Advanced VPP Grid Integration

Knowledge Sharing Report

25/5/2021 – Version 1.0

In partnership with:

Empowering South Australia

PURPOSE

This document is the final Knowledge Sharing Report for SA Power Networks' Advanced VPP Grid Integration Project. This report describes the project, the activities undertaken, outcomes achieved and key lessons learned.

DISCLAIMER

This Project received funding from the Australian Renewable Energy Agency (ARENA) as part of ARENA's Advancing Renewables Program. The views expressed herein are not necessarily the views of the Australian Government, and the Australian Government does not accept responsibility for any information or advice contained herein

PROJECT OVERVIEW

The Advanced VPP grid integration project has developed a web interface (API) to exchange data on available distribution network export capacity ('dynamic operating envelopes') between SA Power Networks and Tesla's 1,000-customer South Australian VPP. This has enabled the VPP to dispatch at higher levels of export power than would otherwise be possible while participating in the wholesale energy and FCAS markets, while still remaining within the safe operating capacity of the local network. This project was the first to demonstrate the use of DNSP-provided dynamic operating envelopes by a significant VPP during live market trading in the NEM.

The project began in January 2019, with live operations commencing in July 2019. The project formally concluded in March 2021, although the system remains in operation.

The project has been led by SA Power Networks, in collaboration with Tesla and with CSIRO as research partner. Any parties interested in discussing the contents of this report directly with SA Power Networks are encouraged to contact Bryn Williams, Future Network Strategy Manager, at bryn.williams@sapowernetworks.com.au.

Further information on related ARENA trials can be found on the ARENA web site.

EXECUTIVE SUMMARY

Virtual Power Plants (VPPs) that aggregate many customers' individual Distributed Energy Resources (DER) such as batteries and solar under market-aware control strategies have great potential as part of Australia's future energy mix. VPPs enable new value streams for individual customers and, having the ability to respond rapidly to inject or sink large amounts of power, can potentially play a key role in balancing an energy system dominated by intermittent renewables. VPPs also, however, present particular challenges in grid integration because the physical capacity of the local distribution network, in particular the low voltage (LV) network, to accommodate the energy exported during VPP operation is limited at certain times.

To protect the integrity of the network for all customers, distribution network operators typically set static export limits at each connection point, currently 5kW for most small customers in South Australia. These limits must be set at a level that ensures that energy exports do not cause local failures in the worst-case conditions, including when multiple batteries in a VPP are dispatched to export at a time when the network is already heavily loaded. Modelling conducted in 2018 by SA Power Networks suggested that these limits would likely need to be reduced in many areas to protect the network if there is widespread enrolment of household DER in VPPs[1].

Static export limits effectively set a cap on the maximum power of a VPP. If networks had a means to set export limits dynamically, according to the local conditions of the network at a point in time, then greater export capacity could be made available at times when the network assets are lightly loaded, increasing the opportunity of the VPP to be dispatched for market benefits. This concept has gained considerable interest in Australia's electricity sector in recent years, and is often referred to as the use of 'dynamic operating envelopes'.

In 2018, SA Power Networks recognised that Tesla's South Australia VPP project, which has a goal to become the largest VPP in the world, presented a unique opportunity to pilot this kind of sophisticated approach to integrating VPPs with the distribution network, and to test this at scale in a real-world implementation. SA Power Networks partnered with Tesla and CSIRO to develop the $2 million Advanced VPP-Grid Integration trial, with $1 million of funding support from ARENA. This flagship project, a first for industry, was launched in 2019 with the 1,000 customer sites that form Phase 2 of Tesla's SA VPP rollout.

In this project, SA Power Networks and Tesla have co-designed an Application Programming Interface (API) that enables the secure real-time exchange of data between Tesla's and SA Power Networks' systems via the internet. This enables Tesla VPP sites to register electronically with SA Power Networks, provide telemetry data, and receive dynamic export limits that reflect the actual export capacity available at their location as it varies over time. To enable the solution, Tesla implemented changes to the global firmware in its Powerwall 2 product, and SA Power Networks designed and developed an abstract model to estimate available export capacity across all LV network areas in South Australia. These components were successfully delivered in July 2019 and have been tested across 1,000 customer sites for an 18-month field trial.

In the early stage of the project SA Power Networks established two national industry forums, the *DER Integration API Technical Working Group* and the *VPP Technical Reference Group*, to consult broadly on API design for the DNSP/DER interface. These groups have since expanded and become part of broader industry efforts to progress Australian standards for smart DER.

Since October 2019, Tesla has successfully operated their VPP at exports exceeding their previous static limit of 5kW per site while maintaining compliance with the limits received via the API across a variety of network conditions. The project found that through time-varying and locational export limits the total export capacity of the VPP could be increased from 5MW to 6-8MW during solar hours without compromising network quality of supply during periods of network congestion or in unexpected events. The trial also tested the

[1] SA Power Networks, *LV Management Business Case*, Supporting document 5.18 to SA Power Networks' 2020-2025 Regulatory Proposal, January 2019, available at Phase 4 - 2020-25 Regulatory Proposal | Talking Power

ability to override the forecast export limits in a local area to take into account the impact of planned maintenance or unplanned outages, and demonstrated safe and well-defined fallback behaviour in the event of loss of communications.

It was found that time-varying and locational export limits could enable DER to be hosted at higher levels of penetration, particularly distributed energy storage VPPs conducting arbitrage between solar and non-solar hours. The results support the view that a dynamic network capacity management approach can enable larger, more active DER and demand management systems to continue to operate under higher levels of DER penetration than would otherwise be possible with static limits.

The project has explored the increased value that can be provided to all customers from existing DER and network assets through this approach, particularly at peak demand times. One observation is that the amount of additional export capacity that can be made available varies between different customers, depending on where they are located on the network. The Tesla VPP's commercial model, which shares benefits equally across all participants, was found to be a successful way of eliminating any potential complexity or inequity this could cause for customers.

As far as we are aware, this project has been the first to demonstrate the use of DNSP-supplied dynamic operating envelopes by a large-scale VPP during real-world trading in the NEM. This project won the prestigious Energy Networks Australia Innovation Award in 2020, and was also awarded Utility Magazine's 2020 Industry Innovation Award.

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DOCUMENT CONTROL

Version	Date	Author	Notes
v0.95	12/3/2021	A. Ward, B Williams	Draft for final project milestone
V1.0	5/5/2021	A. Ward, B Williams	Issued

1 INTRODUCTION

1.1 Context

Virtual Power Plants (VPPs) that aggregate many customers' individual DERs under market-aware control have great potential as part of Australia's energy mix. VPPs enable new value streams for individual customers and, having the ability to respond rapidly to inject or sink large amounts of power, can potentially play a key role in balancing an energy system dominated by intermittent renewables.

VPPs also, however, present particular challenges in grid integration because the physical capacity of the local distribution network, in particular the low voltage network, to accommodate the un-diversified local energy peaks associated with VPP operation is limited. The extreme energy flows that result from the co-ordinated dispatch of multiple batteries in the same local area can breach local distribution network technical constraints, pushing local voltage outside of regulated limits or overloading network assets like pole-top transformers.

This is illustrated in the figure below, which shows real aggregated load data from the SA Power Networks (SAPN) 100-customer Salisbury battery trial[2] from a week in January 2017. The figure shows the spike in demand created on the 13th of January when the customers' batteries were instructed to charge from the grid to maximise customers' available backup power, as part of a pilot storm mitigation program. In this event the un-diversified load significantly exceeded normal afternoon peak demand. Also shown is the potential impact of a market event (e.g. wholesale price spike or contingent event) that causes the VPP operator to dispatch all batteries to discharge to the grid at a time when PV exports are already high.

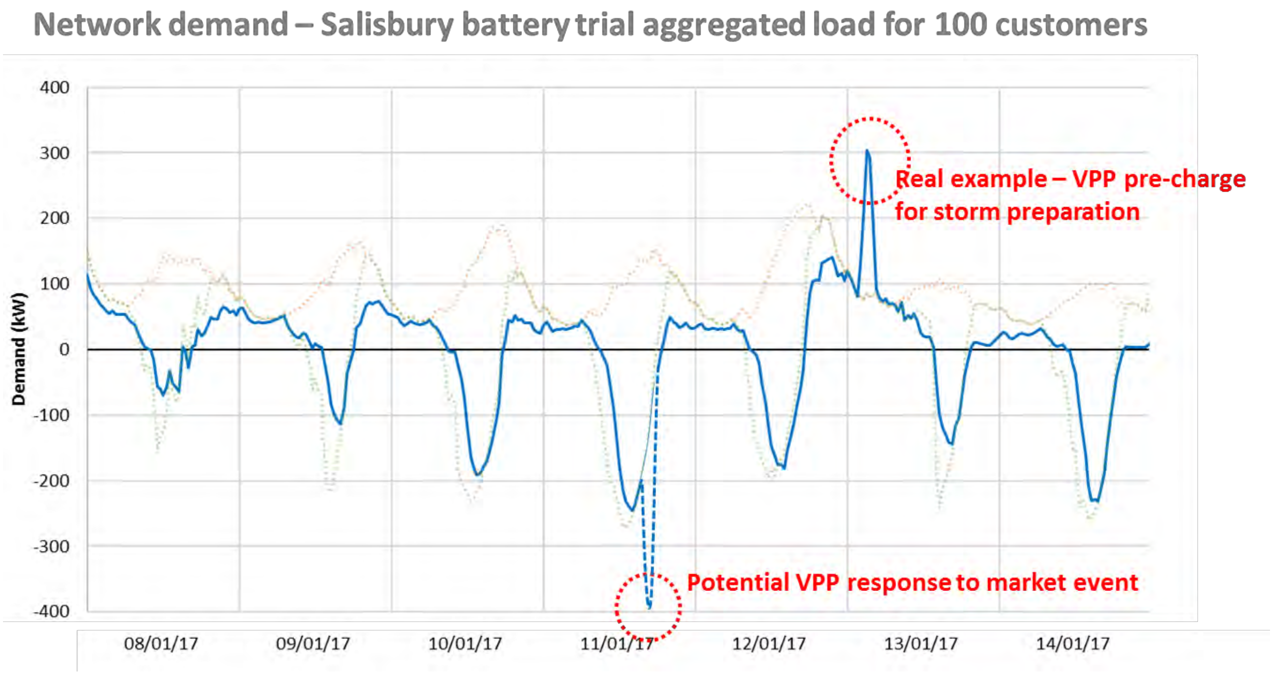


Figure 1.1: Network demand profile with VPP aggregation

[2] SA Power Networks, *Salisbury Residential Energy Storage Trial Summary Report*, accessed at https://www.sapowernetworks.com.au/future-energy/projects-and-trials/residential-battery-trial/

To protect the integrity of the network for all customers, networks must consider the worst-case event, and set static export limits at each connection point to ensure that such an event will not cause local failures. This means that the maximum power of the VPP as a whole is capped. In South Australia the standard export limit for a small customer is 5kW per phase, but modelling conducted in 2018 by SA Power Networks[3] suggested that these limits would likely need to be reduced in many areas to protect the network if there is widespread enrolment of household DER in VPPs.

If networks had a means to set export limits dynamically, according to the local conditions of the network at a point in time, then greater export capacity could be made available at times when the network assets are lightly loaded, increasing the opportunity of the VPP to be dispatched for market benefits. Such dynamic export limits will be a key capability of a Distribution System Operator (DSO) in an energy system dominated by distributed generation, to increase hosting capacity and open up as much of the available distribution network capacity as possible for generation without compromising security of supply. This concept has gained considerable interest in Australia's electricity sector in recent years, and is often referred to as the use of 'dynamic operating envelopes'.

In the time since our original Salisbury trial it has become apparent that these issues are about to be tested in South Australia on an unprecedented scale. In 2018, Tesla and the SA Government announced plans to roll out battery storage and solar PV to up to 50,000 customers in coming years to create a VPP of up to 250MW of battery capacity. This would be by far the largest VPP in the world, and a very significant resource in South Australia's energy market. The rollout commenced in 2019 with an initial 1,100 sites (5MW). The VPP is currently rolling out to a further 3,000 Housing SA sites, and Tesla has also brought more than 1,000 other sites into the VPP through the Tesla Energy Plan offered through retailer Energy Locals, bring the total capacity to over 13MW as of March 2021.

There are now eight other VPPs currently active in South Australia in addition to Tesla's, including three of significant size from AGL (5MW), Simply Energy (5MW) and ShineHub (>2MW) that are actively participating, along with Tesla, in the FCAS market through AEMO's VPP Demonstrations project[4]. VPP enrolments continue to grow steadily, driven by the SA Government's Home Battery Scheme subsidies.

1.2 The Advanced VPP Grid Integration project

The Advanced VPP Grid Integration project is a $2 million partnership between SA Power Networks, Tesla and CSIRO, with $1 million of funding support from ARENA. The project was conceived in 2018 when SA Power Networks recognised that Tesla's South Australia VPP presented a unique opportunity to pilot a more sophisticated and dynamic approach to integrating VPPs with the distribution network, and to test this at scale in a real-world implementation.

The primary goal of the project was to explore whether the amount of energy the VPP can export through the network can be increased by as much as two-fold at certain times through the use of dynamic, rather than fixed, export limits.

[3] SA Power Networks, *LV Management Business Case*, Supporting document 5.18 to SA Power Networks' 2020-2025 Regulatory Proposal, January 2019, available at Phase 4 - 2020-25 Regulatory Proposal | Talking Power

[4] AEMO, *Virtual Power Plant Demonstrations Knowledge Sharing Report #3*, February 2021, accessed at https://aemo.com.au/-/media/files/initiatives/der/2021/vpp-demonstrations-knowledge-sharing-report-3.pdf?la=en

1.2.1 Technical overview

The concept technical architecture for the project is shown in the figure below.

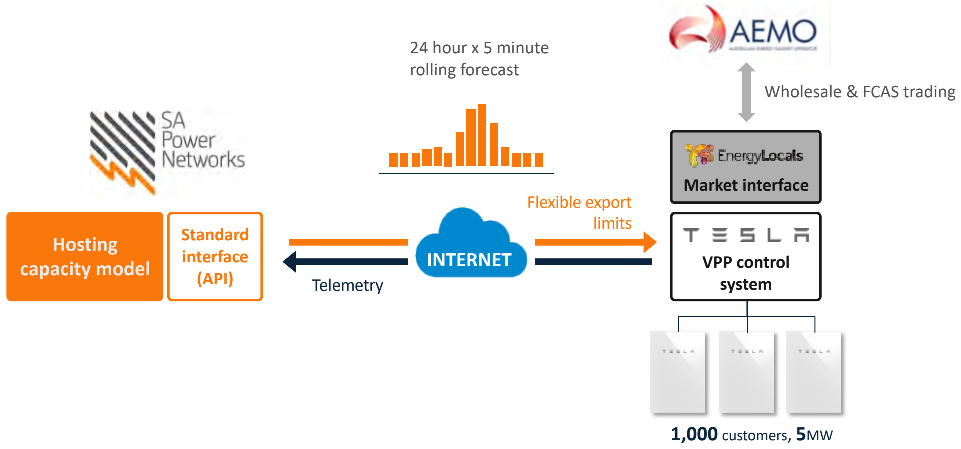


Figure 2.1: System concept architecture

In this trial, SA Power Networks has developed a model to estimate available hosting capacity for every LV area of the network. The model generates a rolling 24 hour forward forecast of available export capacity in five minute intervals for each area – the local 'dynamic operating envelope' for the network.

Tesla downloads this via a secure web services Application Programming Interface (API). The operating envelope data can be accessed either in the form of a flexible export limit for each NMI, or as an aggregated limit for a local group of NMIs.

The flexible limit allows each VPP site to export more than the standard 5kW static export limit at times when the network is unconstrained, increasing the overall dispatchable power of the VPP from 5MW to up to 10MW at certain times. Tesla's VPP control system takes this into account when dispatching the VPP for FCAS (via AEMO's ARENA-funded VPP demonstrations trial) or for wholesale market trading via their retail partner Energy Locals.

1.2.2 Timeline

The project timeline is shown below.

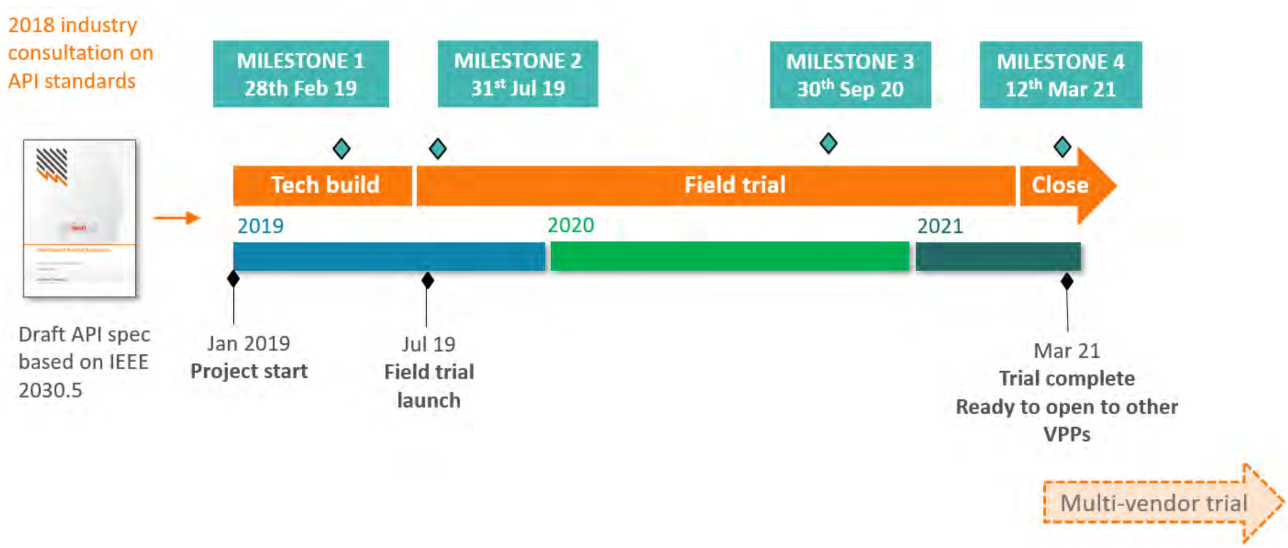


Figure 1.2: Trial timeline and milestones

The project commenced in January 2019, but builds on some early industry engagement on the dynamic export limit concept and potential API standards that SA Power Networks undertook through a series of industry workshops and a consultation paper in 2018[5].

The field trial was originally planned to end in September 2020; however, this was extended to March 2021 in order to capture additional spring and summer data.

1.2.3 Key milestones

Project milestones are summarised in the table below.

Milestone & key deliverables		Date	Status
1.	**Project Establishment** • Preliminary API specification (v0.1) • Initial Proof of Concept Integration demonstration	28 February 2019	Achieved
2.	**Field Trial commencement** • API specification v1.0 • Research Plan complete • Full end-to-end solution demonstration • Live operations ready to commence	31 July 2019	Achieved
3.	**Field Trial – Interim Knowledge Sharing** • Initial analysis of field performance • Research Report (Analysis of the VPP dynamic network constraint management) • Interim Knowledge Sharing Report (draft)	30 September 2020	Achieved
4.	**Field Trial Completion** • Final analysis of field trial outcomes & lessons learned • Final Knowledge Sharing Report (this report)	12 March 2021	Achieved

1.2.4 Project Objectives

The project had the following specific objectives:

- **Objective 1: Design and build DSO-VPP interface and operating model for dynamic operating envelopes**

  Co-design with Tesla, in consultation with other industry stakeholders, a suitable API, communication framework, connection agreements and business rules for DSO/VPP integration and dynamic network capacity allocation.

  It was intended that the learnings from this proof-of-concept could inform the development of an API specification that could become a national standard API for VPP aggregators to access advanced network integration services from DSOs in the NEM.

[5] SA Power Networks, *Improving Integration of Distributed Energy in South Australia – Consultation Paper*, August 2018

- **Objective 2: Develop new hosting capacity forecasting system**

  Develop a new model-based approach to forecasting available network hosting capacity on a dynamic and locational basis, to generate the operating envelopes for the VPP.

- **Objective 3: Test at scale in the real world**

  Test the approach in the real world for a significant VPP during live market trading, over at least one complete season in SA.

- **Objective 4: Demonstrate capability to increase VPP access to network capacity**

  Demonstrate the capability to raise normal export limits for aggregated DER during times and in locations where there is sufficient network capacity.

- **Objective 5: Quantify the value**

  Model and quantify the additional value able to be released over the trial period for the VPP operator vs. static connection limits.

Although the focus of this project was on managing capacity in the distribution network, the project also sought to inform understanding of practical implementation issues associated with the use of dynamic operating envelopes more broadly, including

- the potential to use the same API to help manage system-level constraints or contingencies, by integrating DER into the generation curtailment and load shedding schemes that DNSPs operate under AEMO's direction during contingency events; and

- the role of dynamic operating envelopes in supporting the various future market models for the NEM currently being explored by the Energy Security Board (ESB) in the Post-2025 Market Review process[6].

1.3 Structure of this report

The remainder of this report is structured as follows:

- Section 2 describes the methodology and technical solutions developed for the project;

- Section 3 describes the field trial;

- Section 4 sets out key insights from the trial, with reference to the eight specific Research Questions identified in the project Research Plan[7];

- Section 5 considers opportunities for future work, building on the learnings from this project; and

- Section 6 concludes the report.

[6] Energy Security Board | Post 2025 Electricity Market Design Project, April 2021, accessed at https://esb-post2025-market-design.aemc.gov.au/

[7] Braslavsky, Reedman, Brown & Williams, *Research plan, Advanced VPP grid integration project*, 10 July 2019

2 METHODOLOGY

2.1 System architecture

The overall system architecture and key components developed for the trial are shown in the figure below and described in detail in the sections that follow.

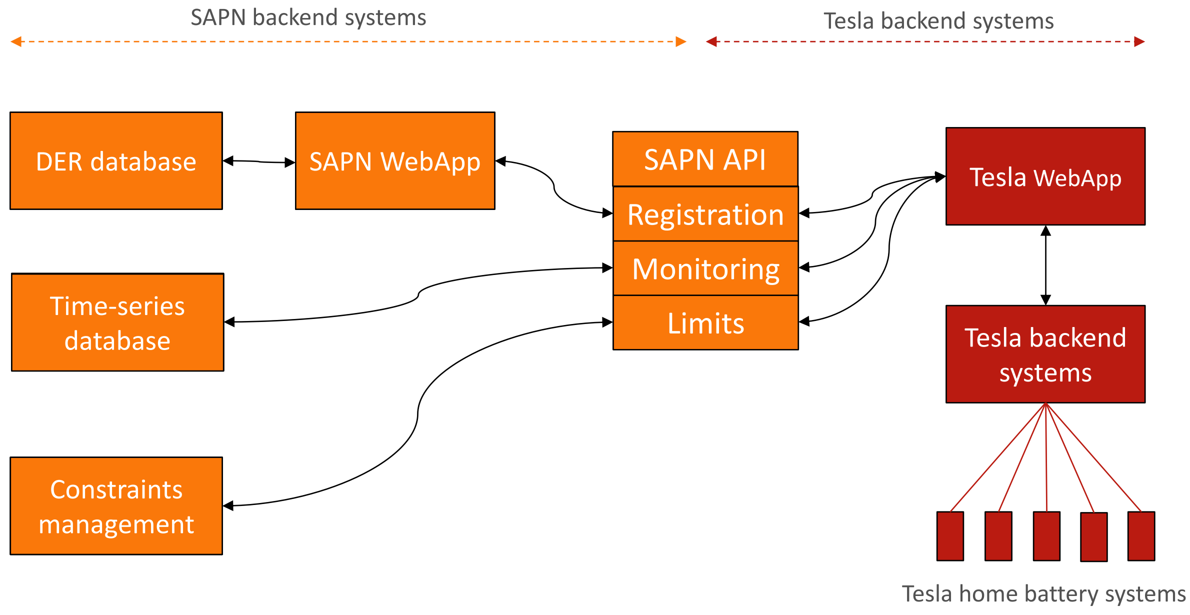


Figure 2-1: System components

2.2 API design

The first technical task for the project was the development of a suitable Application Programming Interface (API) to support the exchange of data, via the internet, between Tesla's GridLogic VPP control platform and SA Power Networks' backoffice systems. While the scope of the field trial was limited to Tesla's VPP, other industry stakeholders were consulted throughout the design process to ensure that the API developed for the project would be an open standard readily supported by other industry participants.

Design goals for the API were that it should:

- Be based on common, industry-supported open standards to the greatest extent possible;
- Be as simple as possible to implement;
- Be scalable to support very large numbers of devices and multiple VPPs; and
- Support industry best-practice cyber security methods.

2.2.1 Industry engagement and technical reference groups

In 2018, prior to commencement of this project, SA Power Networks convened a series of workshops with a broad cross-section of Australian vendors and technology providers in the DER industry to canvas the concept of dynamic export limits and seek industry advice on technical standards in this space[8].

[8] SA Power Networks, *Improving Integration of Distributed Energy in South Australia – Consultation Pater*, August 2018

This work identified the IEEE2030.5 standard as the most suitable existing standard. IEEE2030.5 has been adopted as part of California's 'Rule 21' smart DER requirements, and several technology vendors indicated that they were already working on implementing this standard, either to support the US market or for other Australian DER trials. IEEE2030.5 is a feature-rich and complex protocol, however, and it was designed to support the direct control of DER by utilities rather than the publication of dynamic limits. Hence, for the purpose of this project, it was decided to implement only a minimal subset of the base standard, and it was necessary to modify certain aspects.

SA Power Networks produced an initial draft API specification based on its early industry consultation, and worked with Tesla to refine this to suit the needs of the trial. Two new industry groups were established early in 2019 to collaborate more broadly and help guide the API development process:

DER Integration API Working Group

The *DER Integration API Working Group* brought together key subject-matter experts from other ARENA-funded projects working in this space, to collaborate on detailed API design with a longer-term goal of developing the trial API specification into a fully-featured Australian standard implementation of the IEEE2030.5 standard.

Through this group, the SA Power Networks API was adopted by the Australian National University (ANU) *evolve* project, which has also been trialling the use of dynamic operating envelopes[9]. This working group has grown steadily since its inception and is now convened by ANU. It is currently working towards the release of an Australian Implementation Guide for IEEE2030.5 in 2021.

API Technical Reference Group

A broader API Technical Reference Group was also established, comprising a diverse mix of more than 70 stakeholders across industry, to share information on the project and solicit input from industry stakeholders who were not part of any ARENA-funded trial. This group was subsequently adopted by AEMO as a reference group for AEMO's VPP Demonstrations project.

[9] *evolve* DER Project, February 2019, accessed at https://arena.gov.au/projects/evolve-der-project/

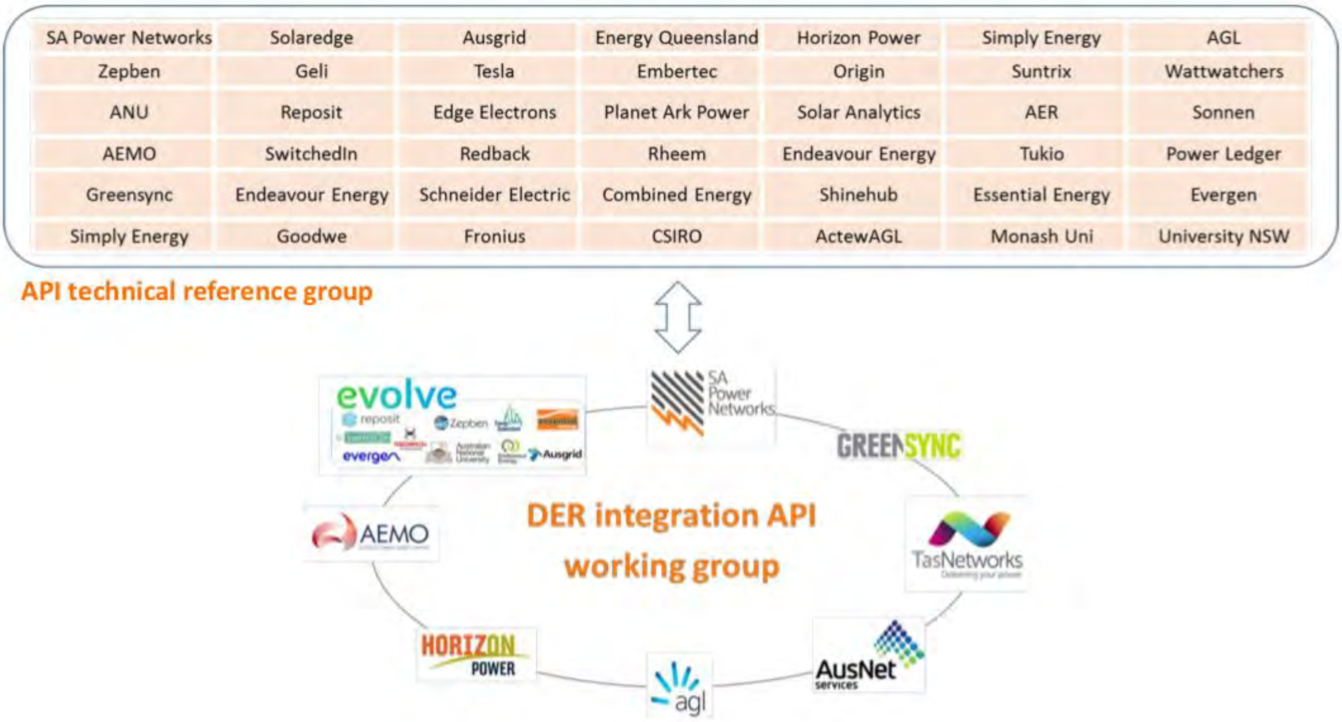


Figure 2-2: DER Integration API Working Group and API Technical Reference Group – founding members

Figure 2-3: DER stakeholder workshop

2.2.2 API functionality

The API supports the following functions:

Registration functions

Registration messages inform SAPN of the location, technical characteristics and control affiliations of the DER when it is installed. The API has the capability to accept both individual and 'batched' registrations (e.g. a daily upload of systems installed in the last 24 hours). Tesla typically registers sites individually as they are enrolled in their VPP control platform.

Monitoring / measurement functions

The API provides a standard method for a DER device or aggregator platform to provide interval monitoring data streams, for example the real power output at the device or network connection point or the voltage at the device terminals. The API accommodates a range of different data types, and data can vary in both the sampling interval (e.g. 30 minutes or 5 minutes) and the frequency of upload (e.g. once daily, or continual updates at the sample rate).

In this project Tesla provides the following 5-minute interval telemetry data per site:

- Site real power – 5-minute average, minimum and maximum;
- Battery terminal voltage – 5-minute average, minimum and maximum; and
- Battery state of charge – instantaneous.

A small number of sites provide this data in a live capacity every 5 minutes, whereas the majority of sites upload a full day of readings as a batch every 24 hours.

SA Power Networks plans to review and rationalise this data set over time in line with its broader data collection strategy, and to add reactive power to support future Volt-VAr trials. In future, this part of the API could also allow for other data feeds such as real-time alerts in the event of an outage, system disturbance or breach of system technical limits detected by an individual DER device or a VPP platform.

Network capacity management functions

This part of the API provides dynamic capacity information or 'operating envelopes' to the VPP in the form of forecast export limits at individual device or aggregate level. The VPP uses this information to manage its output to remain within the limits of the network. In this trial the export limits are set between 5kW and 10kW per site depending on estimated network conditions.

Operating envelopes are currently being provided to Tesla at the level of the network element, or node, that is congested (i.e. the LV distribution transformer for this trial). The intent is that this gives the VPP operator the opportunity to optimise allocation of network capacity across the sites below the congested network element, taking into account battery state of charge or other factors to allocate capacity to sites where it can be most effectively used. Tesla's control strategy does not currently allow for this, however, and at the present time capacity is simply divided equally across all NMIs below a constrained network element.

In the event that the VPP system is unable to communicate with the API, sites will revert to a default export limit. In this trial the default is 5kW, commensurate with normal static limits.

In future, the API could also allow the VPP to provide forecasts of its intended operation in order for SA Power Networks to estimate any potential network impacts.

2.2.3 API specification and implementation

As noted above, the SAPN API is a web-services API based on a limited subset of the IEEE2030.5 standard. The API includes 18 separate API calls to implement the functionality described above. Where possible, IEEE2030.5 calls and conventions have been used, for example in the use of 'Mirror Usage Points' (MUPs) to register telemetry data streams. The API differs from IEEE2030.5 in two key aspects:

1. IEEE2030.5 is device-oriented. Although it supports the aggregation of devices behind a common gateway, it does not have the explicit concept of a 'site', being the point of connection to the distribution network. The site is an important concept in the context of dynamic operating envelopes / flexible export limits, because the customer's export limit arises from their connection agreement with the DNSP and relates to the power flow across the point of network connection, rather than the specific exports or imports of individual devices behind the meter. The SAPN API includes functions to register sites, and to associate individual DER devices with sites, with the NMI used as the unique site identifier.

2. IEEE2030.5 is oriented towards device controls, not operating envelopes. The SAPN API introduces the concepts of 'limits' which apply to a NMI, and 'group limits' which apply to a group of NMIs that are associated with the same network constraint, or 'constraint node' (e.g. connected to the same LV transformer). The API includes functions to query the mapping between NMIs and constraint nodes, as this mapping changes over time due to switching, maintenance and reconfiguration works in the physical network.

To facilitate integration with the API, SA Power Networks hosts an online developer portal that documents all API functions and includes sample code fragments to illustrate how to use the API. This is generated automatically from the actual configuration code used to build the API, so it is always in sync with any changes made in the systems. The home page of the developer portal is shown in the figure below, and full details are contained in the API specification document[10]

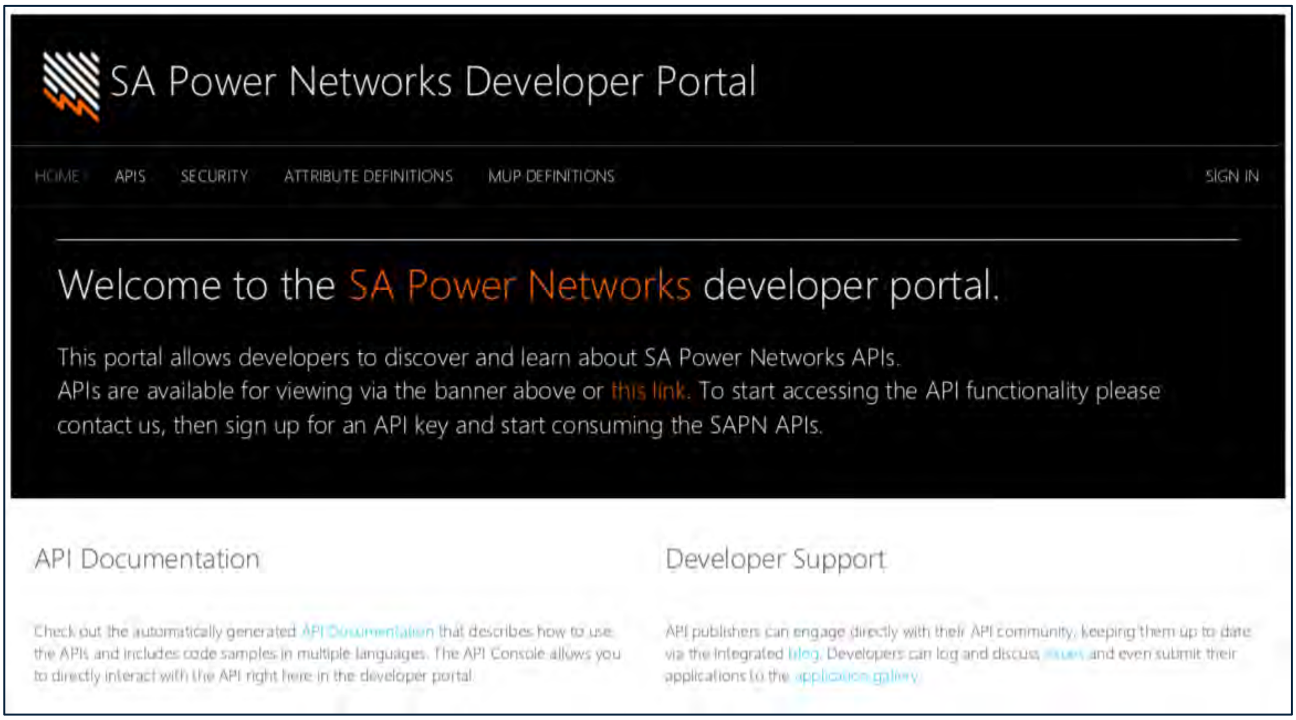


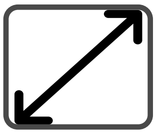
Figure 2-4: The SA Power Networks API developer portal

[10] SA Power Networks Developer Portal, May 2020

2.3 Hosting capacity estimation

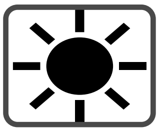
In order to manage the export capacities made available to the VPP, an algorithm (the constraints engine) was developed that estimates the latent network capacity that can be made available to the VPP in each network area at any given time. This constraint engine produces a per-distribution-transformer time series of operating envelopes that are communicated to the VPP via the SAPN API.

The constraint engine comprises the three core components shown below.



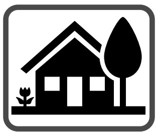
Network model

- 17 low voltage areas modelled in detail
- Every LV feeder is mapped to one of the 17 prototypes, parameterised by its specific configuration
- Thermal limits set according to transformer rating
- Template-based voltage limits – based on customer & conductor type and geographical location



Solar PV model

- Location-based solar model using historical "estimated actuals" from ANU Solcast project
- Enhanced with solar insolation data from Weatherzone (forecasts, updated every 15 min)
- Scaled by installed PV capacity and conversion factor from W/m2



Load model

- Based on analysis of sample set of historical smart meter data by the University of Adelaide – developed load profiles for Commercial, Residential, Residential Hot Water
- Profiles selected and scaled based on temperatures from Weatherzone (forecasts, updated every 15 minutes)
- Scaled by average demand for each load category

Figure 2-5: Hosting capacity model components and key inputs

The network model is based on a prototypical network modelling approach, where detailed modelling and monitoring of a small sample of representative network sections are used to estimate the hosting capacity of the entire network. Figure 2-6 below shows the different criteria used to select the representative sample of LV feeders.

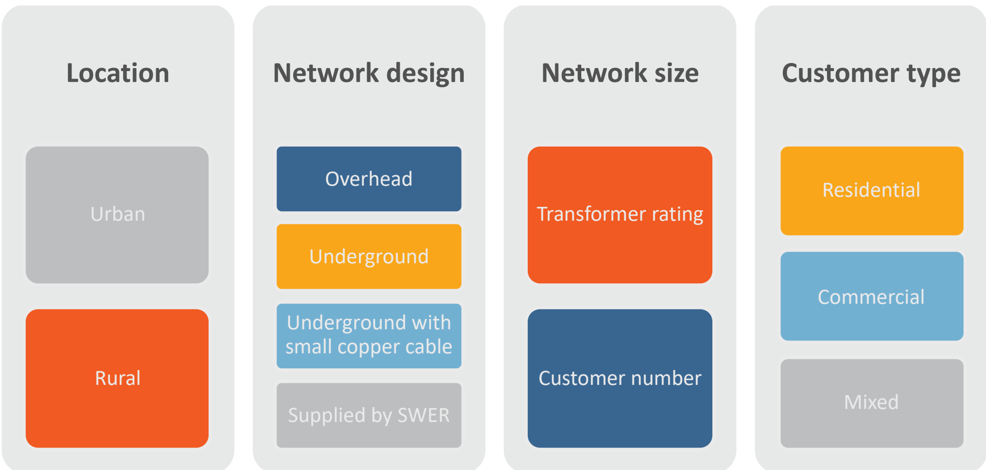


Figure 2-6: Criteria used to select the sample set of LV feeders used in the hosting capacity model

The constraint limits for the VPP trial are calculated for 25 different scenarios:

- A workday and non-workday profile per month (24 scenarios), and;
- A manually activated "heatwave" profile for peak demand days.

For each of the above scenarios, and for each distribution transformer, the constraint engine estimates a raw constraint using the formula:

$$C_i(t) = m \times \min\left(P_{V_i}, P_{T_i}\right) - P_i(t), \tag{1}$$

where:

- i denotes an index that identifies an individual transformer in the set $\{1,2,\ldots,T\}$, where T denotes the total number of distribution transformers associated with the VPP trial;
- $C_i(t)$ is the raw constraint limit estimate for the node/transformer i in kilowatts, as a function of time;
- m is a tuneable confidence margin parameter, $0 \leq m \leq 1$, set for example to 0.2 for a conservative estimate of latent capacity, or to 0.8 for a less conservative estimate. This parameter allows for inaccuracy of the hosting capacity estimation process, and can be increased over time as the hosting capacity model is calibrated and enhanced;
- P_{V_i} is the maximum reverse power flow limit for voltage exceedance at the transformer i, in kilowatts;
- P_{T_i} is the maximum reverse power flow limit for thermal exceedance at the transformer i, in kilowatts; and
- $P_i(t)$ is the reverse power flow modelled at a transformer i in kilowatts – this is the only value that varies in time. This estimated reverse power flow at the transformer is calculated as the difference between power demand and PV generation based on a set of representative load and generation profiles calculated for the SAPN network for each scenario and scaled according to the conditions of the day.

These raw constraints are then adjusted to ensure the operating envelopes sent to the VPP are between 5kW and 10kW per site. An example constraint profile as used in the trial is shown below. This shows exports limited to at or near 5kW per site during solar hours, while additional export capacity is released during the evening peak due to the increase in demand on the local network from non-solar customers.

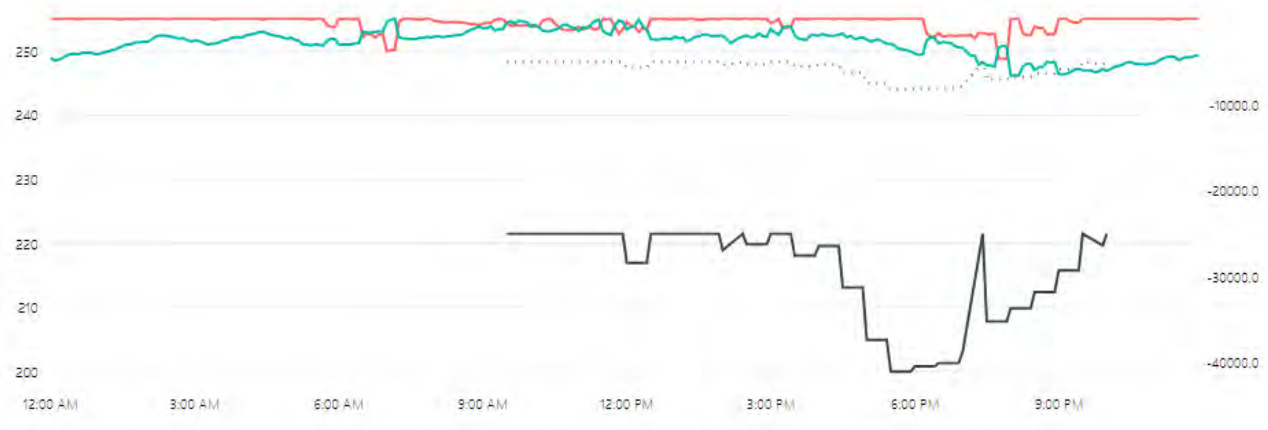


Figure 2-7: Example constraint profile for a constraint node with 5 VPP sites. The solid black line is the nodal constraint, and the dotted black line is the constraint per VPP site. The red line is the export of one of the sites, and the teal line is the voltage

The constraint estimation engine also supports the ability for an operator to apply manual adjustments to network constraints prior to publication via the API, and to exclude specific nodes from receiving limits. While these functions were initially implemented to support end-to-end testing, it became clear through the trial that this kind of functionality is very important to network control room operators for managing unexpected situations or network faults, and will be a key consideration in developing fully operational systems to support a broader roll out of dynamic operating envelopes, as further discussed in Section 4.2.

2.4 Other SA Power Networks supporting systems

Several other internal systems are required to service the VPP API capabilities on SA Power Networks' side. These are described briefly below.

2.4.1 DER database

The DER database stores the current and historical state of registered DER. For this project SA Power Networks' existing DER database, which is normally populated manually with information entered by solar and battery installers on behalf of the customer during the connection application process, was enhanced to allow for the electronic registration of devices via the API. As well as capturing standard information such as the power and capacity of a battery, the data set has been extended to include information about the VPP or aggregation scheme with which the DER is associated.

In future, the electronic registration of DER is expected to lead to significant improvements both in the quality and accuracy of SA Power Networks' DER records, and in the level of compliance to technical requirements such as having the correct AS4777 power quality settings in inverters.

2.4.2 Time-series database

A key aspect of the integration is support for the exchange of time series data for individual VPP sites. The following data streams were sampled for each participating VPP site:

Measurement	Calculation	Interval Length	Latency
Voltage (V)	Minimum	5 minutes	24 hours
Voltage (V)	Maximum	5 minutes	24 hours
Voltage (V)	Average	5 minutes	24 hours
Active power (W)	Minimum	5 minutes	24 hours
Active power (W)	Maximum	5 minutes	24 hours
Active power (W)	Average	5 minutes	24 hours
State of Charge (Wh)	Instantaneous	5 minutes	24 hours

While the majority of sites upload a full day of readings as a batch every 24 hours, the API also supports more real-time telemetry. In the trial, six sites were activated to provide data every five minutes, to field-test this functionality and to explore the potential value of more real-time data in network operations.

For the trial, this data is used primarily

- to confirm that the VPP has operated in accordance with the flexible export limits provided
- to tune the hosting capacity engine by comparing the actual voltage performance in the local network with the expected performance. Note that this data is not used to calculate the network operating envelope in real time; the hosting capacity model is a predictive model, and the data captured from VPP sites is analysed retrospectively to calibrate the model and improve its accuracy.

The trial has also investigated other network use-cases for this data, based on the kinds of benefits that have been achieved in Victoria through analysis of smart meter data. At the time of this trial, this project provided the single largest source of LV power quality data that SA Power Networks had ever had access to, with circa 1,000 sites. Prior to the project, the only LV power quality data available was from a handful of permanently installed transformer monitors and some temporary loggers deployed occasionally for local surveys and incident investigation.

Learnings from the project have helped inform SA Power Networks' longer-term approach to achieving LV network visibility through a variety of data sources, including understanding the technical requirements for data storage and processing, and the potential use-cases. The time-series data platform developed for this project is being extended in other trials to accommodate a wider variety of data sources. These matters are discussed further in section 4.

2.4.3 Data visualization

To provide operational visibility of data received in the trial, an internal data dashboard was constructed using Microsoft's Power BI visualization tool. Power BI allowed for rapid development, flexibility and easy aggregation of data and was the primary tool used to understand VPP operations and network behaviour during the early stages of the trial.

Mid-way through the trial, a dedicated high-performance time-series data processing and visualisation product from Australian company Future Grid[11] was integrated. An example of data visualisation with the Future Grid product is shown below. While this is now the primary time-series data platform for this trial and other related trials, Power BI remains as a valuable tool for rapid prototyping, testing ideas for reports and data visualisations, and ad-hoc data exploration.

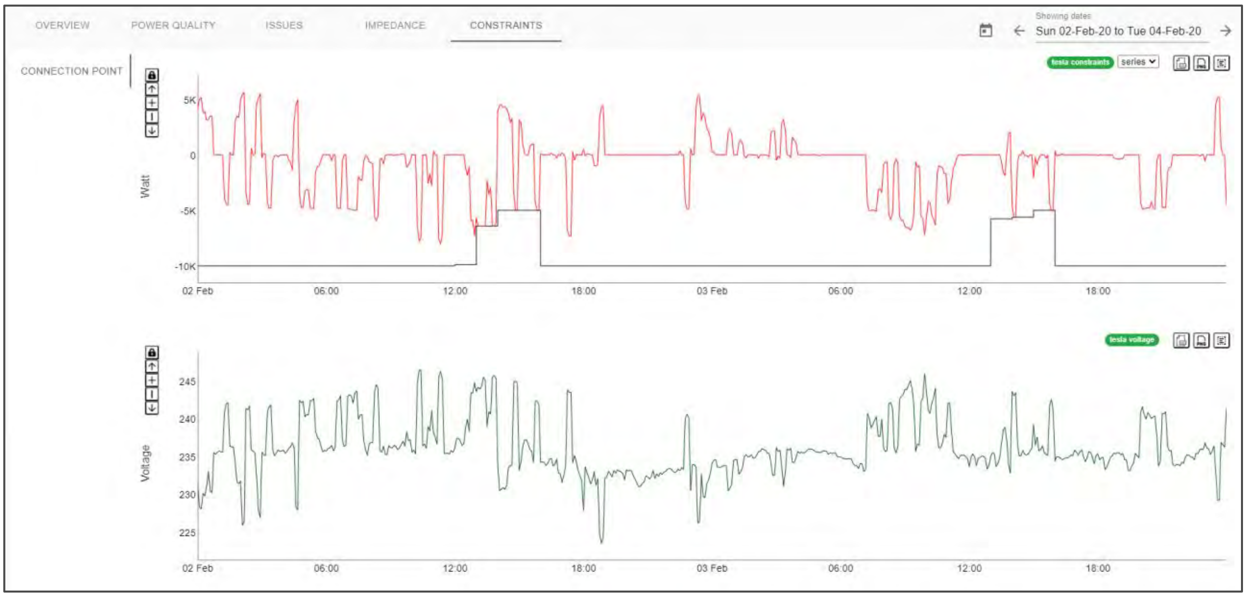


Figure 2-8: Data visualisation with the Future Grid platform

2.5 SA Power Networks technology build

SA Power Networks developed most of the core IT systems required for the project in-house using the Microsoft Azure cloud services framework[12], integrated with the Future Grid time-series data platform. The diagram below shows the technology stack used to enable each capability:

- Device registration and the outbound communication of operating envelopes is conducted through Azure WebApp, with cybersecurity and developer services provided through Azure API Management;
- Monitoring data is ingested through Azure IoT Hub, with monitoring streams set up through WebApp;
- The current and historical state of registered DER is stored in Azure SQL Service, with timeseries data stored in Azure Blob Storage;
- Visualisation and alerting based on monitoring data is provided in the Future Grid platform; and
- The hosting capacity model and constraint management systems are implemented in Azure Databricks, with operating envelopes served to the API via CosmosDB.

[11] Future Grid Diverse Data Platform, accessed at https://future-grid.com/
[12] Microsoft Cloud Adoption Framework for Azure, accessed at https://docs.microsoft.com/en-us/azure/cloud-adoption-framework/

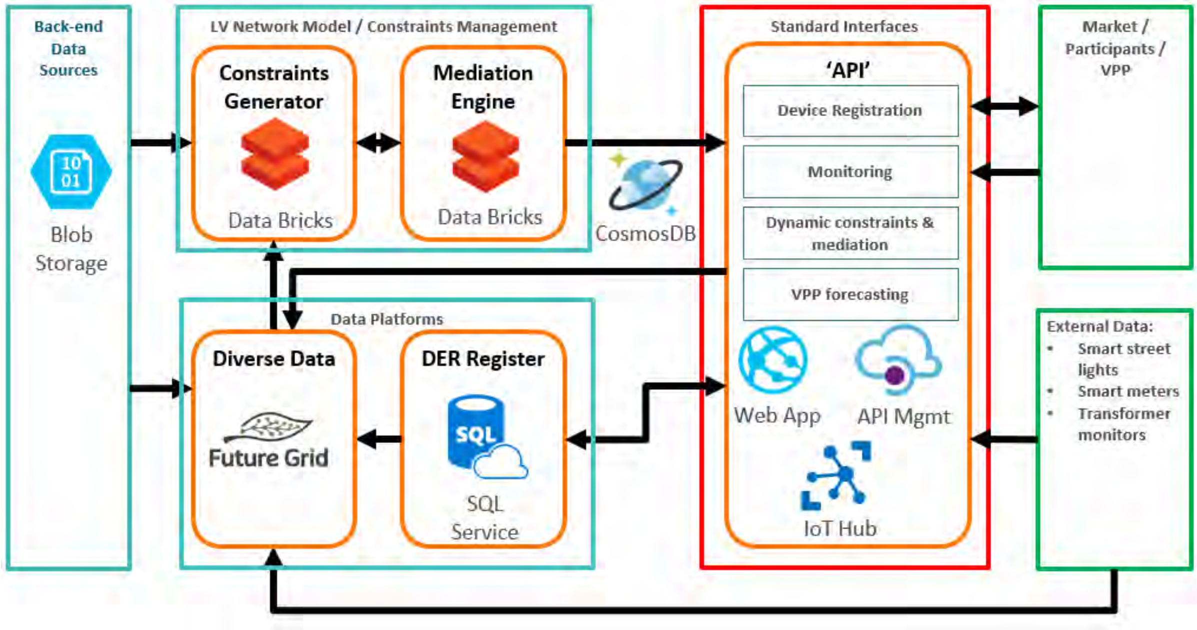


Figure 2-9: Technologies used to implement SA Power Networks' system components

The SA Power Networks components and architecture required development from the ground up, as there were few existing systems within the business that were able to be leveraged, apart from legacy data sources. An early goal established for the project was that the systems developed for the trial should be designed from the outset to be able to scale up to support a full production service in future, with multiple VPPs and hundreds of thousands of devices.

The Microsoft Azure framework was selected as it supports the level of scalability, performance, robustness and cyber-security required for a distribution network operational system, while also providing for the rapid development and flexibility required during the trial.

In all, the trial systems required around 3.2 staff years of development effort, most of which occurred during the first six months of the project. Ten new Microsoft Azure components were developed and deployed for the project, comprising more than 11,000 lines of code.

Key metrics:

3.2 staff years
of development effort

11,000
lines of code

10 new Microsoft
Azure system

2.6 Tesla systems and technology build

Tesla made software changes to several products and systems for this project:

Grid Logic

Tesla's Grid Logic platform is a cloud system that provides for remote configuration, monitoring and maintenance of Tesla's Powerwall batteries. This system is the point of interface with the distribution system operator, and was extended to implement the client side of the SA Power Networks API.

Tesla VPP sites and the Powerwall 2

Each customer site in Tesla's SA VPP consist of three key system components:

1. 5kW Solar PV system with associated inverter
2. 5kW / 13.5kWh Tesla Powerwall 2 – AC coupled
3. Powerwall 2 Gateway to manage site behaviour and communications

In normal operation, the Powerwall 2 Gateway monitors the net power flow at the customer connection point via its integrated meter and manages the battery so that:

- During normal 'solar shifting' mode, the battery tries to maintain a net power flow of zero, i.e. the battery will try to consume any surplus PV during the daytime by charging (up to the point at which the battery is full) [13], and tries to avoid any grid import outside of solar times by discharging the battery to supply the home (up to the point at which the battery reaches its minimum allowed state of charge); and
- During VPP operation, when the battery is dispatched to discharge to the grid, the total export does not exceed the static limit of 5kW.

For the trial, Tesla developed new firmware and configuration settings for the Powerwall 2 and Powerwall 2 Gateway pair to remove the 5kW static site export limit and implement a dynamic connection limit based on the operating envelope received from SA Power Networks.

These software changes were made in Tesla's global production firmware for the Powerwall 2 product. The timeframes involved in Tesla's global software development, test and quality control process were a key consideration in implementation planning for the trial.

A notable limitation of the site configuration is the inability of the Powerwall Gateway to control the actions of the PV system. Site exports are managed through battery control only, therefore battery state of charge can limit the site's ability to respond to coordinated control instructions – for example, if the battery is full, it cannot reduce the site's export level below whatever the solar is generating. Future DER interoperability standards will likely need to specify active control of all site DER, due to the inherit limitations of relying on battery control alone.

Autobidder

Autobidder is used to co-optimise VPP behaviour in response to markets and individual site conditions and is used to manage most communications out to VPP assets.

Importantly, Tesla also does not use strict central control for the operation of their VPP, as is the case for many other VPP operators. Instead, individual Powerwalls have been designed to operate semi-autonomously with reference to price forecasts and other data provided by Autobidder. This approach is well suited to an environment that relies on customer internet for site communications, which is not always reliable. This semi-autonomous site behaviour has implications for the design of the DSO-VPP interface and the operating protocols around dynamic operating envelopes, as discussed further in section 4.

Tesla's Autobidder system had been developed prior to the project and was already in use globally. It was adapted for integration with the Australian National Electricity Market (NEM) to support the operation of the Hornsdale Power Reserve energy storage system in 2017, with further development for small storage systems operating as a VPP occurring for the initial stages of the SA VPP in 2018. For this project, some significant additional functionality was added to the Autobidder system to facilitate the decoding and mapping of node-level operating envelopes received via the API to individual site operating envelopes, and the onward messaging of these to VPP sites.

As the Autobidder system is used to operate Tesla's global battery fleet, any changes must be carefully considered and prioritised within the Autobidder team. Prioritising development work for Autobidder turned out to be the critical path for the trial due to the heavy impact on operational development teams outside the project with a range of other priorities, coupled with the risk of adversely impacting existing operational processes.

[13] The battery will also pre-charge from the grid at times to optimise against SA Power Networks' new Time-of-Use tariffs, and to manage state-of-charge for VPP dispatch.

2.7 Development methodology

The project involved close collaboration between SA Power Networks and Tesla's engineering teams in Australia, New Zealand and the US, and had an ambitious timeline that required the technology design, build and integration phase to be completed within six months. To achieve this the project team pioneered new development methods, business processes and technologies, including:

- Establishing a new cross-functional team combining IT staff, external software developers and network engineers co-located at SA Power Networks' Network Innovation Centre;
- Embedding Tesla engineers into the on-site team to enhance collaboration, co-design and systems integration efforts. This was crucial in overcoming challenges in securing Tesla US-based software engineering resources to implement the necessary changes to their global Powerwall firmware within the tight project timeframe; and
- Leveraging a technology partnership with Microsoft, the Microsoft Azure platform, and an Agile development methodology, to enable rapid development of a secure, scalable architecture for the new systems and tools, notably the innovative model-based hosting capacity estimation engine and the secure interface (API) between SAPN and Tesla.

This project has transformed the way innovation projects are delivered within SA Power Networks. It has introduced a brand-new project delivery methodology that has significantly raised our business capability to undertake similar projects in future.

Figure 2-10: Project implementation team at the Network Innovation Centre

The use of the Microsoft Azure platform turned out to be an excellent choice, and has since opened the door to SA Power Networks modernising its IT development approach more broadly. Building on the lessons learned and the success of the project development phase, many additional new Azure services have since been developed for applications outside of this trial, resulting in an acceleration in the adoption of cloud computing solutions across the business.

The modular technology platform developed for the project will also provide the foundation for our next phase of field trials, the ARENA-funded 'Flexible exports for solar PV' trial[14], and ultimately the launch of flexible export limits as a standard service offering in South Australia for all DER customers.

[14] See https://arena.gov.au/projects/sa-power-networks-flexible-exports-for-solar-pv-trial/

3 FIELD TRIAL EXECUTION

3.1 Trial Phases

Following an initial period of industry consultation to develop the first draft API specification[15], the trial proceeded in three phases: technology build, field trial and close out.

A core goal of the project was to test the operation of dynamic operating envelopes over at least a 12-month period, to explore the performance of the scheme as network hosting capacity changes across all seasons of the year and in a variety of market trading conditions for the VPP. The field trial commenced in July 2019 and was originally planned to end in September 2020. This was subsequently extended to the end of January 2021 in order to capture additional spring and summer data.

The timeline for the project is shown in the figure below, and the various phases of the trial are described in the sections that follow.

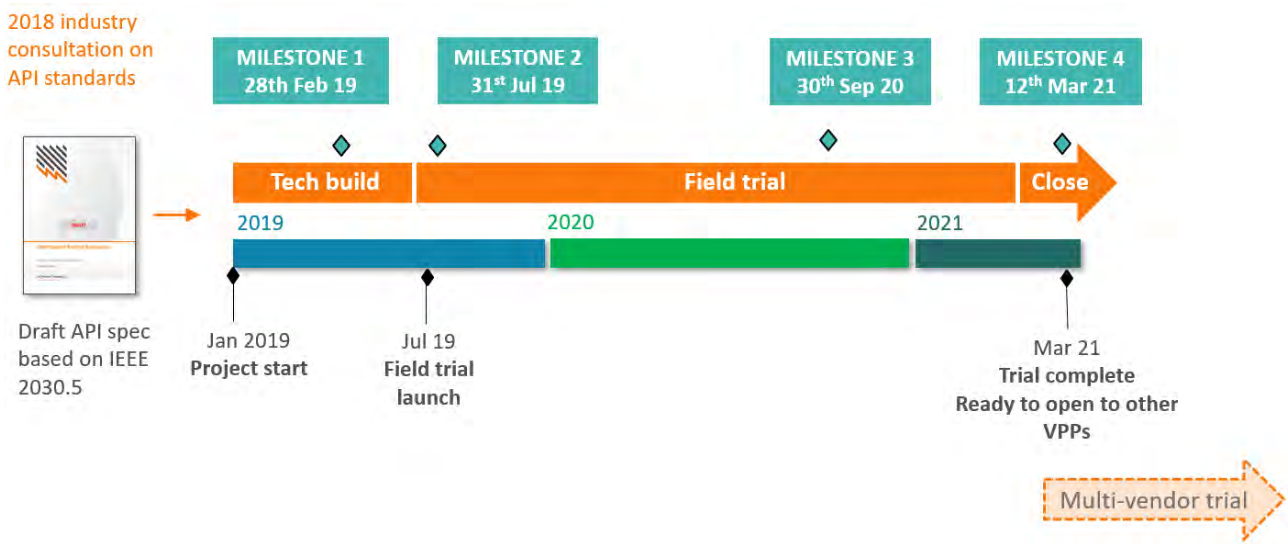


Figure 3-1: Trial timeline and milestones

3.2 Technology Build phase

The technology build phase commenced in January 2019 with the official launch of the project. A dedicated project team was established at SA Power Networks' Network Innovation Centre comprising senior engineers from SA Power Networks' network innovation and IT teams, supplemented with specialist contract IT resources. Tesla engineers were also embedded in the team and located on-site during this phase of the project. As noted above, this proved to be extremely valuable in coordinating design, integration and test activities with Tesla's US-based product engineering teams, and was critical in meeting the aggressive timeframe for this phase of the project.

3.2.1 Development and unit testing

An agile methodology was adopted for the project. While this approach was expected to be well suited to the rapid build out, test and refinement that would be required to meet the project timeline, it also introduced a level of delivery risk, as there was very limited experience in agile development within SA Power Networks' engineering development teams at the time. As described in section 2.7 above, the new

[15] *Improving Integration of Distributed Energy in South Australia – Consultation Paper*, August 2018

method proved highly successful and, as a result of this project, has become SA Power Networks' development method of choice over previous 'waterfall' models.

In line with agile development principles, the technical components of the project were developed incrementally, with build and testing occurring concurrently during a succession of nominal 2-week sprint cycles between January and July 2019. Functionality was added progressively over several phases of development:

- API framework
- Device and site registration
- Monitoring and telemetry data
- Constraint engine and the publication of operating envelopes
- Solution scalability and robustness
- Cyber security (third-party penetration testing)

To expedite testing while ensuring robustness and traceability, an automated test system (Micro Focus UFT) was adopted to allow the automated execution of 657 test scenarios with thousands of validation points.

3.2.2 Integration testing

Once SA Power Networks' development was complete, integration testing with Tesla commenced to prove functionality end to end and to validate all key functions ready for trial go-live. As this testing was conducted using live customer equipment, tests were carefully scheduled and monitored to manage any risk of customer impact if the system didn't perform correctly.

The production systems were brought online at the beginning of July 2019, and testing began with the initial registration via the API of 320 VPP sites. Six of these sites were then activated to provide live 5-minute telemetry data, with the remainder providing data as a daily batch upload, which was the normal mode of operation for the trial.

During the initial telemetry test, around 90% of data was received correctly on each day of testing. The cause of missing data was confirmed as being occasional dropouts in the communications links between customer batteries and the Tesla cloud. This amount of data loss was in line with expectations, as Tesla's VPP relies on the customer's internet connection for communication, which is not always reliable. This phase of testing also identified some specific software and configuration issues that affected data quality, which were resolved.

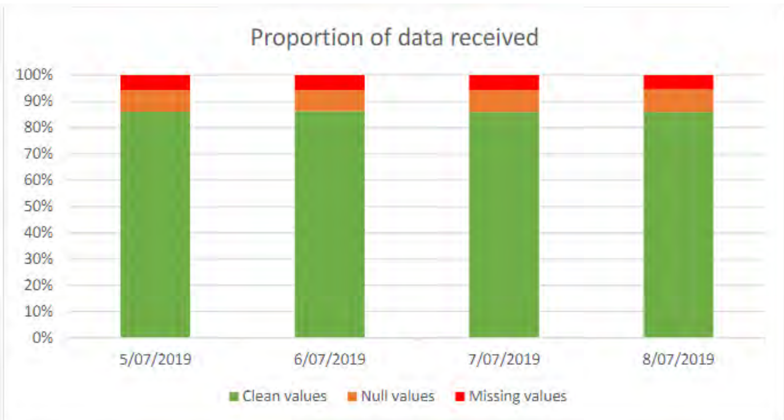


Figure 3-2: Proportion of data received

The generation and use of operating envelopes was tested during this phase using two Powerwalls configured with a beta release of the new firmware and a test system that was able to bypass the normal Autobidder integration for short duration testing. This served as an early proof of concept before the final firmware had completed Tesla's quality assurance process and the solution could be more permanently deployed within Tesla's operational systems.

3.2.3 Operations stage 1 – Registration and monitoring (August 2019 to November 2019)

Following all testing and approval activities, the field trial commenced on schedule on 31 July 2019 with ongoing data transfers between SAPN and Tesla.

The initial stage of the field trial, from August 2019 to November 2019, focused on three areas:

1. The device registration process; during this time Tesla progressively brought new VPP sites on-line, with the number of registered sites growing from 320 to around 750 during the period. Some minor bug fixes and improvements to the registration process were made during this time.

2. Telemetry and model tuning; the data received from the registered VPP sites was used during this time to tune and calibrate the hosting capacity estimation engine. As this was also the first time SA Power Networks had had access to this level of visibility of LV network performance, this phase of the project also investigated the potential benefits of this data across a range of network operational use cases, which was one of the research questions the project was seeking to address. This is detailed further in Section 4.

3. Reliability; during this time we monitored the end-to-end reliability of the system and the robustness of individual system components as input to the decision to proceed to the next stage of the trial, which was the activation of dynamic operating envelopes. Several minor issues were identified and rectified, and the system overall achieved an uptime of more than 98%, sufficient to pass the stage gate to proceed to the next stage of the trial

3.2.4 Operations stage 2 – Dynamic limit activation and test (November 2019 to December 2019)

In November 2019 Tesla had completed the development work in Autobidder required to support ongoing publication of dynamic operating envelopes to individual Powerwalls at scale, and the updates to their global Powerwall firmware required to process and conform to the operating envelopes. This functionality was then deployed progressively to field devices in order to manage any risk of adverse customer outcomes. The initial period of targeted field testing and assessment focused on the following key areas:

1. 1 week of constraints stability and compliance testing across 20 VPP sites

2. Ad hoc forced VPP dispatch across 20 sites with varying nodal limits

3. End to end failsafe tests to confirm proper fallback to the 5kW default limit during communications faults

4. Network stress testing to calibrate the constraint estimation engine

This stage of the trial identified four notable issues:

1. Dynamic operating envelopes are published to the API in 5-minute increments and updated every five minutes. However, Tesla's Autobidder only updates Powerwalls once every 15-minutes during normal operation. In the current implementation, the Tesla Powerwalls update their internal export limit every 15 minutes, based on the export limit published for the last five minute interval in the 15 minute window. In hindsight, it would be better to have devices that are not able to update every

five minutes apply the *minimum* limit received for the time window over which the limit will apply. It was agreed that this change would not be made during the trial, as Tesla is working on a broader update to Autobidder to support 5-minute settlement which will remove the 15 minute limitation in future.

2. Forced dispatch events that are activated directly via the VPP control software and not through the normal Autobidder pathway can exceed published limits. This led to a change to operating procedures to preclude activating forced dispatch events other than through the Autobidder platform.

3. Sites must be initiated to a 5kW limit when first registered in order to establish the default limit for failsafe operation. This was a missing check in the commissioning process that was rectified.

4. Two sites were detected that were persistently non-compliant to the published operating envelope. This was traced to incorrect installation of metering at the site at time of installation.

The final activity undertaken during this stage of the trial was network stress testing, in which operating envelopes were deliberately relaxed, and voltage impacts monitored via the API, in order to tune the constraint estimation engine. An upper limit of 256V was used to calibrate the confidence margin of the constraints engine, with the intention of maximising export capacity available to the VPP even during times of high solar production, while ensuring network limits were maintained within safe levels. The number of sites activated with dynamic operating envelopes was also increased to 70 during this period to cover a broader range of site configurations and network types.

3.2.5 Operations stage 3 – Operating envelope scale up and market operations (December 2019 to March 2021)

Following successful testing of the dynamic operating envelopes, a formal exemption to the 5kW static export limits was issued to Tesla for all 1,000 customer sites in the trial to allow the staged roll out to the remainder of the fleet. The below diagram outlines the progressive roll out approach, which included three further checkpoints to confirm the system was operating as expected, at 250 sites activated with dynamic operating envelopes, 750 sites and at full fleet activation.

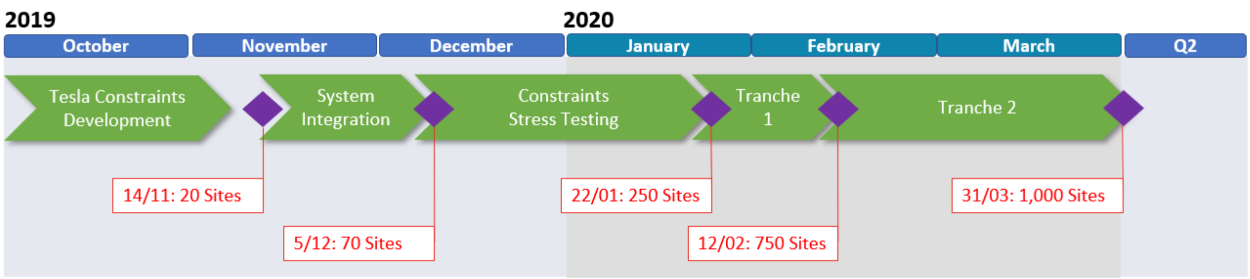


Figure 3-3: Constraints scale-up timeline

Beyond the full fleet activation at the end of March 2020, the VPP was operated for a further ten months (an extension to the original duration) under varying trading conditions. Ongoing operations of the VPP included weekly checks to confirm integration health and constraint engine effectiveness at managing network limits within bounds.

3.2.6 VPP trading during the field trial

Tesla operated its VPP in a number of different trading configurations during the period of the trial, as shown in the figure below. The mode of operation of the VPP during this time was influenced by a number of factors, including:

- Activating the VPP for wholesale market arbitrage under varying market conditions;
- Participation in the FCAS market via AEMO's VPP demonstrations trial; this trial revealed an interaction between the wholesale trading and FCAS operations that caused Tesla to suspend wholesale market trading for a period of time;
- The separation event in February 2020 when SA was islanded from the rest of the NEM for a period of time due to a failure of the Heywood interconnector, which was a period of abnormal operational and trading conditions; and
- The integration of SA Power Networks' new 'Solar Sponge' tariff into the local co-optimisation algorithm in October 2020.

The chart below shows the number of VPP sites that were actively operating with operating envelopes during the period to end January 2021, and the modes in which the VPP was operating during this time.

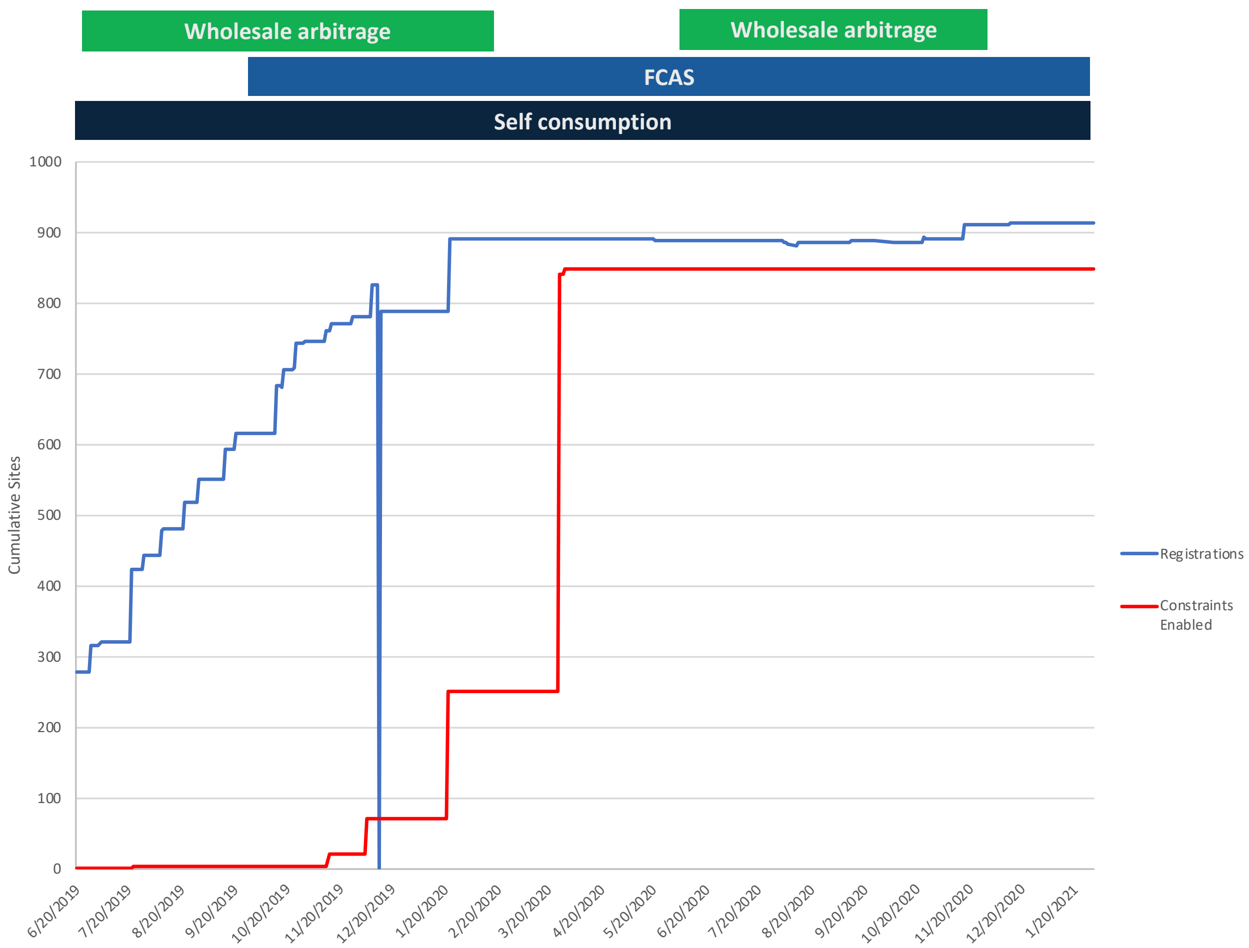


Figure 3-4: Operating envelope activation and VPP operations during the trial

4 INSIGHTS

4.1 Research hypotheses and questions

The project aimed to test the following research hypotheses:

- Existing limits on the level of network exports from customers' renewable energy systems on the SA distribution network can be increased by as much as two-fold by implementing an API to exchange real-time and locational data on distribution network constraints between SA Power Networks and the customers' DER aggregator (VPP provider), and;

- Operating a VPP at higher levels of export power than would otherwise be allowed under normal fixed per-site export limits increases the opportunity for the VPP to provide market and system-wide benefits.

These hypotheses were tested by analysing data collected during the life of the project to answer the following specific research questions:

4.1.1 Managing hosting capacity

RQ 1. To what extent can available DER export capacity be increased compared to the maximum capacity available under SA Power Networks' standard connection rules (currently capped at 5kW export per customer) using dynamic network constraint management via the proposed interface between SAPN and the DER aggregator?

RQ 2. To what extent can the proposed interface support maintaining DER operation within the technical envelope of the distribution network during times when the network is highly utilised (peak solar PV periods), or during unplanned capacity constraints (e.g. network faults or system-wide contingencies)?

RQ 3. To what extent can the proposed interface allow distribution networks to host DER at higher levels of penetration by enabling dynamic, locational export limits compared to standard fixed per-customer export limits?

4.1.2 Visibility

RQ 4. To what extent can the proposed interface securely increase the visibility and management of DER to network service providers?

4.1.3 Economics

RQ 5. What are the costs of implementing the proposed dynamic network constraint management assessed against benefits obtained?

RQ 6. What additional economic value can be enabled to DER operators by dynamic network constraint management, through enabling higher utilisation of existing network capacity?

4.1.4 Customer impacts

RQ 7. To what extent might the proposed dynamic hosting capacity regime impact on customers and their take-up of demand management and third-party DER control?

RQ 8. What are the customer impacts, if any, of the dynamic network capacity management approach?

Further detail on the research questions, the data collected and the methodologies used is included in the project Research Plan[16]. The following sections present the key insights that were achieved in relation to each research question.

4.2 Managing hosting capacity

4.2.1 Research question 1: capability to increase export capacity

To what extent can available DER export capacity be increased compared to the maximum capacity available under SA Power Networks' standard connection rules (currently capped at 5-kW export per customer per phase) using dynamic network constraint management via the proposed interface between SAPN and the DER aggregator?

The average DER export capacity per site made available to the VPP during each month of the year is shown below. The blue line (AC_{24}) indicates the average per-site export **limit** provided across the entire day. However, this VPP only has 5kW of battery capacity per site and hence can only exceed 5kW export when the site solar system is also generating. Hence the green line (AC_{dl}) indicates the average export **capacity** of the VPP throughout the day, where capacity is limited by both export limits and solar generation availability.

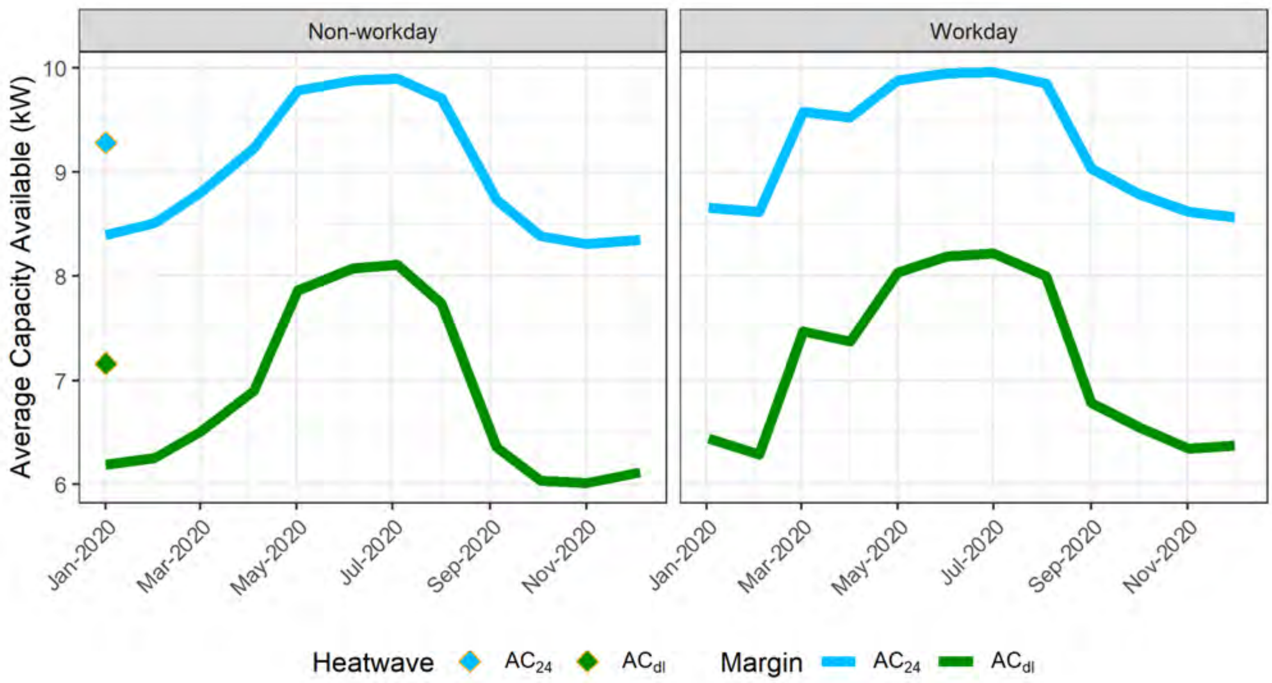


Figure 4-1: Average export limits and capacity provided to VPP

[16] Braslavsky, Reedman, Brown & Williams, *Research plan, Advanced VPP grid integration project*, 10 July 2019

During winter months, the average export capacity of the VPP reaches 8kW/site, or a 60% increase on the VPP's original 5MW export capacity under static limits. During spring and summer months, where there is generally more passive PV exporting on the same networks, the average export capacity reduces to 6kW/site, or a 20% increase versus static limits.

Available capacity varies on a day-to-day basis. By incorporating real-time measurements into the constraints engine, such as solar radiation, temperature and network loads, the average capacity made available to the VPP can be increased by identifying less-congested or high demand periods. This is illustrated qualitatively by the "heatwave" profile, shown as diamonds in the above figure. This illustrates how by incorporating knowledge of temperature and loads, VPP export capacity could be increased from an average of 6.2kW/site on a mild summer day to 7.2kW/site on a peak demand day.

The operating envelopes also vary according to location. This is shown in the boxplot figure below, which plots the distribution of average capacity available across all distribution transformers with VPP sites. During months with high solar insolation, the majority of transformers are restricted to 5kW per VPP site in the middle of the day. In contrast, during winter months, the majority of transformers are never restricted below 10kW per site. The plot indicates that some areas of the network are more congested than others, and hence that the benefits of this approach may depend on the typical locations at which VPP sites are installed. The figure also shows again the difference between heatwave conditions and average summer conditions in terms of the amount of load on local networks, and hence the amount of export capacity that can be made available.

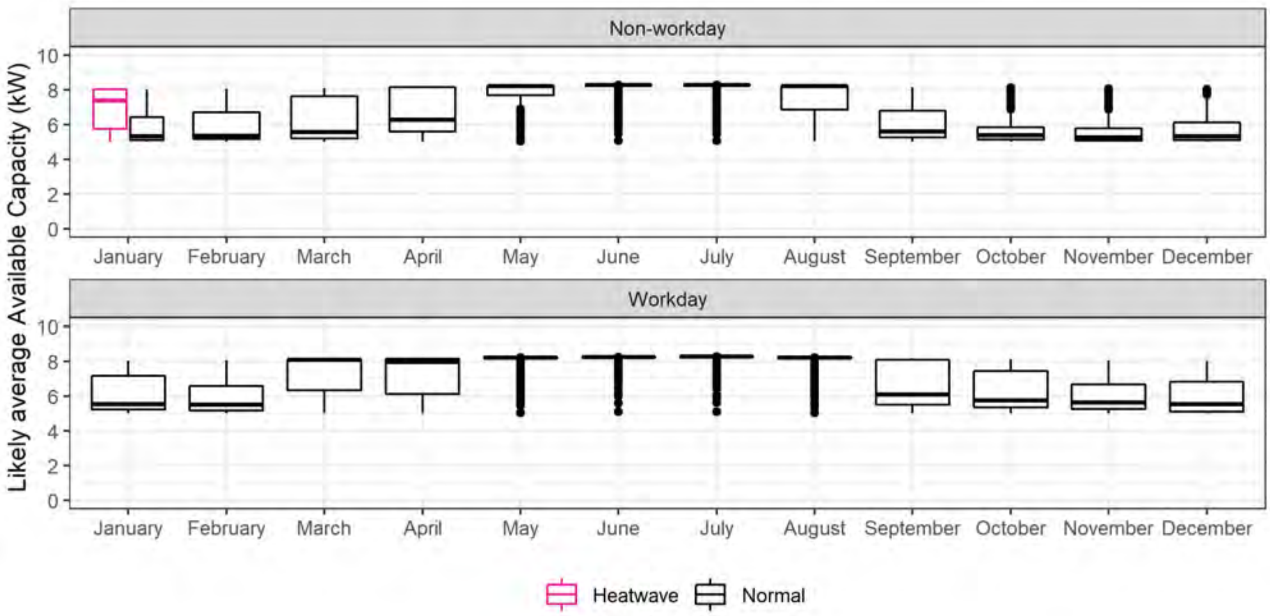


Figure 4-2: Distribution of average available capacity across different VPP sites

The graph below illustrates an individual site, and shows how the operating envelope provided to a VPP site and the solar and battery export capacity of the site combine to create a time-varying export capacity across the day. In the chart:

- The vertical axis shows the amount of available export capacity in excess of the normal static 5kW limit. The standard 5kW limit corresponds to the top of the chart;
- The magenta stepped line shows the published dynamic limit, which is a profile in 5-minute intervals. In this case there are no export constraints overnight (the limit is at the -10kW cap), and the limit reduces through the middle of the day; and
- The blue curve shows the solar profile for the day.

- The orange shaded area is the additional export capacity that can be utilised in practice by the VPP, when the battery can be dispatched to export on top of the solar output for the site.

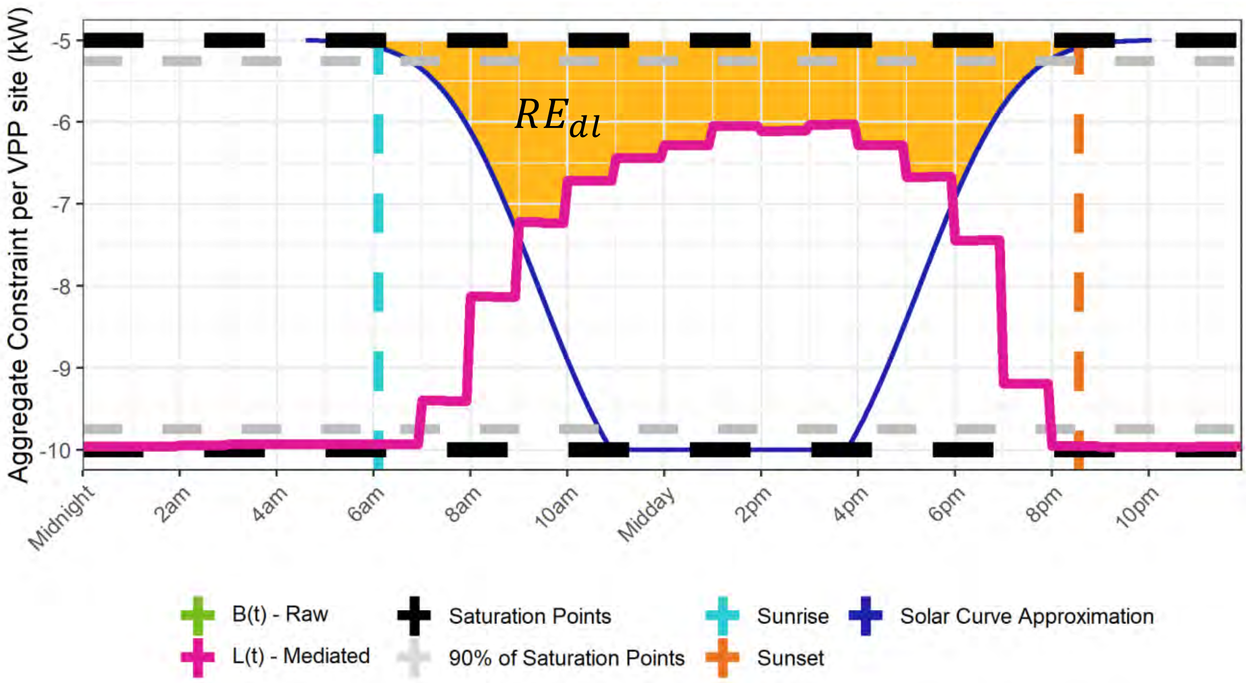


Figure 4-3: Export capacity available to an individual VPP site throughout the day

The chart illustrates that the additional export capacity that can be activated in practice tends to be highest during shoulder periods in the early morning and late afternoon.

The constraint engine can be tuned with a 'confidence interval' parameter to set how conservative the forecast should be. This applies a safety margin to the operating envelopes, in order to compensate for uncertainties in the prototypical network model. In practice it was found that reducing this conservatism factor provides only a minimal increase in export capacity for the VPP. The most significant factor in increasing capacity is simply the change from static to dynamic limits, which immediately unlocks significant extra capacity over the less congested winter months, even with a simple or conservative network model.

4.2.2 Research question 2: maintaining exports within network technical limits

To what extent can the proposed interface support maintaining DER operation within the technical envelope of the distribution network during times when network is highly utilised (peak solar PV periods), or during unplanned capacity constraints (e.g. network faults or system-wide contingencies)?

Conformance to operating envelopes

Enabling DER operation within the technical envelope of the distribution network requires two capabilities:

- The ability for DER to operate successfully within an operating envelope, and;
- The systems and processes to generate suitable operating envelopes.

This project showed that the Tesla VPP could successfully export at levels higher than the normal 5kW static export limit while conforming to a DNSP-provided operating envelope. This is shown below for a single VPP site during live market trading during two weeks in December 2019. The black dotted line indicates the static 5kW export limit, while the black solid line indicates the operating envelope provided through the SA Power Networks API. The red line indicates the net site load. During this week, this VPP site exported at >5kW on six days during less-congested “shoulder periods” in the morning and afternoon, while staying within the operating envelope provided by SA Power Networks.

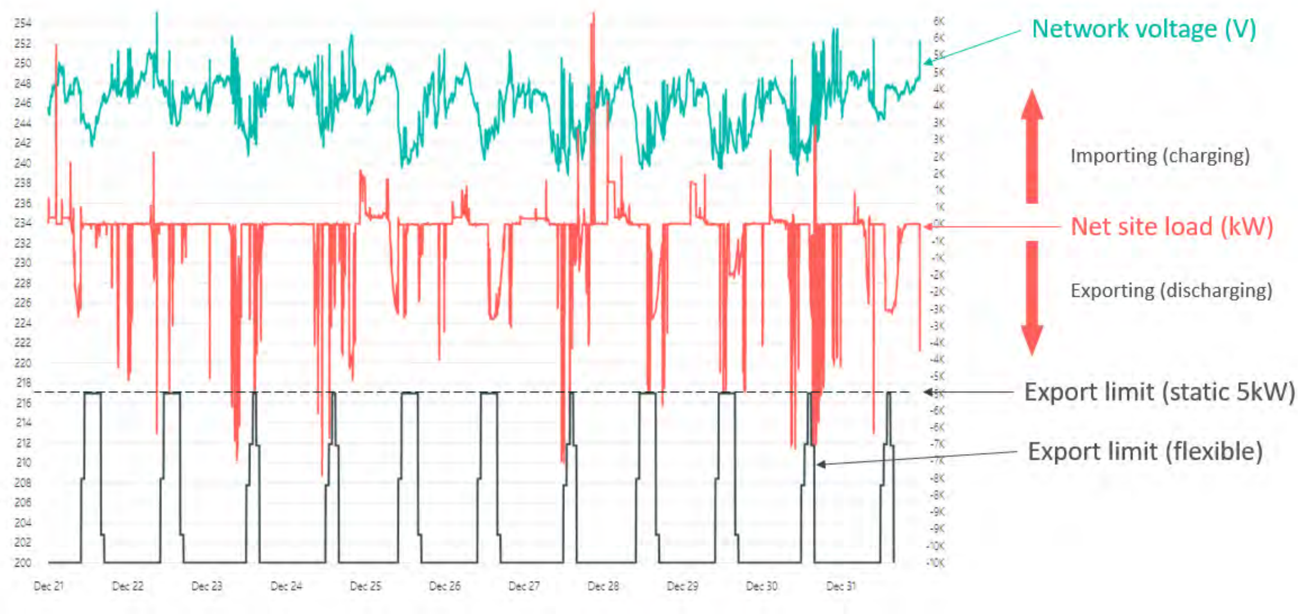


Figure 4-4: site conforming to provided export limits

Daily operation is shown in more detail in the figure below, which shows data from a single site over two days in February 2020. During these days, this site is only constrained to 5kW for a brief period each day during peak solar hours; additional capacity is available during shoulder periods in the morning and afternoon due to the relatively high loads at this time of year. The VPP is able to make use of this additional capacity when dispatched for market services during these shoulder periods.

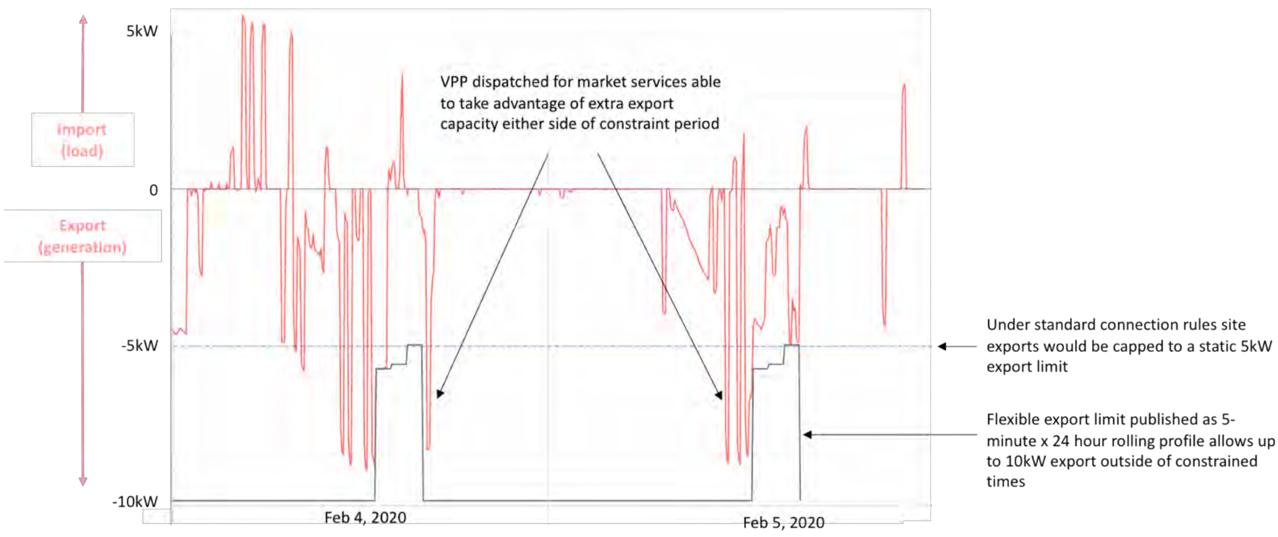


Figure 4-5:VPP site using additional export capacity during shoulder periods

The below plot provides some insight into the overall capability of the VPP control system to maintain compliance with the published operating envelopes over a two month trading period, from the beginning of January 2020 to the end of February 2020. The green line on the plot shows, for each day, the percentage of 5 minute intervals where the *average* export power over the 5 minute period was within the published limit, which is the requirement according to the agreed operating protocol. The chart also shows the percentage of intervals during which the *minimum instantaneous net power* at the site (i.e. the highest instantaneous level of export recorded during the 5 minute interval) was within the published limit.

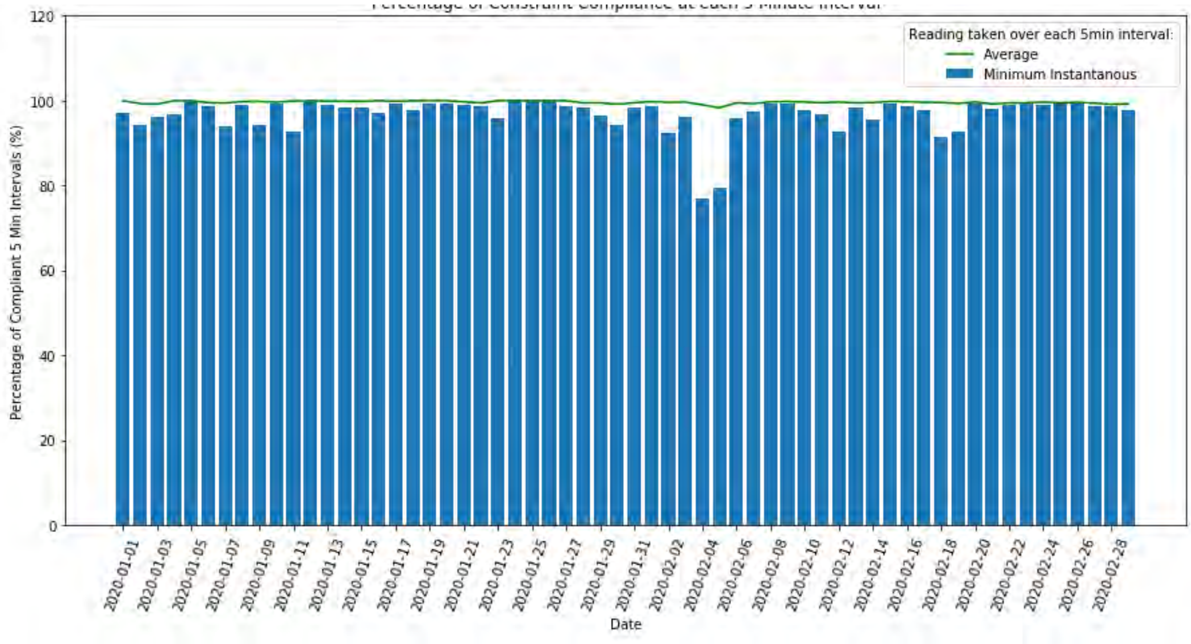


Figure 4-6: Percentage of Constraint Compliance at each 5 Minute Interval

Sites are near 100% compliant when considering only the average readings, which demonstrates that the VPP is technically capable of operating within the dynamic 5-minute limits during normal operation, including wholesale market trading at 5-minute intervals.

The minimum instantaneous readings, however, show that there have been some transient excursions outside the published operating envelopes, notably in the first days of February. This kind of transient excursion can occasionally arise due to a very rapid change in load or generation at a site, where the ramp rate exceeds the rate at which the Powerwall's control system can respond. Most often, however, this was associated with contingency FCAS response by the VPP. In early February 2020 the SA power system was operating islanded from the rest of the NEM due to a failure of the Heywood interconnector at the end of January, and the VPP was very active in providing FCAS support at this time. This illustrates that there are specific considerations around the use of operating envelopes for VPPs that are configured to provide fast frequency response, as discussed further below.

Operating Envelopes during Contingency Scenarios

Operating envelops are calculated for steady state system normal operation, rather than contingency events. The typical binding constraint for a particular LV area is voltage rise on reverse flow. AS 60038-2012 governs nominal voltage on electrical systems during normal conditions. During short-term emergency conditions, some leeway exists. This is also reflected in the AS4777 standard that applies to PV inverters, with the existence of sustained overvoltage settings with a typical timeout of 10s, which allow for transient excursions. This suggests that DNSPs should consider 'emergency operating envelopes' that allow for a greater level of export energy in certain circumstances than the steady-state operating envelope, where the risk to the network is low and the benefit to the overall system is high.

In the present trial we have not implemented separate 'emergency operating envelopes'. Given the system security benefits of enabling very rapid autonomous frequency response in the batteries, a decision was taken for the trial to allow transient excursions outside the published limits while providing contingency FCAS services. Practically, this meant that operating envelopes were given a lower control priority than the frequency droop response in the site control system, which meant that there was no reduction in the speed at which the batteries were able to respond to a frequency disturbance. This facility provided Tesla the capability to activate additional FCAS raise services during contingent events.

During the trial, the associated network risk of allowing transient exports outside the published operating envelope was considered acceptable as it was mitigated by several factors:

- the relatively low concentrations of VPP sites per LV area;
- the fact that only a portion of total VPP export capacity (initially 2MW out of 5MW) was registered for contingency FCAS services;
- the fact that the prevailing network limits were voltage-driven, not thermal capacity;
- the fact that inverter power quality response modes have highest priority and will limit FCAS response if voltage is out of band; and
- the requirement for the VPP to provide telemetry and visibility of local network performance, so that the network could be carefully monitored for any power quality impacts on customers.

As this kind of active VPP integration becomes a standard service and VPPs continue to grow in size, a more considered approach to the application of operating envelopes during contingency frequency response may be required.

An example of such an FCAS event can been seen in the AEMO Virtual Power Plant Demonstrations Knowledge Sharing Report #2[17]. On 2 March 2020, SA separated again from Victoria, resulting in significant frequency fluctuations that triggered contingency FCAS responses. The two plots below show the VPP response at aggregate and single-site levels.

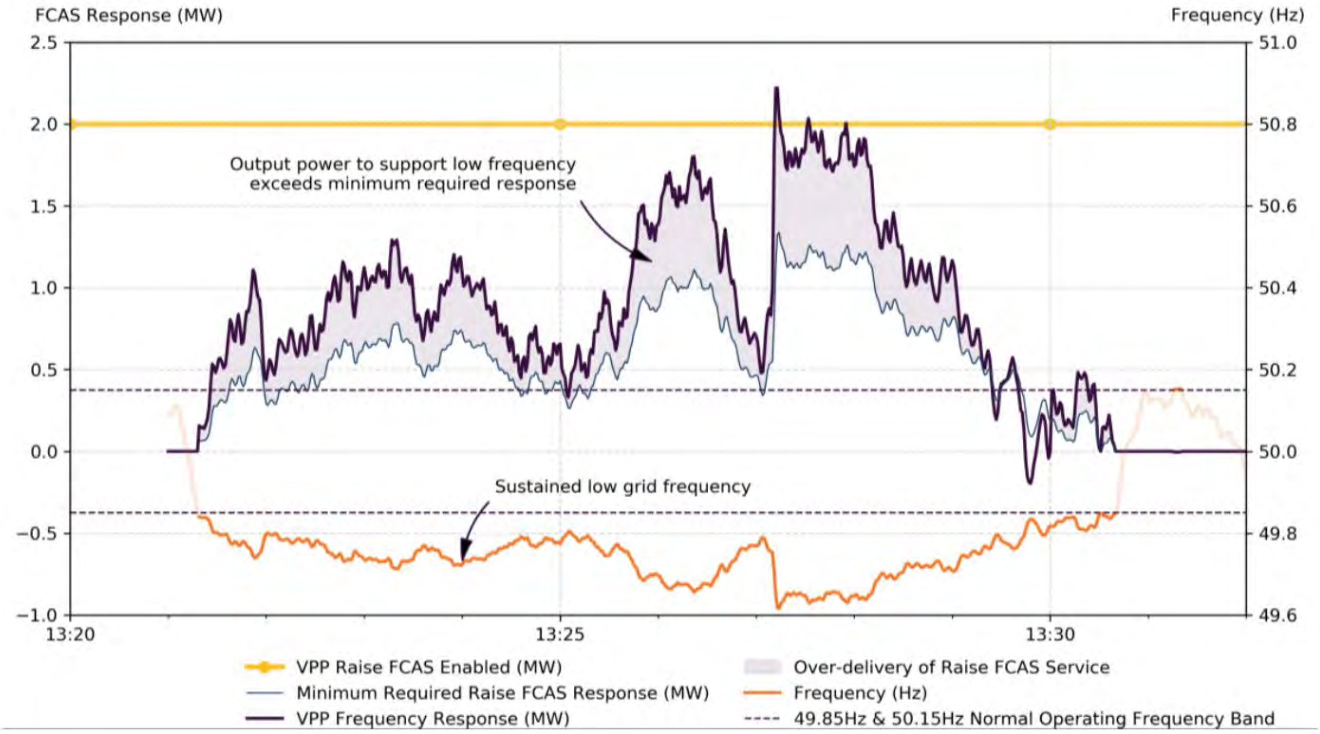


Figure 4-7: Aggregate FCAS Raise Response 2/03/2020

[17] AEMO Virtual Power Plant Demonstrations - Knowledge Sharing Report #2, July 2020, accessed at https://arena.gov.au/assets/2020/07/aemo-virtual-power-plant-demonstrations-report-2.pdf

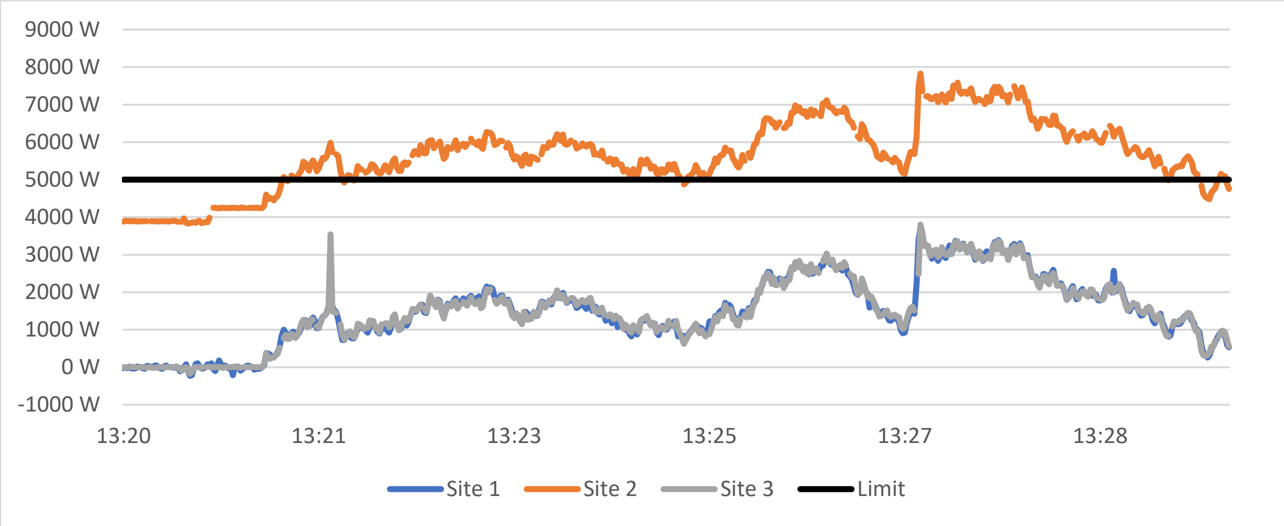


Figure 4-8: Site Level FCAS Raise Response 2/03/2020

Figure 4-8 shows the individual response at three VPP sites. It can be seen that, prior to the event, sites 1 and 3 are operating in zero-export mode, as is common when the battery is charging from PV or entirely supplying the site load. For these sites, the total FCAS response reached a peak of 3.8kW export power per site during the event. Site 2 illustrates an alternative behaviour, with PV exports in progress prior to the event in the order of 4kW, presumably due to the battery already being full at this site. As the frequency drops and the battery responds, a protracted export above the 5kW published limit can be observed, peaking at 7.8kW. All three sites produce an almost identical response profile.

This illustrates the benefit from the additional export capacity allowed. Under a standard connection agreement all exports would be capped at 5kW, meaning that sites like site 2 would not be able to participate in the contingency frequency response. In practice, the VPP operator would need to reduce available contingency FCAS raise services during solar hours.

Reviewing power quality data during the event, no power quality issues were identified, although issues would potentially arise for larger local concentrations of devices responding to FCAS. Further analysis of the network impacts of this kind of transient response will be required to develop the business rules and technical parameters around ‘emergency operating envelopes’ which could be supplied to FCAS-responding plant, so that the greatest amount of additional FCAS capacity can be activated in emergencies without the risk of severe overload or tripping of other inverters or network plant.

Local LV voltage constraints

The constraints engine developed for this project was focused on maintaining DER operation within voltage limits on the local LV area. The project initially used a basic hosting capacity estimation process based on seasonal worst-case scenarios to identify the risk of voltage issues. Even this basic approach, which was necessarily conservative as it only modelled high-level seasonal and geographic variability in network loading and did not make use of detailed short-range local forecasts of weather or network conditions, was sufficient to unlock significant additional capacity compared to static export limits, as discussed in RQ1. Early testing with the first-generation hosting capacity model did, however, identify two specific areas for improvement:

- The use of seasonal load and generation profiles unnecessarily restricted VPP capacity on days with unusually high local load or low passive PV generation. This was subsequently improved through the incorporation of more real-time local weather and load data, and;

- Congested periods were not identified successfully on some LV networks where there is high uncertainty in the amount of PV capacity connected on those networks. These networks needed to be provided with a 5kW export limit instead of a time varying export limit. This issue arises from data quality issues in SA Power Networks' legacy DER records, and illustrates the importance of high-quality data on the location and capacity of small-scale DER connected to the network.

The figure below illustrates the effectiveness of the system in maintaining voltage within bounds. It shows the distribution of average voltage measured at the battery for active VPP sites during the period from 27 January 2020 to 9 February 2020. The blue line shows the distribution of network voltage measurements averaged over all 5-minute intervals. The orange line shows the distribution of voltages over only those time intervals when batteries were exporting energy; site voltage is, on average, higher at these times, as expected. The grey line shows the same histogram for those times when site exports were greater than 5kW, i.e. at times when the flexible export limit allowed for exports above the normal static limit. It can be seen that the voltage remains within bounds at these times, indicating that the constraint estimation engine is only providing for higher limits at times when there is sufficient capacity to enable this, and has not caused any negative impact on overall LV voltage levels through this period.

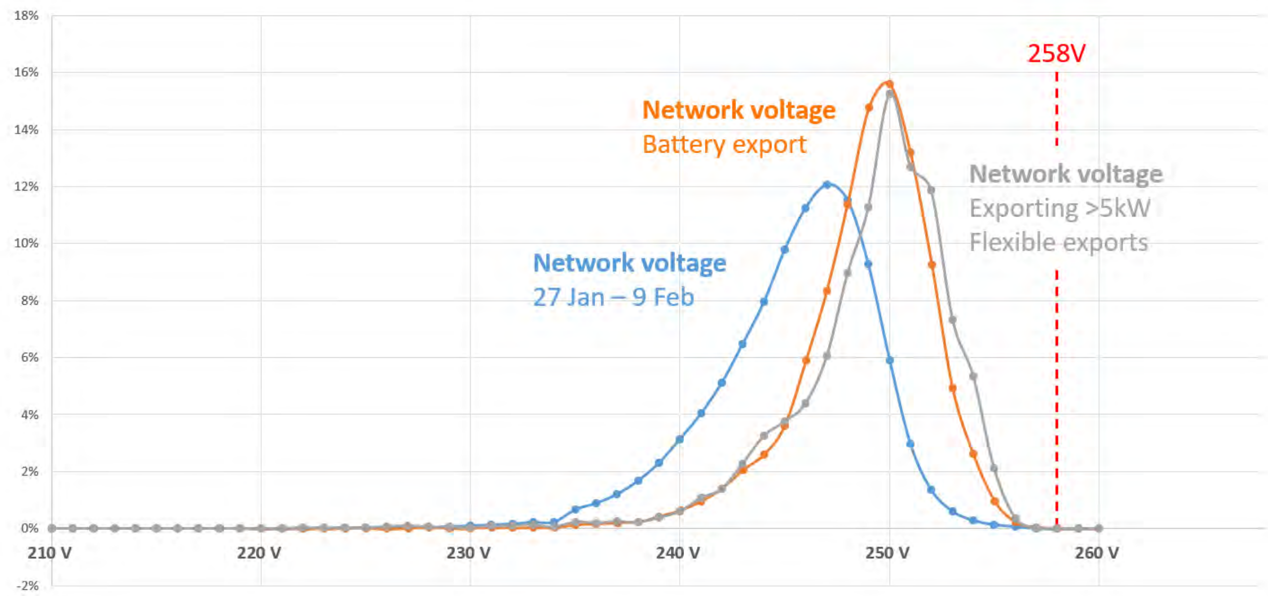


Figure 4.5: Voltage performance at minimum vs maximum limits

Network and system abnormalities

With a suitable control strategy and backend systems, the use of operating envelopes could be extended to other planned and unplanned capacity constraints. Constraints (other than local LV area voltage) investigated throughout the project included:

- System security-related constraints on DER export in SA;
- Substation thermal constraints during transformer outages (planned and unplanned), and;
- Voltage issues due to unplanned outages of voltage regulation equipment.

As many of these kinds of constraints are unplanned and occur rarely, the operating envelopes for these constraints could be much simpler than those for LV voltage. This was trialled during the project through manually lowering operating envelopes to 5kW during unplanned outages of voltage regulation equipment.

The SA islanding event of 31 January 2020 also provided insights into the use of the API to manage system-level contingency events. During this event, the interconnector between SA and Victoria was damaged and SA operated isolated from the rest of the NEM for two weeks, posing frequency control and minimum demand management challenges. During this period, SA Power Networks was requested by AEMO on three occasions to curtail non-scheduled generation. This is currently achieved by issuing run-back commands via SCADA to a small number of large generators (mainly large-scale PV) connected to the distribution network.

The interface developed for this trial has the potential to be used to curtail small-scale DER during contingency events of this nature. This is currently being investigated in the context of the SA Government's new 'Smarter Homes' regulations, which require all new small embedded generator installations (e.g. rooftop PV systems) to have the capability of remote curtailment. Consideration needs to be given to the circumstances in which the kind of curtailment should be activated. During system emergencies, DER aggregated in VPPs can provide essential system services which improve system security, even while other more passive DER may be curtailed. This illustrates the importance of identifying active DER and excluding this from any curtailment during emergencies, so as to not restrict active DER from providing system services.

4.2.3 Research question 3: enabling greater uptake of DER on the network

To what extent can the proposed interface allow distribution networks to host DER at higher levels of penetration by enabling dynamic, locational export limits compared to standard static per-customer export limits?

In the absence of more sophisticated approaches, more widespread aggregation of DER into VPPs will mean that today's static per-household export limits will need to reduce further to protect the integrity of the network. This will leave a great deal of network capacity un-tapped and prevent VPPs from operating at their full potential.

This is illustrated in the below figure, which shows the theoretical additional DER capacity that can be installed across the South Australian distribution network without violating network limits and without network upgrades. Note that this example is based on a conservative estimate of LV network limits and does not take into account upstream constraints and system security issues, so should be considered illustrative only. However, this illustrates the potential differences between static and dynamic approaches.

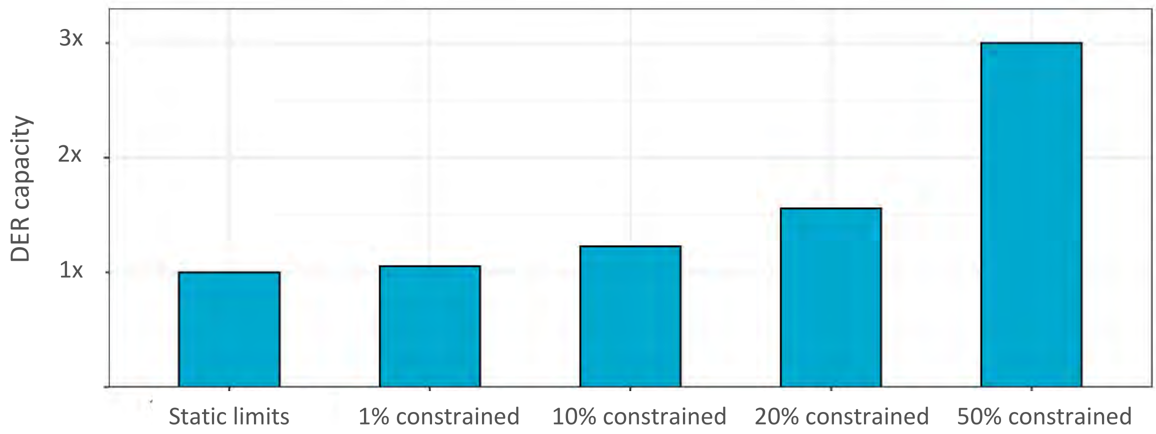


Figure 4-9: Theoretical latent capacity available in SA network under static and time-varying limits

A static export limit can only be imposed without violating network limits if the static limit is low enough such that these limits are never exceeded throughout the year. This sets the baseline for the amount of additional DER able to be added to the SA network without upgrading the network, and is shown as the leftmost bar in the chart. The chart shows how much additional DER could be accommodated using dynamic limits, for different levels of acceptable curtailment. For example, under a dynamic limit regime in which the minimum acceptable availability to export was 80%, around 1.5 times as much additional DER (by capacity) could be accommodated on the network compared to the static limit case.

4.3 Visibility

4.3.1 Research question 4: increasing network visibility and ability to manage DER

To what extent can the proposed interface securely increase the visibility and management of DER to network service providers?

Visibility improvements

Currently, SA Power Networks has poor visibility of the low voltage network and installed DER capabilities and locations. For example, over 90% of overhead low voltage conductor types on the SA distribution network are unknown and, prior to this trial, SA Power Networks only had 400 monitoring devices available on the low voltage network.

As well as communicating operating envelopes, the network-DER interface can improve the visibility and management of DER to network service providers by:

- Improving understanding of DER installed capacity, locations and settings through the electronic registration process;
- Improving understanding of DER behaviour through site and inverter telemetry, and;
- Improving understanding of network behaviour through voltage measurements.

In this trial, the immediate use cases centred around understanding the VPP's impacts on the network, tuning the hosting capacity model, and confirming VPP site compliance to published limits. However, it became evident that the telemetry provided through the API could also help in building a greater understanding of the underlying performance of the LV network, unrelated to the VPP operations.

For example, the voltage data shown below is from a site where analysis of the telemetry data provided through the interface revealed a faulty neutral at one of the VPP sites, which is a potential electric shock hazard for the customer. This plot shows a severe deterioration in voltage performance from the time of the fault to the time it was corrected.

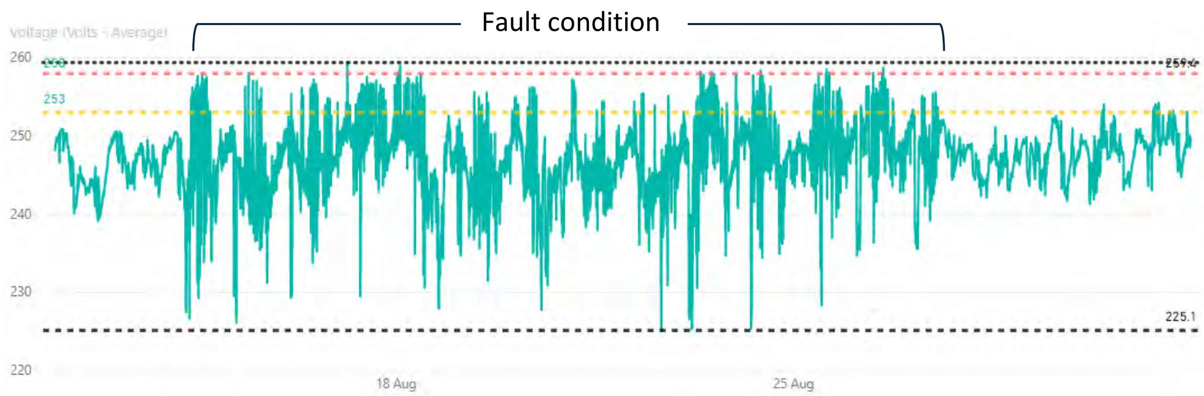
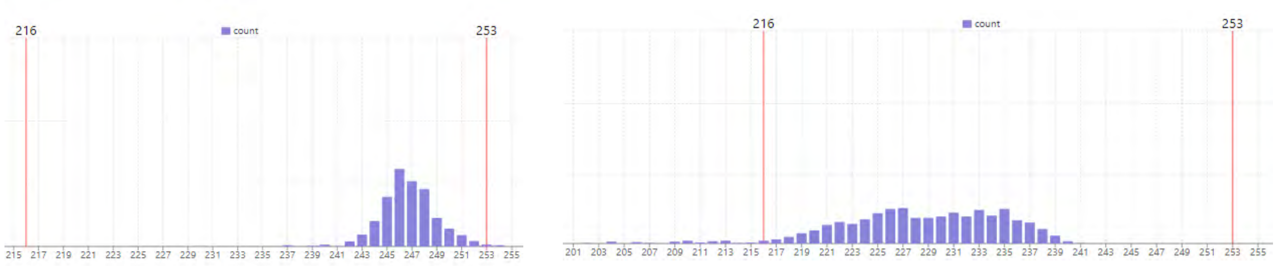


Figure 4-10: Neutral fault detection using voltage telemetry data

Neutral fault detection is an important use case of LV network visibility that can reduce the number of shock incidents and lead to improved consumer safety. However, its implementation in Australia is currently limited outside of Victoria due to the lack of voltage data available at the premises. Obtaining telemetry data from non-traditional sources such as inverters could enable this and other use cases that have been implemented using smart meter data in Victoria to be extended to other jurisdictions that do not have the requisite access to voltage data from smart meters.

The telemetry data received via the API also revealed around 20 sites where the VPP equipment had been installed or commissioned incorrectly, resulting in sites that appeared to be non-compliant to the published operating envelopes when in fact they were operating correctly (for example, at some sites, the export meter was added twice to the Tesla gateway).

This kind of data also gives insights into the voltage management challenges faced by networks in areas of high solar PV. The histograms in Figure 4-11 below show the distribution of customer voltages in the same local area of the network over two different five minute intervals on different days. During mild, sunny daytime conditions in spring, customer voltages are distributed at the high end of the allowed range, as solar PV raises local voltage. In the same area on a hot summer evening, however, when demand is high and solar output is low, voltages are at the low end of the allowed range, with a number of customers actually experiencing under-voltage in this area.



(a) 10-11-2019 10:00 **(b) 30-01-2020 20:00**

Figure 4-11: Voltage distribution during (a) minimum demand (spring daytime, high solar) and (b) peak demand (summer evening)

This illustrates why managing high daytime voltage issues due to solar PV is not as simple as just statically lowering network voltage in the affected area, as this can cause under-voltage problems during peak times. Instead, networks need to invest in implementing more active and dynamic voltage regulation capabilities across the network, which were not historically required.

One learning from the trial was that the impedance of the customers' on-site wiring must be taken into account in interpreting the data, because the voltage measurements received via the API were obtained at the battery inverter, which can be some electrical distance away from the connection point to the network. This means that under high export conditions, the battery may raise the voltage within the customer's premises while the local LV network, and neighbouring customers' supplies, remain compliant. An analysis was conducted on expected voltage rise at Tesla VPP sites between the network and the inverter, and a threshold of 256V at the inverter was chosen to calibrate the constraints engine, as this typically corresponds to the 253V upper-limit for regulatory compliance at the network connection point. This enabled significant additional capacity to be released to the VPP compared to the initial settings, which were based on an upper limit of 253V at the inverter. This illustrates that the specific characteristics of each data source must be taken into account when networks use a variety of different measurement points to estimate voltage in the LV network.

Scalability of the approach

One aspect of this research question was to explore the scalability of the approach to support many thousands of monitoring data points from multiple parties via the API.

The trial of 1,000 installed DER captures 4GB of time-series metering data per month. One reason the Microsoft Azure Cloud platform was chosen to host the solution is that it is highly scalable in terms of performance, and the trial systems have been designed so that the solution could be scaled up to 1,000,000 devices across multiple VPPs with minimal change to the trial architecture. With moderate changes, the architecture provides a pathway to scaling to much larger number of devices, although this would not be expected to be necessary for the South Australian network.

The Azure platform also provides highly scalable and performant analytics tools, which allow for data exploration and processing for business use. Costs can be managed by choosing which data is to be maintained in a highly available state for real-time analysis, and which can be moved to lower-cost storage.

For the trial, the system was configured to allow for the following data volumes:

1. 1,000 concurrent device registrations;
2. all devices sending 7 metering streams every 5 minutes;
3. all devices concurrently sending 24-hours of 5-minute readings for 7 metering streams (840,000 concurrent readings); and
4. all devices concurrently requesting 24-hours of 5-minute export limits (288,000 export limits).

This specification has proved to provide ample performance throughout the duration of the trial and will be scaled accordingly to support future applications.

Reliability

This research question also considered the reliability of the systems. Distribution networks have traditionally deployed their own monitoring devices where they have a high degree of control over the end-to-end reliability. As DNSPs seek to broaden their visibility of the LV network by making more use of data streams from a diversity of external devices, delivered via the internet through APIs, they need confidence that the overall reliability of these data feeds can be managed to a level that ensures that critical operational processes aren’t compromised.

The SAPN API and associated backend systems have not experienced any system outages during the field trial, even though only a single server instance has been used for the purpose of the trial. Consideration will need to be given to deploying multiple instances of these systems across multiple regions to ensure high availability as the system moves from trial to production, something the Azure platform is designed to support.

There were a small number of instances in the trial where services running in the Tesla systems experienced outages that impacted the sending of the time-series monitoring data over the API. In these instances, the issue was picked up by the SAPN project team through manual monitoring of the incoming data, typically several days after the outage occurred. In these cases Tesla quickly restored the operation of the service and the data began to flow again. Some key outcomes from these incidents include:

- Instantiation of a backup server for the Tesla monitoring data push service; and
- Identification for the need of automated data monitoring and alerting on the SAPN API to ensure issues can be detected and rectified in a timely manner to minimise data loss.

As expected, the least available communications link in the system chain proved to be the internet communication down to the Powerwall devices. Evidence from the project suggests that sites experience outages for approximately 5% of the time that result in monitoring data loss and/or the inability to communicate export limits to the device. Improving this communication link would likely come at significant additional expense to customers and VPP operators, so the approach adopted in the trial has been to mitigate the impact of these outages through:

- The use of fallback export limits when export limits cannot be obtained due to a communications interruption. These were configured to be 5kW in this project; and
- Buffering of monitoring data to be sent when communications are re-established and implementing capabilities to backfill missing data over the API. Tesla has buffering capabilities on their Powerwall systems but the capability for data backfill on the API was not implemented in this project.

These approaches have proved effective for the trial, and are recommended as the basis for the operating protocol for this kind of system at scale.

Cyber security

The final consideration examined in this research question was the need to ensure that the data communicated via the API is secure against tampering or other cyber-attack.

Security was a foundational element of the solution architecture to safeguard the network-VPP API. As illustrated in the figure below, multiple layers prevent unauthorised communication with the API; IP Whitelisting, TLS, Mutually authenticated X.509 certificates and a separate, out-of-band process for VPP registration & issuing of certificates.

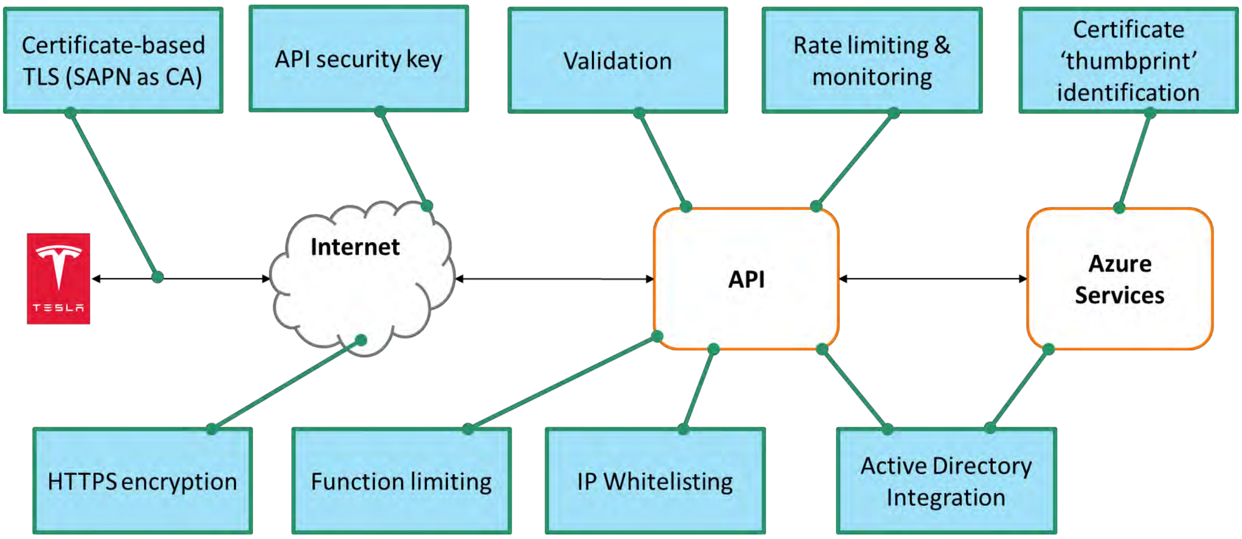


Figure 4-12: Solution cyber security

While the trial only involved integration with a single VPP, the system was designed to support multiple VPP operators and aggregators. The architecture provides for structural segregation of data from different VPPs and the secure storage of individual site data to prevent the possibility of any leakage of data from one VPP operator to another. The outbound data provided to third parties via the API is strictly limited to meet Critical Infrastructure Centre (CIC) requirements.

As noted in section 3.2 above, the security architecture was subjected to a comprehensive Threat Modelling Risk Assessment during the design phase, and an independent cyber-security firm was engaged to undertake penetration testing of the API prior to trial go-live.

4.4 Economics

4.4.1 Research question 5: costs and benefits

What are the costs of implementing the proposed dynamic network constraint management assessed against benefits obtained?

This research question considered whether the benefits to an individual VPP operator or aggregator of integrating with the API would outweigh the costs.

Costs

This analysis examined the costs and benefits from the VPP operator's perspective. It did not consider the cost to the DNSP of implementing the supporting systems and the DNSP API, as the majority of these costs are expected to be required in some form if DNSPs are to manage high levels of DER on the distribution network, even in the absence of VPPs.

The actual cost to Tesla of implementing the API for this trial was $460,065. For the purpose of the analysis this cost was assumed to be up-front in the first year of the trial with no ongoing costs. We consider that this represents an upper bound on the cost for a VPP operator to integrate with the API and benefit from dynamic operating envelopes, with the cost to future VPP operators likely to be significantly lower. This is because Tesla's costs include the initial costs to co-design and develop the API and the associated operating protocols from scratch, as there was no pre-existing standard nor precedent for this manner of VPP-grid integration. The national DER Integration API Working Group is now well progressed on developing a standard API and operating procedures for Australia, informed by the lessons from this trial and related ARENA trials, which will reduce the cost to future VPPs and aggregators.

Benefits – preliminary assessment

The benefits to the VPP operator accrue from the value of the additional energy able to be dispatched by the VPP under the dynamic limit scheme above what would have been possible under static export limits. For today's VPPs, this value arises from wholesale market energy trading, and from participation in the FCAS market.

To explore the potential benefits, CSIRO first undertook a preliminary, high-level analysis that considered wholesale market trading benefits only (i.e., not including FCAS), for a VPP of the size of Tesla's (1,000 customers / 5 MW). The analysis used a linear optimisation model developed by Tesla to simulate market trading behaviour, and estimated the potential economic value for a VPP operator from wholesale market trading at various levels of per-site export capacity. The analysis was based on wholesale market conditions as of mid-2019, and considered three cases:

- Wholesale market revenues for a 1,000 customer VPP where all sites are able to export at up to 5kW. This represents the status quo under current static export limits. However, as noted in section 1.1, the South Australian distribution network is reaching saturation in many areas, and a 5kW per-site static export limit for new DER connections is not sustainable without very significant network investment. In the absence of the kind of flexible limit piloted in this project, the basic static limit will need to reduce significantly in coming years;

- Wholesale revenues for a 1,000 customer VPP where sites are limited to a maximum of 2kW export per-site, which is more consistent with the sustainable long-term hosting capacity of the network, and hence the future level for static limits in the absence of a flexible limit scheme (since this analysis was undertaken, analysis has indicated that a static limit of 1.5kW per customer in constrained areas is more likely); and

- Wholesale revenues for a 1,000 customer VPP where sites can export to a maximum of 10kW. This represents the upper-bound of the value for a VPP under the dynamic export limit scheme implemented in the trial. In practice, the value able to be accessed will be less than this, as the dynamic limit scheme cannot guarantee 10kW per site at all times that the VPP wants to dispatch to export for wholesale market trading. In general, however (although not always), a high wholesale price will correspond to a period of high local demand, when export capacity is greatest, and so there is generally good correlation between the trading intervals in which the VPP wants to export for market arbitrage and the times at which the dynamic export limit scheme can make available the most export capacity.

The table below summarises the net present value (NPV) calculations from this preliminary analysis. A real discount rate of 7% p.a. was used to convert future cash flows to present value terms.

	2kW limit	5kW limit	10kW limit
Costs (to 2030, $million)	0.46	0.46	0.46
Benefits (to 2030, $million)	1.23	2.92	3.18
NPV (to 2030, $million)	0.77	2.46	2.72

Table 1: Net present value (NPV) summary for 1,000 customer VPP, wholesale energy trading only

The findings from this initial analysis indicate that, given current market conditions:

- Increasing the dynamic export limit from 2kW to 5kW has the potential to create up to $1.7 million additional value for the VPP from wholesale market trading. Increasing the dynamic export limit from 2kW to 10kW has the potential to create up to $1.95 million additional value;
- In a future where the alternative static export limit is 2kW or less, the NPV to implement the interface to enable exports up to 5-10kW for a 1,000 customer / 5MW VPP would be positive purely on the basis of wholesale market trading; and
- With a 5kW static export limit as the counterfactual, the NPV to implement the interface to achieve an incremental increase in export capacity from 5kW to 10kW for a 1,000 customer / 5MW VPP would be marginal if the only value stream for the VPP were wholesale market arbitrage.

Hence this analysis suggests that the benefits of implementing the interface for a VPP operator would exceed the costs under any of the following conditions:

- Static export limits are reduced below 5kW per customer;
- The VPP can access additional revenue streams as well as wholesale market trading, e.g. FCAS;
- Costs reduce through the development of national standards; or
- The installed VPP capacity using the interface is greater than 5MW (noting that the integration costs are essentially fixed, but the benefits scale with the size of the VPP)

It is likely that all of the above conditions will be met for VPPs in future. In particular, it became apparent during the course of the trial that FCAS was a material source of value for the VPP, with FCAS revenues significantly exceeding revenue from wholesale market trading during the trial period. This is explored further in the following section.

4.4.2 Research question 6: enabling additional economic value

What additional economic value can be enabled to DER operators by dynamic network constraint management, through enabling higher utilisation of existing network capacity?

The economic value proposition for residential batteries and Virtual Power Plants (VPPs) consists of a value stack across multiple streams, as illustrated in the table below.

Type of revenue stream	Revenue stream	Current status	Phase 1	Phase 2	Phase 3
Behind the meter value	Solar and storage self consumption	Currently available	✓	✓	✓
	Behind the meter wholesale energy cost reduction	Currently available	D	✓	✓
Wholesale energy	Wholesale energy export	• Active participation in the wholesale market through Program Retailer Energy Locals	D	✓	✓
Ancillary services	FCAS	• Active participation in AEMO's FCAS VPP demonstration program	D	✓	✓
SAPN Network Services	SAPN Network Tariffs Grid services	• Volt-VAr field testing completed, discussions to expand trial for wider deployment across SAPN's network • Tesla are in the process of evaluating SAPNs new proposed network tariffs and incorporating into VPP operations demonstrating advanced tariff optimisation • Exploration of additional network services • Increased network visibility at low costs	X	D	D / ✓
Other	Network Demand Response/ Emergency reserve capacity	• Potentially available through AEMO's RERT program • Demand Management Incentive Scheme (DMIS) • Explore control signals via API	X	D	D
Ancillary services (NEW)	Synthetic Inertia Regulation FCAS	Under discussion with AEMO and SAPN	X	X	D / ✓

Table 2: Residential battery and VPP Revenue Streams (source: Tesla)

Four value streams were activated during the trial:

1. **Solar Self Consumption:** avoided Network Use of Service (NUoS) and wholesale energy charges through the local generation and consumption of energy. This value stream is available to all owners / operators of solar PV or battery systems regardless of VPP participation. This is typically the primary driver for customers installing systems, given the relatively high cost of grid energy in South Australia (e.g. the default market offer in South Australia is 37.73c/kWh[18]). This value stream is independent of the site export limit and so is not considered further in the analysis;

2. **Wholesale Energy Cost Reduction:** in cases or times of year where PV and batteries cannot meet an individual customer's daily energy needs, batteries will pro-actively charge from the grid at low spot market prices and/or low time-of-use network tariff times, to avoid importing grid energy when prices are higher;

3. **Wholesale Energy Export:** the VPP operator is paid the prevailing market spot price for exports; and

4. **Contingency FCAS:** through the concurrent AEMO VPP Demonstration project, the VPP was bidding into all 6 contingency FCAS markets.

As the benefit of self-consumption is not affected by export limits, for the purpose of this analysis the benefits that can be affected by the dynamic limit scheme can be split into the two categories of additional energy exports for market trading, and the additional provision of contingency raise FCAS capacity.

[18] 2020/21 AGL Residential Standing Offer

Wholesale market value

Following from the high-level analysis described in section 4.4.1 above, we first consider the future value of wholesale market trading in more detail.

Over the life of the project there have been some significant shifts in the South Australian energy market:

- South Australia has transitioned from having the highest spot prices in the National Electricity Market to among the lowest;
- Daily lowest wholesale energy prices now occur regularly in the middle of the day rather than overnight;
- Negative price events have reduced the value proposition of solar PV exports, with retail feed-in tariffs expected to reduce as a result; and
- Daily energy arbitrage opportunities have increased from $71 to $84 per customer on average.

Figure 4-13 below shows the change in average wholesale energy price in South Australia since 2018 compared to the average across all NEM jurisdictions. SA average prices fell below the NEM average for the first time in 2020.

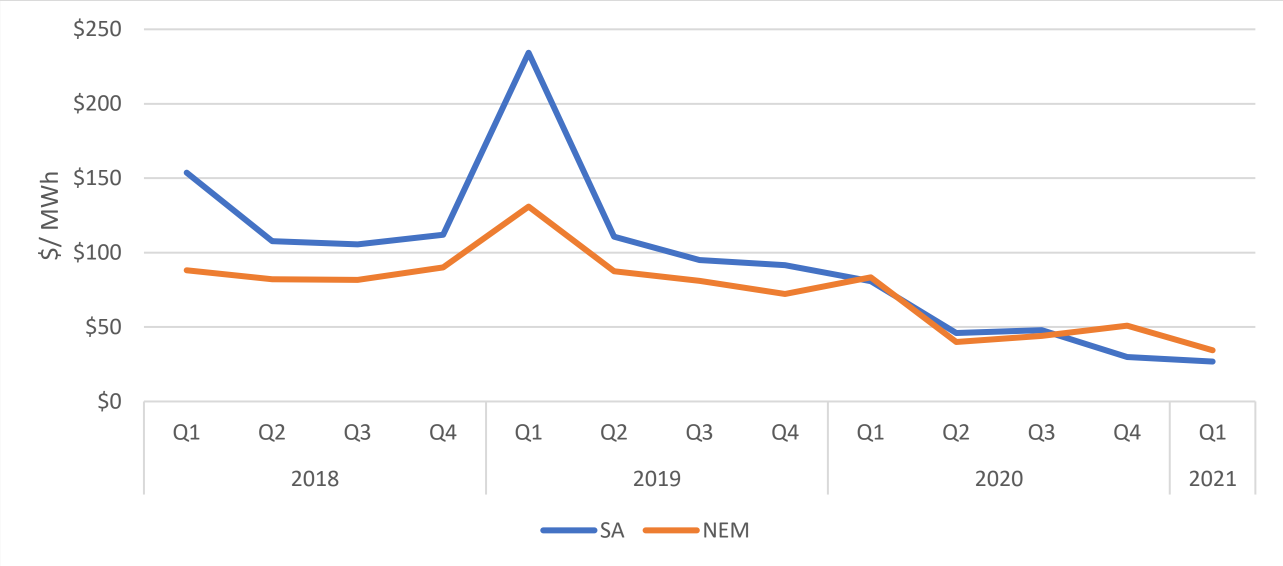


Figure 4-13: Wholesale Energy Prices

Figure 4-14 below shows the change in the average daily wholesale price profile between 2018 and 2020. Although there was significant daytime solar PV generation in 2018, the wholesale price at that time generally held up through the middle of the day, as there was sufficient demand for the energy. With the continued rapid growth in solar, by 2020 we began to see more frequent periods when supply exceeded demand through the middle of the day and the interstate interconnector reached the limits of its capacity to export surplus energy interstate. This has led to more frequent episodes when the wholesale price has collapsed to zero or gone negative.

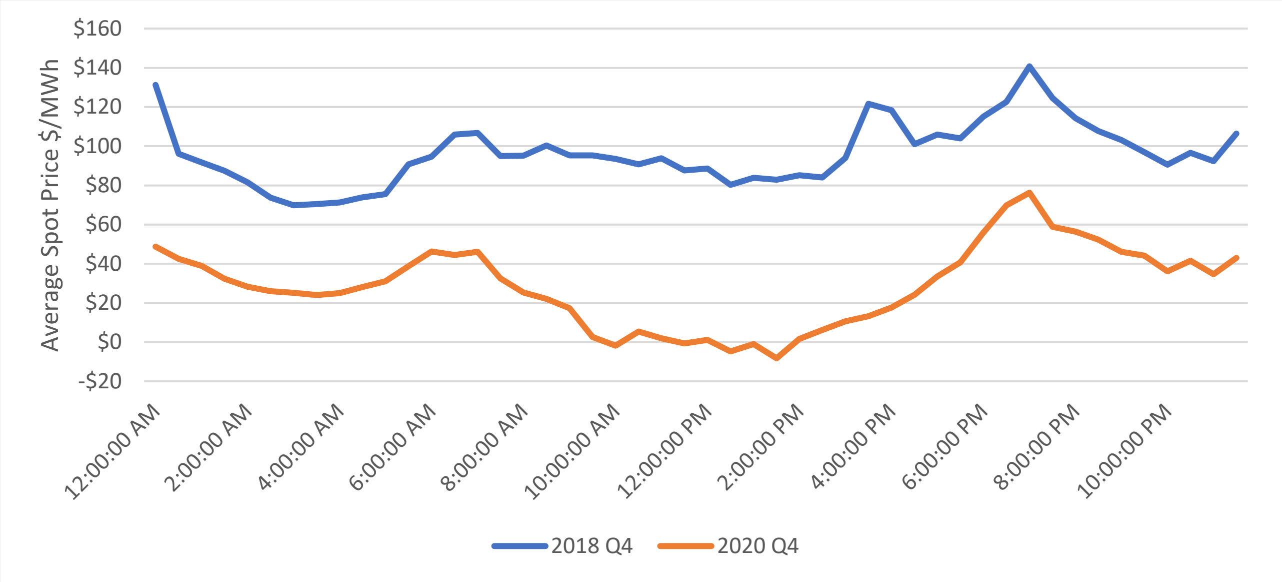


Figure 4-14: Average Daily Price Profile

Figure 4-15 below shows the actual revenue earned by the VPP from wholesale market trading over the entire period of the trial, from July 2019 to the end of January 2021.

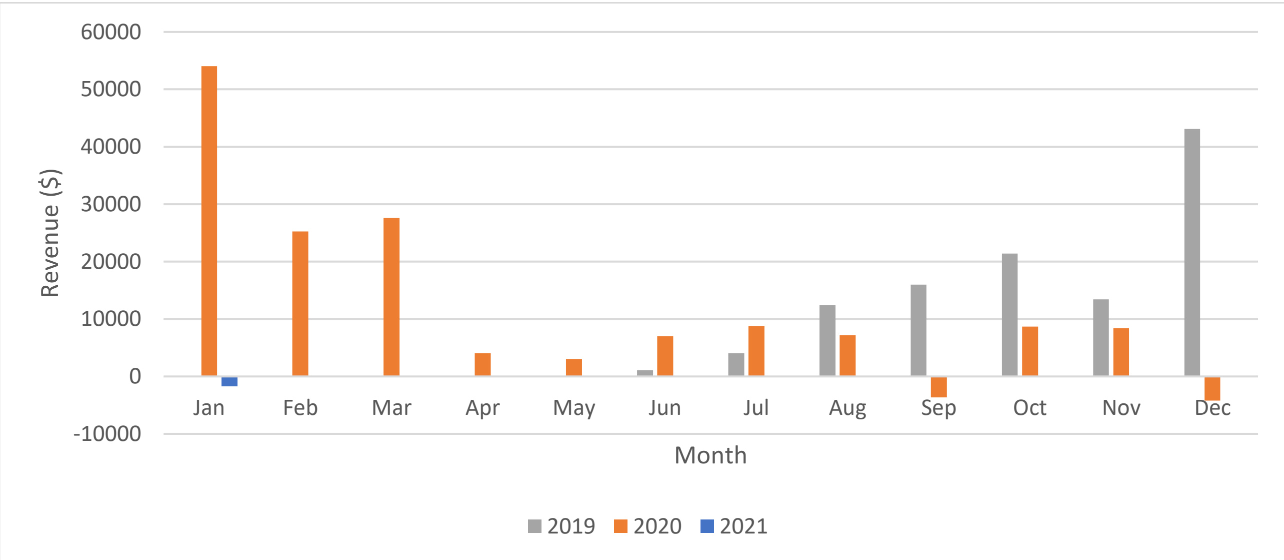


Figure 4-15: VPP Export Revenue by Month

As noted earlier in section 3.2.6, the VPP traded in several different modes of operation during the trial period. The reduction in trading revenues from April to June 2020 is because wholesale market trading functions were essentially paused during this time to resolve an issue with the interaction between market trading and the calculation of FCAS response identified through AEMO's VPP Demonstrations trial. After this period, market trading resumed, but at a reduced capacity, which limited the opportunity for the VPP to make use of the higher export limits made available through the API.

It can also be seen that net monthly wholesale trading revenues were negative on three occasions during this period, in September and December 2020 and January 2021. This is reflective of the fact that the VPP is unable to curtail solar output directly as there is no control path from the Tesla gateway to the solar inverter, so once the site battery is full it is no longer possible to prevent energy from being exported at times of negative wholesale price.

Figure 4-16 shows export revenue broken down by day for the month of January 2020. It illustrates that, at least in today's market conditions, the majority of wholesale market revenue tends to arise from a small number of extreme market price events such as occurred on 30 January 2020.

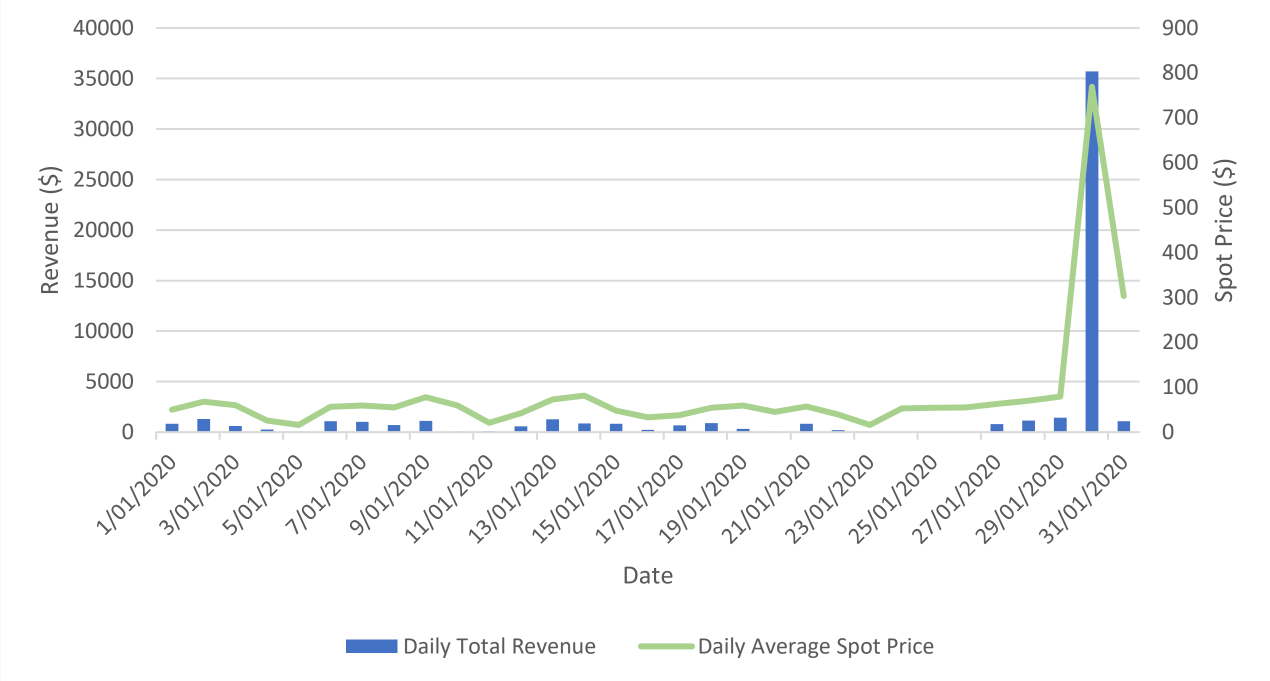


Figure 4-16: Net daily export revenue - January 2020

These factors, as well as the introduction in July 2020 of SA Power Networks' 'solar sponge' time of use network tariff, suggest a number of potential changes to the technical configuration of future VPPs compared to the configuration used in this trial:

- VPP sites should be configured to enable active curtailment of solar PV by direct control of the solar inverter during negative price events (since the trial began, the SA Government has since moved to mandate this capability for new solar PV as an emergency measure, but the trial illustrates the value to VPP operators of having this level of control for normal market trading);
- VPP operators will need improved forecasting of negative price events, or extreme positive price events, to optimise battery state of charge in the lead-up to the event to maximise the revenue potential;
- There may be a shift towards smaller PV systems, where systems are financed by VPP operators (noting that customer preference seems likely to remain biased towards systems of 5kW or more even if this may not be the most economically efficient); and
- We may see the emergence of battery-only VPP sites.

FCAS value

Figure 4-17 below shows the revenue earned by the VPP from participation in the FCAS market over the trial period. Note that although this trial commenced in July 2019, the VPP was only registered for FCAS raise services (i.e., FCAS services that rely on the export of energy) in September 2019, on the commencement of AEMO's VPP Demonstrations trial. The chart, which is from AEMO's most recent

Knowledge Sharing Report from the VPP Demonstrations project[19], also includes revenues from other VPPs that joined AEMO's trial from April 2020 onwards, but it can be seen that Tesla's VPP (shown in red) has accounted for almost all of the FCAS revenue achieved by VPPs in Australia to the end of January 2021.

Similar to the discussion above in relation to wholesale market volatility, the chart illustrates the potential for occasional extreme market conditions – in this case the separation event at the end of January that resulted in extreme FCAS prices in South Australia during February 2020. In this month alone Tesla's VPP earned more FCAS revenue than the total for the sixteen other months between September 2019 and January 2021.

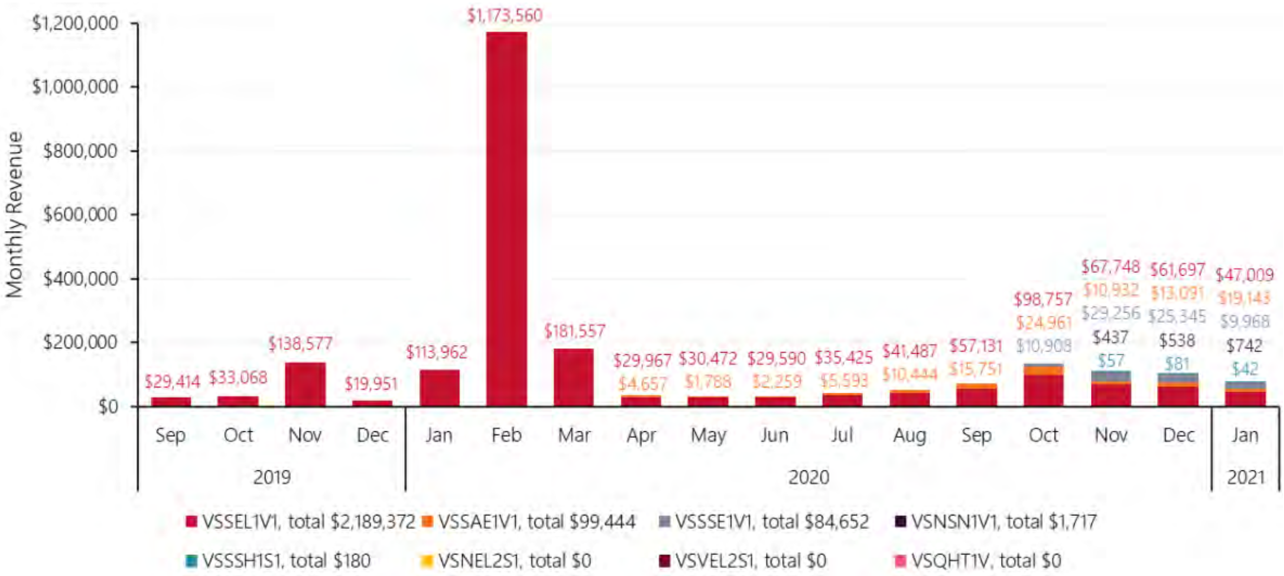


Figure 4-17: Revenue from FCAS (VSSEL1V1 = SAVPP inc. TEP Customers; source: AEMO)

In the relatively short time since the first VPPs were rolled out, revenues from the contingency FCAS markets have represented a significantly larger revenue opportunity than wholesale energy trading (noting that this was not always the case e.g. December 2019). As more resources enter the FCAS market and as the recent Mandatory Primary Frequency Response rule change comes into effect for scheduled and semi-scheduled generators[20] the differential is likely to reduce, but we expect both FCAS and energy market participation will remain as important and complementary revenue streams for VPP operators in coming years.

Implications of dynamic operating envelopes

As noted above, the VPP operated in several different modes during the trial period due to factors external to the trial, which meant that there were periods during the field trial when the dynamic operating envelopes were not able to be utilised by the VPP. The period from January to March 2020 was a period of continuous operation under the dynamic operating envelope regime which included both high demand summer periods and low-demand autumn periods, and has been examined in detail. The below plot provides some insight into the VPP's utilisation of export limits >5kW during the period.

[19] AEMO Virtual Power Plant Demonstrations - Knowledge Sharing Report #3, February 2021, accessed at https://arena.gov.au/assets/2021/02/aemo-virtual-power-plant-demonstrations-report-3.pdf
[20] See https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response

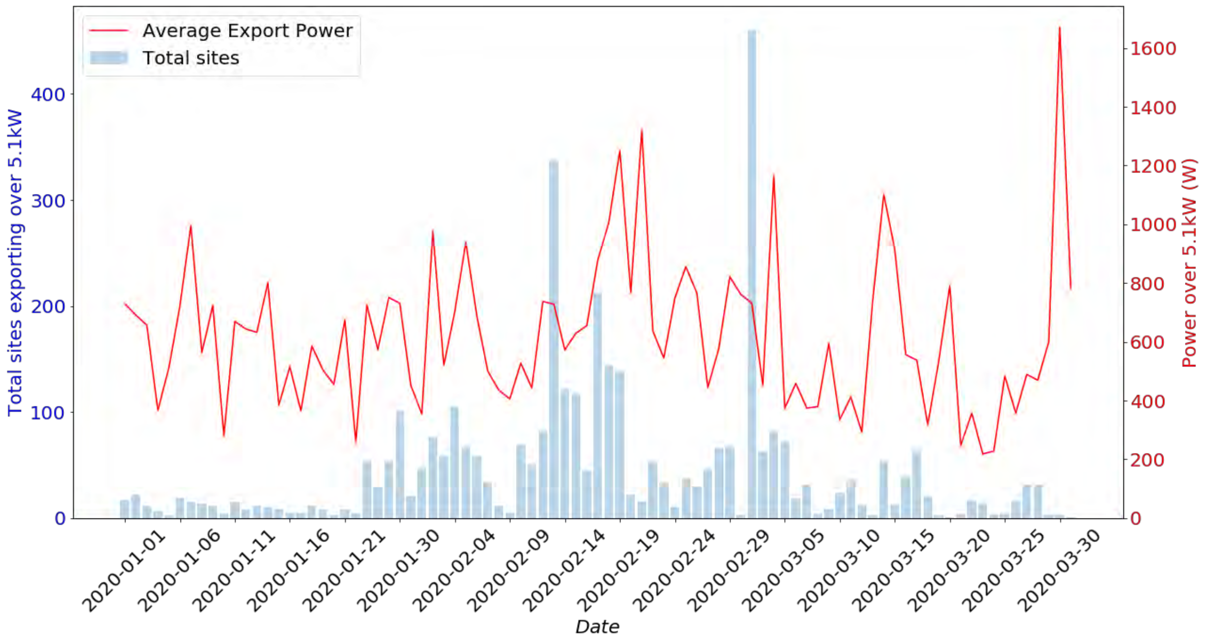


Figure 4-18: Average daily export power over 5.1kW

The above plot shows the average export power over 5.1kW, over the period of January 1st to Marth 31st 2020. The bars indicate the number of sites that had an average power over 5.1kW and contributed to the average over the group, shown by the line. 5.1kW was conservatively chosen to filter out minor variations above 5kW, which occur regularly from normal battery operation as solar generation and household load vary continually. Of note is 3 March 2020, where the greatest number of sites were exporting over 5.1kW.

One observation from the trial is that the upside potential is highly varied across the VPP and through time. The below plots highlight the varied response to a price spike occurring during solar hours on 2 March 2020.

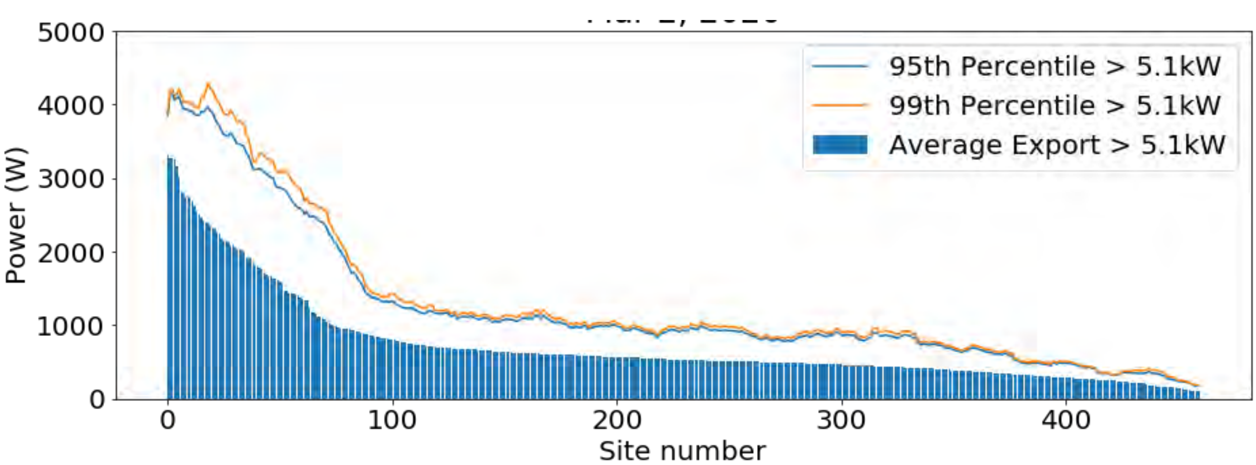


Figure 4-19: Average export power over 5kW (2 March 2020)

In descending order, the average exports over 5.1kW are shown for each site. The lines above display the 95th and 99th percentile for each site. Percentile lines are smoothed using an averaging window spanning 20 sites.

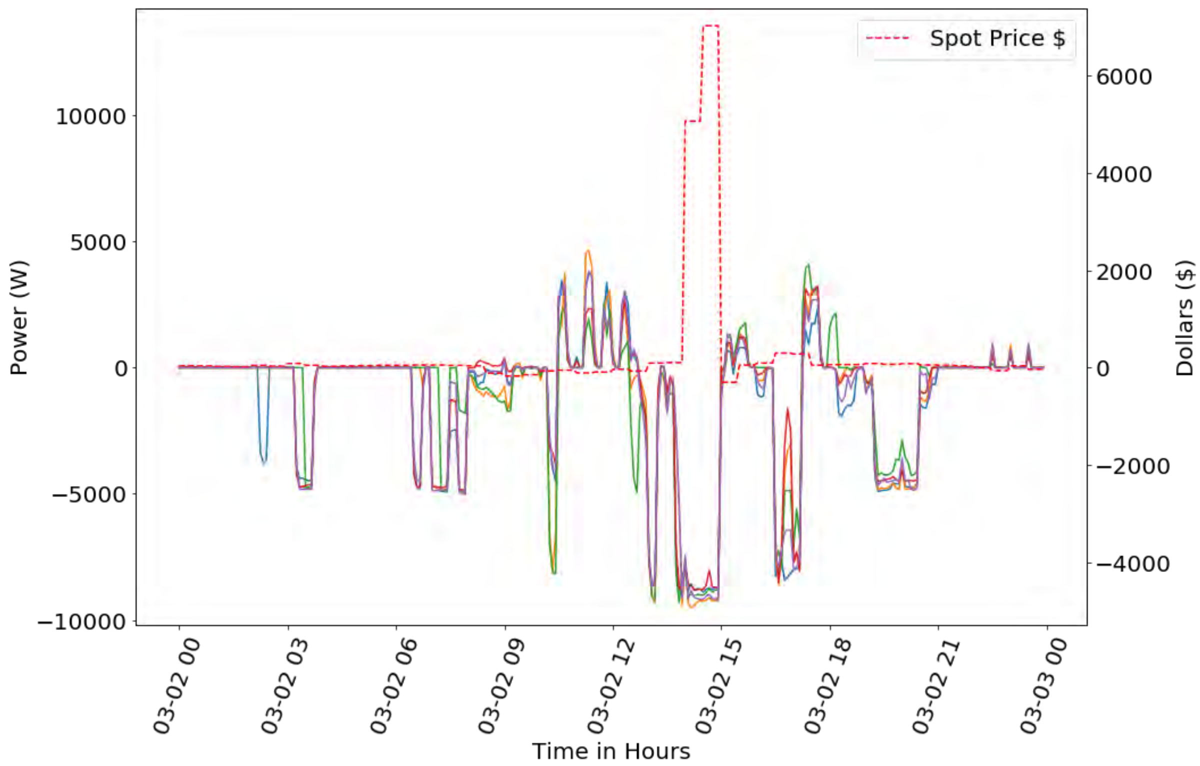


Figure 4-20: Top 5 exporting sites (2 March 2020)

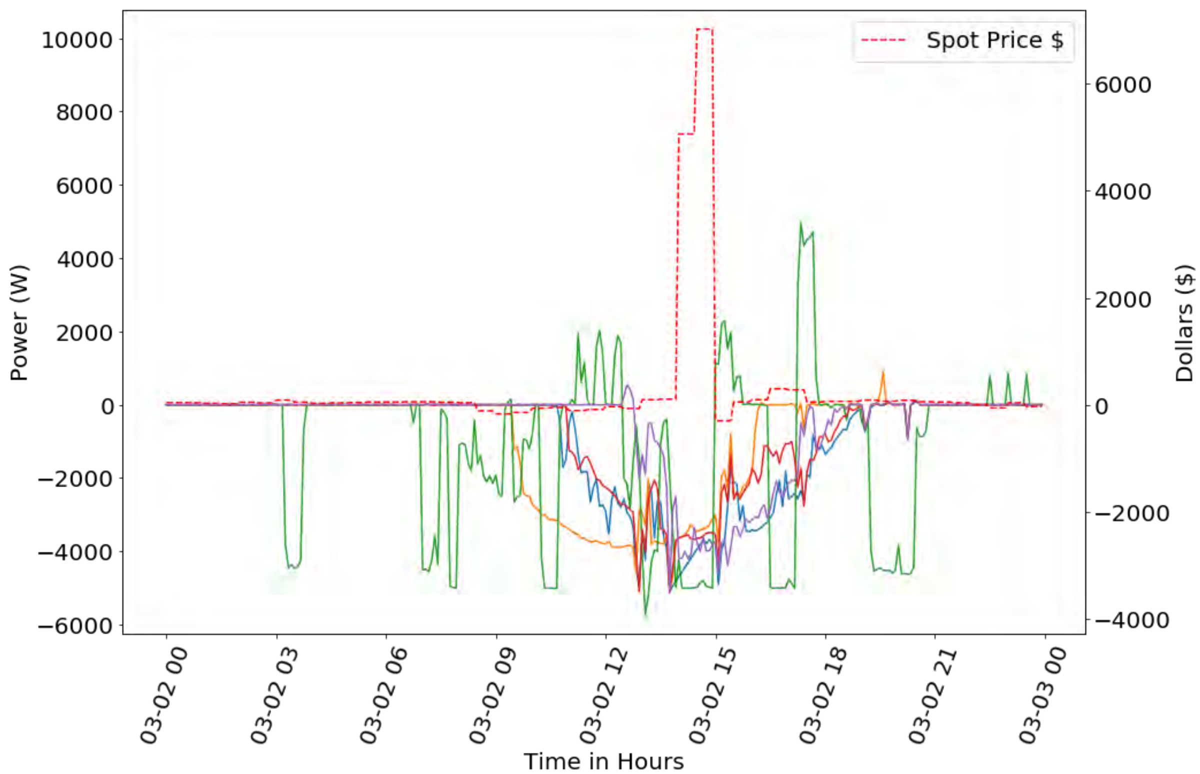


Figure 4-21: Bottom 5 exporting sites (2 March 2020)

Four distinct patterns of operation can be observed in the above plots, namely:

1. The spot energy market is a clear driver of site behaviour;
2. Many sites receiving the full 10kW export were able to take advantage of the market conditions;

3. Many sites were capped to 5kW export due to constraints engine behaviour or individual site configuration; and
4. Some sites follow a typical solar export curve, suggesting that their batteries may have been offline at the time.

It is hypothesised from these results that the greatest economic benefits are generated by enabling export limits which, at some times and locations, match the battery capacity at the site. At the moment, the static export limit of 5kW matches the export capacity of the majority of home batteries. In future, as static export limits decrease, and battery export capacities increase, the benefit of dynamic export limits will increase.

In this context it is important to consider that site equipment selection has been optimised according to existing static export limits (5kW per phase) and prevailing technical standards, namely TS-129 and AS4777.2:2015. As such each site was configured identically with a 5kVA PV inverter and a 5kVA Powerwall 2. Therefore, the maximum theoretical export outside of solar hours was 5kW, with additional export up to 10kW only possible during solar hours, when wholesale prices are typically depressed. This limits the opportunity for upside for purely wholesale market trading. We expect that the benefits of operating envelopes will increase over time as static export limits are reduced to align with network hosting capacities, in which case the majority of VPP site system sizes will have the capability to export at levels exceeding these limits throughout the day.

To analyse the impact of dynamic operating envelopes on FCAS, Tesla examined the trial data to look for periods of time where the static 5kW export limit had been exceeded concurrently with a contingency triggered FCAS response.

During the entire field trial duration only one such event could be identified, on the 2nd of March 2020, when frequency dropped to 49.62Hz, which highlights the rarity of such events. This can be explained by the fact that several conditions must be met for this to occur:

1. Batteries must be fully charged
2. Solar production must be high and exporting to grid
3. The contingency event and subsequent frequency drop must be severe enough to cause a large enough response such that the sum of solar production and FCAS response is greater than the 5kW export limit

The plot below is the actual 1 second telemetry of the VPP fleet response to the 2 March event, overlaid with the expected response of an equivalent VPP with 1, 2 or 3MW registered FCAS capacity. The chart also shows the current static 5kW site export limit, and a potential future 1.5kW static site export limit. Key insights from the FCAS response are that:

1. The VPP provided a > 3MW equivalent response but in doing so approximately 150 sites had breached their static 5kW site export limits
2. The combined duration of excursions over the 5kW limit lasted only roughly 90 seconds
3. The VPP could provide a 2MW equivalent response without breaching any site 5kW exports
4. Even a 1MW response would have breached a 1.5kW site export limit

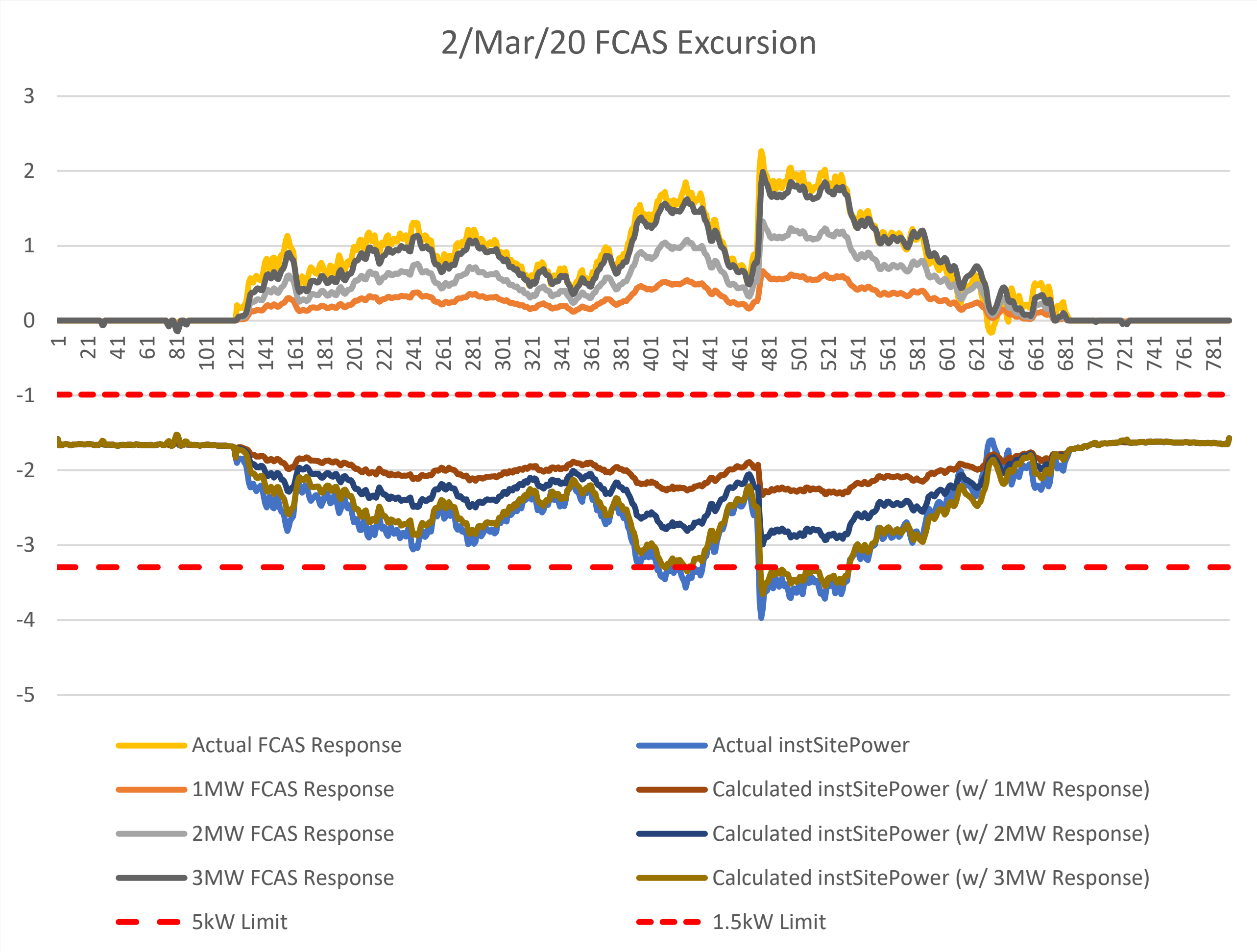


Figure 4-22: Response on 2 March 2020

To examine the consequent financial impacts on the VPP from an FCAS perspective, Tesla has provided the chart below showing the capacity the VPP actually bid into the different contingency FCAS markets on the 2nd of March.

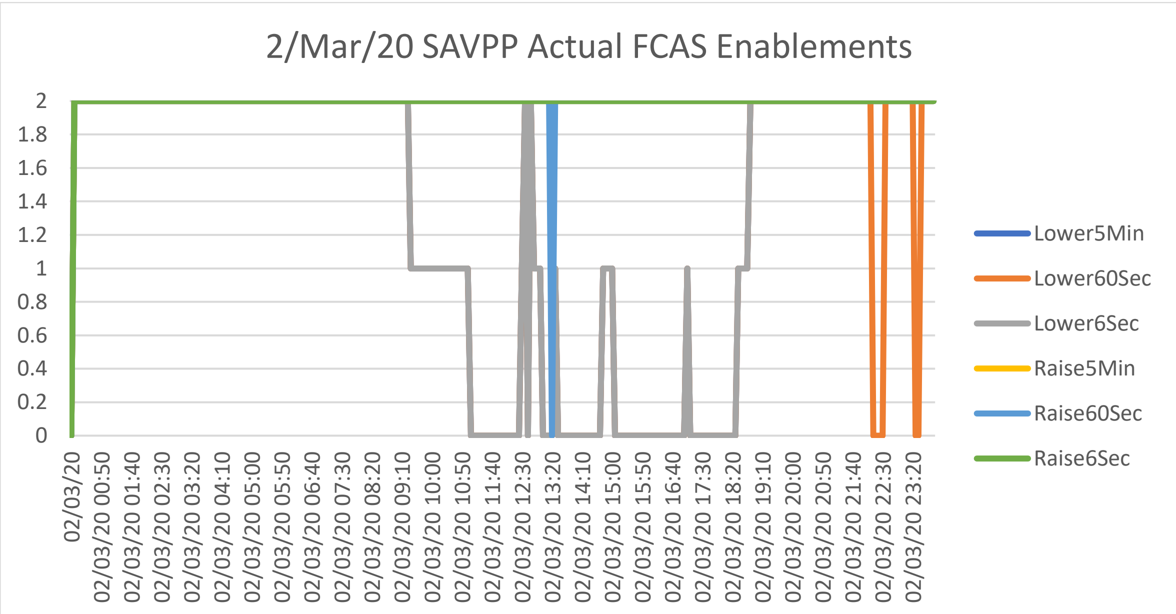


Figure 4-23: FCAS Bids on 2 March 2020

Figure 4-23 above shows that Tesla's VPP was registered for only 2MW during this period. However, as shown in Figure 4-24 below, being able to add an additional 1 MW of FCAS with dynamic exports enabled would have increased revenues by 46%.

Additionally, when comparing to a potential future state of 1.5kW static export limits, where the VPP would have had to bid 0MW into the raise FCAS markets, this would have significantly reduced FCAS revenues (18% of actual) as shown in the *Revenue 3MW Lower, 0MW Raise* case below.

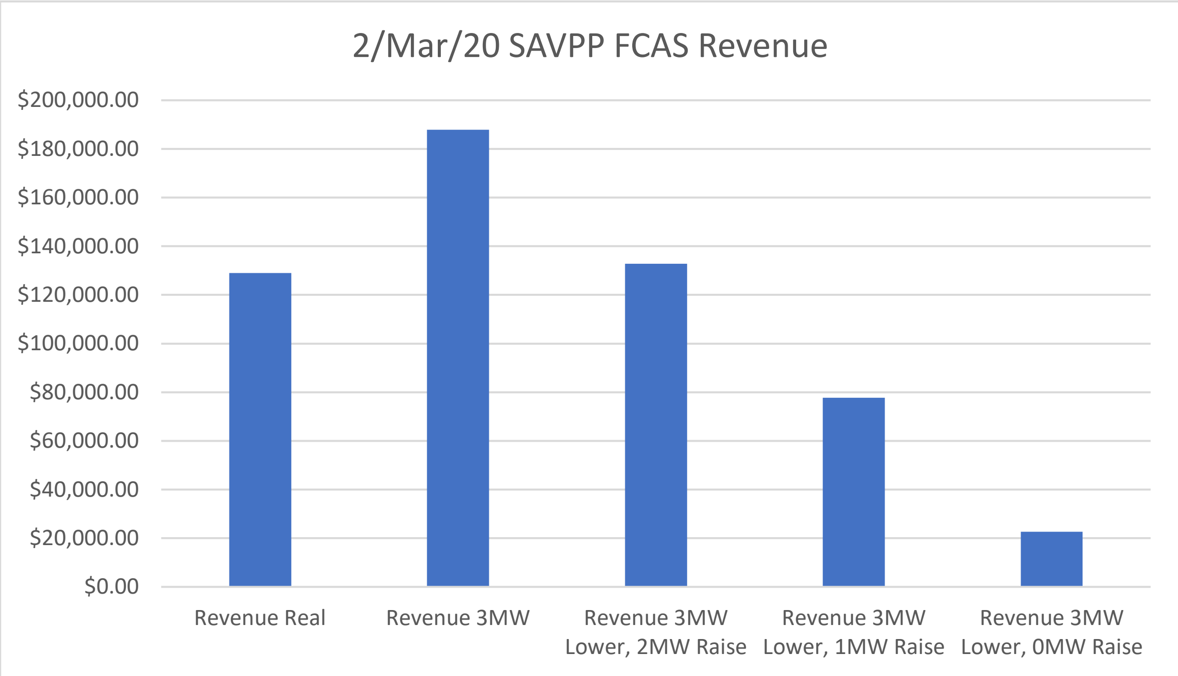


Figure 4-24: FCAS Revenue on 2 March 2020

The exercise of attempting to identify FCAS responses and their interaction with site export limits has highlighted the rarity of site export limit excursions over 5kW caused by FCAS responses during the trial, and the short duration of the excursions. The likelihood of FCAS response causing exports above 5kW in future has been potentially further reduced by the introduction of Mandatory Primary Frequency Response for larger generators. The plot below is the 5 minute average frequency as measured by a Powerwall from February 2020 to April 2021 demonstrating the reduced frequency variance and number of deviations outside of the nominal operating frequency band (NOFB) since the new rules came into force in November 2020.

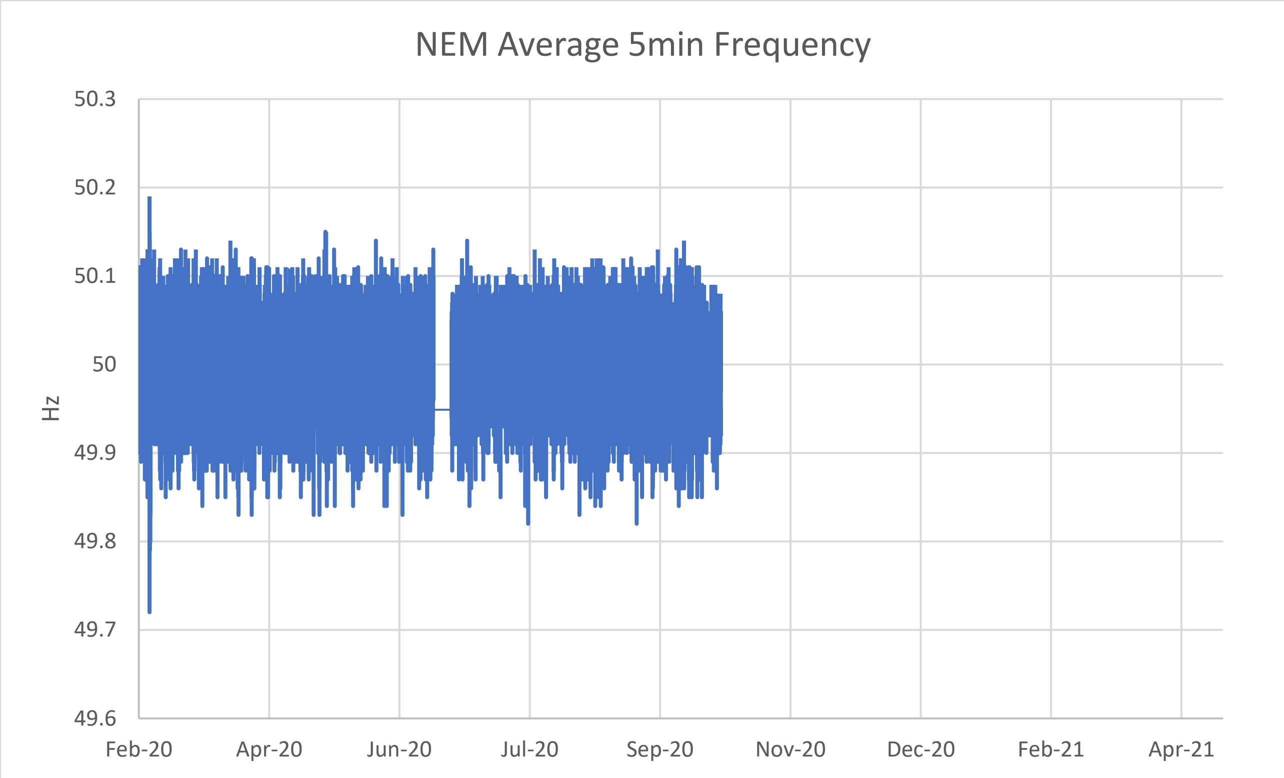


Figure 4-25: Impacts of Primary Frequency Response on system frequency

In summary, the trial suggests that there is not currently a material risk to the network of VPP sites exceeding a 5kW static limit due to FCAS response for sites configured with 5kW PV and a 5kW battery. In a future where static site export limits are reduced and VPPs are larger and more numerous, however, flexible export limits are likely to significantly increase the opportunity for VPPs to continue to bid into and participate in FCAS raise markets.

4.5 Customer impacts

4.5.1 Research question 7: impact on customer uptake of DER

To what extent might the proposed dynamic hosting capacity regime impact on customers and their take-up of demand management and third-party DER control?

The proposed dynamic hosting capacity regime provides the following benefits vs the current state in which inverters switch off or ramp down in response to local voltage rise in areas of congestion:

- More confidence in expected operation;
- More connection options; and
- Less frequent disconnection or curtailment of inverters due to overvoltage.

As shown in RQ1, the proposed dynamic hosting capacity regime provides a 20%-60% increase in the export capacity available to a VPP versus static 5kW export limits, with the greatest increases in export capacity associated with low solar PV generation. Hence it is likely that the dynamic hosting capacity regime favours the use of larger, active DER systems with storage and/or demand management over smaller, passive systems.

It is noted that the South Australian network is approaching or exceeding its capacity to host DER under 5kW static export limits, and so if the VPP ecosystem in South Australia continues to grow over the next

5-10 years, it is likely this will be under greatly reduced static export limits. This would act to increase the benefit of the dynamic hosting capacity regime vs static limits.

From the customer perspective, dynamic operating envelopes can enable VPP operators to create more value from energy and FCAS markets using customer's DER assets than static limits, especially when static limits are reduced from their current level to a level more consistent with the true hosting capacity of the distribution network. As such, the transition to dynamic operating envelopes will support the continued growth of the VPP market as DER penetration continues to grow. This in turn will mean that customers will continue to enjoy the opportunity to enrol their batteries and other home resources in VPP schemes and receive a share of the value created.

4.5.2 Research question 8: other customer impacts

What are the customer impacts, if any, of the dynamic network capacity management approach?

Customer benefits arise from increasing the use of existing assets, both the network and DER, and therefore reducing overall energy costs. In practice, this means that under the dynamic network capacity management approach, VPPs are provided with the ability to export at their full capacity at times and locations where energy is most needed by other customers. This increases market access to low cost energy from VPPs when this energy is most valuable, while reducing costs associated with network investment.

Dynamic operating envelopes also serve to increase the ability for VPPs to participate in the provision of FCAS services, a service they are ideally suited to provide. Greater volumes of FCAS-registered resources will serve to reduce FCAS costs in the long term, ultimately leading to lower costs to customers.

Finally, the additional capacity and the capability to communicate with DER, as well as the visibility of DER available through the interface, can also be used by networks to improve reliability and security of supply for all customers, not just those in the VPPs.

The provision of operating envelopes at the network node level (e.g. at the distribution transformer) rather than at the NMI level has specific implications for customers that warrant further consideration. The idea is that the VPP aggregator can receive an aggregated limit for a group of sites under their control, and choose how to allocate that capacity between individual sites in a way that is most optimal for the operation of the VPP. It is, however, the customer, not the VPP aggregator, that pays network charges, and it is the network connection agreement between the DNSP and the individual customer that defines the customer's obligations with respect to conforming to site limits. Therefore if an aggregator is to decide how local capacity is allocated between their individual customers, this must be enacted with the consent of both the customer and the network. Effectively, the customer needs to opt-in to allowing the aggregator to set their export limit, rather than the network, and the network must qualify the aggregator as a party trusted to disaggregate nodal limits to individual sites on its behalf.

Finally, a finding from RQ1 which could impact on customers is that the benefits of the dynamic network capacity management approach can be uneven between customers depending on their location on the network. This trial successfully demonstrated that an approach such as the Tesla VPP, in which benefits are shared across all participants, can be used to remove any increase in complexity due to the performance of different sites and increase predictability for customers.

5 FUTURE WORK

5.1 Tesla VPP expansion to 3,000 homes

On 4 September 2020, Tesla announced phase 3 of the SA VPP, further expanding the SA VPP by 3,000 additional community houses, and this rollout is currently underway. In line with phase 2, these sites consist of a 5kW Solar PV system and a 5kW/13.5kWh Powerwall 2. Opportunities to integrate these sites with SAPN's API will be explored as a logical stepping-stone to opening the integration up to a broader range of VPP operators in 2021.

5.2 Expansion to multiple VPPs/aggregators

The integration of Tesla's VPP platforms via the API and publication of flexible export limits in this project was intended to prove the concept for a service offering that can be taken up by other VPP operators and aggregators post trial. Thus, the technology systems developed by SA Power Networks were designed and developed from the start to support multiple VPPs and contain the foundational functionality to allocate available network capacity between multiple participants.

In July 2020, SA Power Networks conducted the first integration of the API with a third party outside of the Advanced VPP Grid Integration trial, for registration and telemetry functions only. This has been an opportunity to test the onboarding and integration processes developed as part of the trial, and demonstrated that other vendors can easily integrate with the API. However, further work will be required to define the rules for capacity allocation and develop appropriate service level agreements required to operate a production service. SA Power Networks is scoping trials to bring further VPP operators on board in 2021 to further explore these issues.

5.3 Expansion to solar PV

While batteries and VPP participation are becoming more popular in South Australia, most DER installations consist only of solar PV systems. This means the proliferation of solar PV continues to be the key driver of DER network constraints on the distribution network today. It is widely accepted that the application of flexible export limits presents the most efficient way of enabling the uptake of solar PV when compared to zero or near zero export limits that are being imposed by some distribution networks today.

This concept is being developed and tested in our new Flexible Exports for Solar PV trial[21], also with funding from ARENA. In this project we have partnered with Victorian DNSP AusNet Services, three market-leading inverter vendors (Fronius, SMA and SolarEdge) and one inverter gateway provider (SwitchdIn) to deliver an advanced network connection option for solar customers. The aim is to provide a new option for customers wishing to connect solar PV in areas of the network that are reaching capacity, who may otherwise be required by DNSPs to configure their systems to permanent zero or low export limits.

This project will build upon the foundational technical work completed by SA Power Networks in the Advanced VPP Grid Integration Project to enable this new customer service offering. The table below summarises some key areas in which the new project builds upon the work done in our Advanced VPP Grid Integration project.

[21] See https://arena.gov.au/projects/sa-power-networks-flexible-exports-for-solar-pv-trial/

Focus area	Approach in advanced VPP grid integration project	Scope in Flexible Exports for Solar PV project
Customer facing offer	Given the nature of the battery ownership in the SA VPP, no customer facing offer was required to support flexible exports in this project	Develop the customer facing service offering for flexible exports, build into connection agreements and test customer experience of this service offering with participating customers during a 12 month field trial
Quantification of benefits	Quantifies the benefits of flexible exports for a VPP participating in wholesale energy trading and FCAS	Quantify the benefits for solar PV customers for participating in flexible exports as compared to fixed zero or near-zero export limits
IEEE 2030.5 compliance	The API specification in this project was based on the IEEE 2030.5 standard with specific alterations and simplifications to better suit the purposes of both parties and enable the dynamic exports concept to be demonstrated.	Many solar PV OEMs are developing IEEE 2030.5 compliant systems in response to the California Rule 21 smart DER mandate. Thus compliance with the standard for solar PV flexible exports will leverage the work OEMs have completed in other markets enabling inter-jurisdictional interoperability. To achieve this, the project will develop: • An IEEE 2030.5 implementation guide and compliance process based on CA Rule 21 requirements • An IEEE 2030.5 compliant utility server integrated with the SAPN API
Capability in technology vendors systems	Capability for flexible exports in Tesla's VPP control platform	Capability for flexible exports in market leading solar PV inverter manufacturers platforms and many other non compatible systems through the SwitchDin gateway device

5.4 Flexible exports as a standard connection offering

Once these further trial projects are complete, SA Power Networks intends to expand the flexible exports for solar PV and VPPs into production service offerings for all new DER customers. The implementation of this production capability will be backed by the funding proposed in our LV Management Business Case[22] which has been approved by the AER for implementation in the 2020-2025 period.

This program forms part of SA Power Networks' long-term plan to double the amount of solar on the network by 2025.

[22] SA Power Networks, LV Management Business Case, attachment 5.18 to SA Power Networks' 2020-2025 regulatory proposal, accessible at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/sa-power-networks-determination-2020-25/revised-proposal