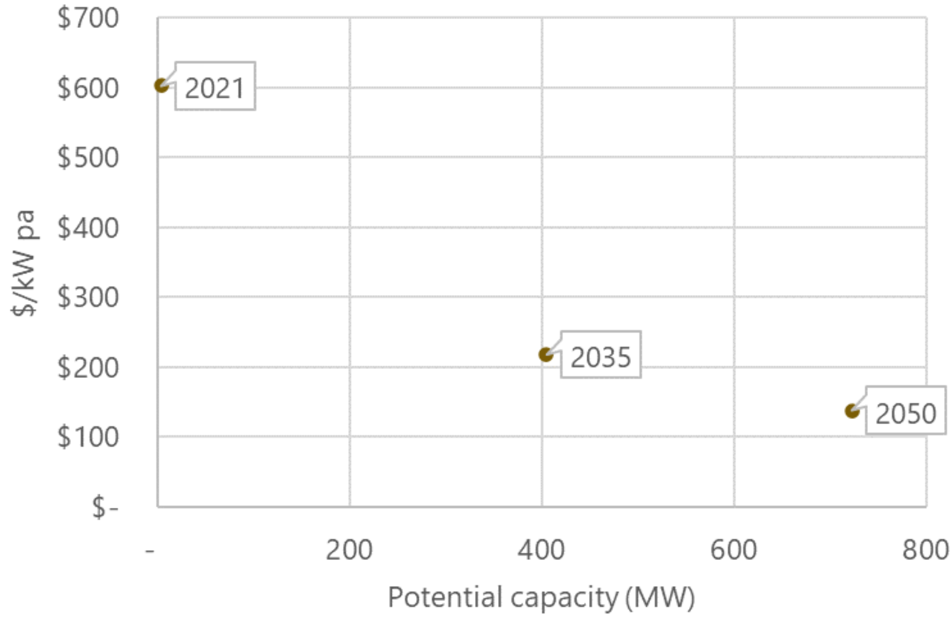
	Unit	2021	2035	2050	Source
Experience curve	Average annual cost reduction, %	-8%	-7%	-2%	Weighted average of experience curves for standalone PV and standalone battery, assuming battery cost out of total PV + storage system cost is 46% (small battery) or 68% (large battery), with the proportions

	Unit	2021	2035	2050	Source
					derived based on data from (Ardani, et al., 2017)
Battery lifetime	Years	10	10	10	(Lazard, 2019)
PV system lifetime	Years	25	25	25	(MBIE, 2016)
O&M costs	% capex	1.2%	1.2%	1.2%	Weighted average of O&M costs (as % capex) for standalone PV and standalone battery
PV (3 kW) + battery (6 kW)	**Annualised costs, $/kW**	**$334**	**$55**	**$12**	Assumes a total cost of $17,000 in 2020,[34] and nets out electricity cost savings
PV (5.6 kW) + battery (3 kW / 6 kWh)		**$578**	**$140**	**$80**	Based on 2016 capex of USD 21,029 based (Ardani, et al., 2017), and excluding US-market specific cost components. Electricity cost savings are then netted out
PV (5.6 kW) + battery (5 kW / 20 kWh)		**$1,213**	**$362**	**$255**	Based on 2016 capex of USD 36,016 based (Ardani, et al., 2017), and excluding US-market specific cost components. Electricity cost savings are then netted out

Solar PV + storage – commercial

Figure 16: Commercial PV + battery storage supply curve

[34] https://www.mysolarquotes.co.nz/about-solar-power/residential/how-much-does-a-solar-power-system-cost/



Commercial PV + storage capacity was estimated using estimates of projected commercial rooftop solar capacity from (Transpower, 2020a), and assuming that the proportion of commercial dwellings with solar that have PV systems with batteries is the same as for residential buildings.

Similar to residential PV + storage systems, the cost estimates above for a commercial system (1 MW PV / 2 MWh battery) are netted of electricity cost savings. The detailed cost assumptions are as follows.

Table 21: Commercial PV + storage cost assumptions

	Unit	2021	2035	2050	Source
Experience curve	Average annual cost reduciton, %	-7%	-6%	-2%	Weighted average of experience curves for standalone PV and standalone battery
Battery lifetime	Years	10	10	10	(Lazard, 2019)
PV system lifetime	Years	25	25	25	(MBIE, 2016)
O&M costs	% capex	1.2%	1.2%	1.2%	Weighted average of O&M costs (as % capex) for standalone PV and standalone battery, assuming battery cost is 47% total PV + storage system cost

PV (1 MW) + battery (0.05 MW / 2 MWh)	**Annualised cost, $/kW**	**$603**	**$218**	**$138**	Assumes a total cost of USD 4,086,500 in 2019 as per (Lazard, 2019), and nets out electricity cost savings

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For more information, please contact:

David Reeve
Mobile: +64 21 597 860
Email: dreeve@thinkSapere.com

Wellington	Auckland	Sydney	Melbourne	Canberra
Level 9	Level 8	Level 18	Level 7	PO Box 252
1 Willeston Street	203 Queen Street	135 King Street	171 Collins Street	Canberra City
PO Box 587	PO Box 2475	Sydney	Melbourne	ACT 2601
Wellington 6140	Shortland Street	NSW 2000	VIC 3000	
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P +64 4 915 7590	P +64 9 909 5810	P +61 2 9234 0200	P +61 3 9005 1454	P +61 2 6100 6363
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