DISTRIBUTED BATTERY ENERGY STORAGE SYSTEMS IN NEW ZEALAND

POWER SYSTEM OPERATIONAL IMPLICATIONS

TECHNICAL REPORT

Transpower New Zealand Limited
June 2019

Keeping the energy flowing

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Foreword

At Transpower we are seeking to play a strong role in enabling New Zealand's energy future. Many readers will be aware of our recent publication of *Te Mauri Hiko* [1] and subsequent thought pieces to inform the debate on how, through electrification, we can transform how our energy needs are supplied through electrification to meet our goals to limit climate change.

Achieving that outcome will depend on our abilities to successfully integrate new technologies for generating, storing and controlling the use of electricity across our power system. We want to identify what we need to enable successful integration, to ensure a reliable "fit-for-purpose" power system at an early stage. This will ensure the development of various standards, codes and market arrangements are properly informed. In achieving this outcome, we'll avoid the consequences of poorly managed integration seen in other power systems globally.

Our findings on the addition of significant distributed BESS in the New Zealand context align with what has been seen overseas. The self-consumption of excess daytime solar PV generation by consumers that BESS enables can play a significant role in mitigating the impacts of large-scale uptake of solar PV in isolation. If the appropriate market signals and coordination arrangements are in place, the greater the storage capacity of the BESS compared to the solar PV capacity, the greater the potential benefit to us, in terms of managing the impacts on power flow across the grid and avoiding the need for network investment.

The potential addition to the mix of significant EV charging requirements reinforces the need for market signals that enable coordination. Hypothetically, the charging of 2 million EVs in New Zealand at the end of the working day, without any incentive to defer charging to later in the evening, would add 25 per cent to today's winter evening peak demand. This would require added transmission and peaking generation capacity, which we can work to avoid.

Although a large-scale distribution of BESSs would ultimately bring little benefit in terms of managing one of our current challenges, managing dry winters, their potential is impressive in a separate and significant sense: their ability to transform the way the power system responds to major events. Today, typically three to five times each year we have a major under-frequency event due to the sudden loss of a large generator or the HVDC link. Our studies of frequency performance with BESS enabled to respond to these events demonstrated likely superior performance compared to the reserves we rely on today in such events, reducing the impacts on consumers.

The solar PV investigation we carried out in 2007 showed us that our system voltage management would be challenged with the addition of 4 GW of solar PV, especially in the middle of the day. This study found that the addition of distributed BESSs can help address this issue, especially if a BESS is large enough to be able to charge up in the middle of the day. We'll do further work on regional impacts with different assumptions on BESS, and include the impact of EV charging in these studies.

In enabling New Zealand’s energy future, in our role as system operator, Transpower will continue to explore the benefits and challenges in aiding this transformation, through our proactive studies of impacts on power system dynamics. This will ensure our future power system, as an integrated whole, meets our expectations to provide a largely renewable and reliable electricity supply to power New Zealand’s economy.

John Clarke

General Manager Operations

1 Introduction

As New Zealand's electricity system operator, Transpower has been working to identify the impacts of new technologies on our power system for over 10 years. In 2007, we published our findings on wind integration. In 2017, we published further work on the impact of the large-scale uptake of rooftop solar PV.

In 2018, we have been investigating the potential impacts on our power system of an anticipated increase in both grid-connected and distributed, non-dispatchable, renewable generation and other emerging energy technologies.

This report shares our findings. It looks at the operational impacts on our power system of a widespread uptake of distributed rooftop solar PV coupled with BESS (that is, a hybrid solar PV BESS), and increased system loading due to electric vehicle (EV) charging. Figure 1 shows how this scenario would apply at a typical household level.

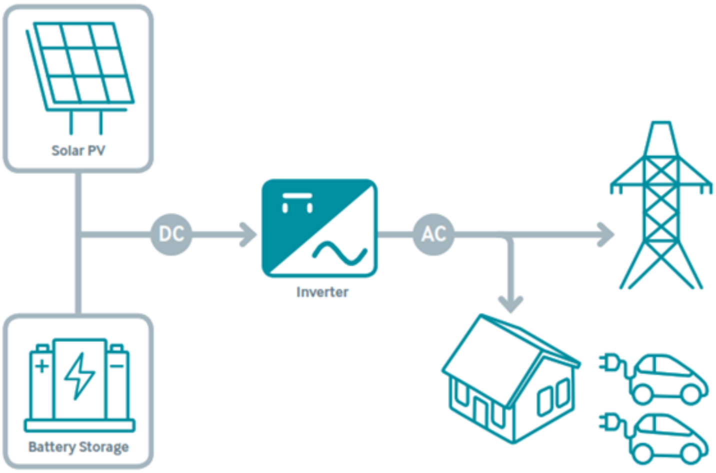


Figure 1 – Hybrid solar PV BESS and EV scenario

Transpower's work on understanding these impacts will enable us to be prepared for the future, by ensuring our systems, tools and processes are fit for purpose.

On a more practical level, this investigation also provides useful context for the development of the Electricity Industry Participation Code (the Code), including the principal performance obligations (PPOs) the Code sets out for Transpower as system operator. This in turn supports Transpower's strategic priority of *"Play an active role in enabling New Zealand's energy future"*.

By ensuring that the Code continues to develop to cater for new technology, including behind-the-meter distributed, non-dispatchable, renewable generation, we can provide New Zealand consumers better opportunities to participate in the energy and reserves market, potentially reducing the payback period on their investment in hybrid solar PV BESS, increasing the level of overall competition and reducing costs to consumers.

Transpower’s *Te Mauri Hiko* [1] discussion paper, which examined the potential future scenarios that might impact New Zealand's energy future, forecast a high uptake of the energy technologies this report investigates. It highlighted the need for us to continue to undertake investigations of this nature, given our commitment to helping New Zealand to achieve its decarbonisation goals.

2 Background

2.1 New Zealand power system

The New Zealand power system is relatively small. It encompasses two islands, connected by an HVDC link. Today, the North Island power system serves an island maximum load of 4,500 MW, and the South Island a maximum load of 2,200 MW. Most of the time, excess electricity from South Island hydro generation is exported through the HVDC link to supply load in the North Island.

The New Zealand system has a mixture of generation types, including fast-ramping hydro, slower-ramping thermal, constant geothermal and variable wind and solar PV. Currently, the system has a high proportion of dispatchable renewable generation resources (hydro and geothermal) and a low proportion of non-dispatchable renewables (wind generation makes up about 7 per cent of our mix, and solar PV less than 1 per cent). As a result, under certain conditions, system inertia can be low, making frequency management more challenging.

Several features of our power system have the potential to impact the integration of distributed, non-dispatchable generation. One significant feature is the fact that our system is an isolated power system with a high proportion of electricity already generated from sources that can vary in availability; namely hydro and wind generation. It is necessary for us to understand the potential impact to New Zealand's security of supply due to additional variable energy sources that are not highly correlated to either hydrology or wind resources.

Peak system load in New Zealand occurs during the evening, especially in winter. Major generation sources are remote from most major loads; as a result, the amount of electrical power that can be delivered through the grid to supply these loads is constrained in some major centres (in particular, Auckland).

In the early morning the grid is lightly loaded, creating voltage management issues in areas such as the Upper North Island (UNI) and Upper South Island (USI). Transpower frequently employs operational mitigation measures to manage voltages in these areas, including dispatching additional generators to provide extra reactive power regulation capability, and removing transmission circuits from service.

The system uses a range of ancillary services to manage system frequency within limits:

- fast instantaneous reserve (FIR: reserve that must act within 6 seconds of an under-frequency event and then maintain its post-event output for 60 seconds)
- sustained instantaneous reserve (SIR: reserve that must act within 60 seconds of an under-frequency event and then maintain its post-event output for 15 minutes)
- interruptible load (IL: reserve provided through the disconnection of load following an under-frequency event. Can be provided as either FIR or SIR)
- over frequency reserve (OFR: reserve provided by generating units that can be armed when required and automatically disconnected from the system due to a sudden rise in system frequency)

- frequency keeping (FK: a service provided by one or more generating units to manage short-term supply and demand imbalances by quickly varying their output to ensure the system frequency is maintained at or near 50 Hz)
- automatic under-frequency load shedding (AUFLS: a system by which large blocks of load are armed with AUFLS relays ready to be disconnected when the frequency falls below a pre-programmed threshold).

For details on the frequency and voltage management practices Transpower uses today, including contingent event classification and managing frequency stability, see Appendices A.8 and A.9 and the system operator website.

2.2 Battery energy storage systems

Around the world, BESS technology allows people to store electricity economically, close to where they use that electricity. It can also store local sources of generation, such as rooftop solar PV, and smooth out the impacts that variable generation can have on the power system. Widespread distributed BESSs are likely to fundamentally change the way that we operate power systems in the future.

Internationally, regions with high levels of residential solar PV generation are faced with a particular challenge: the issues caused by unused solar PV generation feeding back into the power system throughout the day. One solution to this challenge is to impose a limit on solar PV generation feed-in to distribution networks and grids. Power system operators can help home owners to handle those limits by encouraging them to install a BESS, to minimise, or even eliminate, feed-in, without wasting their excess solar PV generation.

The recent success of the Hornsdale Power Reserve BESS in South Australia has proven the capability of BESSs to support power system stability. The 129 MWh system there has taken a majority share of the frequency regulation market, and reduced the cost of frequency regulation by 90 per cent since its commissioning in December 2017 [2].

Virtual power plants (VPPs) comprising large numbers of distributed behind-the-meter BESS installations are also being deployed across South Australia. These provide grid services such as frequency regulation, and are also enabling homeowners with solar PV a higher level of self-consumption [3].

The New Zealand power system has yet to formally harness BESS technology to provide ancillary services.

In September 2017, we published a discussion document titled *Battery Storage in New Zealand* [4] that quantified the potential value to the New Zealand system from BESS services. One of our key findings was that batteries offer the greatest value when they are located closer to the end consumer. Behind-the-meter installations have the potential to provide a range of services both for the owner directly and upstream, to the whole power system. This finding, and the growth we have anticipated in VPPs, led us to embark on this study.

2.3 Impact of solar PV generation

This investigation builds on our 2017 work on the impact of high levels of solar PV generation on the power system [5]. This section outlines our key findings from that work.

Solar PV generation sourced from rooftop solar PV panels will play an important role in supplying New Zealand's future electricity needs. Uptake is still low in New Zealand, but is increasing significantly in other countries. In some circumstances, this has negatively impacted on the ability of power systems in those countries to operate.

Our 2017 investigation looked at the existing power system's ability to accommodate up to 4 GW of installed non-dispatchable distributed solar PV generation capacity. We found that today's power system could enable up to 2 GW of solar PV generation with minimal impact, but that higher levels would have a more challenging impact, in terms of both voltage and frequency management.

We also found that it would be likely that, as the uptake of solar PV generation increased, grid-connected generation would be dispatched off during periods of peak solar PV generation output, in order to balance generation with load. This situation would create a lightly loaded grid, with the following characteristics.

- The circumstance of there being fewer grid-connected synchronous generators would reduce:
  - system inertia, resulting in a rapid decline in system frequency following a loss-of-generation event
  - system strength, resulting in larger voltage disturbances during and after a loss of generation or load event
  - both voltage and frequency-regulating ability, impacting voltage and frequency quality.
- With maximum solar PV generation, there would be a low system load at midday; this would result in high system voltages in some instances, which would be difficult to manage within operational limits and would require investment in voltage support assets.
- Solar PV generation output declines in the late afternoon/evening, resulting in a greater need for dispatchable grid-connected generation at that time. This would coincide with the usual increase in evening demand, and have operational implications for slow-ramping thermal and base load geothermal generation: see Figure 2.

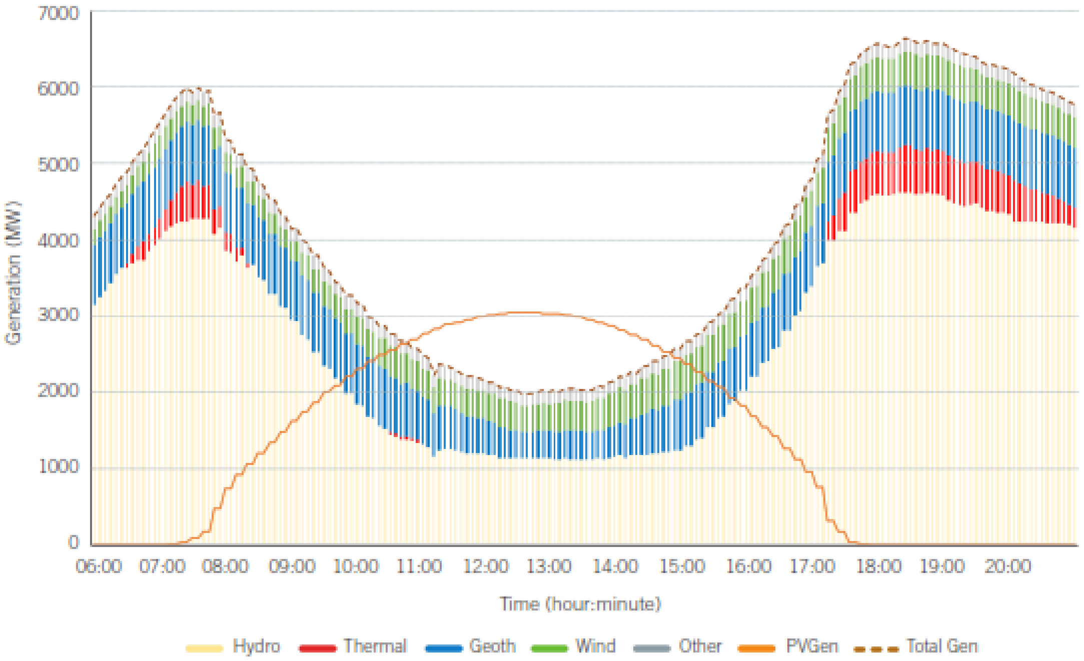


Figure 2 – Typical winter day generation mix with 4 GW installed PV generation capacity

3 Investigation outline

Building on our 2017 investigation into the impacts of solar PV generation on the power system, this investigation sought to identify the potential impact of distributed BESSs on the short-term operation of the New Zealand power system, including the implications for the delivery of our system operator service.

This report considers power system impacts at transmission-grid level; it has deliberately not considered the significant issues within distribution networks or smaller regions in the power system. Our areas of focus were the overall impacts on electricity flows across the grid (the load profile), grid voltage management and how the power system responds to system events (frequency management).

3.1 Objectives

The objectives of this investigation were to:

- increase our understanding of how distributed rooftop solar PV coupled with BESS and EV charging could impact the operation of the power system
- identifying how distributed BESSs could meet the challenges presented by high levels of solar PV uptake, as described in the 2017 investigation
- provide insights that we can use to inform our identification of future operational needs and development of the Code, and increase the efficiency of our power system operations.

3.2 Our scenarios

This section presents the scenarios we adopted for this investigation. It sets out:

- the individual hybrid solar PV BESS system our scenarios envisage for each home (section 3.2.1)
- a scenario of nationwide uptake of this system, alongside two case studies of EV uptake (section 3.2.2)
- the two models of hybrid solar PV BESS charging and discharging behaviour we considered (section 3.2.3)
- the model of EV charging behaviour we considered (section 3.2.4)
- the seasonal effects we considered (section 3.2.5).

Appendices A.1–A.4 present more detailed information on our scenario assumptions.

3.2.1 Hybrid solar PV BESSs in the home

The scenarios in this report take today’s power system as a baseline, and hypothetically add the same hybrid solar PV BESS to every home. We considered a hybrid solar PV BESS that consists of:

- a 3.5 kW rooftop solar PV installation
- a 3.5 kVA inverter
- either a 3.5 kWh (small) or a 14 kWh (large) BESS.

A 3.5 kW rooftop solar PV installation is a typical small solar PV installation on a standalone New Zealand private residence. We chose a 3.5 kVA inverter simply to match the rooftop solar PV; we assumed it met the requirements of AS/NZS 4777.2:2015 [6].

Our scenarios involve two different standard sizes of BESS currently available in New Zealand, to assess the benefits of different amounts of storage in a typical home. The small BESS could store the solar PV generation output for a typical sunny winter's day, and the large BESS could store the solar PV generation output for a typical sunny summer's day.

A key aspect of this hybrid system is the way the solar PV and BESS are coupled. Two common configurations can achieve this: AC coupled and DC coupled, as Figure 3 shows.

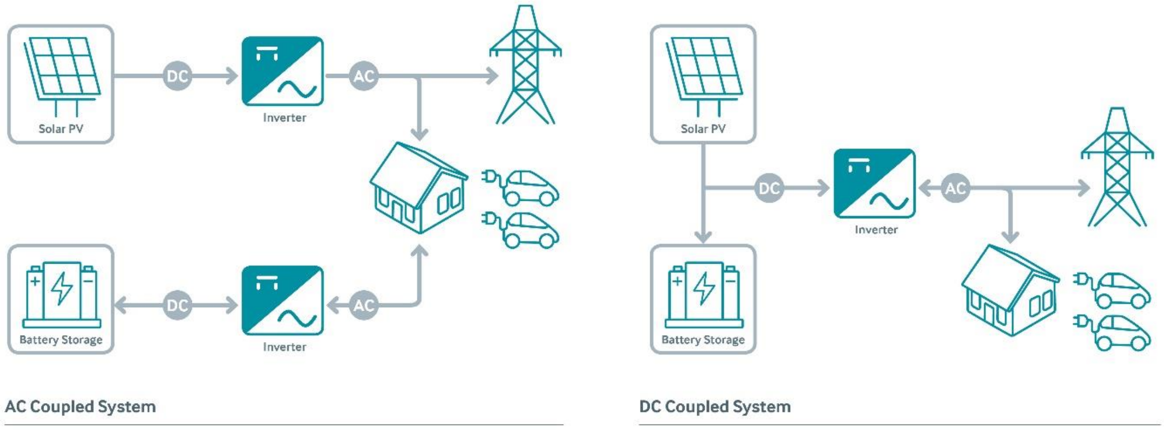


Figure 3 – AC and DC coupled systems

An AC coupled system feeds the PV generation through a standard grid-tied inverter that converts it to AC for use by household load, for export to the grid or for feeding into a battery-based hybrid inverter to enable DC battery charging.

A DC coupled system has a dedicated charge controller that converts and conditions the PV generation for battery charging and use within the system. The battery inverter converts this to AC for use by household load or for export to the grid.

Each configuration has benefits and drawbacks. Choice of configuration depends on consumers' objectives, project location, footprint, equipment availability and price. For our investigation, we chose a DC coupled configuration: unlike that of an AC coupled system, a DC coupled system's ability to provide support to restore system frequency after a power system event can be constrained during periods of high PV generation, and therefore provides the most challenge to integrate into the power system.

Appendix A.1.2 provides additional information on the hybrid solar PV BESS in our scenarios.

3.2.2 Hybrid solar PV BESSs and EVs across the country

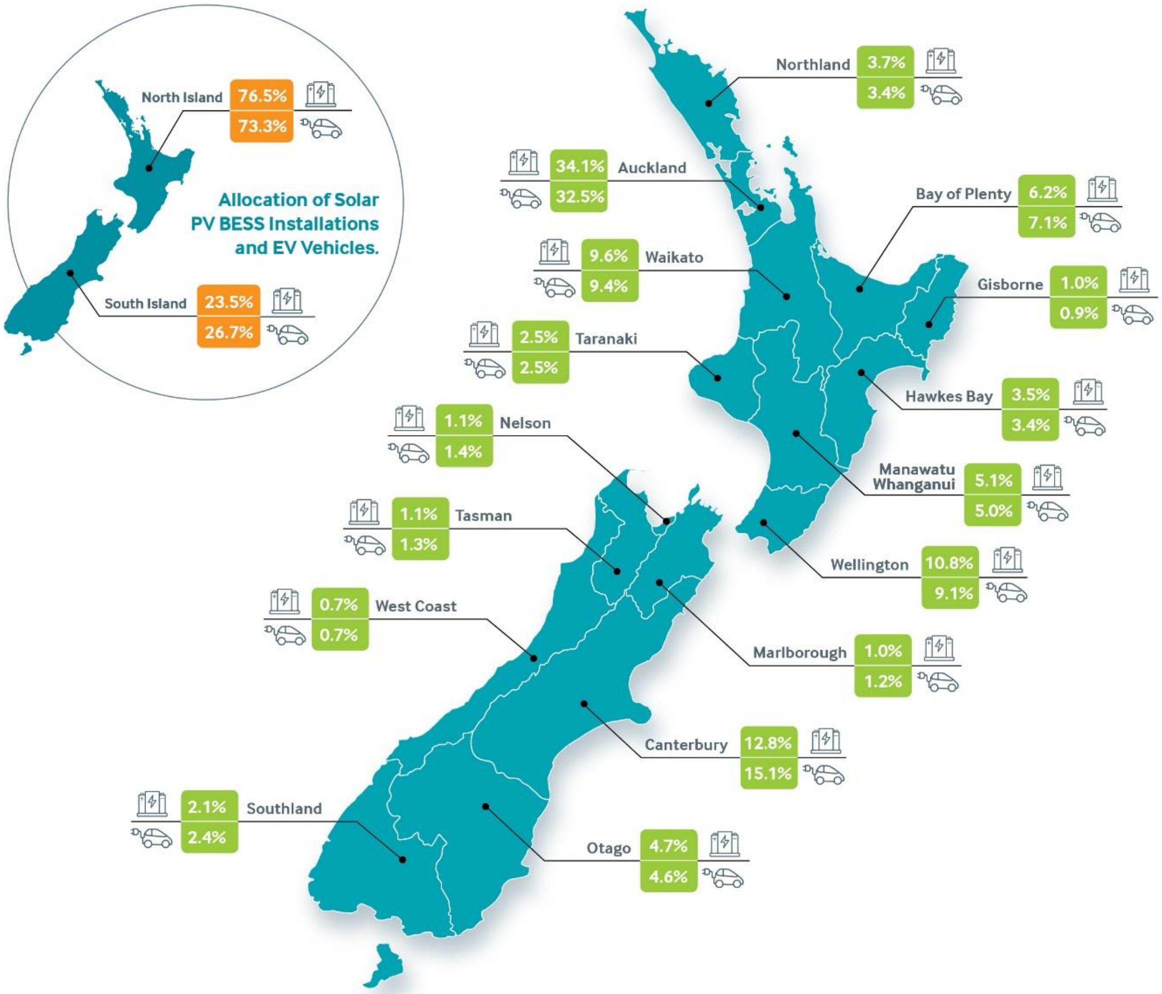
We developed an uptake scenario for the hybrid solar PV BESS we envisaged for individual homes, drawing on the analysis and findings of our 2017 investigation. We selected the most extreme case that investigation had considered: 4 GW of installed solar PV geographically spread across the country, based on regional population and dwelling information, grid exit point (GXP) distribution factors and solar irradiance data. To provide a sense of scale, 4 GW of installed distributed solar PV represents slightly less than half the currently installed capacity of all other forms of electricity generation in New Zealand; it would generate up to 3,500 MW of electricity in the middle of a sunny summer's day, and up to 3,000 MW in the middle of a sunny winter's day. Over an entire year this amount of installed solar PV generation could produce around 20 per cent of New Zealand's annual electricity needs – about 8,000 GWh.

A fully charged small BESS in every home would provide a total of 4 GWh of distributed storage across New Zealand. However, this is roughly equivalent to only 0.7 per cent of the nominal controlled hydro energy stored in lake Taupō, and 4 per cent of the daily electricity use in New Zealand.

We looked at the impact that BESSs can have on the overall profile of electricity use during the day. To this end, we included two case studies of EV uptake. The first envisaged a nearer-term case of 64,000 EVs (approximately 1.8 per cent of New Zealand's current light vehicle fleet), based on the government's uptake target for 2022; the second envisaged a longer-term case of 2 million EVs (approximately 55.5 per cent of New Zealand's current light vehicle fleet), aligning with *Te Mauri Hiko*'s 2050 base scenario. We assumed a geographical distribution of EVs based on scaling existing regional light vehicle registration data available from the Ministry of Transport [7].

To simplify our modelling, we aggregated all the hybrid solar PV BESS and EV charging and discharging loads we envisaged to their connected GXP. That is, rather than individually model over 1.1 million hybrid solar PV BESSs distributed across New Zealand, we aggregated them to 168 large hybrid solar PV BESSs: one at each GXP.

Figure 4 shows a geographical spread of hybrid solar PV BESS and EV resources across New Zealand based on this aggregation.



Region	Number of Solar PV BESS Installations	Solar PV Installed Capacity (MW)	Small BESS Installed Capacity (MWh)	Large BESS Installed Capacity (MWh)	Low EV number of Vehicles	High EV number of Vehicles
Northland	42,286	148	148	592	2,181	68,162
Auckland	390,857	1,368	1,368	5,472	20,805	650,150
Waikato	109,714	384	384	1,536	6,033	188,525
Bay of Plenty	70,857	248	248	992	4,554	142,328
Gisborne	11,429	40	40	160	553	17,277
Taranaki	28,571	100	100	400	1,592	49,759
Manawatu/Whanganui	58,286	204	204	816	3,202	100,058
Hawkes Bay	40,000	140	140	560	2,173	67,902
Wellington	123,429	432	432	1,728	5,823	181,977
Tasman	12,571	44	44	176	861	26,902
Nelson	12,571	44	44	176	866	27,063
Marlborough	11,429	40	40	160	779	24,335
West Coast	8,000	28	28	112	460	14,375
Canterbury	146,286	512	512	2,048	9,647	301,480
Otago	53,714	188	188	752	2,913	91,016
Southland	24,000	84	84	336	1,558	48,693

Figure 4 – Distribution of hybrid solar PV BESSs and EVs across New Zealand

3.2.3 Hybrid solar PV BESS charging and discharging behaviour

A key aspect of our investigation was the adopted charging and discharging behaviour of a BESS within the hybrid solar PV BESS. We modelled two different charging and discharging behaviours – self-consumption and optimised behaviour – as follows.

- Self-consumption: Within this model, the battery operates with the goal of maximising solar PV generation self-consumption before exporting to the grid: this would benefit a consumer looking to optimise the return on their investment in the absence of any other consumer incentives. BESS charging and discharging is driven by the interaction between household load and its associated PV generation. BESS charging begins in the morning when solar PV generation starts exceeding household load; discharging begins in the evening when load starts to exceed solar PV generation. No charging of the BESS from the grid occurs. Appendix A.2 provides details of the charging profile methodology.
- Optimised: Within this model, the BESS operates with the goal of flattening the daily load curve (that is, minimising the difference between system load peaks and troughs) by charging from the grid when system load is low and discharging when load is high. This would benefit the power system operator more than consumers; it would require consumer incentives to achieve. We only considered this type of charging behaviour for the larger BESS. Appendix A.3 provides details of the charging profile methodology.

These behaviours share the following base assumptions.

- We envisaged a minimum state of charge (SOC) of 20 per cent for each BESS; this minimum would extend the useful life of a BESS.
- We adopted a charge/discharge rate of 1C,[1] limited to 3.5 kW, to accommodate our modelled 3.5 kVA inverter.
- We considered both GXP-level residential load and solar PV generation profiles.
- We envisaged that solar PV generation would be used primarily to supply household demand, and any surplus would be used to charge the integrated BESS.
- We assumed that, when the BESS was not charging, additional solar PV generation would be exported to the grid.

3.2.4 EV charging behaviour

For simplicity, we considered the charging of EVs only as an additional load, without any provision of vehicle-to-grid (commonly known as EV2G) feed-in or response to frequency or voltage events. We assumed an average daily driving distance of 32 km, corresponding to approximately 6 kWh of energy consumption per vehicle per day.

Our hypothetical EV batteries were charged based on a weekday 'passive charging' approach, which assumed a significant portion of people would simply plug in their vehicles as soon as they got home at the end of the day (based on the charging profile prepared by Concept

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[1] Charge and discharge rates of a BESS are usually quantified by C-rates, which describe the ratio at which a BESS charges or discharges relative to its capacity. A fully charged BESS that discharges at a rate of 1 C will be fully discharged in one hour; one that discharges at a rate of 0.5 C will be fully discharged in two hours.

Consulting for their *Driving Change* report) [8]. This charging profile correlates with evening peak load and represents a ‘worst case’ for EV charging behaviour.

3.2.5 Seasonal effects

We wanted to understand how the impacts of our scenarios would vary due to seasonal effects. To this end, we looked at actual generation and load profiles extracted from market schedules for the following two cases:

- a sunny summer’s day (8 January 2017) representing a lightly loaded system, with around 15 hours of sun available for solar PV generation
- a sunny winter’s day (15 August 2017) representing a more heavily loaded system, with a high evening peak and fewer than 10 hours of sun available for solar PV generation.

3.3 Use of market schedules in our scenarios

One of the main inputs into our investigation were vectorised Scheduling, Pricing and Dispatch (vSPD) market schedules representative of each of the scenarios we studied. These allow us to understand what the generation and load profiles would look like for each scenario over a full 24-hour period.

To develop these market schedules, we modified the historic summer and winter GXP load profiles to incorporate the different uptake and charging/discharging behaviours of hybrid solar PV BESSs and EVs. Broadly, GXP load would be reduced when solar PV generation or BESS is supplying household load, and increased when EVs are charging.

We used our new GXP load profiles to determine which of the original generators scheduled would still be dispatched to balance supply and demand. The more expensive grid-connected generators were dispatched off in our scenarios where load was decreased (due to solar PV generation or BESSs discharging).

Appendix A.5 contains additional information on how we prepared these new market schedules.

3.4 Limitations

It is important to note that, in creating the scenarios for this investigation, we assumed no market signals to modify consumer response or inform consumer behaviours. In reality, the way consumers engage with BESS charging and discharging, solar PV generation and EV charging would be far more diverse. Our simplified scenarios kept the scope of our investigation manageable. Importantly, they serve as a stress test, to help us identify where we need to carry out further investigation, with more refined assumptions.

Other limitations of our investigation include the following.

- We did not consider certain specific features of BESS management systems (for example, temperature regulation and control), including limitations imposed on BESSs during charging and discharging.
- We did not take into account any curtailment of solar PV generation: in our scenarios, all available solar PV generation throughout the day was used to supply household load or charge the BESS, or was exported to the grid.

- We assumed that BESSs provided no reactive power support; in reality, BESSs can have this capability, and making use of it would aid voltage management.
- We assumed an unconstrained distribution network, and did not model impacts within distribution networks and voltage management strategies within these networks.

4 Impact on system load profile

This section presents our findings on how our hypothetical EV charging load and our hybrid solar PV BESS scenarios would impact the seasonal daily system load profile. It also presents a comparison with the extreme 4 GW solar PV daily load profiles presented in the 2017 investigation (which did not take BESSs and EVs into account).

4.1 Impact of EVs on system load profile

Figure 5 shows how the passive charging of EVs in both our low-uptake and high-uptake scenarios would impact on typical summer and winter daily load profiles, without considering factors introduced by our hybrid solar PV BESS charging/discharging scenarios. This allows us to understand how today's power system could accommodate EV charging in isolation of other distributed energy resources.

Scenario	Peak load (MW)	Trough load (MW)	Flatness – load spread (MW)	Max load ramping (MW/hr)
Today summer	4,371	3,085	1,286	368
Today summer + solar PV	4,223	587	3,636	881
Today summer + low EV charging	4,419	3,087	1,332	373
Today summer + high EV charging	5,899	3,156	2,743	501
Today winter	5,996	3,797	2,199	890
Today winter + solar PV	5,996	1,749	4,247	1,926
Today winter + low EV charging	6,043	3,799	2,244	899
Today winter + high EV charging	7,485	3,867	3,617	1,175

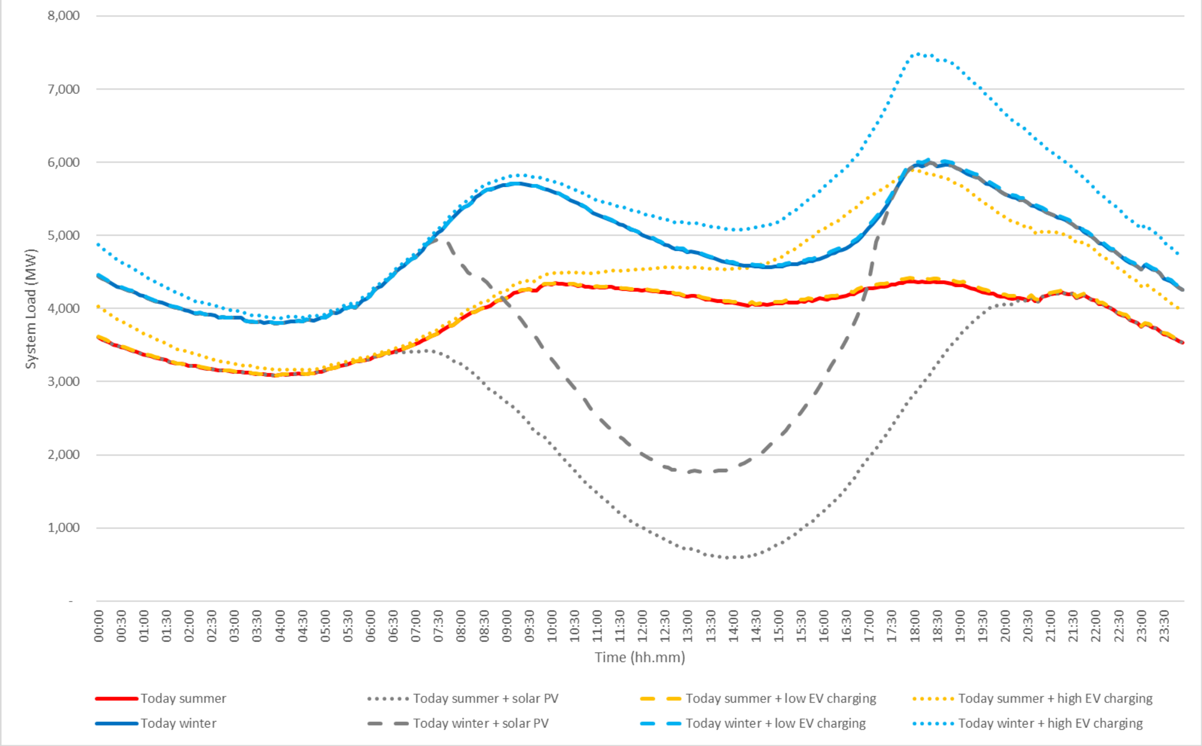

Figure 5 – EV charging impact on typical daily load profiles

Our investigation found that, our power system would be able to accommodate a high number of EVs under most conditions. Ensuring that EV charging occurred during periods of low system load, rather than during the evening peak, would bring benefits both in terms of power system operation and the deferral of asset investment needed to meet high peak loads.

4.1.1 Low EV uptake

This analysis shows that, with a low EV uptake (64,000 vehicles), there would be a minimal change to both the summer and the winter daily load profiles, entailing only a small increase in load throughout the day and a 50 MW increase to the evening peak load. We therefore see no potential for this scenario to affect the operation of the power system, and as such we have not considered this scenario in subsequent analysis.

4.1.2 High EV uptake

The analysis shows that, with a high EV uptake (2 million vehicles), there would be a change in both the summer and winter daily load profiles; the load would gradually increase in both summer and winter from around 09:00 in the morning until 04:00 the next day. The evening peak load in both summer and winter would, significantly, increase by around 1,500 MW. Our summer evening peak would increase to 5,900 MW, similar to today’s winter evening peak of 6,000 MW without significant EV charging; this would be unlikely to impact on the operation of the power system, given the distribution of load across New Zealand. The equivalent winter evening peak would be approximately 7,500 MW, requiring around 80 per cent of today’s installed generation capacity to supply. This would challenge the operation of the power system during periods of significant generation and transmission outages or fuel shortages, such as during a dry winter. The maximum winter hourly load ramp rate (the rate at which conventional generation has to replace solar PV generation as it declines in the late afternoon) would increase from around 890 MW/hr to 1,175 MW/hr. This is unlikely to cause any operational issues with our present generation mix and capabilities, as set out in the 2017 investigation.

4.2 Impact of hybrid solar PV BESS and EVs on summer load profile

During summer, solar PV generation is higher due to sun angle and longer daylight hours. System load is lower compared to winter, due to the reduced load dedicated to space heating. Figure 6 shows how the different combinations of hybrid solar PV BESS, charging behaviour[2] and our high EV uptake scenario would impact on the summer daily load profile. The subsections that follow explore our findings on relevant combinations in greater detail.

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[2] Unless noted otherwise BESS were considered to have a ‘self-consumption’ charging behaviour in this investigation.

Scenario	Peak load (MW)	Trough load (MW)	Flatness – load spread (MW)	Max load ramping (MW/hr)
Today	4,371	3,085	1,286	368
Today + solar PV	4,223	587	3,636	881
Today + small solar PV BESS	3,717	594	3,123	1,417
Today + small solar PV BESS + high EV charging	4,103	819	3,284	1,378
Today + large solar PV BESS	3,406	1,305	2,101	798
Today + large solar PV BESS + high EV charging	4,811	1,878	2,933	1,056
Today + large solar PV BESS (optimised)	3,404	1,659	1,745	877
Today + large solar PV BESS (optimised) + high EV charging	4,808	2,124	2,684	1,127

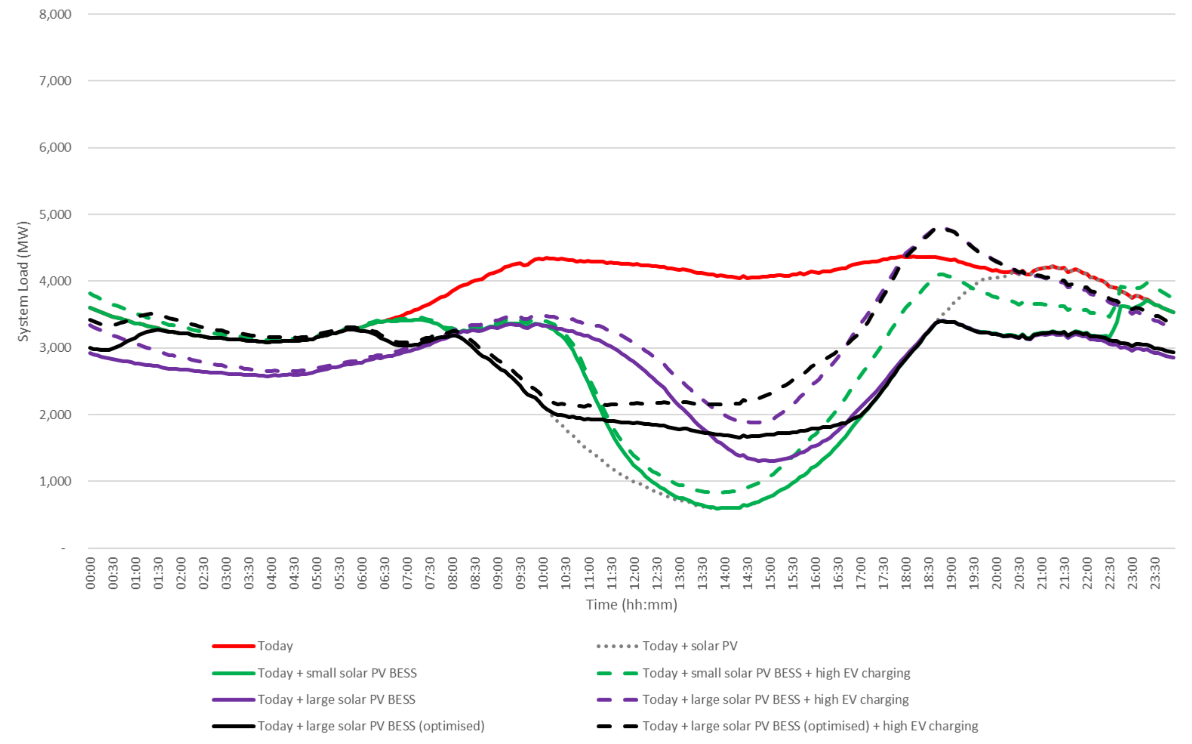

Figure 6 – Solar PV BESS and EV charging impact on typical summer daily load profile

4.2.1 Small solar PV BESS / high-uptake EV charging

In the scenarios that envisage a small solar PV BESS either in isolation or alongside high-uptake EV charging, we found the following.

- **High-uptake EV charging would increase the midday load, offsetting solar PV generation.** During midday peak solar PV generation, a minimum system load of 594 MW would occur around 14:00. At this time, over 3,000 MW of grid-connected generation would be displaced; however, certain generators need to remain dispatched (constrained on) to provide reactive support in key areas to manage high voltages due to low system load. The combination of BESS high-uptake EV charging would increase the system load during this period to 819 MW. The additional load from EV charging during this period of high solar PV generation would help reduce operational over-voltage concerns.
- **Small BESS discharging would help reduce the evening peak, due to high EV charging.** During the typical evening peak period, as solar PV generation would reduce at each residence, its BESS would begin to discharge. BESS supply of household load would continue to increase as solar PV generation decreased. Without BESS discharging to meet some household load, the system peak under the high-uptake EV charging

scenario would reach 5,889 MW. When BESS discharging is included, the evening peak would be 4,103 MW: 268 MW less than the present-day evening peak.

- **Load ramps-up would occur in the late evening when small BESS have fully discharged.** A small BESS would have insufficient energy available to supply household load throughout the entire evening, creating a sharp ramp in load around 22:30. This is faster than the ramp rate we currently experience during our winter evening peak. In reality, this sharp ramp-up is unlikely to occur, due to diversity in BESS size, solar PV generation output and cloud cover, meaning that not all BESSs will be depleted at the same time.

4.2.2 Large solar PV BESS / high-uptake EV charging

In the scenarios that envisage a large solar PV BESS either in isolation or alongside high-uptake EV charging, we found the following.

- **Early morning load would be decreased.** A large BESS can be fully charged over the course of a summer's day, and has sufficient stored energy to supply any household load not met by PV generation. In fact, a large BESS's charge would never fall below 30 per cent at any time, including during the night. This means that in this scenario the early morning load (around 04:00) would be reduced by approximately 500 MW, due to the BESS supplying all household load at that time. Existing early morning over-voltage issues would be exacerbated by this load reduction; this might, in the short term, require dispatching more generators (constrained on) and switching out lightly loaded circuits to manage voltage.
- **The midday load would increase compared with the equivalent small BESS scenario.** The large BESS would require more solar PV generation to fully charge than the small BESS does. As a result, during the midday, rather than PV generation being fed into the power system and reducing the system load, it would be used to charge the large BESS. Taking a high-uptake EV charging load into account, the minimum system load would increase to 1,878 MW at 14:45. This higher and delayed minimum load would ease the over-voltage issues experienced during midday with peak solar PV generation.
- **Large BESS discharging would help reduce the evening peak due to high EV charging.** Again, as in the equivalent small BESS scenario, the large BESS would help to mitigate the increase in the evening peak due to high-uptake EV charging. However, the large BESS would have the additional benefit of sufficient storage to maintain output throughout the evening and avoid the sharp ramp-up in load that would occur in the small BESS scenario when the small BESS's charge is depleted.

4.2.3 Large solar PV BESS (optimised) / high-uptake EV charging

In the scenarios that envisage a large solar PV BESS within an 'optimised' charging/discharging behaviour model either in isolation or alongside high-uptake EV charging, we found the following.

- **In this scenario, large BESSs would not be discharged in the early morning, to avoid over-voltage issues.** The additional remaining charge would be used to smooth the morning peak. Unlike in the equivalent non-optimised scenario, the morning load profile would remain the same as present-day levels; that is, there would be no exacerbation of the early morning over-voltage issues. The remaining stored BESS charge from the previous day would be used to help smooth the morning peak.

- **Midday load would be managed to remain above 2,000 MW, including high-uptake EV charging.** The BESS optimised charge logic would delay rapid charging until 10:00, to minimise the effect of the peak midday solar PV generation on the power system. This would increase the system load during the peak solar PV generation period by approximately 246 MW compared with the equivalent non-optimised scenario. Maintaining midday system load (including high-uptake EV charging) above 2,000 MW would ease the challenge of managing over-voltage issues.
- **In this scenario, large BESS discharging would help reduce the evening peak due to high-uptake EV charging.** Again, as in the other BESS scenarios, there would be sufficient charge remaining in the large BESS to help smooth the evening peak and reduce it by almost 1,000 MW from the present-day peak. In the context of a high uptake of EVs, in this scenario large BESSs could help maintain the evening peak below 5,000 MW: lower than today's winter evening peak by almost 1,000 MW.

4.3 Impact of hybrid solar PV BESS and EVs on winter load profile

The opportunity for our different hybrid solar PV BESS combinations to support the power system differs during winter. At this time, PV generation is reduced, due to lower solar potential, while the load is significantly higher during morning and evening peaks, due to increased demand for space heating. Figure 7 shows how the different combinations of hybrid solar PV BESS, charging behaviour and our high EV uptake scenario would impact on the winter daily load profile. The subsections that follow explore our findings on relevant combinations in greater detail.

Scenario	Peak load (MW)	Trough load (MW)	Flatness – load spread (MW)	Max load ramping (MW/hr)
Today	5,996	3,797	2,199	890
Today + solar PV	5,996	1,749	4,247	1,926
Today + small solar PV BESS	5,764	1,859	3,904	1,647
Today + small solar PV BESS + high EV charging	6,438	2,083	4,355	1,562
Today + large solar PV BESS	4,956	3,124	1,832	624
Today + large solar PV BESS + high EV charging	4,984	3,402	1,581	607
Today + large solar PV BESS (optimised)	4,507	3,132	1,376	660
Today + large solar PV BESS (optimised) + high EV charging	5,697	3,624	2,073	774

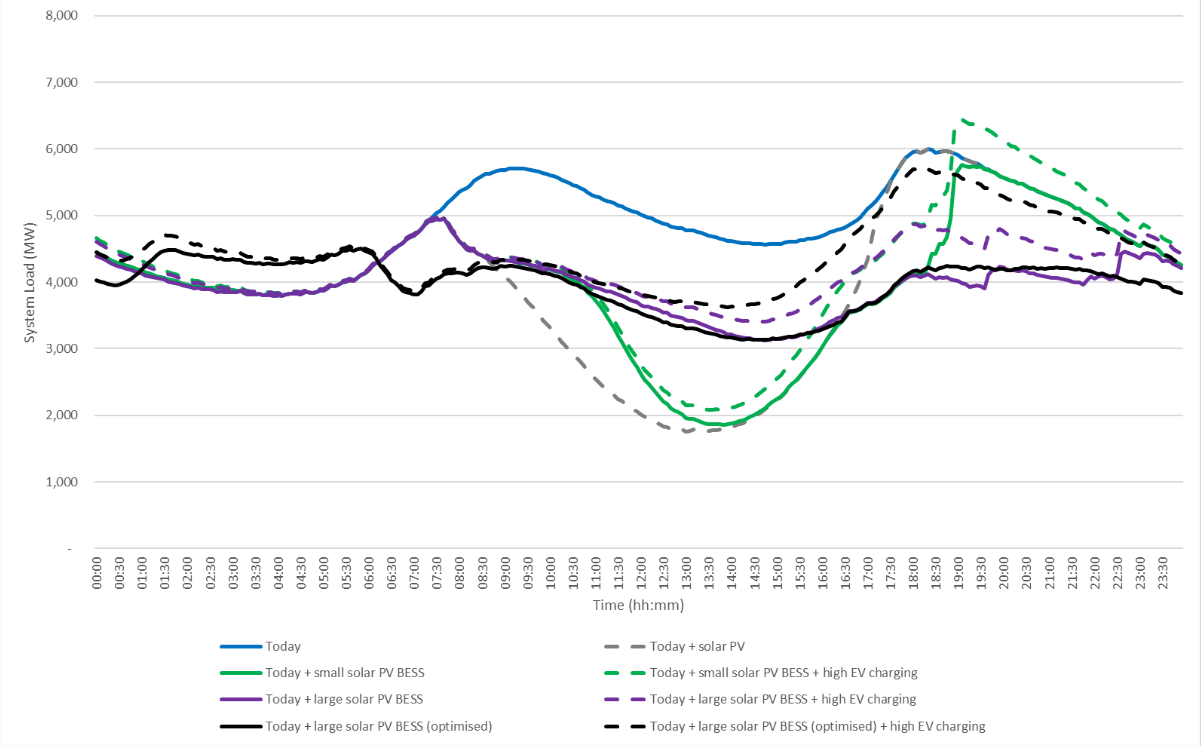

Figure 7– Solar PV BESS and EV charging impact on typical winter daily load profile

4.3.1 Small solar PV BESS / high-uptake EV charging

In the scenarios that envisage a small solar PV BESS either in isolation or alongside high-uptake EV charging, we found the following.

- **Morning load would decrease due to solar PV generation.** During winter mornings, solar PV generation would supply a portion of the morning load, resulting in a smaller morning peak load of around 5,000 MW at 07:45. This would be a slight improvement on the present-day morning peak load of 5,700 MW at 09:20.
- **Midday load would be improved compared to summer.** Taking into account winter's higher load, in our scenario envisaging a small BESS and no EV charging, a midday trough of 1,859 MW occurs at 13:50. This is significantly higher than the equivalent summer trough of 594 MW. This higher midday trough would necessitate less onerous voltage management compared to that required in summer.
- **There would be a fast ramp-up in the evening load when BESSs have fully discharged.** Taking into account the increased winter load and reduced solar PV potential, our small BESS installation would not have enough storage capacity to supply the household load throughout the evening. A small BESS would become fully discharged at

around 19:30, before the evening peak has passed, resulting in a very rapid load ramp-up. However, as noted in discussion of the summer scenarios, this ramp-up is due to the lack of diversity in our investigation assumptions, and would not occur in reality.

4.3.2 Large solar PV BESS / high-uptake EV charging

In the scenarios that envisage a large solar PV BESS either in isolation or alongside high-uptake EV charging, we found the following.

- **Overnight load would not change.** In light of the lower solar PV generation output of a winter's day, large BESSs would be unable to fully charge, and would be depleted by 22:30. As a result, just as in the equivalent small BESS scenario, the overnight load would remain unchanged, unlike in the equivalent summer scenario, in which the large BESS would discharge throughout the night and reduce the system load. With the addition of a small amount of EV charging load, and no BESS discharge during early morning periods, the minimum overnight load reached would be 3,829 MW, meaning there would be no voltage management concerns.
- **There morning ramp-up would remain prior to commencement of solar PV generation.** The larger BESS would have no impact on the system load during the usual morning load ramp-up, because it would be fully depleted. However, as in the equivalent small BESS scenario, the morning peak would be reduced to approximately 5,000 MW at 07:45, when solar PV generation would start to supply household load.
- **Midday load would increase compared to the equivalent small BESS scenario.** The large BESS would have sufficient capacity that it would be able to continue to charge throughout the day, using any excess solar PV generation available. As a result, the midday trough would largely be flattened, and a higher minimum load of 3,124 MW would occur at the later time of 14:45 (not taking into account high-uptake EV charging). With this level of load, voltage management is not likely to be a concern.
- **Large BESS discharge would reduce the evening peak (including high-uptake EV load) to below the present-day peak.** Large BESSs could store more energy; they would continue to discharge and supply household load into the evening, and significantly shave the evening peak. The evening peak load, even taking into account high EV uptake, would reach only 4,984 MW: approximately 1,000 MW lower than the present-day winter evening peak. Unlike in the small BESS scenario, there would be only a small ramp-up when large BESSs were depleted; however, this would occur after the evening peak.

4.3.3 Large solar PV BESS (optimised) / high-uptake EV charging

In the scenarios that envisage a large solar PV BESS within an 'optimised' charging/discharging behaviour model either in isolation or alongside high-uptake EV charging, we found the following.

- **Overnight load would increase, due to large BESSs within an optimised model charging from the grid.** Large BESSs would have sufficient capacity available overnight to allow it to be charged from the grid during the trough period. This would increase the system load by approximately 500 MW from the present-day extent, resulting in an overnight trough load of 4,264 MW at 03:55 (not taking into account high-uptake EV charging). This increase in load would greatly improve voltage management.

- **Morning peak would flatten.** If large BESSs were charged overnight from the grid, they could discharge during the morning ramp-up, and flatten the present-day morning peak by approximately 1,400 MW.
- **Midday load would increase compared to the equivalent small BESS scenario.** Large BESSs would charge during the midday period, raising the trough to a midday minimum load of 3,132 MW at 14:45 and minimising the steepness of the evening ramp-up. Again, at this level of load voltage management would be unlikely to be a concern.
- **Large BESS discharge would reduce the evening peak (even taking into account high-uptake EV load) below the present-day peak.** With large BESSs discharging across the evening peak, the additional high-uptake EV load would be smoothed to a peak of 5,697 MW: lower than the present-day system peak. With discharge controlled to minimise a simultaneous drop in output when BESSs are depleted, there would be no observed ramp-up, as we saw in the equivalent non-optimised BESS scenarios. At all times, the load ramp rate across the day would be slower than it is in the present system load profile.

5 Implications for voltage management

Our 2017 investigation found that a significantly reduced midday load due to high levels of solar PV generation would cause over-voltage challenges in both summer and winter.

This section reports on our investigation of the impact of the regional changes to the load profile in our scenarios (excluding EV charging) on voltage management in both the Upper North Island (UNI) and Upper South Island (USI). Voltage management in both these regions today can be challenging for the system operator during periods of low load.

Appendix A.6 contains details on the investigation assumptions and methodology we used to assess the implications on voltage management, and Appendix A.8 contains information on the system operator's existing voltage management practices.

5.1 UNI voltage management

5.1.1 Today's situation

The UNI region constitutes Northland, Auckland and Hamilton (grid zones 1, 2 and 3). The system operator needs to routinely manage voltage in the UNI, raising voltage levels when load is high and reducing voltage levels when load is low.

In comparison to its load, the UNI region has little local generation; electricity must be imported to meet the regional load. Reactive power support is required for voltage management enabling a secure transfer of electrical power into the region and keeping voltage within acceptable operational limits.

To maintain voltage, the system operator manages a range of reactive power compensation devices, including capacitor banks, static Var compensators (SVCs), static synchronous compensators (STATCOMs) and grid-connected generation. In total, the installed reactive power injection capacity across the UNI is approximately 2,150 Mvar, while the reactive power absorption capacity is approximately 630 Mvar.

Figure 8 shows how the UNI load, voltage and reactive power profiles today vary across the course of our typical summer and winter day scenarios.

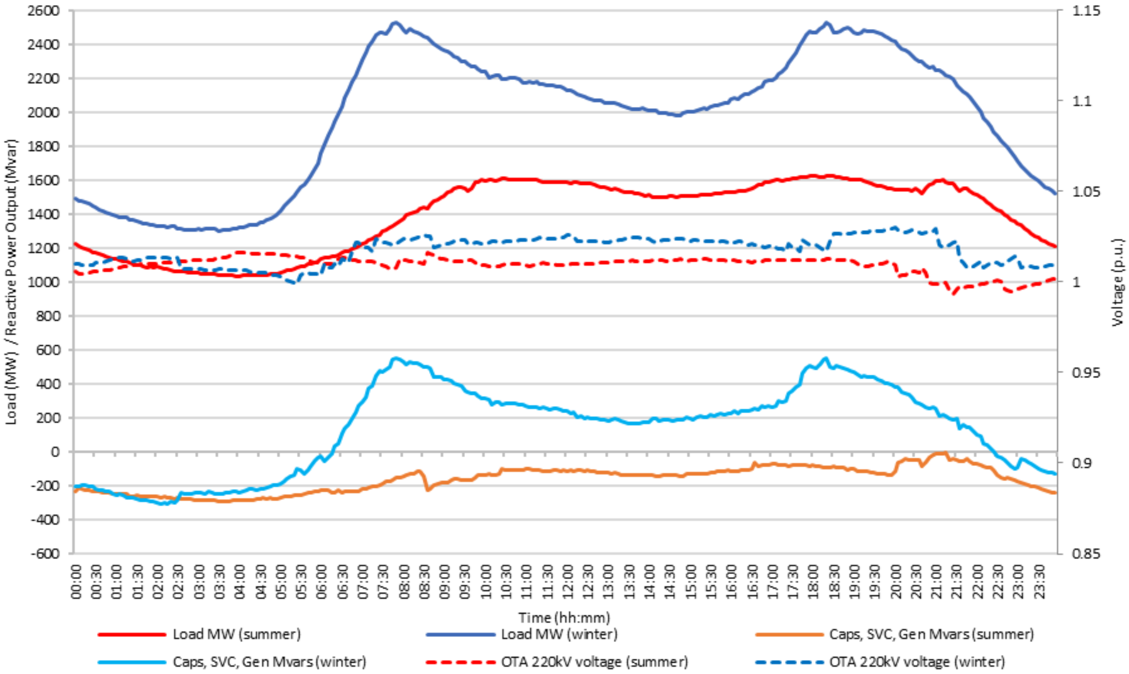

Figure 8 – UNI system load, voltage and combined reactive power profile for summer and winter

Under normal operating conditions today, the UNI region has adequate reactive power compensation devices to support and regulate voltage during high load periods.

Managing voltage during low load periods, especially in summer, is more challenging; at this time, the system operator has insufficient reactive power compensation devices available to absorb reactive power and lower voltage. We typically need to employ two additional operational measures to manage the UNI voltage: dispatching nearby generators to absorb reactive power from the system, and removing lightly loaded transmission circuits from service.[3]

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[3] In the UNI region, we typically use three transmission circuits in our over-voltage management approach: the Pakuranga-Whakamaru 1 and 2 and Pakuranga-Penrose 3,220 kV transmission circuits.

5.1.2 Impact of distributed hybrid solar PV BESS in summer

Figure 9 shows a comparison between the likely collective effect of the small and large distributed solar PV BESS installations in the UNI region on summer voltage management.

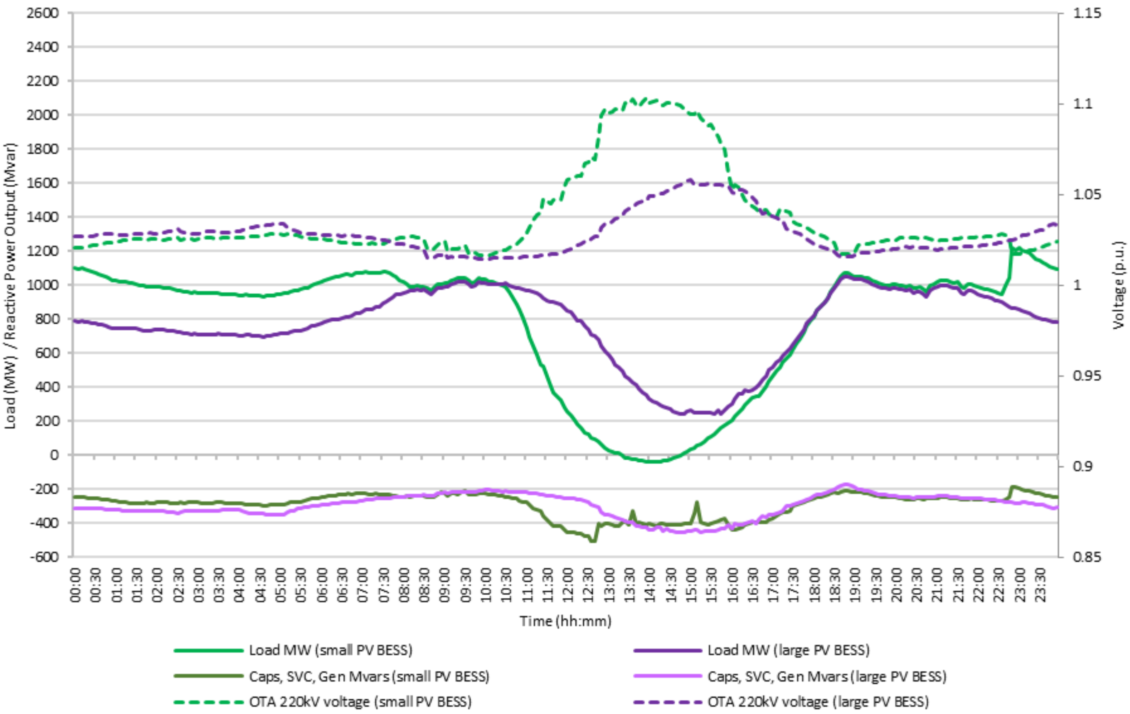

Figure 9 – Summer UNI system load, voltage and combined reactive power profile for the small and large BESS scenarios

Our investigation found the following likely effects for our small and large BESS scenarios.

- Small BESS scenario:

  Due to large amounts of solar PV generation in the region, and small BESSs reaching full charge quickly, we found that, in this scenario, the UNI load would fall below 0 MW between 13:20 and 14:45, as excess solar PV generation would be exported to the grid.

  There would be insufficient UNI reactive support equipment to manage voltage during this low load situation; our equipment would reach maximum absorption capability. This situation would be made worse as synchronous generators are dispatched off as system load reduces and therefore are unavailable to absorb Mvar. Even with two 220 kV circuits switched out, the Otahuhu 220 kV bus voltage would exceed the allowable 1.1 p.u. during the midday period; this reflects system-wide over-voltage issues that would be likely in other parts of the region.

- Large BESS scenario:

  In the case of widespread large BESSs, the minimum UNI load would remain higher than it would for the small BESS scenario during the midday period (due to BESSs charging), reaching a minimum system load of 243 MW at 14:45.

> Again, all the UNI reactive support equipment would be fully utilised to manage voltage during the low load period, and the ability of synchronous generators to absorb Mvar would be reduced, as many would still be dispatched off due to the low system load. Our investigation found that system-wide over-voltage issues would still be present throughout the region in this scenario, however, they were significantly lower than in the small BESS scenario, and never exceeded the 1.1 p.u allowable limit.

The percentage loading on the UNI SVC/STATCOMs in both our BESS scenarios exceeded the 75 per cent present-day operating limit. Additionally, in both scenarios two 220 kV circuits were switched out for the entire day as an operational measure to further help manage voltage; this impacts on the resilience of the grid to respond to an unplanned system event.

To ensure we can manage voltages in the UNI region during midday in summer, when solar PV generation is high and load is low, we will need to invest in more reactive power compensation devices, or accept reduced grid resilience to enable more circuits to be switched out.

5.1.3 Impact of distributed hybrid solar PV BESS in winter

Figure 10 shows a comparison between the likely collective effect of the small and large distributed solar PV BESS installations in the UNI region on winter voltage management.

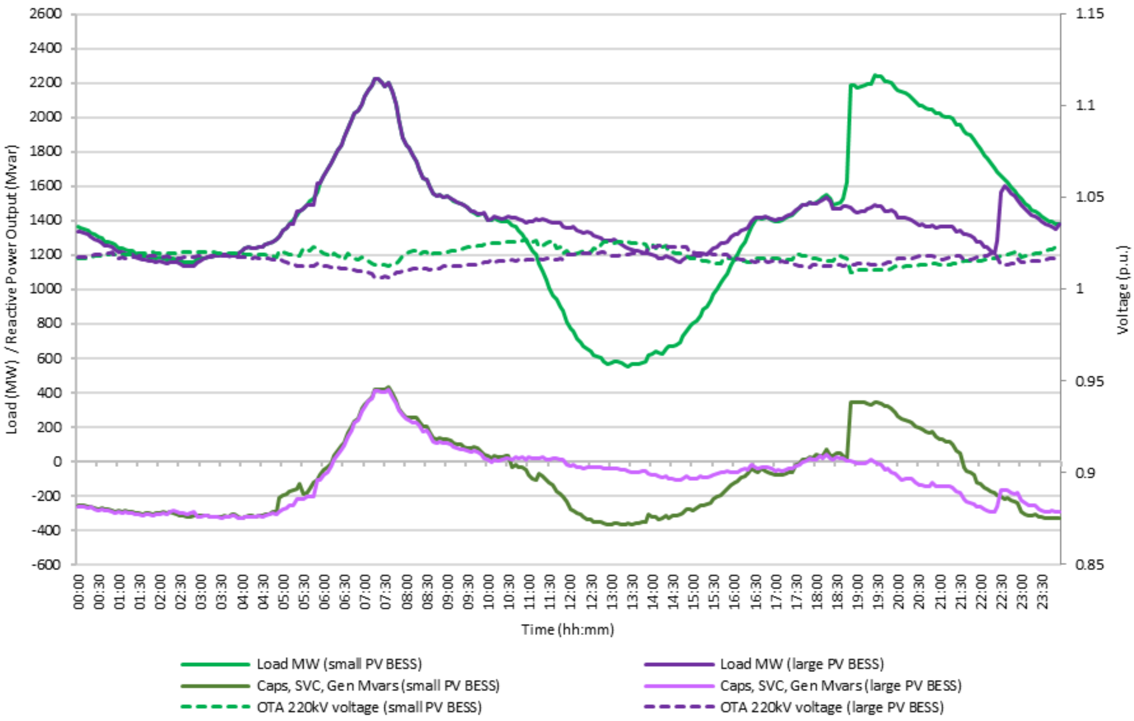

Figure 10 – Winter UNI system load, voltage and combined reactive power profile for the small and large BESS scenarios

Our investigation found the following likely effects for our small and large BESS scenarios.

- Small BESS scenario:

  In this scenario, the midday trough load of 553 MW in winter would be significantly higher than for the equivalent summer scenario, due to reduced solar PV generation and an increase in load due to space heating. We could adequately manage this low load situation with existing reactive power compensating devices and operational measures (switching out one 220 kV circuit for periods of the day).

  Due to the fact the small BESSs would not be able to smooth the load profile as well as the larger BESSs, more active voltage management would be required.

- Large BESS scenario:

  In the large BESS scenario, the UNI load profile would be relatively smooth by comparison, and the reactive power absorption and injection requirements would be much lower. No additional operational measures such as switching out 220 kV circuits would be required to manage voltage.

The Otahuhu 220 kV bus voltage would remain within the acceptable present-day operating range in both the small and large BESS scenarios.

5.2 USI voltage management

5.2.1 Today's situation

Like the UNI, the USI has little local generation, relying on power imported to meet the regional load of Nelson, Christchurch, Canterbury and the West Coast (grid zones 9, 10, 11 and 12).

We employ similar operational measures in the USI to manage voltage within an acceptable operating range. This includes use of reactive power compensation devices, generation support and the removal of transmission circuits.[4] In total, the installed reactive power injection capacity across the USI is approximately 240 Mvar, while the reactive power absorption capacity is approximately 490 Mvar.

Figure 11 shows how the USI load, voltage and reactive power profiles today vary across the course of our typical summer and winter day scenarios.

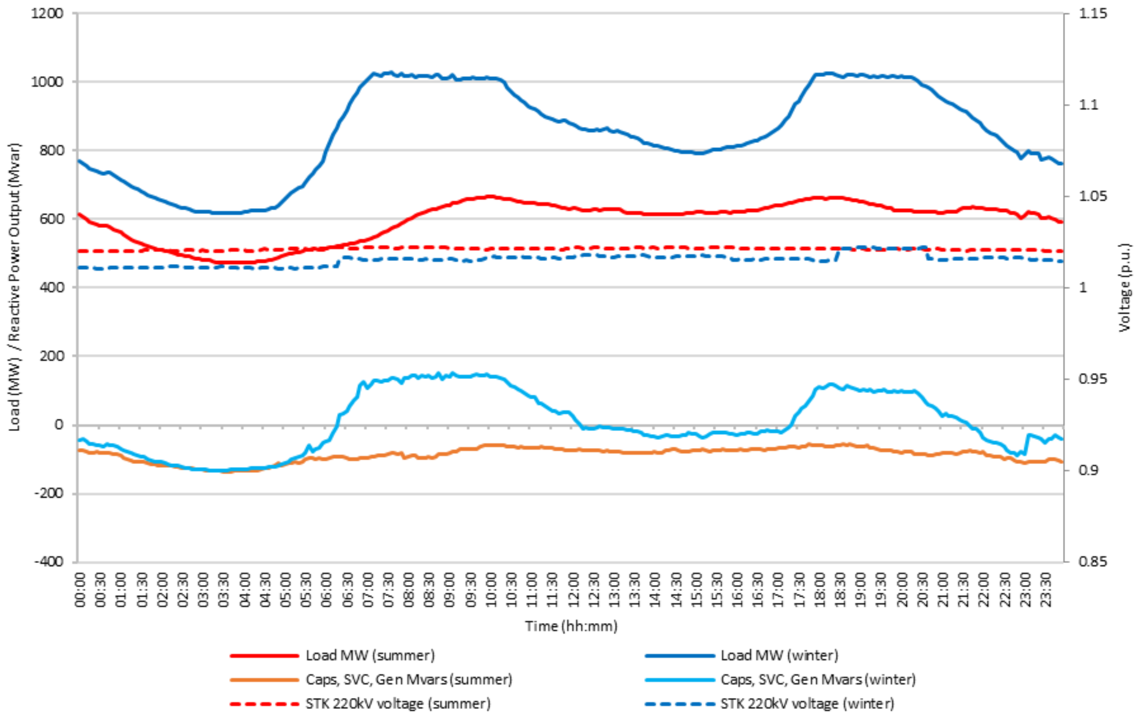

Figure 11 – USI system load, voltage, and combined reactive power profile for summer and winter

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[4] In the USI region, three transmission circuits are used as a part of the over-voltage management approach: the Islington-Kikiwa 1, Islington-Livingston 1 and Ashburton-Islington 1 220 kV transmission circuits.

5.2.2 Impact of distributed hybrid solar PV BESS in summer

Figure 12 shows a comparison between the likely collective effect of the small and large distributed solar PV BESS installations in the USI region on summer voltage management.

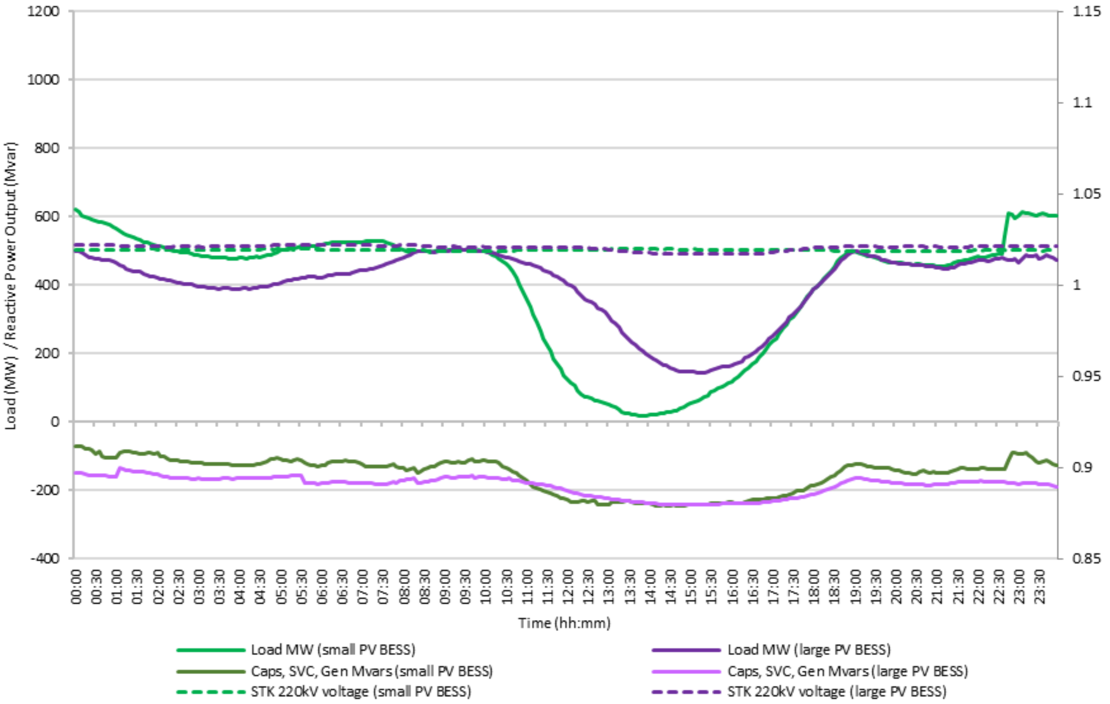

Figure 12 – Summer USI system load, voltage and combined reactive power profile for the small and large BESS scenarios

Our investigation found the following likely effects for our small and large BESS scenarios.

- Small BESS scenario:

  In this scenario, due to large quantities of solar PV generation in the region, the midday load would reduce to 18 MW at 13:50, compared to today’s minimum of 473 MW. We would also see a rapid ramp-up of load at around 22:30 as the small BESSs’ charge would be depleted.

- Large BESS scenario:

  In the large BESS scenario, the midday load would only reduce to 141 MW at 15:20.

In both BESS scenarios, the Stoke 220kV bus voltage would remain within the acceptable present-day operating range. However, to achieve this, the percentage loading of the USI reactive power compensation devices for both scenarios would exceed the 75 per cent present-day operating limit. Additionally, one 220 kV circuit would be switched out for the entire day as an operational measure to further help manage voltage; this impacts on the resilience of the grid to respond to an unplanned system event.

To ensure we can manage voltages effectively in the USI region during midday in summer, when solar PV generation is high and load is low, we will need to invest[5] in more reactive power compensation devices, or accept reduced grid resilience to enable more circuits to be switched out.

5.2.3 Impact of distributed hybrid solar PV BESS in winter

Figure 13 shows a comparison between the likely collective effect of the small and large distributed solar PV BESS installations in the USI region on winter voltage management.

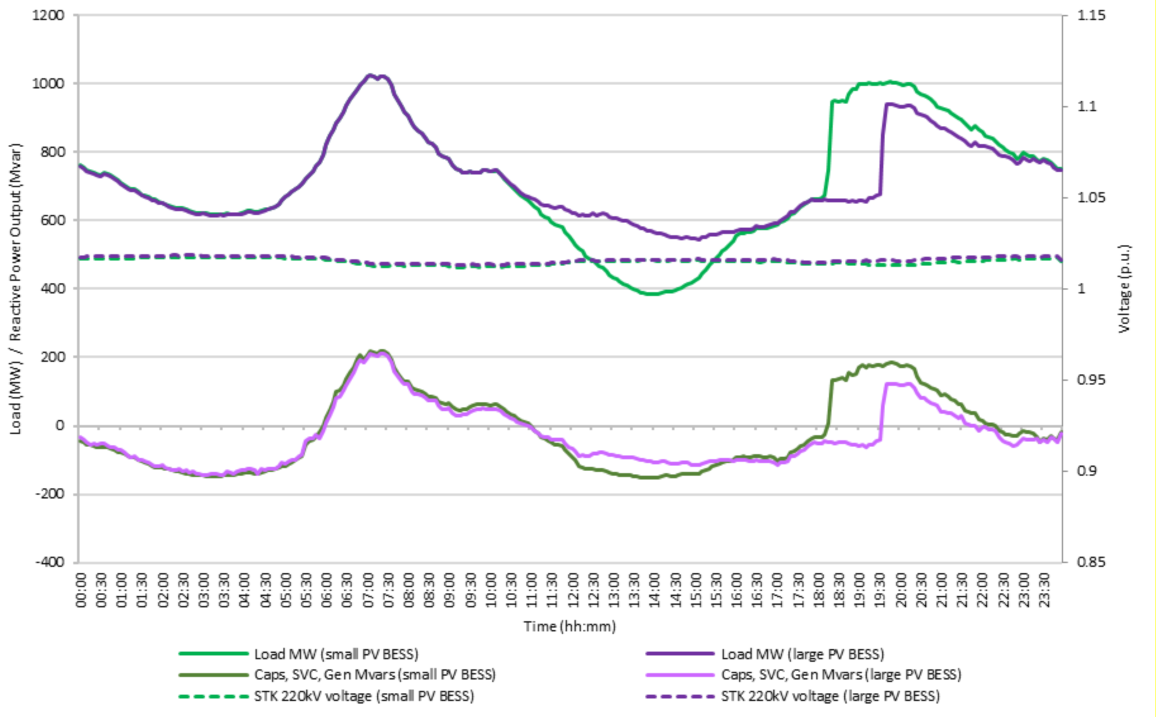

Figure 13 – Winter USI system load, voltage and combined reactive power profile for the small and large BESS scenarios

Our investigation found the following likely effects for our small and large BESS scenarios.

- Small BESS scenario:

  In the small BESS scenario, the midday load would reduces to 385 MW at 13:55; this compares with an equivalent 618 MW today. There would still be periods in the early morning and evening at which load would be being controlled to around 1,000 MW. A large ramp-up of load would be likely around 18:10, as BESSs' charge was depleted.

- Large BESS scenario:

  In the large BESS scenario, the midday load would only reduce to 544 MW at 15:05. The need to control load to around 1,000 MW would remain in the early morning, but not be a

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[5] Since this investigation was completed, Transpower has made plans to install a new 110 kV air cored shunt reactor at Kikiwa by early 2020; this will provide an additional 50 Mvar of reactive power absorption.

factor in the evening. As in the small BESS scenario, we would see a large ramp-up of load when the BESSs’ charge was depleted around 19:30.

In both scenarios, the Stoke 220kV bus voltage would remain within the acceptable present-day operating range. All reactive power compensating devices would remain within the present-day 75 per cent operating limit; however, to achieve this, we needed to switch one 220 kV circuit out for the entire day.

6 Implications for frequency management

New Zealand’s power system is relatively small, making it susceptible to frequency deviation caused by changes in load and generation. Managing frequency can be challenging at times of low system inertia, resulting in a high rate of change of frequency (RoCoF) following an event where a generator or load trips.

Our 2017 investigation showed how grid-connected synchronous generation will be displaced during periods of high solar PV generation. The implications of fewer grid-connected synchronous generators on frequency management include:

- reduced system inertia, resulting in a faster decline of system frequency following a loss-of-generation event
- fewer generation assets able to provide under- and over-frequency instantaneous reserves (IR), resulting in reduced frequency quality.

We know that BESSs connected to the grid via modern inverters are flexible, and can be programmed to respond to frequency, voltage or both. This means that, in addition to their simple load management function, BESSs have the capability to provide frequency control functions. Because they have no spinning mass, the power outputs of these devices can be changed in the order of milliseconds; in contrast, conventional spinning reserves can take seconds to respond.

This section reports on our investigation into BESSs’ ability to provide frequency management services to the New Zealand power system, to address the impact of fewer grid-connected synchronous generators as a result of high solar PV generation.

Appendix A.7 provides details on the investigation assumptions and methodology we used to assess frequency management capability. Appendix A.9 provides information on the system operator’s existing frequency management practices, including descriptions of frequency reserves used today.

6.1 Relationship between BESS SOC, solar PV generation and IR

BESSs’ ability to switch between generation and consumption presents us with an opportunity to respond to an over-frequency event by increasing grid offtake; similarly, it presents us with an opportunity to respond to an under-frequency event by reducing grid offtake or increasing injection into the grid. The ability to do either is determined by the SOC of the individual BESSs and the output of the solar PV generation at the start of the frequency event.

6.1.1 Hybrid solar PV BESS inverter rating limits response

The quantity of response (IR) provided by BESS in our investigation focuses on the net change in power flow between the inverter and the grid, and not just the output of the BESS itself. The following points are important in regard to this.

- We assumed that the solar PV generation produced at the time of a frequency event would continue to be generated.

- BESS would not be allowed to charge or discharge faster than a maximum rate of 1 C. Therefore, the inverter can only offtake from the grid, or supply to the grid, the additional power that keeps the charging rate below 1 C.

To demonstrate these points, Figure 14 shows example power flows for our small BESS installation. This scenario represents a period when solar PV generation is increasing, and the BESS SOC means it can still both charge and discharge at a rate of 1 C.

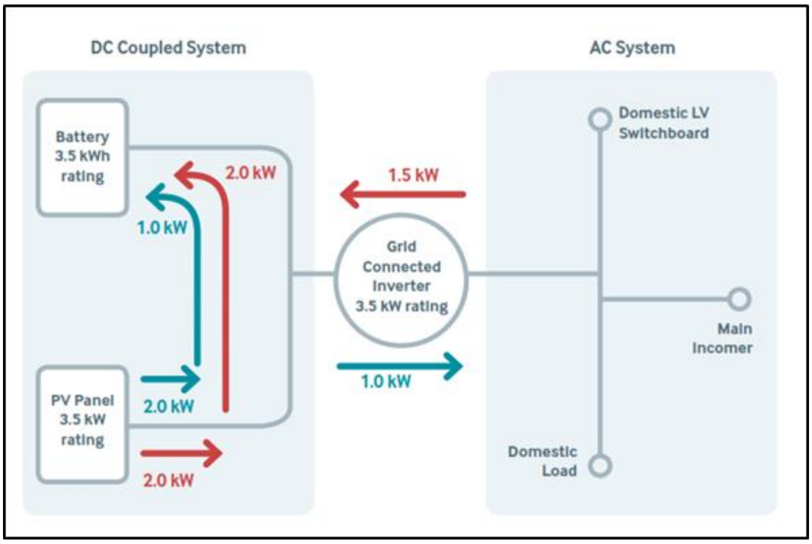

Figure 14 – Pre- and post-contingency over-frequency reserve power flows in a DC coupled small hybrid solar PV BESS installation

For an over-frequency event, the pre-contingent power flows are represented by the blue arrows, and the post-contingent power flows are represented by the red arrows. If the solar PV generation in this example feeds 2 kW into the BESS, and the BESS is rated to charge at a rate of 3.5 kW, then it can only be charged by an additional 1.5 kW to reach the 1 C charging constraint. However, in the AC system (as Figure 14 shows) there is a net change at the inverter of 2.5 kW (1.0 kW export switching to 1.5 kW import); this is the estimated available over-frequency IR we consider in our analysis.

For an under-frequency event in the same scenario, the solar PV generation would export the 2 kW it is generating into the grid; the BESS could stop charging and instead supply 1.5 kW into the grid as well. In the AC system, there is a net change at the inverter of 2.5 kW (1.0 kW export increasing to 3.5 kW export); this is the estimated available under-frequency IR we consider in our analysis.

6.1.2 Daily availability of IRs

The interaction of solar PV generation charging and household load discharging a hybrid solar PV BESS across the course of a day drives the ability of the BESS to provide different IRs for frequency management.

Figure 15 displays how SOC impacts the availability of the small and large hybrid solar PV BESSs in our scenarios to provide different frequency reserves[6] for our summer and winter scenarios. These graphs represent the collective capability of all New Zealand behind-the-meter hybrid solar PV BESS installations, assuming self-consumption charging behaviour.

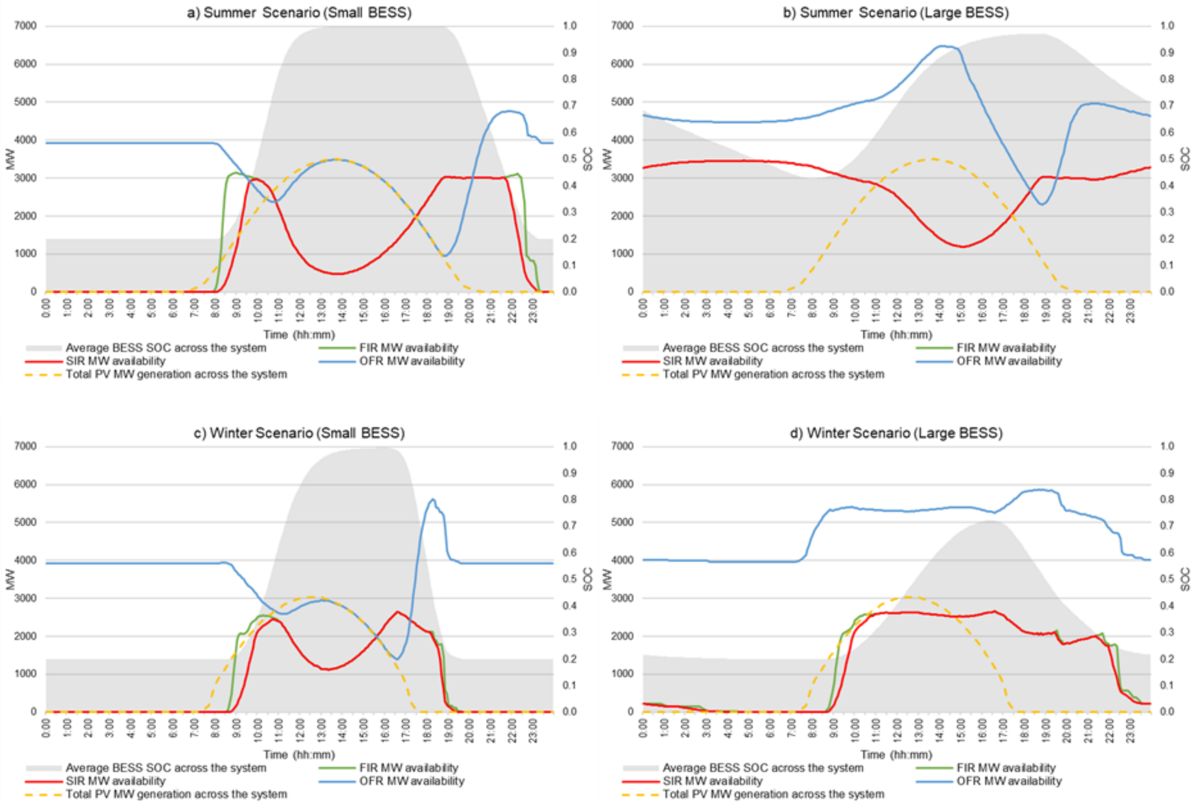

Figure 15 – BESS under-frequency (FIR/SIR) and over-frequency reserve availability

The availability of FIR or SIR is affected by SOC; large quantities of reserve are available when SOC is above minimum (in our scenarios, we did not allow SOC to fall below 20 per cent, to maintain BESS health) and solar PV generation is below peak levels. At peak solar PV generation levels, the inverter limits the ability to provide FIR/SIR, and acts as a bottleneck in the DC coupled system.

Over-frequency reserve (OFR) availability would be high for all periods except when the SOC is at maximum and solar PV generation is low. In this situation a BESS is unable to charge from the grid, as it is full, and there would be little or no solar PV generation to stop spilling into the grid to help rebalance supply and demand.

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[6] Including FIR, SIR and over-frequency reserve (OFR).

A key point to note is that at all times of the day in both summer and winter, our different-sized BESSs could supply at least one type of frequency reserve, to support the system operator with frequency management.

6.2 The ability of BESSs to respond to a frequency event

The speed at which a frequency reserve responds is important: the quicker the load-generation imbalance is restored, the quicker the fall or rise in system frequency is arrested. The ability of BESSs to respond more quickly to frequency events than synchronous generation would address the loss of conventional FIR, SIR and inertia our 2017 investigation foresaw in the 4 GW scenario, as synchronous generators are dispatched off during periods of high solar PV generation.

It is important to note that, for a BESS to be available to respond to a frequency event, its inverter must remain connected to the grid over the range of voltages and frequencies specified in AS/NZS 4777.2:2015. A BESS failing to remain connected during a frequency event would have the result of increasing the generation and load imbalance, as BESS offtake or injection would be removed from the grid. We would need more reserves to correct this imbalance, adding additional cost to the operation of the power system.

This section looks at how BESSs can respond to frequency events.

6.2.1 Comparison between BESS and present-day performance

To compare BESS and our present-day response to a frequency event, we prepared a winter day evening (21:30) peak load scenario (excluding the impact of solar PV generation or BESS on load) and simulated an under-frequency contingent event: a 390 MW generator tripping. We looked at how the system frequency would recover if FIR was provided in this scenario using present-day technology, and compared it with how it would recover if BESSs, instead, responded to the event. Figure 16 shows our results.

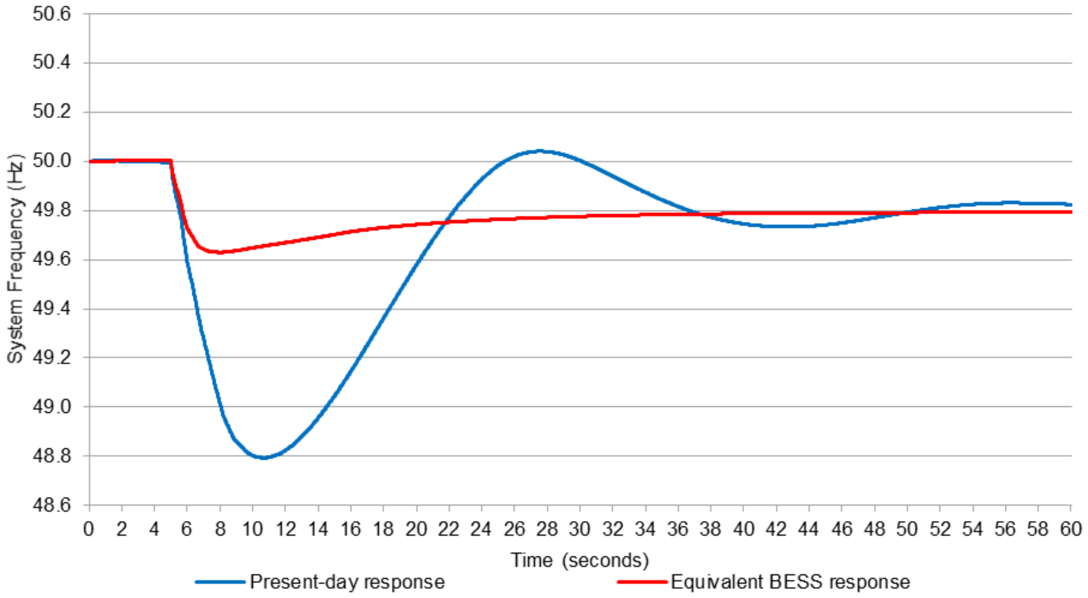

Figure 16 – Under-frequency event comparison between a present-day system response and an equivalent BESS response

Our simulated present-day response assumed that large quantities of spinning reserves were available, resulting in a high system inertia. In the simulation, the frequency dropped to a minimum of 48.8 Hz within 6 seconds of the event occurring, before recovering to 49.8 Hz. Synchronous generation ramped up by 250 MW, and the HVDC responded with 70 MW of reserve to support the frequency. Approximately 90 MW of IL was disconnected as part of the FIR allocation after the system frequency dropped below 49.2 Hz for more than 1 second. The total system response was approximated to be 410 MW.

We set up the equivalent BESS case with 410 MW of FIR provided by BESSs only. We tuned the droop characteristic of the BESSs to match that of the present-day system response, and set the BESS models to be frequency sensitive and fast acting.

Figure 16 clearly shows how the same quantity of IR provided by BESSs responded faster and arrested the fall in system frequency more effectively than the present-day combination of FIR products. The approximate minimum system frequency reached was only 49.6 Hz within 3 seconds of the event occurring. The BESSs' response resulted in a quicker recovery to 49.8 Hz, and no frequency oscillations.

6.2.2 Increasing the effectiveness of FIR provided by BESS

Because BESSs are very configurable within the boundaries of their operational limits, we can adjust them to provide IRs that respond faster than the current 6-second FIR technical requirement.

We carried out additional analysis for the same 390 MW contingent event to determine the effectiveness of FIR provided by BESS tuned with different initial ramp rates, but injecting a similar magnitude of power into the system. We tuned the BESSs to have initial ramp rates ranging from 85 MW/s to a maximum of 325 MW/s.[7] Figures 17 and 18 show our results.

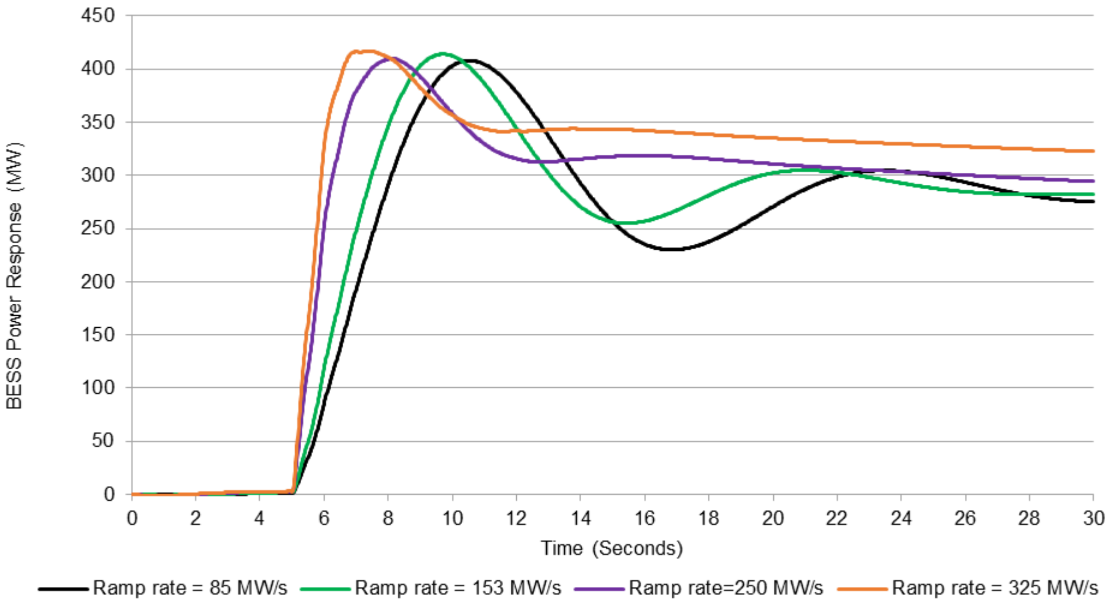

Figure 17 – BESS FIR power response at different ramp rates

The fastest-responding BESSs (those with a ramp rate of 325 MW/s) provided slightly over 400 MW of frequency reserve in just 1.3 seconds, arrested the fall in frequency quickest and produced a more stable frequency recovery. The slowest-responding BESSs (those with a ramp rate of 85 MW/s) reached maximum frequency reserve in 5 seconds, and produced a frequency response similar to the present-day response Figure 16 shows for conventional FIR.

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[7] For under-frequency events, the collective North Island governor response typically observed today has a ramp rate between 50 and 100 MW/s. This is a wide range, as many factors (including system inertia, size of the contingent event and HVDC response) can influence the rate.

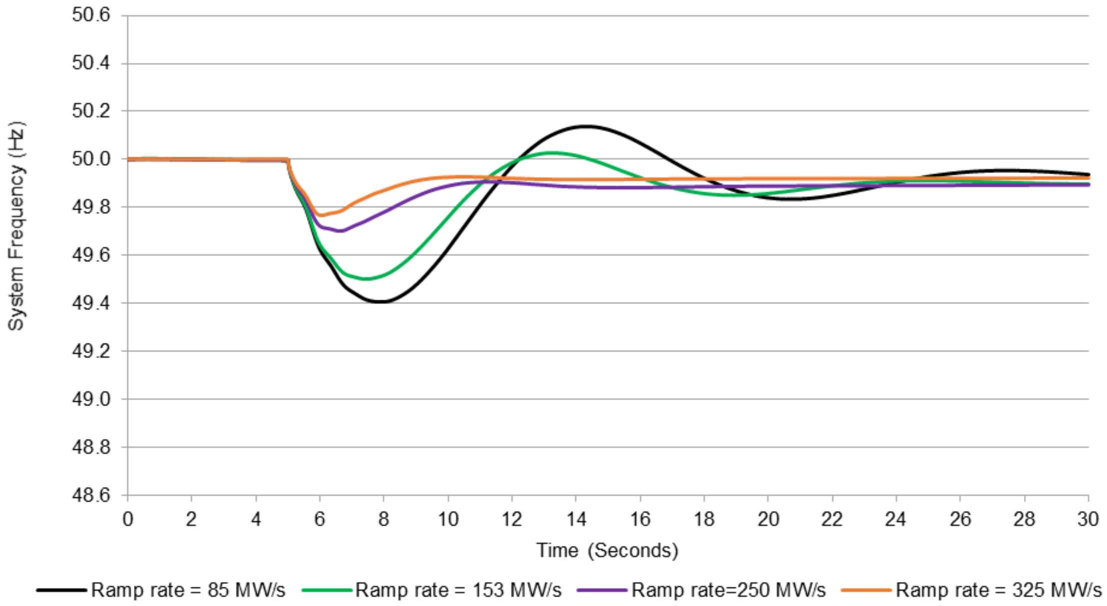

Figure 18 – System frequency response to BESS FIR with different ramp rates

6.2.3 Limitations of BESSs' response to a frequency event – low SOC

When BESSs have a low SOC early in their charging cycle, there is a period in which they will not have enough energy stored to offer FIR for 60 seconds or SIR for 15 minutes at their maximum discharge rate.

We prepared a summer day morning (08:10) peak load scenario and simulated a 390 MW contingency event, to investigate how small BESSs might respond in this situation. At the time of our simulated event, we assumed the average SOC of all BESSs in the system was 20.28 per cent: 0.28 per cent above the minimum operating level, and insufficient to provide a full FIR response.

Figure 19 shows the results: the BESSs with low SOC initially responded as we expected (just like BESSs with high SOC), and then ran out of energy after 36 seconds. The almost instantaneous ramp-back of the BESSs' active power output caused a second frequency deviation of nearly 1 Hz before conventional present-day FIR could respond.

In reality, the likelihood of such a second under-frequency event occurring is low. We expect that diversity in the SOC across the system would reduce the probability and magnitude of this effect.

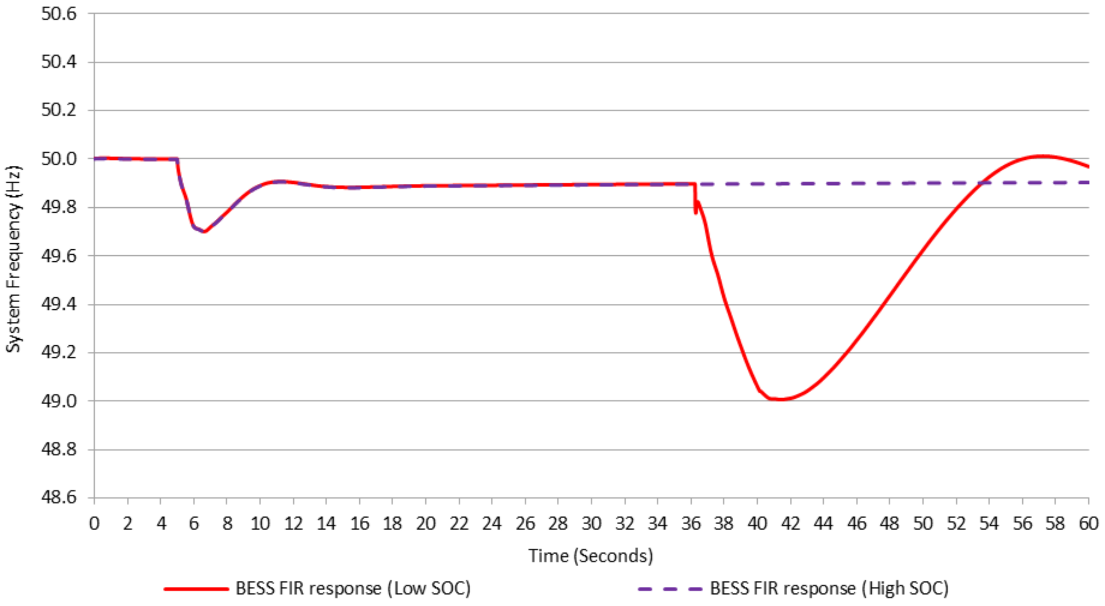

Figure 19 – Comparison of system frequency response for FIR provided by BESS with both high and low SOC

6.2.4 Limitations of BESS responding to a frequency event – high SOC

When BESSs have a high SOC and/or solar PV generation is high, we anticipate two limitations in the hybrid solar PV BESSs' ability to respond to frequency events.

- BESS with high SOC will not be able to sustain offtake from the grid for a long period of time in response to an over-frequency event.
- Solar PV generation can be feeding into the grid and using most of the inverter capacity in our DC coupled system, meaning there is limited headroom available for the BESSs to increase their output in response to an under-frequency event.

To demonstrate these effects simultaneously, we prepared a summer day midday (13:40) low load scenario in which the grid is lightly loaded and there is minimal synchronous generation online; the time we chose represents a time of peak solar PV generation feed-in, and at which the average SOC of BESSs across the New Zealand system would be 99.8 per cent. We simulated an HVDC bipole tripping contingency (involving loss of 90 MW north transfer resulting in an under-frequency event in the North Island, due to not enough generation, and an over-frequency event in the South Island due too much generation) that separated the North and South Islands. We then looked at small BESSs' ability to provide FIR and OFR in the North Island and South Island respectively to restore system frequency.

Figure 20 shows our results. In the South Island, the frequency would initially rise to 50.15 Hz after 0.92 seconds, and then start to recover as initially BESS provides OFR. However, due to the high average BESS SOC at the start of the event, some BESS would be unable to sustain the required offtake from the grid; they would cease to charge, and subsequently trigger over-frequency events at 35 and 46 seconds.

In the North Island, the frequency would fall to 49.64 Hz after 0.72 seconds. The drop in FIR availability from BESSs at the time of the event would be due to peak solar PV generation feed-in at this particular time (as described above). Despite this, there would still be enough FIR distributed across New Zealand to respond to the event and restore the system frequency.

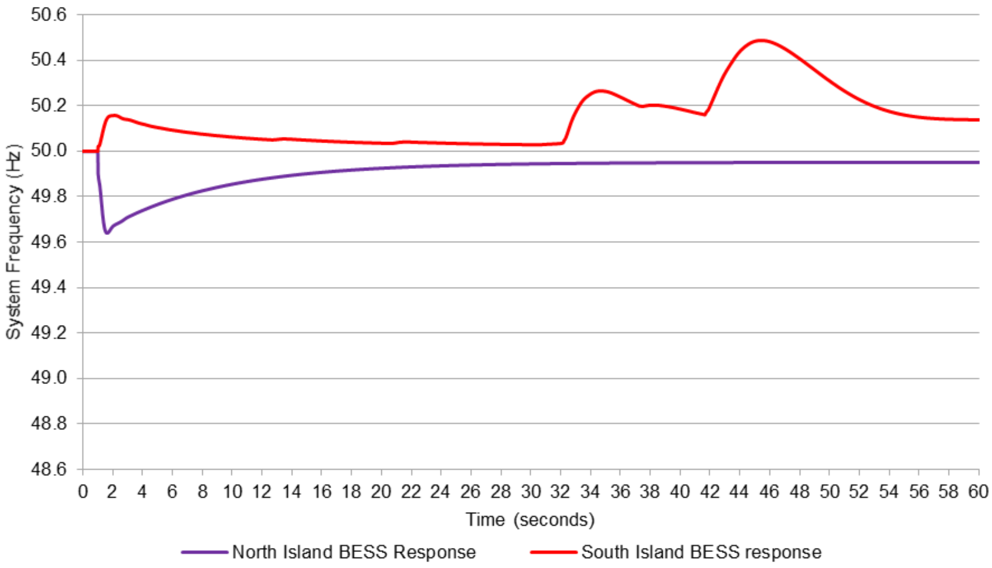

Figure 20 – North and South Island system frequency response with BESS FIR and

6.2.5 Synthetic inertia

The RoCoF during a frequency event is related to the amount of inertia available in the power system at the time. Low inertia results in a high RoCoF, which may lead to frequency falling too fast for IRs or AUFLS to respond to arrest the fall. In a worst-case scenario, this could result in a blackout of an island. Today, synchronous generators provide inertial response; they release kinetic energy stored in the rotating mass as active power injection during the start of an under-frequency event. This initial injection is short, lasting not more than 2–3 seconds.

When BESSs have low SOC and are unable to offer unconstrained FIR or SIR, they still have the capacity, when appropriately developed and tuned, to provide a high-power, fast-acting, short-duration discharge to support the system in this situation. This type of support is typically referred to as synthetic inertia response.

Synthetic inertia is particularly useful during light system load conditions, when there are fewer grid-connected synchronous generators able to provide inertial response. A synthetic inertia response can help to reduce the RoCoF after the start of a frequency event, allowing conventional FIR and SIR time to respond to restore the system frequency.

To investigate the ability of BESSs to provide synthetic inertia, we prepared a scenario entailing a 390 MW contingent event like that discussed in section 0, on a winter day evening (21:30). This time, we configured the BESSs to provide a synthetic inertial response, instead of FIR. Figure 21 shows that the aggregated BESS output lasts for just 2.5 seconds, but in large enough quantities to help arrest the RoCoF from 0.32 Hz/s in the present-day system to 0.24 Hz/s for the 160 MW BESS synthetic reserve. This reduction in RoCoF would allow additional time for synchronous generators to react to the frequency deviation and increase their outputs to provide conventional IR.

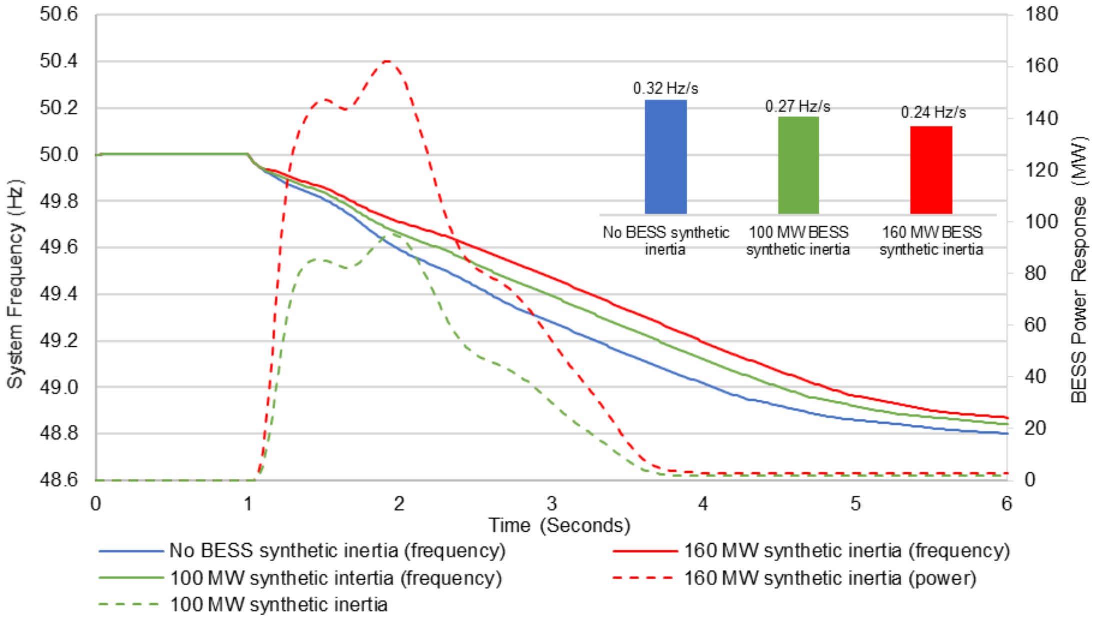

Figure 21 – System frequency response with BESS synthetic inertia

7 Key findings and conclusions

The capabilities of BESSs are well known and integrated in power systems elsewhere in the world. Our investigation looked specifically at the New Zealand context, and sought to help us understand the likely collective impact of a high penetration of distributed hybrid solar PV BESSs in New Zealand.

Our 2017 investigation of solar PV found that the inclusion of 4 GW of solar PV on today's power system would result in the displacement of large amounts of synchronous generation and low loadings on the grid, causing high voltages during the day when solar PV generation is high. As solar PV generation decreases and load begins to increase at the evening peak, synchronous generation needs to rapidly ramp up to supply load. While these challenges are not insurmountable, they make the operation of our power system more challenging.

In addition to the benefits BESS technology offers to consumers themselves, we found that BESSs could help us address the challenges identified in our 2017 investigation in the following ways.

- They could improve our use of the grid and generation by smoothing the daily load profile, deferring investment that we might otherwise need to make to enable high-uptake EV charging or solar PV generation (subject to BESS size, uptake and charging behaviour).
- They could help our IRs perform even better than they presently do, which could improve our system frequency management in response to system events.
- They could provide a synthetic inertial response, to slow the change in system frequency in response to system events and address the loss of system inertia as synchronous generation is displaced due to solar PV generation.

We also found in the course of this investigation that New Zealand's current power system could accommodate increases in system load due to passive charging associated with the uptake of EVs. A hypothetical low uptake of 64,000 EVs would present no challenges to operation of the power system at a transmission level, and even 2 million EVs could be accommodated under most conditions.

However, our investigation also found that introducing distributed hybrid solar PV BESSs in regions already prone to challenging voltage management issues (the UNI and USI) would not improve the situation; in fact, without proper coordination (for example, limiting injection onto the grid), they could make it worse. Our simulated scenarios in this regard showed that, while BESSs would help to lift the midday trough created when solar PV generation is high, with existing reactive compensation devices and operational measures such as switching out transmission circuits, high voltages would still be difficult to manage to an acceptable level. Any investment in added reactive compensation devices on the grid would need to keep pace with the uptake of solar PV, to enable the system operator to continue to meet its PPOs in regard to voltage and maintain a reliable power system.

It is important that the Code continues to evolve, to enable the 'grid-supporting' capabilities of BESS to benefit the New Zealand power system, and that market design reflects, accommodates and incentivises these capabilities.

The following sections present our key findings in relation to the system load profile, voltage management and frequency management in turn.

7.1 Implications for system load profile

This investigation has shown us the potential for incorporating BESSs and EV charging into our system, to help smooth the daily load profile both in summer and winter and address the large midday trough caused by 4 GW of solar PV. In all cases, combinations of BESS and EV charging helped reduce the impact of this trough. In some circumstances, they helped reduce the morning and evening load peaks as well.

We found that BESS capacity, charging behaviour, seasonal load and solar PV potential impacted on how beneficial each of the various combinations were at smoothing the daily system load profile. In general, we observed that an uptake of larger BESSs would perform better in smoothing the daily load profile, and help us avoid the sharp ramp-ups of generation we noted in our small BESS scenarios, when the BESSs were depleted in the evening. The exception to this was the summer early morning load period: in this case, larger BESSs would still be able to discharge, and hence result in a lower system load than we see today. We could reduce the effects of this impact if we could incentivise optimised BESS charging/discharging behaviour.

Overall, smoother system load profiles would allow us to make better use of our transmission and generation assets, and make it less challenging for us to manage the power system securely and efficiently in most situations.

7.2 Implications for voltage management

Voltage management in both the UNI and USI are currently challenging for the system operator. Our investigation found that the localised impact of hybrid solar PV BESS on reducing the system load through the middle of the day when solar PV generation is high could create high voltage management challenges for the grid. Our investigation focused on the grid, but we expect that these high voltage impacts would affect the distribution network as well.

Grid-connected inverters within a hybrid solar PV BESS can be configured with different volt response modes, as specified in AS/NZS 4777.2:2015; this could help manage local voltage within distribution networks. Our investigation did not consider this ability, as we could not establish the effect this would have at grid level. We believe that there would be some beneficial impact to grid voltage management if these volt response modes were enabled.

Our investigation did not involve a direct comparison with voltage management findings from the 2017 investigation, due to the use of different study techniques. However, anecdotally, we can say that BESSs are likely to help reduce the impact on high voltage management that large amounts of solar PV generation in isolation would cause. This is due to BESSs' ability to offset solar PV generation injecting into the power system in the middle of the day, helping to increase system load. The larger the BESS, the greater its ability to help in this regard. Although we did not consider it in our analysis, a small increase in system load due to EV passive charging throughout the day would also help ease the midday high voltage challenges.

7.3 Implications for frequency management

Our investigation has shown that BESS SOC and amount of solar PV generation determines the ability of BESSs to provide different frequency reserve. Even when our scenarios assumed self-consumption charging behaviour, which is aimed at maximising the benefit for the consumer rather than the system, we always found that across a day, in both summer and winter, our different sized BESSs could supply at least one type of frequency reserve to support the system operator with frequency management.

We demonstrated that when BESSs are appropriately configured and tuned, they can respond as fast or faster than present-day IRs, recovering frequency faster and stabilising with fewer oscillations. In addition, appropriately configured and tuned BESSs can provide synthetic inertia that could potentially replace inertial response lost from synchronous generators displaced from the system during periods of high solar PV generation.

We found that when BESS is not at the right SOC to supply the full duration of the reserve it is offering subsequent frequency events can result, as the BESS rapidly changes its output from either discharging or charging. In reality, it is likely there would be sufficient diversity in distributed BESS response and SOC that the probability and magnitude of these events would be very low. Regardless, we should give careful consideration to the development of BESS reserve products, to ensure a smooth ramp occurs at the end of the BESS's reserve provision and minimise frequency fluctuations.

Overall, we found that BESSs can provide excellent support for frequency management in New Zealand, and help the system operator meet its PPOs in this regard. To enable this support, the Code will need to evolve, to allow BESSs to provide IRs or other new products.

8 Recommendations

Considering our findings, we make the following recommendations, to ensure the system operator and New Zealand as a whole make effective use of the opportunities BESSs offer for the benefit of consumers and the operation of the New Zealand power system.

Transpower, in its role as system operator, is committed to working with the industry to develop the Code and electricity market design to incentivise or marketise coordinated charging and discharging behaviour for distributed BESSs and EVs.

8.1 Understanding a changing load profile

Our investigation has shown that distributed hybrid solar PV BESS and EV charging behaviour can influence and change the system's daily load profile. As the penetration of these technologies increases, so does their combined influence. As solar PV generation, BESSs, EVs and other distributed energy resources become embedded in distribution networks, the load appearing at GXPs is likely to become more dynamic and more challenging to forecast.

Recommendation 1: Increase our understanding of BESS and EV charging and what it means for the system operator's load forecast

- Identify how information from consumers with BESSs and EVs can inform our view of the distributed response of both on the system operator's load forecast, to aid future studies on the impact of increased uptake of distributed energy resources within distribution networks.

8.2 Understanding the impact of different BESS voltage modes

Our investigation has shown that in some regions high uptakes of hybrid solar PV BESS will make management of local voltage challenging in the middle of the day. Inverters have voltage modes that may help reduce the impact of this challenge, but we did not consider this as part of our investigation.

Recommendation 2: Investigate different BESS voltage mode impacts on power system voltage management in the UNI

- Undertake further investigation of the impact of BESSs on regional voltage management with a case study of both hybrid PV BESS and EV charging on UNI voltage management, including the different inverter voltage modes specified in AS/NZS 4777.2:2015.

8.3 Support for enabling BESS ancillary services for frequency management

Our investigation has shown that BESSs' ability to rapidly change active power output is well suited to help us manage system frequency following a contingent event. BESSs could provide FIR, SIR or OFR and even inertia lost when synchronous generation is dispatched off from the system during periods of high solar PV or wind generation.

Recommendation 3: Enable BESSs to provide ancillary services for frequency management

- Carry out further case studies on the ability of BESSs to provides frequency management support, including on the impact of the SOC of distributed BESSs at different times during the day. This will inform reserve market design for both existing (FIR/SIR/OFR) and new (synthetic inertia) ancillary services for managing frequency.

8.4 Adherence to inverter standard

Because forecast levels of solar PV, BESS and EV uptake in the New Zealand power system are high, it will be essential to ensure that the inverters installed with these technologies comply with the voltage and frequency limits for sustained operation specified in AS/NZS 4777.2:2015. This will provide the system operator with confidence of inverter behaviour during a contingent event. Failure to comply with this standard will add additional cost to the operation of the New Zealand power system.

Recommendation 4: Enforce compliance with AS/NZS 4777.2:2015

- Carry out studies to confirm the future system costs of non-compliance with the current standard, inform the Electricity Authority of these potential costs and encourage the Ministry of Business, Innovation and Employment to require inverter installations to comply with the current standard and any future revisions.

A.1 Investigation assumptions

This appendix provides additional details on the assumptions we used to perform our investigation studies.

A.1.1 General

1. We ran studies using results from real time pricing (RTP) market schedules incorporating load and generation data.
2. Our studies focused on the impact to the existing grid, with no consideration for future grid or generation build, as did our 2017 solar PV investigation. Including future grid configurations would have required our investigation to also assume a specific forecast date for the uptake of our hybrid solar PV BESS and EV scenarios.
3. In the market schedule the GXP power factor was maintained at unity through solar PV generation injection, BESS charging/discharging and distribution network control. This ensured that we could use the net load from the market model.
4. Solar PV generation injection was based on sunny day generation profiles for both summer and winter cases.

A.1.2 BESSs

1. As we would expect BESSs in the New Zealand context to be primarily installed behind the meter (refer to our *Battery Storage in New Zealand* [4] report), our investigation only considered these types of installations.
2. We would expect behind-the-meter BESS deployment to closely follow the installation of rooftop solar PV; we therefore assumed all storage to be part of a hybrid solar PV BESS. Our *Battery Storage in New Zealand* report found that behind-the-meter installations provide the maximum value. Taking this into account, we focused only on this type of system, which also allowed us to leverage the modelling we had previously performed for our 2017 investigation to model the charging behaviour. This approach avoided the complexity of modelling grid- or distribution-connected BESS with uncertain drivers (eg, outage management or load shifting).
3. We assume our maximum BESS charge rate (in amps) matches the Ah rating of the BESS. This is also known as 1 C.
4. There are electrical losses entailed in charging and discharging BESSs’. We assumed a one-way inverter efficiency of 95 per cent.
5. BESSs are operated within pre-defined charge limits to extend their life (that is, the BESS management system will prevent complete discharge). We assumed discharge would stop at 20 per cent SOC.
6. We assumed that all BESSs would utilise the connected solar PV inverter that would behave as we had modelled in our 2017 investigation; that is, according to AS/NZS 4777.2:2015.
7. We assumed that BESSs only supported one full charge/discharge cycle per day; a determination of optimal charging times was outside the scope of our investigation.
8. BESSs can initiate charge and discharge to provide the different ancillary services modelled in this study.
9. We tied our modelled regional uptake of BESS to the solar PV generation uptake we had modelled for our 2017 investigation.

10. The solar PV capacity modelled in our 2017 investigation provided us with an upper bound to the quantity of BESSs installed, both at a site and national level. We assumed a 3.5 kW panel size per site.
11. Our investigation distributed the solar PV generation potential across the 14 grid zones, and then applied it to all GXPs, as in our 2017 investigation.
12. As BESSs were only charged from solar PV generation in our scenarios, the quantity of energy stored in a BESS varied based on the seasonal profile of that generation (that is, in summer, the quantity stored was greater than it was in winter).
13. We assumed that BESS charging and discharging behaviour promoted self-consumption, meaning that we assumed households used BESS discharge to meet household demand, and drew any shortfall from the grid.
14. We assumed that BESSs commenced charging each day once solar PV generation exceeded the household demand, and that they began discharging in the late afternoon, when solar PV generation no longer met demand.
15. We aggregated BESS response at a GXP level, mimicking the possible approach of third-party aggregators, network companies, retailers or industry standards.
16. We assumed that BESSs were not responsive to frequency under normal operation. BESS response is very fast; we modelled the contingency response bound to the connected inverter's rating (AS/NZS 4777.2:2015 inverter standard). With enough BESS capacity in the power system (all configured to perform frequency regulation), we would expect the system frequency to be extremely stable at 50 Hz.

A.1.3 EVs

1. The adoption of electric vehicles is introducing large quantities of BESSs to New Zealand. Their expected behaviour, however, is still relatively unknown; for this reason, we limited this investigation to focus on their charging behaviour, and did not at all consider the potential for bi-directional V2G power flow. EV-to-grid injection is based on the premise that there is an economic benefit to discharging at a specific time. To identify optimal possible discharge periods, we would have had to carry out an economic study (taking into account the multiple charge/discharge cycles of a BESS) considering both round-trip efficiency and the difference between retail rates for energy injection and offtake. This was beyond the scope of our investigation.
2. We assumed that EV BESSs would be charged based on a 'passive charging' approach; that is, we assumed that a significant portion of people would simply plug in their vehicles as soon as they got home. This charging profile correlates with the current pattern (peak load in the evening) and represents a 'worst case' for EV charging behaviour. We based our approach on the weekday passive charging profile prepared by Concept Consulting for their recent *Driving Change* report [8].
3. We based our assumptions for location of EV BESS charging on vehicle registration data available from Ministry of Transport [9]. We based uptake levels on the Ministry of Business, Innovation and Employment's fleet size forecast [10], which incorporates the government's goal of approximately 64,000 electric vehicles by the end of 2021. We also incorporated the forecast 2050 uptake level for EVs (2 million) from *Te Mauri Hiko*'s base scenario.
4. We based the quantity of charging on an average daily driving distance [11] of 32 km, corresponding to approximately 6 kWh of energy consumption per vehicle per day.

5. We assumed EV charging behaviour to be based around the vehicle and charging infrastructure currently available (that is, low speed, 3 kW, with household charging as the primary source).
6. We assumed EV charging not to be responsive to frequency and voltage, and therefore modelled it in our investigation as an additional MW load.

A.2 Self-consumption BESS charging profile

This appendix describes the process we used to prepare GXP-level BESS charging profiles for our investigation. These profiles were necessary to investigate the impact of BESS on the New Zealand power system. We incorporated them into existing RTP market schedules using vSPD, to determine changes in generation and power flows.

To simplify our modelling, we aggregated household BESS installations to produce a single BESS at their connected GXP. We needed both GXP-level residential load profiles and solar PV generation profiles to determine BESS charging profiles according to the charging assumptions above.

A.2.1 Residential load profile

This section describes the steps we used to derive the residential load profile driving the charging behaviour.

Normalised national residential load profile

There are no readily available daily GXP profiles of residential load; we therefore had to infer profiles from available data sources. We used GXPs deemed to be ‘residential’ based on data from the Electricity Connections Snapshot Report on the Electricity Authority’s Electricity Market Information (EMI) website[8] as a basis for our work. A ‘residential’ GXP is one at which more than 90 per cent of connected installation control points (ICPs) are residential.

We used the proportion of residential ICPs at each GXP as a proxy to determine the percentage of the total GXP load to attribute as residential load. For both the summer and winter investigation days, we normalised the residential load at each GXP and used the average of all GXPs to create a normalised national residential load profile.

Average daily household energy consumption

We used information on regional council residential energy consumption for 2016 was available from the Residential Consumption report on the Electricity Authority’s EMI website. This provided us with average residential household energy consumption on a monthly basis by region.

We took these average monthly household consumption values for the relevant summer and winter investigation months and divided them by the number of days in that month to create an average daily household load for each region. For simplicity, we made no distinction between a peak weekday and a minimum weekend day.

Calculating GXP daily residential load profiles

To produce a daily residential load profile at each GXP, we scaled the normalised national residential load profile by the applicable region’s average daily household load, then multiplied

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[8] See information on proportions of ICPs as at 30 September 2017: www.emi.ea.govt.nz/r/dpmef

it by the number of hybrid solar PV BESS installations connected to that GXP. Figure 22 gives an example of a resulting typical residential load profile.

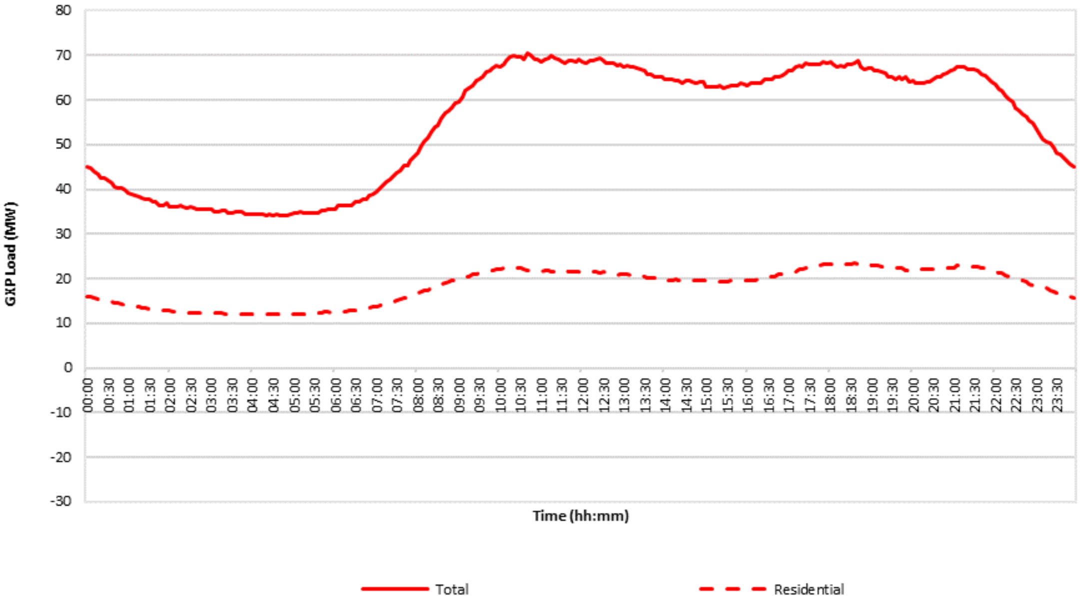

Figure 22 – Albany GXP: daily residential load profile (summer)

A.2.2 Solar PV generation profile

This section outlines the second input we used to develop a BESS charging profile: the solar PV generation profile. We used the profiles we developed for our 2017 investigation for this purpose; these profiles envisaged an extreme 4 GW of installed rooftop solar PV. Figure 23 shows an example of the resulting solar PV generation profile for the Albany 33 kV GXP alongside the residential and total load profiles.

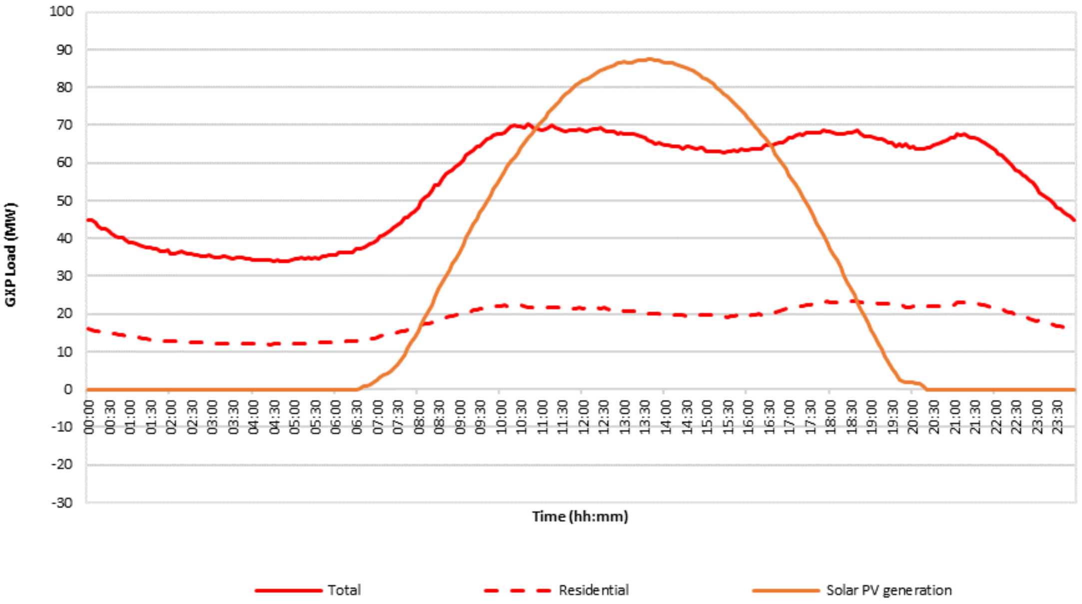

Figure 23 – Albany GXP: daily solar PV generation, residential and total load profiles (summer)

A.2.3 Number of solar PV and BESS installations

We developed each GXP profile using a regional and GXP distribution factor to split the overall national solar PV generation, accounting for regional solar PV potential, population and number of dwellings.

To determine the number of hybrid solar PV BESS installations, we used the GXP distribution factor to back-calculate the total installed solar PV capacity at each GXP. We then divided these solar PV capacities by the 3.5 kVA inverter size used for our investigation, to obtain the number of installations at each GXP.

A.2.4 BESS charging/discharging profile

To establish daily charge and discharge profiles for BESSs, we prepared a script that used both the residential load profile and the solar PV generation profile.

The script looped through two days for each GXP, to account for any remaining BESS charge at the end of the day. This enabled a BESS in our scenarios to continue to discharge into the early morning of the second day, using any remaining charge. We used only the data from the second day to generate the BESS profile.

When the solar PV generation was greater than household load in our scenarios, the BESS was charged by the energy difference (until it was fully charged). When household load was higher than solar PV generation and the BESS had a SOC above the minimum operating limit, the BESS discharged based on the energy difference (keeping below the inverter capacity).

We then used the charge and discharge values we calculated for each trading period across the day as an input for rerunning the market schedules using vSPD. Figure 24 shows the BESS charge/discharge profile for our large (14 kWh) BESS at the Albany 33 kV GXP. Charging activity is displayed as positive MW values, and discharging as negative MW values.

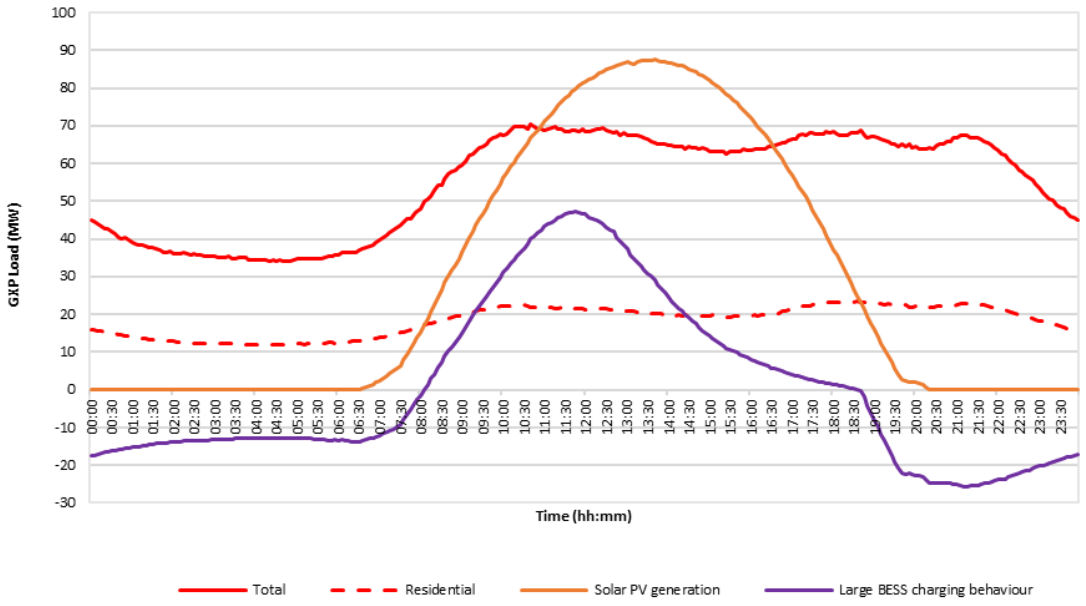

Figure 24 – Albany GXP: daily large BESS charging, solar PV generation, residential and total load profiles (summer)

A.3 Optimised BESS charging profile

We created an optimised BESS charging and discharging algorithm to demonstrate the benefits BESS could have on system operations if the system operator could control charging and discharging behaviour. In this regard, our investigation also considered the ability to charge BESS from the grid, to enable additional value.

We used two objectives to optimise BESSs' charging and discharging routine:

- optimise solar PV generation – BESSs were to store solar PV generation when generation was high and use it when there was no solar PV generation. This was to avoid exporting solar PV generation to the grid and reducing reliance on grid-imported electrical power
- flatten the daily load curve – BESSs were to charge from the grid when the system load was low, and discharge when it was high.

The specific charging period we focused on was the early morning period. We set the charging level by considering the amount of energy needed to shave the morning peak, while still retaining enough BESS capacity to charge from solar PV during the day.

During the midday period, we managed charging in our scenarios by considering three factors: the solar PV generation, residential load and midday minimum demand. The objective was to maximise BESS charging to reduce the effect of high solar PV generation on reducing system load.

To reduce the evening peak, our BESS optimisation scenarios aimed to maintain the system below a specific load level. They envisaged BESSs being charged over the day, to ensure that the stored energy was adequate to shave the required amount of load from the evening peak. To ensure that BESSs did not cause a sudden step change in load, we reduced the discharging rate slowly prior to BESSs reaching their minimum SOC.

A.4 EV charging profile

The additional load EV charging would introduce to the system is dependent on the number of vehicles, how those vehicles are distributed around the country, and their daily charging profile. This section describes the methodology we used to create the EV charging profiles we used in this investigation.

A.4.1 EV uptake and distribution

Additional load from EV charging could lead to localised transmission and voltage issues, depending on how the load is allocated around the country.

This investigation considered two EV uptake scenarios: a low uptake of 64,000 and a high uptake of 2 million.

We assumed that EVs would increasingly replace existing vehicles in the national fleet, and would be spread across the country according to the current distribution of vehicle ownership [7]. Table 1 below shows the distribution we used. We distributed the EV charging load derived from these regional totals to the GXPs within particular regions, using the ratio of hybrid solar PV BESS installations to determine each GXP's allocation of load.

Table 1 – National distribution of EVs

Region	2016 registered vehicles	% of total	Number of EVs	
			Low uptake	High uptake
Northland	122,761	3.4%	2,181	68,162
Auckland	1,170,928	32.5%	20,805	650,148
Waikato	339,536	9.4%	6,033	188,525
Bay of Plenty	256,334	7.1%	4,554	142,328
Gisborne	31,116	0.9%	553	17,277
Taranaki	89,616	2.5%	1,592	49,759
Manawatu-Wanganui	180,206	5.0%	3,202	100,058
Hawke's Bay	122,292	3.4%	2,173	67,902
Wellington	327,742	9.1%	5,823	181,977
Tasman	48,451	1.3%	861	26,902
Nelson	48,740	1.4%	866	27,063
Marlborough	43,827	1.2%	779	24,335
West Coast	25,890	0.7%	460	14,375
Canterbury	542,969	15.1%	9,647	301,480
Otago	163,921	4.6%	2,913	91,016
Southland	87,696	2.4%	1,558	48,693

A.4.2 Daily EV charging profile

The uptake of EVs will raise the system load; the most significant aspect of this will be the timing of their charging; particularly whether it occurs during periods of peak or low load.

Vehicle charging profiles are based on many factors, including driving patterns, vehicle BESS capacity and charging behaviour. There have been many attempts to create a daily load profile of EV charging in New Zealand, including a 2016 approximation by the Ministry of Business, Innovation and Employment used in their electricity demand and generation scenarios.

In 2017, Concept Consulting published a paper titled *"Driving Change" – Issues and options to maximise the opportunities from large-scale electric vehicle uptake in New Zealand* [8]. This document presents a comprehensive daily charging profile based on multiple inputs and different charging scenarios. Notably, it is based around similar assumptions to those in our non-optimised BESS charging scenarios, including that charging tends to occur when drivers return home each day. Leveraging this passive charging profile enabled us to avoid the significant analysis and development that would have been involved in creating our own charging profile.

Concept's EV charging profile assumed different charging technology and a different daily charge quantity. We normalised hourly kW charging rates, to convert them to quantities relevant to our investigation.

We then created a script taking both the quantity of EVs per GXP and the normalised passive charging profile as inputs. The script looped through a 24-hour period for each GXP, applying EV load to each five-minute period across the day to create the five-minute GXP level EV charging profiles.

We then used the five-minute GXP-level EV charging profiles as an input for vSPD, in parallel with our BESS charging and solar PV generation profiles. Figure 25 presents the EV charging profile for the total system.

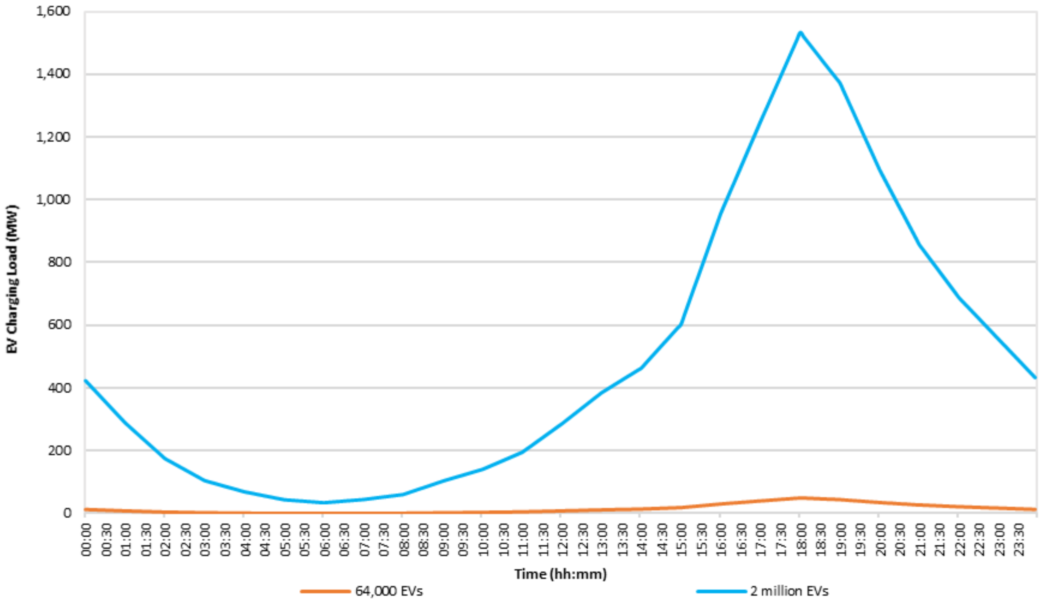

Figure 25 – EV charging profile (total system)

A.5 Market schedule preparation

We selected historic summer and winter peak days as a basis for the market schedules used in this investigation. We used the generation schedules and load profiles for these dates to analyse the impact of BESS and EV charging.

For each summer and winter day, we extracted 288 five-minute RTP cases.

We added BESS and EV charging profiles (explained in A.2, A.3 and A.4) into the market schedule, using offsets to GXP load values. We created a modified vSPD version to incorporate these GXP offsets. Our modifications included:

- offsetting nodal load values using specified GXP-level solar PV generation profiles and a total of national solar PV installed used as a scaling factor
- offsetting nodal load values using specified GXP-level BESS charge/discharge and EV charging profiles
- ignoring ramp rates for the first five-minute interval, allowing generators and the HVDC to start from an unconstrained position, at their initial dispatch
- relaxing any branch limit constraints found to be binding (and causing infeasible solutions) for all study cases. The branches we relaxed were: MCH_T1.T1, KIK_T1.L1 and ABY_T2.T2
- revaluing all zero-price generation offers (for example, wind farms) to 1 cent, to avoid non-physical losses in the market calculation.

We then used load and generation outputs from vSPD for both voltage and frequency analysis.

A.6 Voltage analysis (quasi-dynamic)

To investigate and gain insights on the impact BESSs have on voltage, we performed quasi-dynamic modelling that analysed both steady state voltage and thermal issues across the power system, focusing on whether increased levels of BESSs would improve or exacerbate existing system issues (for example, whether the existing light-load over-voltage problems at night would worsen or improve).

Using DIgSILENT PowerFactory's quasi-dynamic analysis function, we performed steady-state power flow simulations over each day, looking at five-minute intervals, focusing on specific known regional congestion issues, voltage issues and other challenges our 2017 investigation had identified.

A.6.1 Data inputs

Our analysis was based upon the outputs from the RTP market schedules for both the selected summer and winter days. These included:

- generation dispatch schedules
- GXP load profiles, including load adjustments made for solar PV generation and BESS and EV charging profiles
- the PowerFactory grid model – we used the Transpower base case 2016/17 model, as our 2017 investigation had done
- historical voltage profile and reactive support equipment information.

A.6.2 Assumptions

Our voltage analysis used the following key assumptions.

- BESSs provided no reactive power support.
- Solar PV generation was used primarily to supply household load, and any surplus to charge the integrated BESS.
- When a BESS was fully charged, additional solar PV generation was exported to the grid.
- A BESS was deployed with each solar PV installation in a DC configuration. The quantity and distribution of solar PV installations was based on our 2017investigation's 4 GW scenario.
- We did not consider any optimised BESS charging.
- We did not consider any EV charging load.
- We only considered existing reactive power compensation devices.
- The generation and load profiles we used are from actual 2017 summer and winter market schedules.
- We only considered generation available in the relevant market schedules for reactive support.

A.7 Frequency analysis (dynamic)

The objective of our dynamic analysis was to identify the value BESSs could provide to support frequency, inertia and reserves at different times of the day: in particular, we looked at how the speed of BESS response would compare with that of FIR (IL and spinning reserve), and how high levels of charging or discharging could provide a type of artificial system inertia.

We performed our analysis using Powertech Labs transient stability analysis tool (TSAT), studying select periods of interest to reduce the scope of our investigation. Using BESS charging profiles, we identified specific trading periods for which, depending on the state of BESS charge, the capacity may or may not be used for frequency management.

A.7.1 Data inputs

Our analysis was based upon outputs from the RTP market schedules for both the selected summer and winter days. These included:

- generation dispatch schedules
- GXP load profiles, including load adjustments made for solar PV generation, and BESS and EV charging profiles
- grid configuration (New Zealand full grid); we incorporated distribution of generation and load profiles into the grid model
- dynamic models (inverter models) from DIgSILENT and/or Western Electricity Coordinating Council (WECC) models
- a generator, automatic voltage regulator (AVR) and governor models based on the Transpower master case.

A.7.2 IR capability

To determine the effectiveness of BESSs to provide fast frequency response, we used BESS charging/discharging profiles to determine periods at which BESS can offer different types of reserve.

We performed the IR capability analysis as follows.

- We selected periods at which BESSs can offer IR, then created TSAT power-flow cases ensuring IR was appropriately scheduled.
- We ran non-disturbance tests to ensure our simulation cases initialised correctly, followed by generation, load rejection and circuit fault tests to ensure our cases produced reasonable simulation results.
- We rain simulations to illustrate BESSs’ frequency response capability. Standard generation and load rejection tests compared the reserves obtained from synchronous generators, IL and BESSs.

A.8 Voltage management practices

New Zealand’s power system is a typical centralised power system, in that its main load centres are located some distance from areas of significant generation. Generation is built near to fuel sources, and electrical power is delivered to load centres through long high-voltage transmission circuits.

Managing grid voltage issues is a fundamental component of power system operation. Maintaining voltage within operational limits is important to ensure secure operation, avoid equipment failure and, critically, to safeguard end consumers.

When transmission circuits are heavily loaded to deliver active power to demand centres, they consume reactive power, causing voltage to drop at the receiving end. The system needs sufficient reactive support (for example, capacitors or SVCs) at the receiving end, to avoid voltage collapse and therefore enable the secure supply of active power.

During periods of low system demand, the corresponding low levels of power flowing through the transmission system make the grid capacitive. The resulting lightly loaded grid produces reactive power, which increases voltage.

Various operational measures have been established for managing voltage and voltage stability to ensure secure system operation. These include:

- SVC/STATCOM
- switching capacitor banks
- dispatching generators to absorb or inject reactive power
- switching out transmission circuits under periods of light load.

Further information on voltage management practices can be found on the system operator website.

A.9 Frequency management practices

Frequency management is a high priority in New Zealand, to ensure the power system is operated securely and reliably. The system operator has an obligation to maintain frequency within bounds contained within Part 7 of the Electricity Industry Participation Code; this stipulates that frequency is to be maintained:

- within the normal band between 49.8 Hz and 50.2 Hz (both inclusive) arising from a supply and demand imbalance
- at or above 48 Hz for both islands during a contingent event
- at or above 47 Hz in the North Island and 45 Hz in the South Island during an extended contingent event.

In addition, the Code stipulates that a generator must remain connected to support frequency when system frequency is within the statutory limits.

Transpower as system operator manages the system frequency at or below 52 Hz in the North Island and 55 Hz in the South Island following a credible contingent event or an extended contingent event to prevent generators disconnecting at high frequency.

Further details on frequency management practices, including contingent event classification and management of frequency stability, can be found on the system operator website.

A.9.1 Under-frequency IRs

The current regulatory framework in the New Zealand market only anticipates IRs being provided by synchronous generation or IL; the reserve product requirements were developed from this viewpoint. A system event causing a shortfall of energy injection and offtake will cause system frequency to fall. This drives generators to increase output to arrest the fall in frequency and replace the missing energy injection. IL provides short-term supply/demand balancing until generators have increased their output to replace the lost capacity. Table 2 illustrates the key performance parameters for the current IR offer types.

Table 2 – IR Performance requirements as set out in the Electricity Industry Participation Code 2010

IR offer types	Measure	FIR	SIR
Partly loaded spinning reserve and tail water depressed	The additional capacity (in MW) provided x seconds after a 'contingent event'	6 seconds	N/A
	The average additional output (in MW) provided during the first x seconds after a contingent event	N/A	60 seconds
	Sustained for a period of	At least 60 seconds	At least 15 minutes
IL	The drop in load (in MW) that occurs within x seconds of the system frequency falling to or below 49.2 Hz	1 second	N/A
	The average drop in load (in MW) that occurs over the first x seconds after the system frequency falls to or below 49.2 Hz	N/A	60 seconds
	Sustained for a period of	At least 60 seconds	Until instructed by the system operator

A.9.2 Over-frequency IRs

Presently, we rely on generators to support the grid frequency by reducing their output to arrest a rise in system frequency. In extreme cases, when the imbalance is too great, controlled disconnection of generators is performed to manage the imbalance quicker than synchronous generators can respond and prevent the system frequency from rising above 52 Hz. This ancillary service is provided through contractual agreements known as over-frequency arming contracts. Contracted generators are armed at times when a contingent event might cause the system frequency to rise above 52 Hz.

Contracted generators are set to trip at different frequency setpoints, to quickly rebalance the generation and load in the event that load is lost from the grid. However, the exact reserve MW provided by these generators is not procured to match the largest contingency in the system. The generation tripped in an over-frequency event is dependent on the operating point of the generator prior to the event.

Glossary of terms and acronyms

Term	Meaning
AC	Alternating current
Ancillary services	The services and functions that support the continuous flow of electricity so that supply will continually meet demand. In New Zealand these are IR, voltage support, black start, OFR and FK
AUFLS	Automatic under-frequency load shedding: a system by which large blocks of load are armed with AUFLS relays ready to be disconnected when the frequency falls below a pre-programmed threshold
AVR	Automatic voltage regulator: an electronic device for automatically maintaining generator output terminal voltage at a set value under varying load and operating temperature.
Bipole	An electrical power transmission line having two direct-current conductors in opposite polarity
Bus (Busbar)	The common primary conductor of power from a power source to two or more separate circuits within a substation
Code, the	Electricity Industry Participation Code
Contingent event	An event for which the impact, probability of occurrence and estimated cost and benefits of mitigation are considered to justify implementing policies intended to be incorporated into scheduling and dispatch processes pre-event (see also **extended contingent event**)
Contingency	The uncertainty of an event occurring, and the planning to cover for it; for example, in relation to transmission, the unplanned tripping of a single item of equipment, or, in relation to a fall in frequency, the loss of the largest single block of generation in service, or loss of one HVDC pole
DIgSILENT PowerFactory	A power system analysis software application for use in analysing the transmission system
Dispatch	Scheduling active and reactive power generation to meet demand
DC	Direct current
EV	Electric vehicle
EV2G charging	Electric-vehicle-to-grid charging: the process by which a vehicle discharges energy from its onboard battery back into the power system
Extended contingent event	An event for which, in the reasonable opinion of the system operator, resources can be economically provided to maintain the security of the grid and power quality with the shedding of demand
FIR	Fast instantaneous reserve: reserve that must act within six seconds and then maintain its post-event output for 60 seconds (see also **SIR**)
FK	Frequency keeping: a service provided by one or more generating units to manage short-term supply and demand imbalances by quickly varying their output to ensure the system frequency is maintained at or near 50 Hz
Frequency	Rate of cyclic change in current and voltage, measured in Hz

Term	Meaning
Generator	A device that converts rotating mechanical movement into electric power. The current generated can be either alternating (AC) or direct (DC)
Governor	A device for automatically maintaining generator speed to a set value under varying load and operating temperature.
Grid	See **Transmission system**
GXP	Grid exit point
HVDC	High voltage direct current
IL	Interruptible load: reserve provided through the disconnection of load following an under-frequency event; can be provided as either FIR or SIR
Inverter	An apparatus that converts direct current into alternating current
IR	Instantaneous reserves
Mvar	A unit by which reactive power is expressed in an AC electric power system, corresponding to 1 million var
OFR	Over-frequency reserve: reserve provided by generating units that can be armed when required and automatically disconnected from the system due to a sudden rise in system frequency
Power system	A network of electrical components deployed to supply, transfer and use electric power
PPO	Principal performance obligation
p.u.	Per unit: an expression of a system quantity as a fraction of a defined base-unit quantity (for example, power, voltage or current)
PV	Photovoltaic: describes generating electric power by using solar cells to convert energy from the sun into a flow of electrons by the photovoltaic effect
Ramp (Ramp up)	Move a generator or HVDC link to a designated load level at a specified rate
RoCoF	Rate of change of frequency
RTP	Real-time pricing
SIR	Sustained instantaneous reserve: reserve that must act within 60 seconds and then maintain its post-event output for 15 minutes (see also FIR)
SOC	State of charge (in this context, within a BESS)
SPD	Scheduling, Pricing and Dispatch: optimisation software used to schedule and dispatch generation and calculate energy and reserve prices for the electricity market every trading period (see also **vSPD**)
STATCOM	Static synchronous compensator: a power system device that provides dynamic reactive support, being able to act as either a source or sink of reactive AC power
SVC	Static Var compensator: a power system device that provides dynamic reactive support, being able to act as either a source or sink of reactive AC power
Transmission system	An electric system that interconnects generators and loads and generally provides multiple paths among them

Term	Meaning
TSAT	Transient stability analysis tool: A power system analysis software application for use in analysing the transmission system
UNI	Upper North Island
USI	Upper South Island
VPP	Virtual power plant: a system that integrates several types of power sources to give a reliable power supply akin to a grid-connected generator
vSPD	Vectorised Scheduling, Pricing and Dispatch (see also **SPD**)

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