TRANSPOWER

BATTERY STORAGE IN NEW ZEALAND

DISCUSSION DOCUMENT
SEPTEMBER 2017

CONTENTS

SUMMARY

Transpower operates at the very heart of New Zealand's economy, providing connections that power our way of life. Our two roles as grid owner and system operator are interdependent and both are essential for the power system to operate successfully. We work with generators, distributors, retailers and technology providers to power Kiwi homes and businesses.

Electricity is a convenient means of transferring and using energy. In New Zealand, our hydro lakes store energy on a large scale. However, until now we have had limited options to store electricity cost-effectively close to where it is used.

Around the world, battery technology now offers opportunities to store electricity economically, close to where it is used. It can also store local sources of generation, such as rooftop solar, and smooth out the impacts that variable generation can have on the power system. Widespread, distributed storage could, and most probably will, fundamentally change the way that power systems will be operated in the future.

Long-term, we expect that battery or other storage technologies installed in homes, businesses, vehicles, distribution networks and grid substations could alter our transmission business by covering short-term imbalances in supply and demand. We will be able to operate the power system differently, having more flexibility to schedule energy transfers and grid outages to optimise the use of the grid, grid generation and distributed energy resources. We explore these future possibilities in depth in our perspective document, Transmission Tomorrow.

Despite these changes, the services that the national grid provides will be enduring. New Zealand's remotely located renewable generation will continue to be an economic, low-carbon electricity source. Our focus on resilience will continue to deliver essential services to New Zealand communities, households and businesses.

As a critical infrastructure provider, these expectations need to be incorporated into our investment decisions over the short and long term. Developing a realistic view of the future will ensure we continue to provide attractive, cost-effective services that meet our customers' changing needs.

We considered hosting our own trial of grid-connected battery storage, but first we chose to investigate the benefits of battery storage across the electricity supply chain. We did this by investigating the costs, benefits, regulatory, technical and commercial implications of battery storage located in different regions of New Zealand and at each point in the electricity supply chain. We developed various applications for battery storage and considered how these could also provide the services that are required to operate the electricity system. These applications were applied to separate case studies which were evaluated for a range of high-level assumptions using a range of industry metrics.

Our key findings

1. Batteries offer greater value when they are located closer to the end consumer, where there is the potential to provide a range of services both for the owner directly, and upstream to the whole network.
2. The value of these services is unlikely to be realised by the consumer until the appropriate market pricing and payment structures, systems and tools are available.
3. The value of each service at different places in the electricity supply chain varies widely across the country and within individual networks.
4. Grid-connected batteries are not presently economic and we consider these are unlikely to be so before 2022.
5. Distribution-connected or community-scale batteries are expected to be economic from 2020.
6. Some specific commercial or industrial end-consumer battery applications are economic now. The case for these would be further strengthened if Time-of-Use lines charging, combined with full open access to all market energy services, were available.

Where to from here?

Our assessment is that due to the potential for greater revenues and the likelihood of more constraints arising, projects near load centres in the Upper North Island will offer the highest value. Further, we consider that this value increases the closer it is located to end-consumers. Projects at distribution substations or at a consumer level are forecast to be economic in the next few years, due to the falling cost of battery systems.

We do not plan to carry out our own large-scale trials with batteries on the national grid. Instead we will seek opportunities to work with and learn from others by contributing to joint projects where appropriate.

We will also encourage industry changes, such as market reforms, that allow battery owners to maximise the value they can get from owning a battery.

Through our demand response programme, we will continue to engage with early adopters in this space to accelerate the benefits of distributed storage.

The findings from our investigation will continue to help us and the wider industry better understand and prepare for the opportunities and challenges ahead.

Engage with us

Battery storage is only one part of the technology equation. Later this year, we aim to publish a companion report exploring the opportunities and challenges of solar electricity generation.

We hope these papers will contribute to ongoing conversation and development in the electricity industry, and we welcome opportunities to discuss them with you.

CONTEXT

New Zealand's renewable electricity system

Electricity makes up around one quarter of all energy used in New Zealand. It is mostly generated from renewable hydro (58%), geothermal (11%) and wind (8%) sources, located far from major demand centres. Total installed generation is approximately 9500MW and produces approximately 42,000GWhr (151PJ) of electricity each year. Thermal generation (23%) presently has an installed capacity of approximately 1800MW, and we note that during the last three years approximately 1000MW of additional thermal generation has been decommissioned due to market forces. Solar generation (0.07%) mostly comprises distributed rooftop installations, with a total capacity of approximately 50MW. Due to our large base of renewables no explicit subsidies or feed-in tariffs have been developed to encourage renewable wind or solar PV installations.

Our national transmission system operates a core backbone of 220 kV and 110kV lines and a high voltage direct current (HVDC) link between the North and South Islands connecting these renewable generation sources with electricity users across the country. Our arrangement and operation of the HVDC link enables a national frequency keeping and reserves market to be operated across both islands which enables these services to be offered at substantially reduced cost compared to thermally dominated systems overseas.

In terms of electricity consumption, approximately 25-30% is used by residential consumers, and the average household uses approximate 18-25 kWh each day.

Figure 1

NEW ZEALAND ELECTRICITY SYSTEM GENERATION CAPACITY MIX

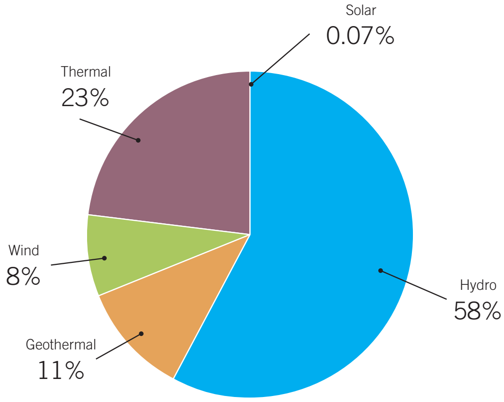
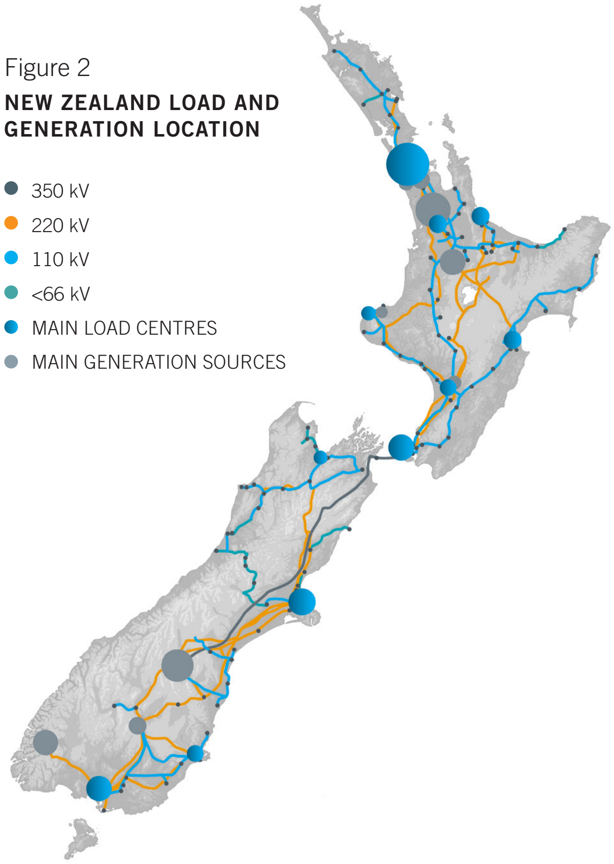


Figure 2

NEW ZEALAND LOAD AND GENERATION LOCATION



Consumer participation in the electricity market

At present, New Zealand electricity consumers have limited ability to participate in their electricity market. New technologies and platforms, integrated into the electricity system, would enable electricity consumers to offer their storage as a resource to others in the system.

Various electricity industry participants have recognised the potential for new technologies to change the sector, and are actively investigating or trialling these at both consumer and distribution level.

In addition to the technical issues, the industry is currently looking at different ways to price services so consumers have the right incentives to use electricity in ways that will reduce their power costs immediately and deliver value for the whole community in the longer term.

Although tools such as peer-to-peer trading and demand response programmes for residential consumers show signs of future potential, many battery services cannot presently be monetised, and developing ways to do this will increase options to realise value for end-consumer battery owners.

The outcomes of these pricing changes and any subsequent market design and Electricity Code changes may alter the way transmission and distribution services are delivered and charged, and how consumers are enabled to participate in the market.

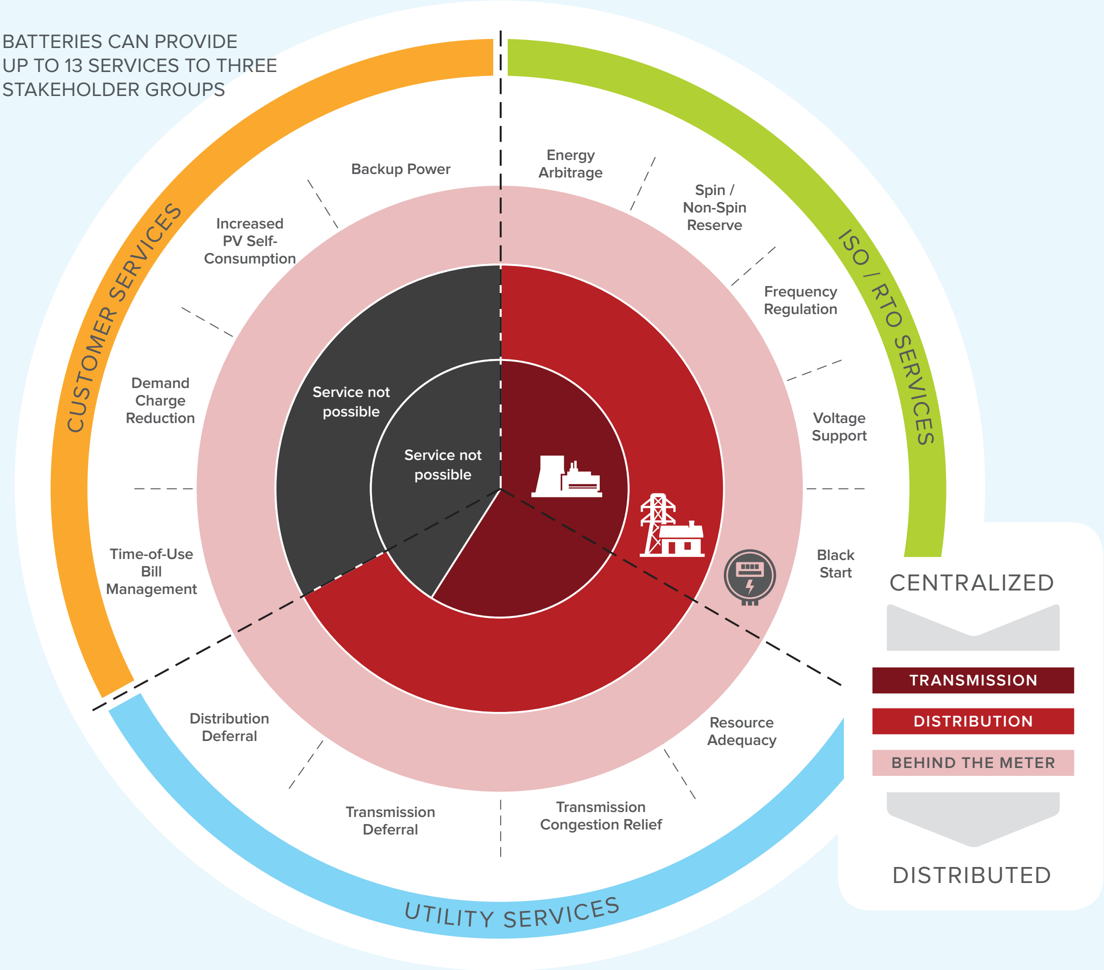
GETTING VALUE FROM BATTERIES IN NEW ZEALAND

Services batteries can provide

International research[1] identifies 13 services that batteries can provide to the electricity system.

Figure 3

RMI BATTERY SERVICES DIAGRAM



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[1] In particular, we relied on the USA-based Rocky Mountain Institute's paper The Economics of Battery Energy Storage (2015). http://www.rmi.org/electricity_battery_value

These comprise four fundamental categories:

- Back-up power supply – keep the power on when there is an interruption in electricity supply.
  - Black start
  - Back-up power
- Moving energy – store energy when it is abundant (and cheap) for use or sale when supply is tighter (and more expensive).
  - Energy arbitrage
  - Time of use bill management
  - Increased solar PV self-consumption
- Manage capacity – reduce demand during peak times, so that less distribution, transmission or generation capacity is needed.
  - Demand charge reduction
  - Transmission congestion relief
  - Transmission deferral
  - Distribution deferral
- Stabilise the power system – help even out variations, restore balance, or improve voltage.
  - Frequency Keeping
  - Instantaneous Reserves
  - Resource Adequacy
  - Voltage support

Most research on this topic reflects international experience with different industry regulations, structures, demand patterns, generation mixes, and environmental and policy obligations than are present in New Zealand. To understand how owners can get value from batteries here, we have analysed the services above and applied them to the New Zealand context.

Determining potential value from battery services

The value of each of the battery services listed above varies by region, location in the electricity supply chain, and demand. This is a result of both market-based revenues driven by supply and demand (particularly seasonal hydrology, growth, weather and plant availability) and non-market based costs driven by spare capacity across transmission and distribution networks.

The high-level analysis for the value each of these services can provide is assessed for different geographic locations in the country and different positions within the electricity supply chain. We apply these values to a series of case studies later in this report.

The figures and tables below provide:

- the assumptions about market prices that we used to determine potential battery value;
- a summary of potential battery value for each service; and
- a summary of potential benefit for each place in the electricity supply chain.

We emphasise that the values given are based on a range of present market conditions, historical trends, industry disclosures and current pricing structures. Deriving revenue from long-term historical trends is not necessarily a predictor for the future, but it does provide a starting point. The services are not necessarily additive, or realisable in all locations. They represent today's market, and do not consider the possible effect that increased storage options could have on market prices. In this report, we consider battery owners as 'price takers' who maximise potential revenue against prevailing market prices.

For the full data around our assumptions and value modelling, see Appendix 1.

Table 1

ASSUMPTIONS ABOUT MARKET PRICES FOR POTENTIAL BATTERY SERVICE VALUE

SERVICES	ASSUMPTIONS
Energy arbitrage	We analysed daily spot price data over a seven-year period (to account for hydrological variations) to calculate an average daily “off-peak” to “peak” market price for each major transmission network region. This difference ranges from ~$15-20/MWh in the South Island to ~$30/MWh in the North Island. We used these values in the case studies for batteries located at generation and transmission network sites; in the commercial/industrial sector we used a typical TOU tariff to determine arbitrage values.
Spin/non-spin reserves	We based our assumptions on 2016-17 year-to-date trends, because our procurement costs have significantly reduced since the upgrades to our HVDC and the introduction of a national Reserves market and multi Frequency Keeping in 2016. The reserve cost is assumed at approximately ~$6/MWh in the North Island and ~$3/MWh in the South Island.
Frequency regulation	We based our assumption on the 2016 average of ~$12/MWh in the North Island and $14/MWh in the South Island. This service is capped at 15MW per Island.
Voltage support	We based this value on equivalent Statcom carry costs of ~$40k/KVA/pa, assuming dynamic reactive support is required. This can be considered an upper bound, acknowledging that voltage support can also be provided from other potentially lower cost options such as capacitors and synchronous condensers.
Black start	We consider that there are limited opportunities for batteries to receive revenue for black start services. The total cost for this service each year is ~ $600k, currently spread across four providers, so we assume $50k pa fixed at generation site only.
Resource adequacy	In a capacity market, this is typically valued as the annual carrying cost of an open cycle gas turbine (OCGT) plus fixed O&M costs.[2] However, given that batteries do not provide the same sustained energy as an OCGT, this is discounted to ~$100/kW/pa to take a conservative approach. We acknowledge there an expected additional upside to battery storage, from the faster response and lower operational cost (avoided start-up and low load running).

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[2] OCGT annual carry cost is ~$150-170/kW/year.

SERVICES	ASSUMPTIONS
Transmission deferral (transmission congestion relief)	The cost of transmission deferral covers a range from both short to long term. We used our Demand Response Programme[3] trial payments as an estimate for short-term substitute for transmission deferral. For long term deferral we used a significant proportion of the capital component of the HVAC interconnection charge. We have therefore assumed a LRMC value for transmission deferral for this report to be in the range \$30-\$80/kW/pa. If transmission upgrades can be deferred or avoided by a battery, then it is assumed the owner will receive payments of similar value via either the Demand Response Programme or a contract with the Grid Owner, but not both.
Distribution deferral	Network costs range from \$100/kW/pa[4] to greater than \$200/kW/pa, depending on the nature of the network. Australia (LV) ranges from \$100-150/kW/pa. The analysis is based on a mid-point of \$150/kW/pa for distribution network expansion costs.
Time-of-Use bill management	Indicative TOU tariff for large commercial customers, including Wellington Electricity's variable lines charges.
Increased PV self-consumption	We assumed that the battery is fully charged with excess solar during the day and discharged over the evening peak, with the avoided costs derived from an average feed-in tariff of 8c/kWh. No allowance has been made for changes to network injection costs.
Demand charge reduction	We used the Wellington Electricity pricing schedule[5] for 300-1500KVA ICPs, at ~\$150/kW/pa.
Reliability/Backup power	There are many factors that go into determining the Value of lost load (Voll) for each customer classification and geographical location. Our assumption in this report is based on the 2013 EA Voll Survey[6] Table 1. Refer to Appendix for a break-down by customer classification. For grid-connected assets, the simple average value of \$25,300/MWh is used to value reliability.

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[3] See https://www.transpower.co.nz/keeping-you-connected/demand-response/our-demand-response-programme

[4] For example, Orion's estimated network long run average incremental cost. Concept Consulting: Electric cars, solar panels, and batteries in New Zealand, Vol 2: The benefits and costs to consumers and society June 2016, Appendix C.

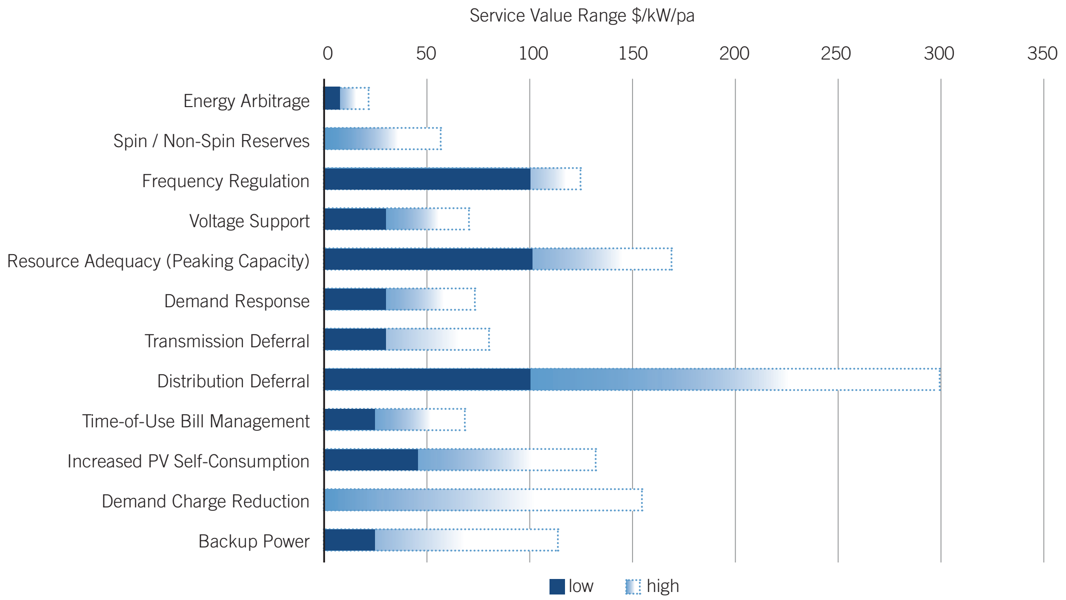
[5] See https://welectricity.co.nz/disclosures/pricing/2017-pricing/

[6] Electricity Authority, Investigation into the Value of Lost Load in New Zealand - Report on methodology and key findings, 23 July 2013 VOLL: http://www.ea.govt.nz/dmsdocument/15385

The value within New Zealand for each of the thirteen services a battery can potentially offer and its range is shown in the following table. It should be noted that the “Black start” service has been ignored as the New Zealand power system offers a low price for black start services compared to other countries. In other fossil-fuelled based electricity systems, the power stations needed to restart the power system are located close to or within major population centres where batteries would also be located – so in theory, batteries can provide this service. In New Zealand, our renewable generation power stations are remote from where batteries will most likely be located, and therefore offer little practical benefit to the power system restart process.

Table 2

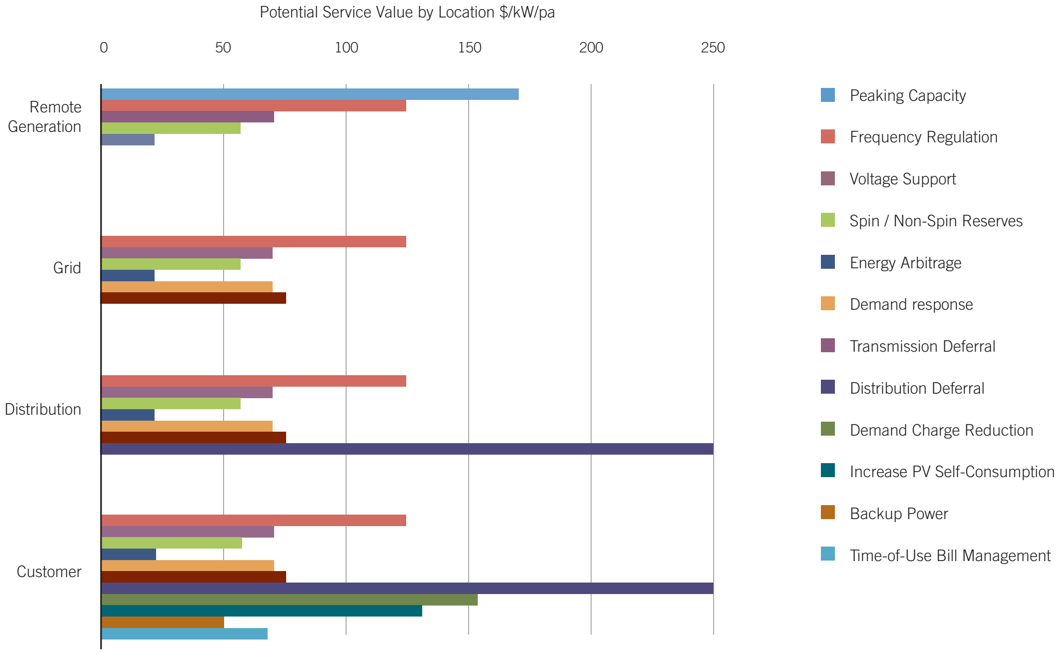
A SUMMARY OF POTENTIAL BATTERY VALUE FOR EACH SERVICE



The following table illustrates how the closer to the end-consumer the batteries are located, the more services and value they could earn if they could participate in all market services.

Table 3

A SUMMARY OF POTENTIAL BENEFIT FOR A BATTERY AT EACH PLACE IN THE ELECTRICITY SUPPLY CHAIN



Revenue from providing battery services

There are some matters to keep in mind when considering how much revenue a case study battery could theoretically provide.

- The battery's location in the electricity supply chain determines which of these services it can provide. Generally, a battery at the consumer end of the supply chain can, from a physics standpoint, provide all these services. A battery located at a distribution substation site can provide fewer, and a battery at a generation site or on the transmission network can provide the fewest.
- Batteries can create the highest value when they are highly utilised, providing multiple services at the same time, or in sequence.
- Some services are not complementary. A battery that is being used to manage capacity will be completely discharged from full to empty and will not be able to provide back-up power supply or stabilise the power system by providing reserves. A battery assigned to provide full back-up power supply would need to be fully charged for maximum effectiveness and could not be used for other purposes. Therefore, when considering the maximum value that a battery could derive from providing multiple services, not all possible revenue streams are likely to be practicable.
- Battery storage can only be assigned to one contracted/paid use at a time. A battery being paid to act as a reserve cannot also provide that same stored energy to manage demand. A battery could assign part of its storage to each activity, but cannot 'double-dip', otherwise system stability could be affected.
- The procurement of grid services in New Zealand is generally low-cost, because of our flexible hydro generation. This means the potential revenue for a battery from providing some services is lower than has sometimes been seen in international examples.

In the New Zealand context, the mechanism to provide these services does not exist at all points in the supply chain. Some services are not presently monetised. Further, market mechanisms or platforms where storage resources can be offered into the market and openly traded through the supply chain do not exist. For battery owners to realise value, these limitations should change.

Some examples include:

- Energy arbitrage – not presently available to residential customers on a fixed or flat tariff, or enabled by existing market tools and rules.
- Voltage support – not required in all regions.
- A battery cannot receive revenue for reserves or demand reduction at times of maximum discharge or at a very low state of charge due to physical constraints and these will need to be reflected in market structures and prices.
- Unconstrained network areas will see no value from transmission/distribution deferral savings or demand response.
- Introducing cost-reflective tariffs has the potential to impact the value of solar PV self-consumption, demand charges and time-of-use bill management for end-consumers.
- Parties may have a different view on the value to them of loss of supply.

In Appendix 2 we summarise these services in the electricity market.

Costs

Below we summarise our assumptions around battery costs. For full details around our assumptions on costs see Appendix 1.

Table 4

KEY COST ASSUMPTIONS

<table>
<tr><th>COSTS</th><th>ASSUMPTIONS</th></tr>
<tr><td>Capital costs</td><td>Based on recent market trends, mid-point costs are assumed for this report to be:
<table>
<tr><th></th><th>Discharge capacity/Storage capacity</th><th>Capital cost</th></tr>
<tr><td>Residential</td><td><10kW/20kWh</td><td>$1250/KWh</td></tr>
<tr><td>Commercial</td><td>≤1MWh/2MWh</td><td>$1500/kWh</td></tr>
<tr><td>Grid Scale</td><td>≥4MW /8MWh</td><td>$1200/KWh</td></tr>
</table>
Thereafter, we assumed costs decline at 10% year-on-year for the next 10 years.[7] The costs are considered to have a variance of +/-40%, based on 2016 OEM and published costs ranging from $900-3000/kWh (depending on the application and specification requirements of the project).</td></tr>
<tr><td>Operational costs</td><td>$30/kW/pa,[8] (~ 1-1.5% of Capex/year)</td></tr>
<tr><td>Efficiency</td><td>88% round trip.[9]</td></tr>
<tr><td>Degradation factor</td><td>-2.21% year-on-year, reflecting a reduction to 80% storage capacity after 10 years.[10]</td></tr>
<tr><td>Charge/discharge cycles</td><td>1-2 per day (refer to Appendix A.1.4).</td></tr>
<tr><td>Discount rate</td><td>7.2% pre-tax real.[11 & 12]</td></tr>
<tr><td>Project life</td><td>15 years.[8]</td></tr>
<tr><td>Depreciation</td><td>10% DV.</td></tr>
<tr><td>Energy price/network cost escalation</td><td>Flat real.</td></tr>
</table>

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[7] Ref Appendix A.1.5.

[8] Lazard's Levelized Cost of Storage Analysis Version 1.0 November 2015.

[9] Based on mid value of 94% charge efficiency and 94% discharge efficiency - EA May TPM report - Page 85 Table 32– refer also footnote 18.

[10] Based on Tesla 10y warranty .

[11] 20 Dec 16, Commerce Commission cost of capital for EDB & TP new IM WACC 5.18% post-tax adjusted to pre-tax at 28% tax rate.

[12] Residential battery cost of capital 5% - no tax applicable to residential income, however GST included in cost of system.

CASE STUDIES

We researched the applications where batteries could be used in New Zealand, and the additional services they might realistically provide. Of all potential options, we have fully developed the five most useful (and economically promising) as case studies, using the revenue and cost assumptions outlined in the previous section. Summaries of these five are presented here.

Location

We considered batteries located in four regions: the upper North Island, lower North Island, upper South Island and lower South Island. We also looked at batteries placed at each location in the electricity supply chain: generation, transmission and distribution substation, commercial/industrial, and residential sites.

Battery use

We defined and evaluated the potential income available to each of these case studies, and assumed that each battery will be utilised for all possible activity by developing a dispatch scenario (refer to Appendix 1).

Typically, the battery in each case study is charged during low price periods overnight and dispatched once or twice each day to earn revenue from the spot market during peak demand periods. Revenue is earned for providing reserves and frequency-keeping services in off-peak times, and we assumed that voltage support services would be available when the battery was not at a low state of charge.

Determining potential value of services

We calculated a net present value for each case study – this is the theoretical maximum value that an optimised battery storage system could receive in an ideal situation. This net present value is based on key assumptions about pricing, cost, and dispatch profile. We also considered several input scenarios for each case study, to compare possible groups of revenue streams.

In tables where we compare these scenarios, we use a simple dollar sign rating to indicate the size of the potential value ($ = some value; $$ = moderate value; $$$ = high value).

Given we expect the cost of batteries to continue to decline, we have compared the potential revenue to present and forecast installed capital costs for 2020 and 2026.

For the full data around our assumptions and value modelling, see Appendix 1.

CASE STUDY 1

GENERATION SITE, NORTH ISLAND

Battery size: 20MW/40MWh

Battery purpose: The battery's primary purpose is to provide energy to cover peak demand, and ancillary services during the rest of the day.

We considered two situations: a battery owned by the generator (merchant plant) and a battery contracted to a generator under a capacity contract (hedged plant).

Figure 4 shows the potential present value of the revenue streams under both scenarios, comparing this to the cost of the battery, both now and forecast in the future. Figure 5 compares the cost of the battery, against the alternative solution (new open cycle gas turbine(s) (OCGT)).

When preparing these Figures we have shown the costs of a battery system today including capital, operating and tax as a stack of bars on the left hand side. We have also shown our expected battery system costs as the stack of bars on the right-hand side. Between these are the potential value stack of services, arranged in different combinations, a battery system may be able to turn into revenue to offset the cost if they were all available to the battery owner today. With regards to the key, for clarity we have separated the revenue stream shown on top, from the cost items at the bottom.

Figure 4

COSTS AND POTENTIAL REVENUE STREAMS FOR GENERATION-SITE BATTERY

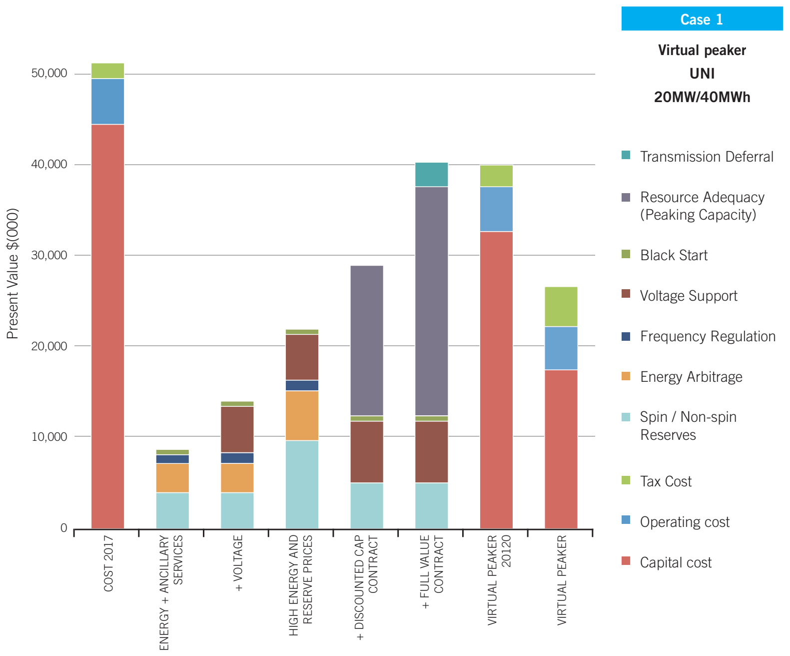
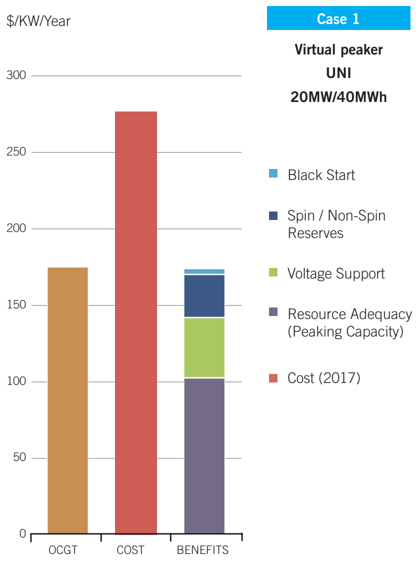


Figure 5

COSTS OF A BATTERY COMPARED TO OCGT ALTERNATIVE



The following table explores the revenue stream value for this case study.

Table 5

REVENUE STREAM VALUE FOR BATTERY AT GENERATION SITE

PRIMARY PURPOSE	REVENUE STREAMS					
	Energy Arbitrage and Reserves	Black Start	Voltage Support	DRP	Capex Deferral	Notes
Energy arbitrage + Ancillary Services	$	$				- $30/MWh arbitrage value for UNI - Black Start contract - Reserve services offered outside peaks - Capacity split each day: 20% Frequency keeping, 80% Reserves
Energy arbitrage + Ancillary Services + Voltage	$	$	$			Voltage support Contact for +/-20MVA
Energy /Reserves prices Increased	$	$	$			- Greater price volatility as supply of peaking capacity tightens, peak to trough spot spread increases from $30-$50/MWh for energy - A tighter reserves and energy market, average annual Reserve prices lifts to $15/MWh
Energy /Reserves prices Increased + Discounted Cap Contract	Reserves only	$	$	$		- Capacity contract to make available 40MWh each day at $100/kW/pa – any energy arbitrage revenue assumed included in the capacity contract - Reserves revenue available - +/- 20MVAR voltage support contract 24/7 - Base Case for Figure 9
Energy /Reserves prices Increased + Discounted Cap Contract + Full Value Cap Contract + Transmission Deferral	Reserves only	$	$	$	$	- BSS close to load centre and can defer transmission upgrades by at least 5 years (1/2 life of battery cycles) or alternatively participate in the DRP if the cap contract is not called Provide equivalent peaking services to an OCGT value lifts to $150/kW/pa - Reserves revenue available - +/- 20MVAR voltage support contract 24/7

Findings: Battery owned by a generator (merchant plant)

A significant increase in the difference between peak and off-peak spot prices and/or ancillary services price would be needed for a stand-alone merchant project to be economically viable.

- An opportunity might emerge after 2020-25, due to the planned closure of thermal plant at Huntly and tightening of the capacity market in the upper North Island as Auckland grows.
- A battery storage system will enable a generator to be more responsive to the National Grid's five-minute dispatch requirements. The battery storage system can "fill in" and dispatch energy to the grid with very short notice while an OCGT starts and ramps up to full capacity, typically over a period of up to 10 minutes. This ability to provide instantaneous reserves will obtain maximum value if spot prices move from the 30-minute average price to a 5-minute price settlement to match physical dispatch.[13]
- There are further benefits for generators in reducing start-up times, short run cycles, minimum stable generation and increasing the response and efficiency of thermal plant. Generators that provide reserves from thermal plant could use batteries instead at much lower marginal cost, creating operational savings. A study of energy storage in California found upwards of US$100/kW/pa value for the avoided start-up costs and variable operations and maintenance. This figure is contextual to the California power system and the operational savings in New Zealand, while positive and increasing the value of such battery storage, are expected to be much lower.

Findings: Battery located at a generator, under a capacity contract (hedged plant)

- This scenario envisages that the battery is under a capacity contract to the generator (for example, owned by a retailer wanting to manage their exposure to high prices).
- Batteries can provide energy for short periods during demand peaks to defer operational costs or replace the need for new OCGT. In a capacity market, this would be typically supported by a long-term capacity contract valued at the carry cost of an equivalent OCGT (approx. $150-170/kW/pa).*
- In the present market, other capacity providers are more cost effective than battery storage (that is, existing peaking OCGT has sunk costs and low operating costs). However, as peak demand grows and existing OCGT plant reaches full capacity, we expect batteries may be cost effective to supply the top of the demand curve, deferring or replacing the need for new OCGTs.
- Battery storage appears comparable on a $/kW/year basis with OCGT, but cannot be compared on an "apples for apples" basis. Although they can both perform similar functions, each has different start-up and short run marginal costs and operating characteristics. In addition to providing capacity at peak times, OCGTs have the added value that they can supply energy on a sustained basis (a valuable feature in a dry year) compared to a battery which shifts energy across the day (little value in a dry year).
- A battery's energy storage capacity is finite – it cannot deliver sustained output like other types of generating plant. A market participant would therefore be unlikely to contract for battery capacity unless it was at a price below the carry cost of an existing thermal plant site, or offered other benefits.
- Given the absence of a liquid capacity market in New Zealand, the Australian market was considered a reasonable proxy indicator of the value of capacity contracts.[14]
- The extent to which the operational characteristics of a battery attract a discount or a premium compared to OCGT is uncertain.

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* Capex recovery @ 10% over 20 years on $1,150 –1300/MW plus fixed operations and maintenance @ $14/MW per year.

[13] We note that the Australian Energy Market Commission has recently started consultation on the impacts of changing their settlement period for the electricity spot price from 30 minutes to 5 minutes. The change has been requested by major energy users to help reduce "distortions" in the market, lower prices, and deliver a signal for battery storage to enter the market with its ability for instantaneous response.

[14] It should be noted a project is under way by ASX NZ Electricity to launch four cap products with $130/MWh and 300/MWh strike prices (at Benmore and Otahuhu).

CASE STUDY 2

TRANSPOWER SUBSTATION SITE, UPPER NORTH ISLAND

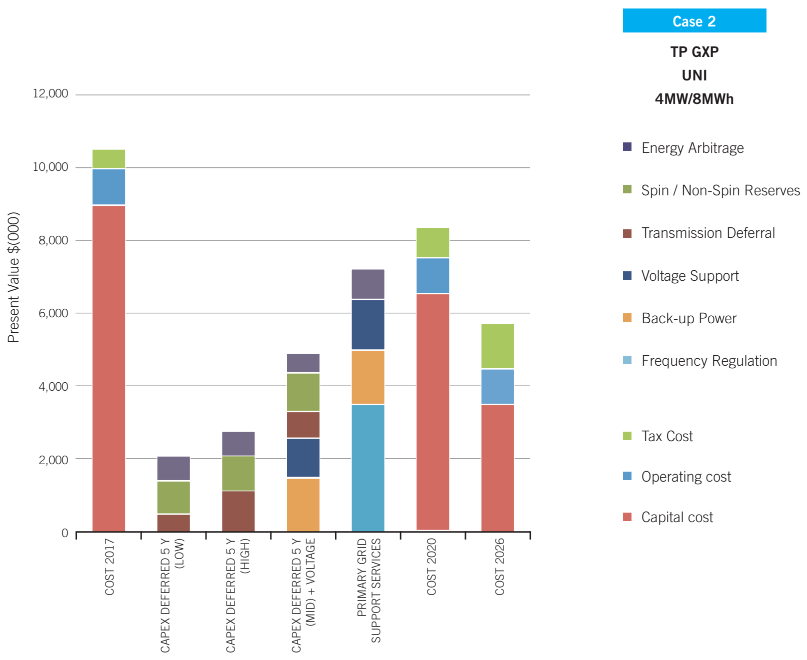
Battery size: 10MW/20MWh

Battery purpose: The battery's primary use is to defer planned capital expenditure, which is required to increase the capacity of the substation. It does this by providing energy during infrequent periods of very high demand for a number of years, until an upgrade is justified. Alternatively, or in combination with capital deferral, the battery could also provide frequency control and voltage management services, and power to some essential users if power supply is interrupted.

Figure 6 illustrates the potential present value of the revenue streams, comparing this to the cost of the battery, both now and forecast in the future.

Figure 6

COSTS AND POTENTIAL REVENUE STREAMS FOR TRANSMISSION SUBSTATION SITE BATTERY



The following table explores the revenue stream groups for this case study.

Table 6

REVENUE STREAM VALUE FOR TRANSMISSION SUBSTATION SITE BATTERY

PRIMARY PURPOSE	REVENUE STREAMS					
	Energy Arbitrage	Ancillary Services	Voltage Support	Capex Deferral	Security	Comments
5 Year Capex Deferral (low) + Energy Markets + Ancillary Services	$	$		$		Primary role is to defer capital spend by 5 years provide Reserves Market Capex spend at LRMC low rate of $30/kW/pa
5y Deferral (high)	$	$		$$$	$	Capex spend at LRMC high rate of $80/kW/pa
5y Deferral (mid) + Voltage support + Backup	$	$	$	$$	$	Capex spend deferred 5 years at LRMC mid-rate of $50/kW/pa Battery provides 8MWh to cover a loss of supply
Grid support services + Frequency + 5y Deferral (mid) + backup		$$$	$$	$	$	Primary role is to provide 24/7 system support in the form of Frequency and Voltage control

Findings: Battery at Transpower substation site

- Capital deferral benefits alone are insufficient to provide a return on investment. However, using the battery for additional services and considering the forecast cost decline for the battery system could mean a project like this would be viable after 2020.
- The value of transmission deferral can be variable, so decisions about batteries for transmission deferral should be assessed on a project-by-project basis.
- The most attractive battery application for the National Grid is likely to be to provide frequency control and voltage support.
- In this case study, the potential revenue is at risk from competing suppliers: if there are a lot of batteries elsewhere on the power system, there may be an over-supply of energy available at peak times, eroding the benefit that this battery could provide.
- The modular nature of battery systems means initial installation could be of the exact capacity required, with the possibility of increasing the storage capacity over time if growth in demand occurs, or relocating the battery if it was no longer needed. This helps lower initial capex and leverages the forecast declining cost curve of batteries over time.

CASE STUDY 3

DISTRIBUTION SUBSTATION SITE, UPPER NORTH ISLAND

Battery size: 1MW/2MWh

Battery purpose: The battery's primary use is to defer planned capital expenditure required to increase the capacity of the substation. It does this by providing energy during infrequent periods of very high demand for a number of years, until an upgrade is justified. Alternatively, or in combination with capital deferral, the battery could also provide frequency control and voltage management services, and power to some essential users if power supply is interrupted.

The graph below shows the potential present value of the revenue streams, comparing this to the cost of the battery, both now and forecast in the future.

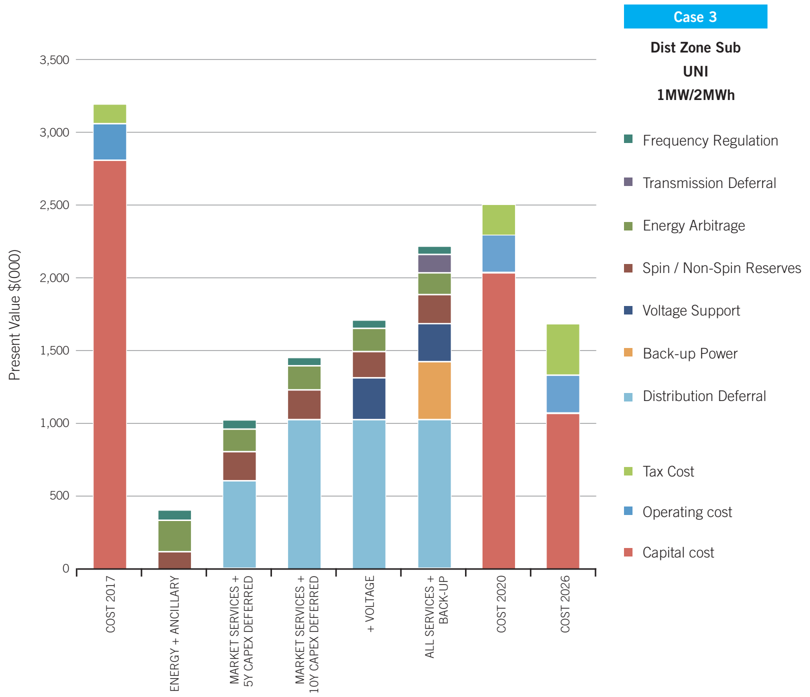


Figure 7

COSTS AND POTENTIAL REVENUE STREAMS FOR DISTRIBUTION SUBSTATION SITE BATTERY

The following table explores the revenue stream groups for this case study.

Table 7

REVENUE STREAM VALUES FOR BATTERY AT DISTRIBUTION SUBSTATION

PRIMARY PURPOSE	REVENUE STREAMS					
	Energy Arbitrage	Ancillary Services	Network Capex Deferral	Transmission Capex Deferral	Voltage support	Notes
Energy + Ancillary Services	$	$				UNI 22KV or 11KV Zone substation
Energy + Ancillary Services + 5y Deferral	$	$	$			Capex spend deferred 5 years at UNI LRMC
Energy + Ancillary Services +10y Deferral	$	$	$			Capex spend deferred 10 years at UNI LRMC
Energy + Ancillary Services + Voltage Support + Transmission Deferral	$	$	$	$	$	Contracted +/-1MVAR 5 year Transmission deferral applicable
All services	$	$	$	$	$	Battery covers a 2MWh loss of supply from the grid at Voll of $25,300/MWh With 10-year capex deferral

Findings: Battery at distribution substation

- As in Case Study 2, capital deferral benefits alone are insufficient to provide a return on investment.
- However, using the battery for additional services and considering the forecast cost decline for the battery system itself could mean a project like this would be viable after 2020.
- The most attractive locations will be at substations with forecast low demand growth, where storage can both reduce peak demand and defer any upgrades.
- The modular nature of battery systems means initial installation could be of the exact capacity required in the first year of need, with the possibility of increasing the storage capacity over time if growth in demand occurs, or relocating the battery if it was no longer needed. This helps lower initial capex and leverages the forecast declining cost curve of batteries over time.

CASE STUDY 3.1

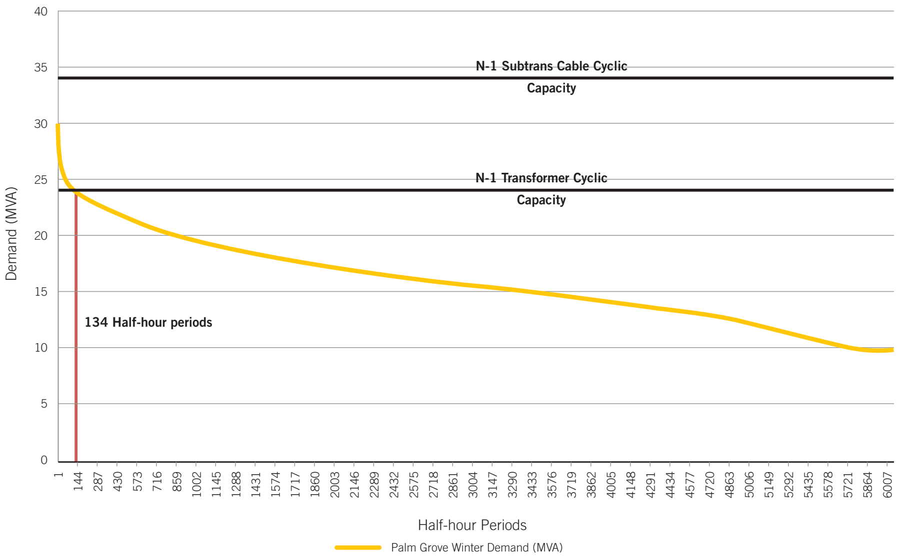
– A REAL-LIFE EXAMPLE:
USING A BATTERY TO DEFER INVESTMENT FOR WELLINGTON ELECTRICITY

Wellington Electricity has investigated different sites where a battery could be used to help defer investment in its network. The example used for this report is based on Palm Grove Substation, which is supplied by double circuit 33 kV underground cables from the Central Park GXP in central Wellington.

Palm Grove substation supplies 10,000 customers and essential water pumping and medical facilities. The transformers are in good condition but have high criticality due to peak loading. The sustained winter peak demand at Palm Grove currently just exceeds the capacity of the two 24MVA transformers. This is currently managed by operational controls after an event. As demand increases, a further network solution will be required.

Figure 8

WINTER LOAD DURATION AT PALM GROVE SUBSTATION



Wellington Electricity has determined that a 1 MW/2MWh battery, reducing the peak load on this substation, would defer the need for additional capital expenditure of approximately $3m by five years.

Figure 9 below shows the potential present value of the revenue streams and compares this to the cost of the battery, both now and forecast in the future.

Figure 10 compares the cost of the battery and the cost of the alternative solution, a diesel generator.

Figure 9

COSTS AND POTENTIAL REVENUE STREAMS FOR BATTERY AT PALM GROVE SUBSTATION

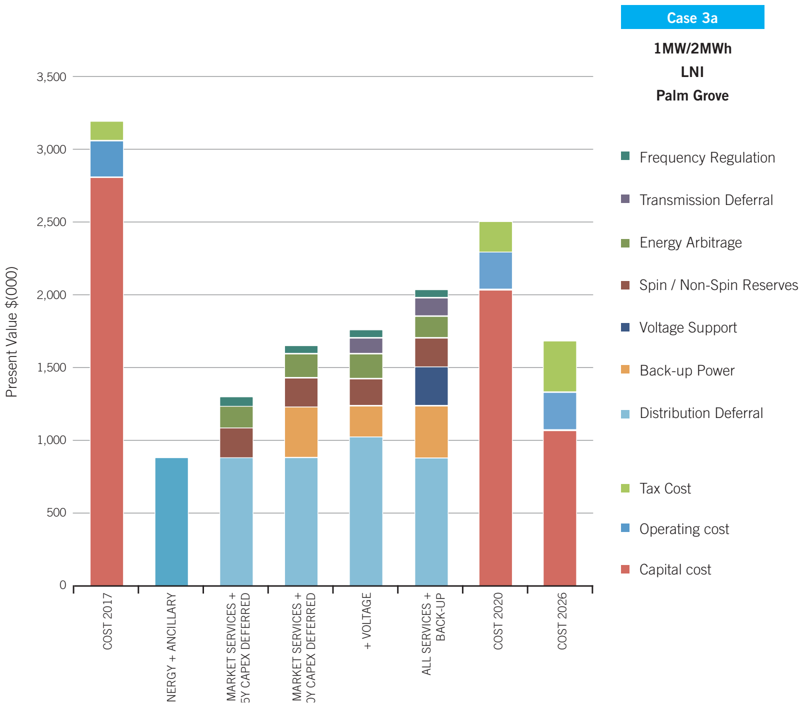
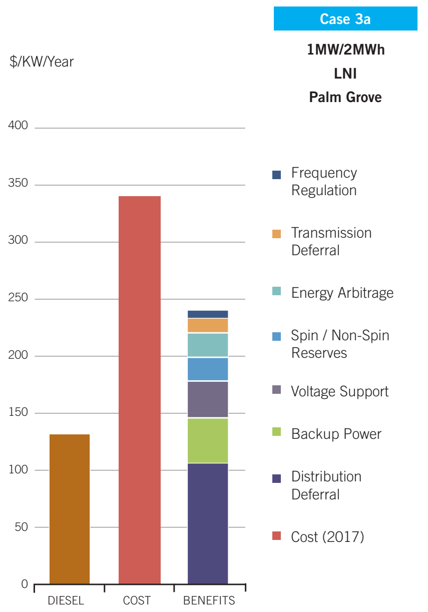


Figure 10

SOLUTION COSTS AND POTENTIAL BATTERY BENEFITS FOR PALM GROVE SUBSTATION



The following table explores the revenue streams for this case study.

Table 8

REVENUE STREAMS FOR BATTERY AT PALM GROVE SUBSTATION SITE

PRIMARY PURPOSE	REVENUE STREAMS						
	Distribution capex deferral	Energy Arbitrage	Ancillary Services	Security	Transmission Capex Deferral	Voltage support	Notes
5y Deferral	$						$3m deferred 5 years
5y Deferral + Energy + Ancillary services	$	$	$				Arbitrage and Reserves + Frequency Keeping
5y Deferral + Security	$	$	$	$			Backup: 2MWhr essential services supply at Voll of $25,300/MWh
5y Deferral + 5 year Transmission Deferral	$	$	$	$	$		5 year deferral of TP Central Park upgrade Base Case Figure 16
All services	$	$	$	$	$	$	Contracted +/-1MVAR voltage support

Findings: Battery at Palm Grove substation

The five-year deferral equates to approximately $100/kW/pa in the long run.

- Using the battery for additional services as well as the savings from deferring investment indicates a battery could be a viable alternative after 2020 as battery costs decline, particularly if this project also defers upgrade costs up-stream on the Central Park/Wilton transmission infrastructure.
- A battery of this size could be redeployed elsewhere at the end of the deferral period at Palm Grove.
- The battery offers several hours of back-up power to Palm Grove's essential water pumping and medical feeders.
- Given Palm Grove's location in the lower North Island, it is unlikely that voltage support contracts would be available or that revenue would be derived from Transpower's Demand Response Programme.
- Assuming demand response has been fully utilised already, a standby diesel generation set would be a lower cost alternative for Wellington Electricity. However, this comes with high operating and management costs and environmental impact considerations as well as consenting and planning constraints.

CASE STUDY 4

BATTERY AT A COMMERCIAL OR INDUSTRIAL SITE, UPPER NORTH ISLAND

Battery size: 100kW/200kWh

Battery purpose: the primary purpose is to lower the owner's electricity bill by:

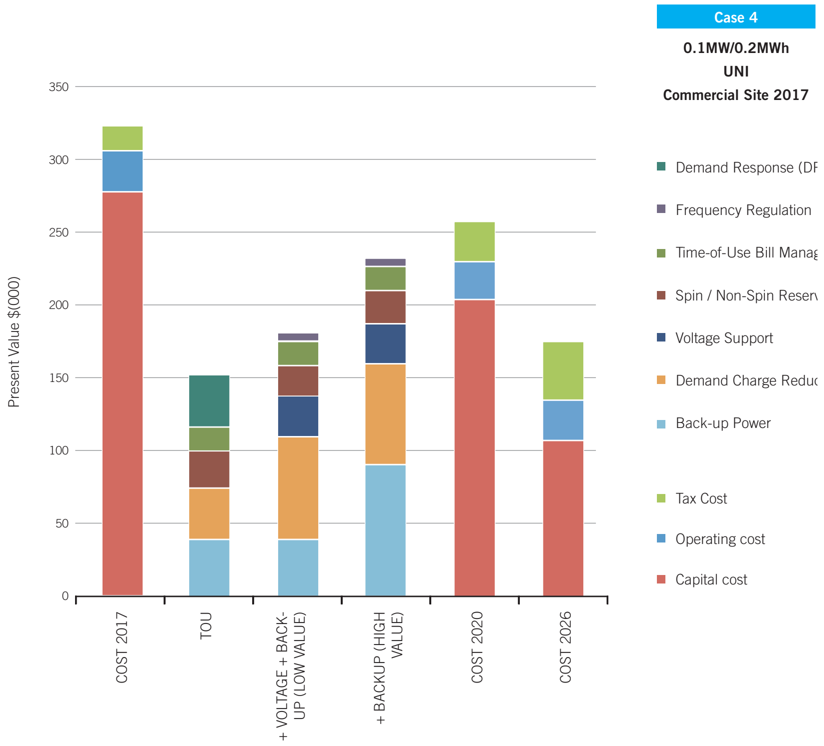
- moving energy to better manage peak demand charges and move use into the lower priced time periods;
- providing back-up power supply for essential systems (such as lighting, EFTPOS/IT systems, other critical processes); and
- participating in demand response programmes and reserve markets.

In this example, we assumed the battery site has consumption lower than 1GWh pa, such as a manufacturing facility or medium sized retail site. We also assumed that energy use at the site is low overnight and generally flat during the day, and that the owner is on a time-of-use energy plan with network charges generally comprising a demand charge based on highest peaks over a defined period.

Figure 11 shows the potential present value of the revenue streams and compares this to the cost of the battery, both now and forecast in the future.

Figure 11

COSTS AND POTENTIAL REVENUE STREAMS FOR BATTERY AT A COMMERCIAL OR INDUSTRIAL SITE



The following table explores the revenue streams for this case study.

Table 9

VALUE ASSUMPTIONS FOR BATTERY AT INDUSTRIAL OR COMMERCIAL SITE

PRIMARY PURPOSE	REVENUE STREAMS					
	Energy Arbitrage	Security	Ancillary Services	DRP	Voltage support	Notes
TOU Bill Management +DRP	$	$	$	$		Load shifting to manage a 25% demand charge reduction Participate in DRP[15] Energy arbitrage on TOU IR Market revenue Backup of essential services at the average Voll of $25,300/MWh
TOU Bill Management +DRP + Increase avoided demand charges + Frequency	$	$	$		$	Load shifting to manage a 50% demand charge reduction Add Frequency Keeping Services Backup of essential services at the average Voll of $25,300/MWh
TOU Bill Management +DRP +Backup (high value)	$	$	$		$	Backup of essential services at the higher Voll rate for “Small Non-residential” rate of $57,000/MWh

Findings: Battery at industrial or commercial site

- This case study is potentially feasible after 2020, depending on the dollar value the customer places on security of supply. (If security of supply is highly valued, it could be sooner as it represents a good investment).
- As a significant part of the potential value is related to managing electricity costs and avoiding peak network charges, the final value will depend on the future shape of the current Transmission and Distribution pricing reviews. In areas where demand is growing, the move to more cost reflective/demand responsive pricing signals is expected to enhance battery value. On the other hand, in areas where demand is flat or declining, there may be no benefit as the network will likely only offer capacity-type charges.
- The potential to add solar PV may further enhance the case for a battery.

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[15] Participation in our demand response programme may be unrealistic if the battery is already managing peaks to avoid demand charges. Therefore, It is replaced by a greater reduction in demand charges in subsequent analysis.

CASE STUDY 4.1

– A REAL-LIFE EXAMPLE: NORTH ISLAND SUPERMARKET

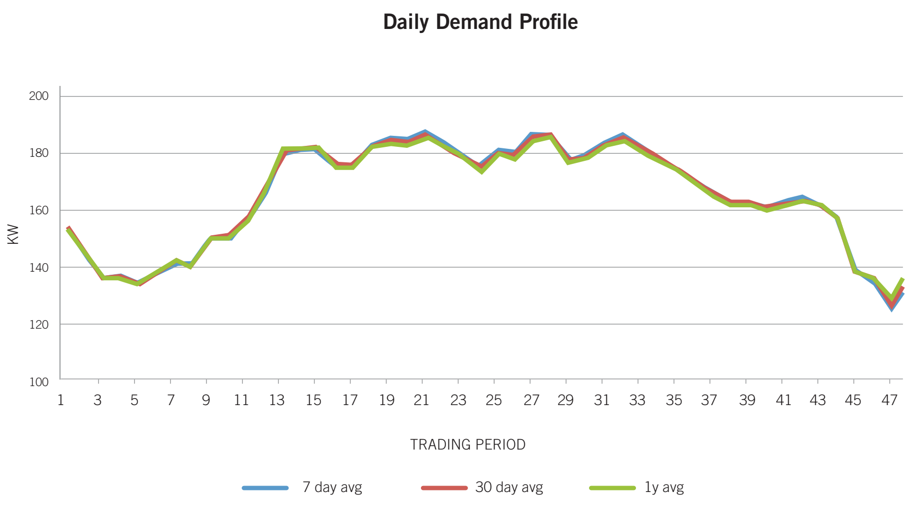
A typical supermarket has a very consistent daily demand profile with approximately 1.5GWh/pa consumption.

The site studied in this example is on a time-of-use energy account, with lines charges dominated by a peak demand charge set by the highest half-hour demand in the previous month.

The site has a reasonably flat daytime electricity use, averaging 180kW.

Figure 12

PROFILE OF DAILY ELECTRICITY DEMAND AT A NORTH ISLAND SUPERMARKET.



A closer look at the half hour data shows arbitrary peaks spread across the day.

Figure 13

PROFILE OF ELECTRICITY USE BY 30-MINUTE PERIOD AT A NORTH ISLAND SUPERMARKET.

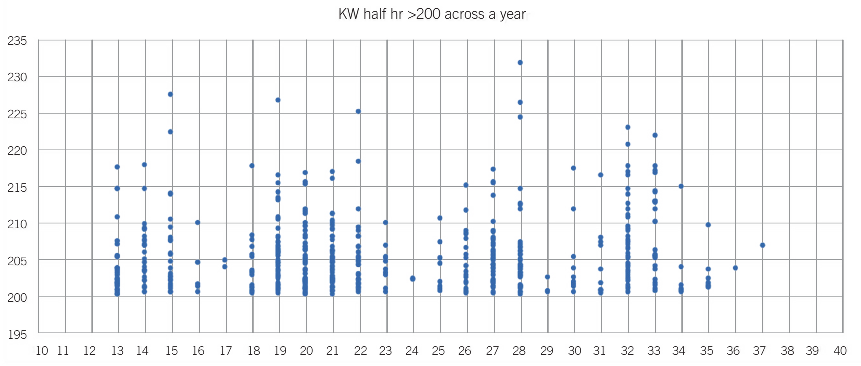


Figure 14

PROFILE OF ELECTRICITY DEMAND BY AVERAGE WEEKLY PEAK AT A NORTH ISLAND SUPERMARKET.

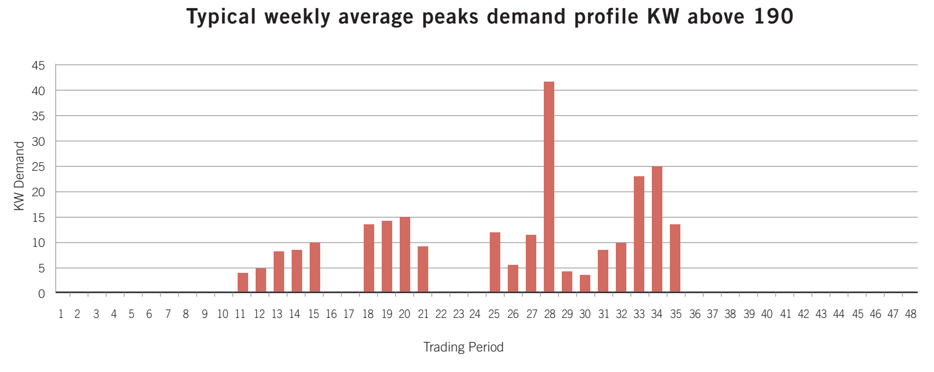
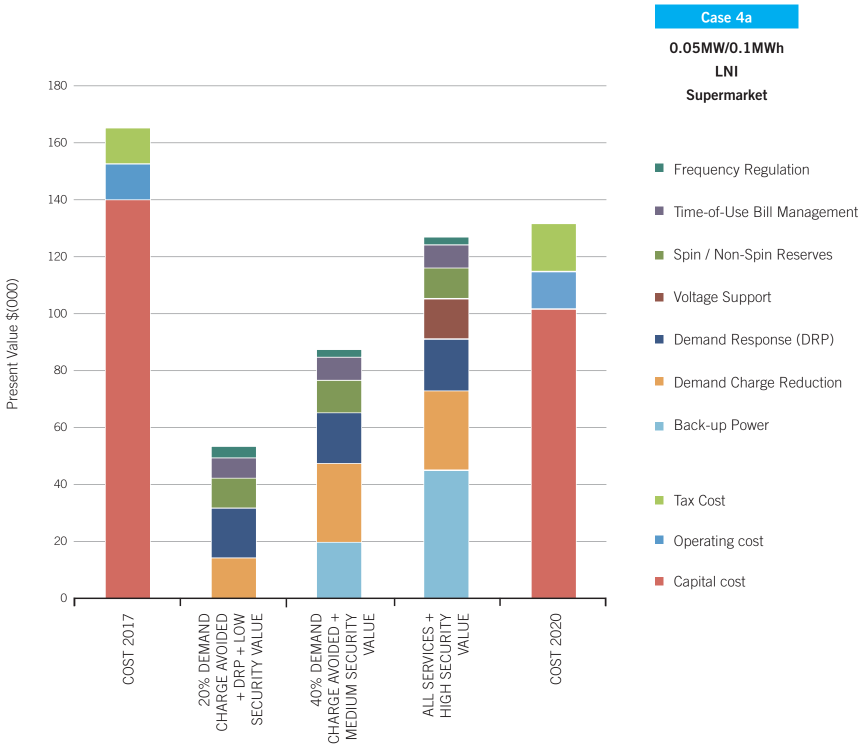


Figure 15 shows the potential present value of the revenue streams and compares this to the cost of the battery, both now and forecast in 2020. It can be seen that it follows a similar trend to the generic commercial case study but with differing values, and is expected to be at a breakeven point 2020 and therefore economic by 2026.

Figure 15

COSTS AND POTENTIAL REVENUE STREAMS FOR BATTERY AT A NORTH ISLAND SUPERMARKET.



Findings:

Battery at large North Island supermarket

- We found an 18% reduction in demand charges was possible (the battery was theoretically sized to manage peak demand greater than 190kW, requiring a 50kW/200kWh battery).
- This suggests that a relatively small battery would reduce demand peaks and avoid a percentage of network lines charges.
- Alternatively, smarter energy management may be a much lower cost alternative, depending on what is driving the times of high energy use.
- A significant factor in deriving value for this battery is how much value the customer places on having back up power to maintain supply.
- A significant part of value is related to lowering the electricity bill and avoiding peak network charges. The final value will be dependent on the future shape of the current Transmission and Distribution pricing reviews. The move to more cost-reflective/demand-responsive pricing is expected to enhance the battery value as charges are further profiled to increase the difference in prices between periods of low and high system demand.
- The addition of multi-market based services is required to generate attractive returns after 2020.

CASE STUDY 5

BATTERY AT A RESIDENTIAL PROPERTY

Battery size: 3kW/6.5kWh

We considered two situations: one where the house already has a 3kW solar PV already installed (as a sunk cost), and one where the house has a battery only.

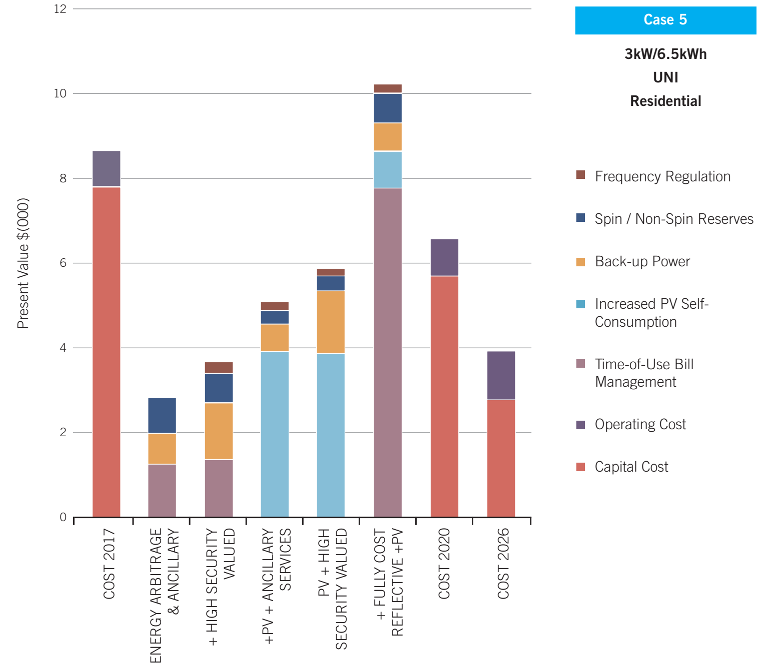
We assumed the home consumes 20kWh/day (the national average for electricity use), and pays approximately 26c/kWh for electricity consumed.

The house with the solar PV can produce 10kWh/day. 30% of this is consumed by the home and 70% is used to fully charge the battery; any residual energy is bought back by the electricity retailer at 8c/kWh.[16]

Figure 16 shows the potential value of the revenue streams compared to the cost of the battery, and the forecast costs for 2020 and 2026.

Figure 16

COSTS AND POTENTIAL REVENUE STREAMS FOR BATTERY AT A RESIDENTIAL HOME



The following table explores the revenue streams for this case study.

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[16] Concept Consulting: Electric, solar, and batteries in NZ Vol2 page 28, June 2016. This is a blended rate of Low User Fixed Charge & Standard tariffs and is broadly in line with the Ministry of Business, Innovation and Employment 2016 Quarterly Retail Sales Survey Report.

Table 10

REVENUE STREAMS FOR BATTERY AT RESIDENTIAL HOME

PRIMARY PURPOSE	REVENUE STREAMS				
	Energy Arbitrage	Security	Ancillary Services	Solar PV	Notes
No Solar PV + Energy arbitrage + Reserves	$	$	$		Reserves market Energy on TOU tariff[17] Fixed rate consumption based lines charges
No Solar PV + Customer Values Security of Supply +Frequency	$	$$	$		Value of Lost Load (VOLL) is increased to national average of $25,300/MWh Frequency Keeping Market
PV Self-Consumption Maximised +Frequency + Reserves		$$	$	$	Maximise PV self-consumption – based on avoiding Standard Tariff Fixed rate consumption based tariff
PV + Higher Value on Security +Frequency + Reserves		$$	$		Voll increased to national average of $25,300/MWh Base Case for Figure 24
PV All services, with fully cost-reflective tariffs	$$	$	$		Fully cost reflective tariffs replace standard flat tariffs - Indicative tariff structured[18] to reflect estimated total cost of system peak capacity PV avoided costs much reduced[19] due to cost reflective tariffs lowering solar value over day time low demand period

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[17] TOU energy only tariff assumed to reflect on average 17c/kWh off-peak and 25c/KWh on-peak.

[18] Based on a strawman cost reflective tariff structure of: 8c/KWh overnight, 45c/kWh over peaks, 12c/kWh during the day and 18c/kW in the evening. This is based on achieving bill-equivalency to the current average consumer's bill of ~$2000/pa and assuming no fixed charges with a shape across the day that reflects typical system peak costs for network and energy.

[19] Feed-in tariffs are assumed to remain at 8c/kWh thus the PV avoided cost drops to 12c/kWh minus 8c/kWh = 4c/KWh.

Findings: **Battery at residential home**

The primary benefit is to increase resilience/security and, for the house with the solar, to maximise self-consumption of the solar PV to get the benefit of avoided energy costs (at net approximately 18c/kWh.

- The value available at a residential level is unlikely to be fully realised until cost-reflective/demand-pricing structures are introduced, and arrangements are established to monetise all services that batteries can offer.
- On the flat tariff structure, no revenue is available from providing market services.
- In the event that cost-reflective tariffs/demand response pricing is widely adopted, it is assumed the battery storage system would have potential to earn income by moving energy and reducing peak demand. This would capture more value for the owner and provide the greatest benefit to the system as a whole.
- Competition for supply of residential systems is expected to increase, keeping a downward pressure on price.
- Depending on the final structure of cost reflective pricing signals, batteries under a cost-reflective tariff are expected to be largely viable even without photovoltaic benefits. In this case, photovoltaic would likely not be installed in a new home build, because a battery would already benefit from charging overnight from the network at a much lower cost than new photovoltaic arrays.
- Voltage control services have not been included as it is expected that network embedded distributed generation equipment standards will soon mandate minimum performance requirements, meaning voltage control may not be available as a paid service at residential level.
- It is not possible to pay individual residential consumers for all battery services using present market tools, systems, and platforms. This is an area of significant opportunity that if addressed could harness collective system benefits of dispersed batteries.

COMPARING BATTERY VALUE AND LOCATION

As an overall comparison, we have evaluated the value that batteries provide in two ways. The first compares normalised net present value of the battery in each case study – one at each location in the supply chain. The second compares the cost of delivering the next unit of electricity at peak times to consumers through the traditional system – generation plus transmission and distribution costs – and through alternative options at the consumer end. Both methods and their results are presented below.

Battery value along the electricity supply chain

To compare our case studies, we have calculated a normalised value of storage that uses the net present value of each and divides it by the capacity provided (details of our assumptions about value and cost are in Appendix 1).

Based on 2017 capital costs and revenue assumption (blue bars), batteries are unlikely to be the best value option for the scenarios we have covered. The highest value locations (lowest costs) are generally toward the consumer end of the supply chain.

When looking ahead to 2020 (red bars) with the forecast capital cost reductions, the value increases across all case studies, but still does not indicate positive returns.

The shaded red and blue bars in case study 5, the residential battery site, indicate the potential impact if a form of fully cost-reflective pricing for networks and network ancillary services was introduced.

After 2020, costs are forecast to decline further to the point where battery storage is expected to have positive returns at distribution, commercial and residential levels if all services can be monetised, and cost-reflective pricing implemented.

Figure 17

COMPARING OVERALL VALUE BETWEEN CASE STUDIES

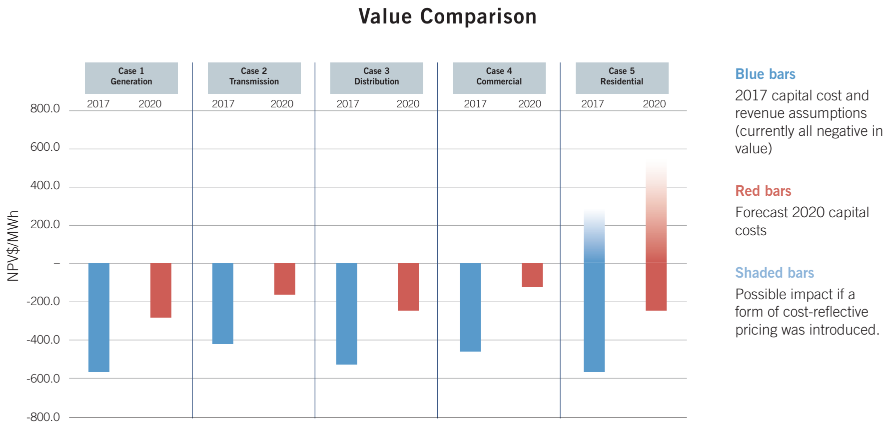
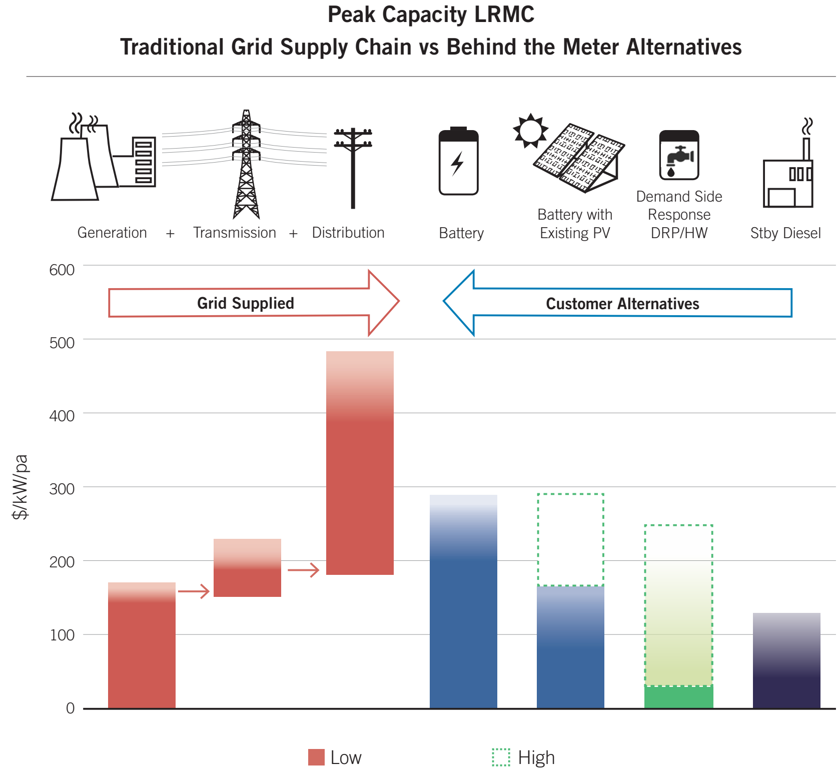


Figure 18

COSTS OF TRADITIONAL ELECTRICITY SUPPLY CHAIN VS CONSUMER ALTERNATIVES



Supply chain peak energy costs

An alternative way to consider the value of battery storage is to compare the traditional supply chain costs of providing power during demand peaks with consumer-provided alternatives.

Cost of traditional supply chain

With reference to our assumptions outlined in Appendix 1, we assume:

- the cost of peak generation is the annual fixed carrying cost of a gas-fired OCGT (approximately $150-170/kW/year);
- the cost of transmission is the long run marginal cost (LRMC) (approximately $30-80/kW/year);
- the cost of distribution lies within the range of lines company LRMCs for providing peak capacity;
- tariff structures are ignored; and
- normal hydrology applies.

This indicates that the fundamental value of peak capacity is in a range of $180-$450+ kW/year, depending on spare system capacity. This is shown by the red bars of Figure 18.

Value of consumer alternatives

The multi-coloured bars of Figure 18 indicate that consumer alternatives could provide peaking capacity at lower cost than the traditional supply chain. For example the use of Demand Response by end consumers is considerably cheaper ($25-250/kW/year) and better value to the end consumer than purchasing centrally generated electricity that needs to be transported across the transmission and distribution networks $180-$450+ kW/year. This finding supports activity already occurring in this space, such as our demand response programme and controllable load tariffs.

However, this finding does not remove the need for the electricity supply chain. Unless a consumer was to install sufficient self-generation and storage to cover all their energy demands, all the time – even during energy scarcity and high demand – the supply chain is still required, as a battery does not generate energy itself but stores energy already generated.

In cases where consumers had an optimally sized solar PV array, the advantages of matching that with a suitably sized battery could offset the battery size, and therefore cost.

As can be seen in Figure 18, the lowest cost option for procuring power during peak demand is demand response programmes, either from existing hot water heater control or, in future, smart appliances like heat pumps, refrigeration or HVAC enabled to respond to real-time load control signals.

We expect that demand response will likely be aggregated by third parties, who will sell the power to industry programmes or directly into the market. Demand response through standby generation will continue to be an option for large organisations that value resiliency, but due to fuelling, environmental and maintenance overheads we do not expect these to be a practical alternative to residential customers.

COMBINING BATTERIES FOR VALUE

The services we outline earlier in this report could be provided by individual, large-scale batteries or many small-scale batteries working together in combination. This could deliver the same real benefits, while lowering overall costs of the power system for New Zealand electricity consumers as well as reducing the costs of battery installation and operation.

Batteries installed at transmission or distribution level tend to be larger and relatively easy for the owner, already present in the industry, to coordinate and supply the required service.

To avoid building new transmission and distribution infrastructure to meet demand peaks, which are all major drivers of costs, smaller battery systems could supply these same services, but would need to be able to deliver them in an aggregated way to the same level of reliability, security and capacity.

When connected, batteries that are smaller and widely dispersed (such as those at an industrial, commercial or residential level) present more opportunity in terms of range of services, but also more complexity in terms of management and coordination.

The greatest challenge is not the technical performance but the manner in which small battery installations can be co-ordinated and paid for their contributions.

As an example, in the future we will need an additional 400MVar of reactive support in Auckland. A technically straightforward, reliable, controllable secure option is to provide a grid-installed Static Var Compensator (STACOM). This would cost approximately $60-80M to build, or approximately $5m each year. This same 400MVar service could be provided by a collection of individual residential batteries, should a suitable technology platform or aggregation service be available. This would require access to approximately 100,000 5kW batteries every day for a number of hours. The amount battery owners could be paid for providing this service could be no more than the cost to provide the STATCOM – which in this case would work out at around $50 per year per household battery.

Virtual power plants

The concept of a virtual power plant (VPP), where batteries are connected by an intelligent control system, and integrated with other forms of load control or on site electricity generation is well established. This aggregated battery model has been trialled internationally and is presently being explored by various parties in New Zealand.

Most of the time, a virtual power plant will help electricity consumers to self-consume stored solar power, benefitting the battery owner and their broader community to manage peaks in demand. The largest issue with any VPP is how much of a connection it retains to the existing network and when it will utilise that connection. Requiring networks to provide peak energy does not address key design and capital issues for networks, which include provision of energy at peak times.

We have been following the work in this area of AGL Energy[20]. Their trial proposes to assist consumers to maximise self-consumption of their solar power and reduce demands on the network for their benefit and the broader community.

Buying and selling power peer-to-peer without using a retailer is not presently possible in the New Zealand market, but systems and structures are set to change. Vector is trialling an energy trading platform allowing customers to buy and sell electricity without using a traditional retailer.

Electric vehicles

Although there are currently only around 3000 electric vehicles in New Zealand, Government policy is targeting 64,000 vehicles by 2021/22. In future, we expect that electric vehicle batteries could have the capability to be part of a battery network, providing services when the vehicle is plugged in to charge overnight. Manufacturers have the technology to enable this, but systems are still in early development and are not expected to be available in New Zealand in less than 3-5 years. Again, the key issue is not technical, but how to integrate trading capacity of the energy storage device – in this example, with the additional ability to be mobile – and as such its value to the network may vary in terms of geography and time.

Solar PV

New Zealand has around 13,000 solar installations, totalling approximately 50MW in solar energy capacity. Ninety-five percent of this generation capacity is located at homes or businesses. At present, this represents just 0.77% of the total system peak demand of 6,500MW. During peak solar output in summer this might reach 2%, still a relatively insignificant value in the current system. We have been studying the potential benefits and challenges of integrating this alternative renewable generation source into the network and will publish our research later in 2017. Batteries add to the ease with which solar PV is introduced to the electricity system, but also add to customer installation costs.

Visibility challenges

As energy storage and solar PV increases, challenges may arise for the System Operator because stored energy and solar PV is largely invisible and masks underlying demand. This may make it more difficult to forecast supply and demand, and to coordinate and manage the ancillary services required to maintain a stable and robust grid.

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[28] For further information, see Appendix A.4

FINDINGS

Our purpose has been to identify where batteries offer the greatest value to electricity consumers, and the New Zealand electricity system. Our six findings are explored below.

1. The greatest value in storage is when it is located close to end consumers

- Batteries offer the greatest value when located as close to the consumer as possible, where there is the potential to provide a range or stack of services both for the owner directly, and upstream to the whole network. This aligns with overseas experience and our own in relation to addressing power factor correction issues.
- The value of energy arbitrage is relatively low in New Zealand compared to other countries, due to the nature of our large flexible renewable generation base. Under most conditions, our hydro system coupled with the upgraded HVDC link reduces the volatility of intra-day prices and the large sustained price spikes evident in thermal dominated systems. In the medium term, energy arbitrage value is likely to continue to be driven by existing hydro storage costs.
- Our Reserves and Frequency Keeping Markets have evolved over recent years and procurement costs have dropped significantly. This removes significant value compared to thermally dominated overseas markets where CCGT's and OCGT's are cycled and run at less efficient part-load to provide these services.
- Auckland's forecast load growth is expected to increase the need for system stability services to provide voltage support and reserves in the Upper North Island. The extent of this will largely depend on the timing of the eventual retirement of the remaining Rankine units at Huntly.

2. Existing markets, tools and systems limit the ability of end consumer storage to participate in all value streams

- The value available in New Zealand at the consumer level is unlikely to be fully realised until cost-reflective/demand pricing structures are introduced, signaling the true cost of system capacity and associated arrangements established to monetise all services that batteries can offer. To achieve appropriate market pricing and payment structures, systems and tools will need to be developed and made available.
- Not all service values are readily accessible or have a transparent market mechanism to monetise their worth (for example, voltage support is currently provided by grid assets or contracted directly with third party asset owners). Under the present Electricity Industry Participation Code, generators are not paid for their voltage support service and, under the present arrangement, neither would batteries.
- The value of batteries acting as both loads and reserves, having the ability to be able to provide very fast acting reserves should be able to be realised. To achieve this, 5-minute dispatch will be required so that the provision of precise, reliable and robust performance is able to be confirmed and then rewarded.
- The functionality of a battery as both a load and a generator at various times will need to be examined, and regulatory and technical barriers to entry addressed in the current Code to enable batteries to monetise the multiple services they offer.

3. The value of the service that each battery can obtain varies widely across the country and the location within the electricity supply chain

- We noted that the market based values for various services will fluctuate and are at risk of considerable volatility. This may be due to an increase in peaking generation and demand side participants as a result of increased penetration of batteries. Investments in grid scale batteries relying on energy arbitrage revenue could well be undermined by the organic increasing penetration of behind the meter Battery Storage System (BSS) and Electric Vehicle (EV) to home/business/Grid - together referred to as Vehicle to Grid (V2G).
- Increased penetration of residential solar PV and utility scale wind generation may see existing conventional/baseload thermal generation plant become less economic to run. This would lead to increased energy price volatility and improve the value of storage as the balancing technology.
- Deferral of capital spend on traditional network infrastructure is very location specific and on its own is not expected to provide a return on investment for a battery for some time at either a Grid or Distribution level (the exception being a location with very low load growth).
- Container based BSS's in the order of 1-2MW have the advantage that they can be implemented relatively quickly to target specific grid constraints in a controlled manner. They can be "right sized" for the first year of need with the possibility of increasing the storage capacity over time if load growth occurs. This would optimise initial capital expenditure and leverage the declining cost curve of future expansion. To address the downside the BSS modules are further expected to be readily relocatable to address any potential stranding risk if the need no longer exists.
- Customer level implementation of behind the meter storage is expected to happen organically not necessarily for purely economic reasons. Customers will value increased PV self-consumption, resiliency, energy cost certainty, perceived environmental benefits and cost of capital differently. This also applies to EV's. The increase in behind the meter storage is therefore expected to be dispersed and benefits may be of limited value to the local network owner if the local network has spare capacity and in some circumstances, may cause network quality issues eg voltage control.
- There is no apparent value in network avoided costs in unconstrained networks with declining load.
- Cost reflective tariffs to customers will decrease the value of solar-only households but increase the use and value of storage, regardless of solar.
- In the long-term battery storage at any location in the supply chain is expected to delay or replace the need to build additional thermal peaking plant and should over time reduce the cost of electricity to consumers.
- Increased Reserves from BSS in the North Island could increase the present north transfer limits on the HVDC thus allowing South Island generators better access to the growing demand in the UNI.

4. Grid-connected batteries are not presently economic and unlikely to be so before 2022

- Transpower will seek further information both technical and commercial for possible 2020-2025 Grid applications, to confirm the viability of such solutions to meet multiple grid needs cost effectively compared to alternatives.

5. Distribution-connected or community-scale batteries are expected to be economic from 2020

- There is uncertainty if present economies of scale will continue to favor network-scale systems vs residential. There is a wide spread of capital cost figures in the nascent market. As the global mass production of batteries ramps up for the EV market, commentators are forecasting a rapid decline in battery costs following a similar pattern to the solar PV market. This coupled with the relatively simple, low voltage, internet-ready, mass-produced stand-alone units may see residential battery costs fall below grid-scale systems. Recent price reductions announced by Tesla, ABB and GM tend to support the view that residential cost may fall faster than bespoke design grid-based system. It could be argued that an EV enabled for V2G is minimal or no cost as it was purchased for lifestyle/transport reasons.

6. Some specific commercial end consumer battery applications are economic now. Their economics would be further improved if Time of Use (TOU) lines charging combined with full open access to all market energy services were available now

- Market tools and the ability to pay end use consumers for the value their BSS or V2G storage brings is presently severely limited. Not all services are enabled to end use consumers such as voltage support, and the ability to pay a widely-diluted consumer base is not presently possible without aggregators or others eroding value on the way.
- Location specific and dynamic cost-reflective distribution pricing is required to provide a tool for networks to incentivise demand response in areas where the network can benefit from additional capacity, security or other services. This also ensures that areas of negligible benefit to the network, are not developed preventing additional costs being imposed on customers. Developing targeted distribution demand response programs which enable networks to contract with third parties is considered essential to enabling the full battery storage value stack to be realised at the consumer level.[21]

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[21] For further examination of this topic, see the May 2017 Electricity Authority Consultation paper Enabling mass participation in the electricity market, How can we promote innovation and participation? (http://www.ea.govt.nz/development/work-programme/evolving-tech-business/enabling-mass-participation/consultations/#c16454). In addition, the Australian Energy Markets Commission (AEMC) has recognised a similar need, releasing a report called Distribution Market Model (http://www.aemc.gov.au/getattachment/25e63b7d-8c28-441b-b315-2d438f285d81/Draft-report.aspx).

Discussion

In preparing this report, we wanted to establish the value of batteries to New Zealand electricity customers and the overall power system. We have been able to identify that there are more benefits where batteries are located closer to end-consumers, provided payment is possible for all the services such batteries could provide.

We have established that presently there are limited options for battery storage to be economic today, but that this will change in the near term. Again, the greatest impact will be at the consumer end. Even when battery systems offer more economic benefits, the value that battery systems offer end consumers and the power system will not be consistent, as these benefits are both temporally and geographically dependant.

Finally, the arrangement, systems and tools of the market will be one of the most significant influences on the ability for electricity consumers to be recognised for the value their battery storage systems offer.

As such, supplementary questions that are raised from this work that include:

- What are the expectations and objectives of consumers?
- What is the real value that each party in the supply chain would be prepared to pay for the services provided by batteries? (We expect this matter will be extremely application-specific.)
- What commercial structures, market design and systems will be required to realise benefits for battery owners, and how will a widely diluted consumer base participate and be paid?
- How will offer and dispatch priorities be managed, “double dipping” be prevented, and the implications of non-delivery and performance shortfalls be managed?
- Is central coordination and/or aggregation required, will emerging Peer to Peer (P2P) technology have an impact?
- How can existing demand response experience be leveraged to inform the tools, platforms and systems required to develop deep, liquid markets for all participants?
- What technical and performance standards and rules are required for domestic, large edge of network/customer or grid scale systems to ensure integrity of the system?
- How will expected growth in EVs impact the system and can these vehicles be enabled to spread charging load and V2G service?

Collaboration of parties in the supply chain will be required to capture the wider benefits of storage identified in this report for the benefit of end consumers. Real benefits are expected to accrue when all key stakeholders are engaged, aligned and focused on the end consumer to ensure markets are open, liquid and deep.

CONCLUSION

Consumers, empowered by modern technology and information, have more choices when it comes to electricity – and these choices are diversifying rapidly. As an industry, we must keep focused on ultimate outcomes that benefit New Zealanders as they engage more closely with their power system.

In summary:

- We see battery storage as a useful tool, both for our business, for others involved in electricity generation and distribution, and for homes and businesses.
- The nature of New Zealand's power system means that the value proposition for batteries is different to typical power systems internationally.
- In time, the decreased costs of battery storage will mean that battery storage more often represents a good investment choice.
- The location of a battery helps determine its potential benefits.
- If market structures, payments and systems develop, more value will be realised from battery technology, strengthening the case for investment.
- Battery uptake will begin to demand different things from power systems, including the National Grid.

Battery trials

We are actively evaluating opportunities for using new technologies throughout our network. As evidenced in this report, we do not expect that grid-scale batteries will be economic for some time, but we are keen to partner with others in the industry who are also exploring how emerging technologies can impact their businesses. In the short term, these may not meet our regulated cost/benefit analysis investment criteria, however our findings indicate we are approaching a cost tipping point.

We believe there will be considerable value in any trials that will better inform future developments across industry.

Engagement

We invite you to engage with us as we work through the implications of our research for New Zealand's power system, and we welcome your input.

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