Virtual Power Plant in South Australia

Final Milestone Report
Submitted: October 2020
Prepared by: AGL Energy

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1. Introduction

1.1. Project Overview

The Virtual Power Plant in South Australia (VPP-SA) project was the first VPP project of its scale announced in Australia in late 2016. The project had ambitions to explore three components of the VPP value chain, including:

- **The sale and installation** of 1,000 behind the meter battery energy storage systems (BESS) across metropolitan Adelaide (*Customer and Field Operations*)
- **The technical capabilities of BESS orchestration** incorporating both hardware and software performance (*Technical Capabilities*)
- **The accessible value of BESS orchestration** including customer solar self-consumption value, network services, and wholesale market services (energy and FCAS) (*Value Pool Assessment*)

**Customer and Field Operations**

The sales and field operations component of the project ran from August 2016 until the end of September 2019, when the 1,000th BESS was installed at a customer premise (noting that AGL’s field operations team continues to manage the installed fleet and carry out maintenance where required). Notably, from late 2018 through to completion of sales in June 2019, AGL undertook a focused sales campaign in specific areas of the network where the provision of VPP services to a distribution network could be demonstrated. The insights and challenges of this campaign are shared both in Section 5.2 of this report, and previous knowledge sharing reports.

**Technical capabilities**

The project was initially launched with Sunverge as the key technology partner with the ambition to include other hardware partners as the project progressed to create a diverse fleet of assets. In April 2018, three additional hardware partners have been added to the program (LG Chem, Solar Edge, and Tesla), and in December 2018 Enbala were contracted to provide VPP software services across the full fleet, another first for the program as the control of each device was to be enabled entirely through ‘cloud to cloud’ integrations (through application programming interfaces, or API’s) at scale.

Over the course of the project, AGL has undertaken a number of VPP capability tests ranging from simple charge and discharge dispatches through to setting of local modes that allow the energy storage systems to act autonomously to changes in grid conditions. Many of the insights from these tests are shared in this and previous knowledge sharing reports.

**Value Pool Assessment**

The in-field testing of VPP capability and performance bridges the gap between theoretical assessments of customer or market value, and the actual value achievable. Importantly, though some of the value pools lend themselves to ‘stacking’, prioritisation of one value over another typically requires a trade-off, or optimisation between pools. This report describes some of the in-field physical boundaries on value based on observations of fleet data, and these inform considerations of the trade-offs between value pools.

A timeline of key project milestones is provided in Figure 1:
Figure 1 Key VPP-SA milestones

- **2016**
  - Aug-16: Project Announcement
  - Sep-16: First BESS installed

- **2017**
  - Jan-17: Formal project launch (65 BESS installed)
  - Feb-17: 150 BESS installed
  - Mar-17: Sales and installations paused to prepare for inclusion of new hardware systems in fleet

- **2018**
  - Apr-18: Announcement of new hardware solution system offerings, and restarting of sales and installation
  - May-18: 500 BESS installed

- **2019**
  - Jun-19: Contracting of Enbala for VPP software services
  - Jul-19: Final (1000th) BESS install
  - Aug-19: Completion of project sales
1.2. Review of Project Outcomes

Key activity outcomes from the VPP-SA project are presented in Table 1, alongside commentary against how these outcomes have been achieved.
## Table 1 Project outcomes

<table>
<thead>
<tr>
<th>Planned Project Outcomes</th>
<th>Outcome Achieved</th>
</tr>
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<tbody>
<tr>
<td>Demonstrating at a commercial scale (5MW/7MWh and 950 battery systems minimum) the ability to control large numbers of distributed energy storage systems as a Virtual Power Plant (VPP) to achieve the following potential benefits:</td>
<td>AGL has sold, installed, and orchestrated a full 5MW fleet of VPP BESS, and demonstrated the capability for the fleet to create value for consumers, networks, and wholesale market participants.</td>
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<tr>
<td>Provide the ability for energy storage systems installed ‘behind the meter’ to provide multiple services for the benefit of the customer, retailer and network service provider (NSP), including: reducing customer bills; reducing network peak demand; wholesale market arbitrage/cap trading; provision of FCAS services and provision of other grid support services (e.g. voltage support).</td>
<td>Through both deployment of BESS’ and analysis of operational data, AGL has explored some of the challenges of integrating and coordinating high penetrations of DER behind the meter, including the network/consumer interface (connection agreements in particular), and the physical network conditions that can influence DER performance (voltage in particular).</td>
</tr>
<tr>
<td>Better understanding of how to co-ordinate and integrate distributed energy storage and solar PV systems into electricity grids to provide grid support.</td>
<td>AGL has demonstrated the capability for a fleet of BESS’ to provide a peak demand management service, and has enrolled part of the fleet into the AEMO VPP Demonstrations trial to participate in contingency frequency control ancillary services (FCAS) markets.</td>
</tr>
<tr>
<td>Potentially reduce broader system costs via reduced need for peaking plant capacity, reduced network capacity requirements, and reduced grid support requirements (e.g. ancillary services).</td>
<td>AGL has explored the quantum of value pools that VPP’s can access, and some of the impacts of prioritisation between markets/value pools.</td>
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<tr>
<td>Better understand the technical and commercial capabilities of VPPs, and what is required for distributed batteries operated as part of a VPP to become commercially viable.</td>
<td>AGL has shared insights and learning from the VPP project in a number of public consultations relating to the integration of DER, and shared project specific insights both in public presentations and knowledge sharing reports.</td>
</tr>
<tr>
<td>Sharing knowledge from the project with the broader industry and with targeted groups (e.g. AEMO/AER/AEMC) that helps facilitate the further development and deployment of VPPs and distributed battery storage in Australia, by:</td>
<td>AGL has presented insights from the project in a number of public forums and participated in ARENA-convened industry workshops.</td>
</tr>
<tr>
<td>Increasing industry understanding of how VPPs can be used to achieve the objectives described above.</td>
<td>AGL has shared project insights with regulatory and policy bodies – details of these engagements and responses to public consultations can be found in Section 5.1.</td>
</tr>
<tr>
<td>Increasing industry understanding of the technical and commercial capabilities, characteristics, and potential of VPPs, to help facilitate their future deployment.</td>
<td>Safety learnings through the project have been shared in knowledge sharing reports, as well as among AGL installers, suppliers, and partners.</td>
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<tr>
<td>Informing regulatory considerations of VPPs and distributed battery storage by relevant authorities (e.g. AEMO/AER/AEMC/Government).</td>
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<tr>
<td>Identifying any key safety, environmental or other learnings of importance to the industry arising from the project.</td>
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</table>
## 2. Project Review

### 2.1. A summary of the project activity undertaken

A summary of the three field operational stages is presented summarised in Table 2.

### Table 2 Summary of the three field operational stages (Stages 1-3)

<table>
<thead>
<tr>
<th>Stage</th>
<th>Approximate number of battery systems installed (and kW/kWh)</th>
<th>Key objectives</th>
<th>Key Activities</th>
</tr>
</thead>
</table>
| 1     | 150 (750kW/1050kWh)                                          | • Establish Stage 1 technical offering, and establish sales, installation and enablement mechanisms  
• Engage stakeholders and begin Stakeholder Reference Group meetings  
• Consideration and planning of Stage 2 technical offering, marketing, etc to determine technical and commercial feasibility  
• Establish operational systems to support streamlined roll out in the rest of the project  
• Demonstrate limited VPP capability | • Completed development of customer offering, and launched product (including novel customer orchestration agreement)  
• Contracted field force partners and began field installations  
• Hosted stakeholder reference group meetings  
• Undertook VPP capability demonstrations  
• Launched targeted marketing campaign in network zones |
| 2     | 350 (1,750kW, 2,450kWh)                                       | • Consider integration of new battery storage systems from suppliers other than Sunverge, if Recipient determines technically and commercially feasible  
• Begin targeted deployment of energy storage systems in specific network areas  
• Refine targeted marketing channels  
• Bed down operational systems and focus on driving down operating cost  
• Demonstrate more sophisticated VPP capability  
• Consideration and planning of Stage 3 technology options to determine technical and commercial feasibility | • Three new hardware providers added to program  
• Streamlined installation operations to standardise install pricing, and increase installation rate to a peak rate of ~30 systems/week  
• Introduced marketing through digital/social channels  
• Analysis of consumer savings, and impact of network power quality challenges on consumer value |
| 3     | 500 (2.5MW, 3.5MWh)                                          | • Drive down operational costs  
• Demonstrate limits of VPP functionality based on available technology  
• Deep analysis to understand the extent of services that can be provided by VPP  
• Begin to develop understanding of the value of VPP services to consumer, retailer, networks | • Hosted stakeholder reference group meetings  
• Contracted Enbala to provide consistent control across multiple hardware types  
• Further ramping of installation capability with increased installer base  
• Testing of VPP use cases for wholesale, and network services in particular  
• Second targeted marketing campaign |
2.2. Project highlights

The VPP-SA project explored multiple areas of the VPP value chain at significant scale and played a key role in catalysing the VPP industry in Australia and internationally. A selection of the key highlights are summarised below.

An international first

AGL’s Virtual Power Plant in South Australia project was announced in 2016, and was at the time, the largest VPP involving residential behind the meter batteries to be announced internationally. As ARENA had hoped at the time of funding, the project has catalysed the VPP industry both in Australia and internationally, and informed the discussion around DER integration in support of customer value.

A VPP of multiple assets types

The project was launched with a single integrated hardware and software platform, with the ambition to expand the range of hardware available to consumers through the course of the roll out. Less than 18 months into the program, the hardware options for consumers were expanded to include the latest generation of battery and inverter hardware with all customers being given the opportunity to upgrade.

Cloud based control

AGL’s intent from the outset of the project was to utilise cloud-based Application Programming Interfaces (API) to control the diverse fleet of assets. Though common today, that approach was novel at the time where most VPP programs relied on a ‘gateway’ device being installed alongside each BESS in the field, each communicating back to a single cloud control platform. AGL’s program was the first to incorporate multiple hardware devices, all controlled by a single VPP software system, via the hardware vendor API interfaces, at scale.

Successfully installing 1000 batteries, no Lost Time Injuries (LTI)

AGL has applied consistent focus and efforts on contractor management. As installers represent AGL to the customer for much of the customer journey and small errors made during an installation can have ongoing impacts on BESS performance, AGL has taken care in the recruitment, training, and ongoing support of installers throughout the program. AGL considers the management of installation quality and HSE performance in the program a major success.

Contingency FCAS participation

AGL’s was the first retailer-led VPP to join the AEMO VPP Demonstrations1, enabling participation of the majority of the VPP-SA fleet in the 6 contingency FCAS markets, and exploring the use of behind the meter DER devices for ancillary services provision.

A rich dataset

From the start of the program, AGL built and maintained a data ingestion platform to retain granular operational data from each device in the VPP. This data is used both to inform customers of the performance of their system (through AGL’s Solar Command platform) as well as to understand the real time position and performance of the fleet. The granular data has also been invaluable in identifying hardware, metering, or connectivity issues at sites, and for informing the discussion around network voltages and their impact on DER performance.

2.3. Project challenges

As the first major VPP involving BESS' to be announced in Australia, the VPP-SA project encountered a number of challenges specific to both the residential battery market (which at the time of announcement was only emerging) and to VPP’s specifically. A selection of the key challenges are summarised below.

Sales

Regardless of the relatively low prices offered to customers for the battery hardware and installation, achieving 1,000 battery sales was an area that required significant effort, as customer eligibility for participation was necessarily limited. Eligibility criteria were developed both to ensure that each battery would be able to contribute meaningfully to the VPP, as well as to ensure that customers could achieve reasonable return on their investment (nominally set at a seven-year simple payback). As noted in prior knowledge sharing reports, there were several eligibility criteria that proved challenging, including:

- Customers were required to have sufficient excess solar and household load to be able to make effective use of a battery.
- Customers receiving a premium Feed-in Tariff for grid exports from their existing solar system (which would be lost if they install a battery) were not eligible to join the program.
- Customers were required to own their home and intend to live there for the 5-year term of the contract.
- Customers were required to have a suitable location to install a battery – this became less of an issue with the newer hardware types that were able to be both ground and wall-mounted.

Additionally, the targeted sale of batteries into network locations identified by the DNSP for the demonstration of network services with a VPP presented its own challenges. In addition to the eligibility criteria for participation in the program, the overlay of a very limited customer pool required very specific approaches to marketing and product design.

As an example with indicative breakdowns, a low voltage circuit with 100 customers connected might have a higher than average solar penetration of 40%, so 40 eligible customers with solar. Of those, 25% (10) of those customers may retain a premium feed-in tariff, and a further 25% (10) have solar systems that are too small to make efficient use of a battery. Of the remaining 20 customers, some will not own the home in which they live, be prepared to make the financial commitment to purchase a battery or be prepared to participate in a VPP. Targeting a 5-10% penetration of batteries within that circuit, the number of sales required within the remaining eligible cohort would be a challenge. Effective marketing, flexible contracts, and measures to improve affordability of the investment are all tools that were used to overcome the targeted marketing challenges.

Hardware deployment

Quality management

Quality management of field-based operations remained a challenge throughout the installation phase of the project. As with all field-based businesses, managing customer experience and quality requires robust training, and close monitoring of installers, as well as comprehensive operational protocols to manage swift resolution of issues should they occur. The installation and commissioning of metering devices was a particular issue as these can be difficult to diagnose during installation without clear test and commissioning protocols.
Installation location

Previous milestone reports have highlighted issues relating to the allowable site voltage rise in the recently revised AS4777.1 (2016). In some instances, this resulted in a requirement to upgrade customer sub-mains at some customer sites due to the limited options for battery locations, relative to the switchboard. Again, the newer hardware systems introduced during the course of the program allowed for a wider range of installation location options, reducing the requirement for sub-mains upgrades in some instances.

Evolving connection agreements

A revision of the SAPN connection standard TS-129, referencing the Australian Standard for grid connected inverter systems, AS4777.1 (2016), came into force during the deployment phase of the program in 2017, which limited the total inverter capacity at any site to 10 kVA. This had the potential to preclude customers with existing solar inverters with a capacity greater than 5 kVA from installing a new energy storage system. SA Power Networks clarified their position on this and updated their technical standard, limiting any grid connected ESS inverters to a total site export limit of 5 kW but with a total allowable inverter capacity of 20 kVA (10 kVA for solar PV inverters + 10 kVA for energy storage inverters).

While the issue was resolved with limited impact to the broader VPP rollout, it was evidence of the impact that connection agreements can have on DER deployment, and how the specific connection agreement that a customer signs up to at the time of connection can have a downstream impact on their ability to participate in aggregation programs in future.

Ongoing VPP operations

Managing customer churn

While most customers engaged in the VPP-SA project have maintained their participation, AGL has seen an average annual churn rate of 1-2%. The most common reason for customers leaving the program is a change of living conditions, typically the sale or lease of the property where the battery is installed. Where this occurs, customers are provided a number of options for exiting the program, including novation of the VPP services contract to the new owners, or the payment of an early termination fee that is prorated to account for the period that the customer has been involved in the program.

Reliable communications

Reliable site communications have been noted by AGL and other VPP operators as an area requiring ongoing focus and management. While there are no foolproof measures to resolve, a combination of the following can help to manage the impact of communications issues:

- clear guidance and instructions for customers and installers on which communications mediums are most reliable;
- thorough commissioning processes;
- failover mechanisms within the hardware itself (to allow for a primary and secondary communications medium), and;
- ongoing monitoring

Reliability monitoring

As with monitoring of connectivity, monitoring general fleet performance and identifying outliers is an essential component of maximising VPP availability and value by ensuring that assets are available for dispatch when required through proactive resolution of issues. Automated systems to identify underperforming sites or operational anomalies can be set up to bring issues to the attention of the VPP controller, and then triaged for resolution by either the installer or hardware vendor using asset level performance data.
2.4. Battery sales and installation metrics

In order to achieve the ambitious target of 1,000 batteries as part of the VPP-SA program, AGL deployed multiple marketing approaches to drive leads and interest, outlined in Table 3.

Table 3 Marketing Channels to drive leads

<table>
<thead>
<tr>
<th>Marketing Channel</th>
<th>Description</th>
<th>Relative Effectiveness</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-announcement capture of interest</td>
<td>In the lead up to the project launch announcement AGL captured interest from potential leads via an online form. Traffic to this site was driven primarily by coverage in traditional media outlets and unpaid social media</td>
<td>Effective in gathering initial leads (drove ~600 leads), challenges with eligibility</td>
</tr>
<tr>
<td>Digital advertising</td>
<td>Digital advertising of low-priced battery and VPP participation offer via Facebook and Google search</td>
<td>Cost effective marketing, lead generation channel</td>
</tr>
<tr>
<td>eDM to AGL customers</td>
<td>Targeted eDMs to customers with solar in specific geographic areas</td>
<td>Most cost effective marketing channel</td>
</tr>
<tr>
<td>DM to target customers</td>
<td>Targeted DMs to customers with solar in specific geographic areas</td>
<td>Limited effectiveness in driving leads</td>
</tr>
<tr>
<td>Local Area Marketing</td>
<td>Targeted marketing campaigns were undertaken with ‘hyper-local’ focus areas to support the demonstration of network services. This marketing included a town hall event, printer flyers and posters, printed press advertorial, targeted Facebook advertising, letter box direct mail and address-based eDMs</td>
<td>Multiple channels were effective in driving interest, awareness, and leads, however lead conversion to sale was limited given eligibility challenges</td>
</tr>
</tbody>
</table>

2.4.1. Installation metrics

The final 1,000 BESS installations after the technology upgrade were predominantly completed between April 2018 and August 2019 (illustrated below) with the quarterly average rate of installations peaking in Q4 2018 at approximately 20 systems per week.

Figure 2 Battery installation timeline

The second phase of installations from Q2-2018 onwards were completed by a total of 23 teams. Of these 23 teams, just 7 were responsible for 80% of installations, outlined in a histogram of team installations in
Figure 3. This balance of installations reflects the extensive coaching and learning required to install residential batteries – of all the teams that installed batteries as part of VPP-SA, a handful were able to safely and effectively install batteries and so completed a significant amount of the volume, whereas other teams struggled and so did not complete a meaningful amount of volume.

Figure 3 Breakdown of installation completions by team

2.5. Sales and installation lessons learned

2.5.1. Sales lessons learned

The project team evolved the marketing and sales process over a period of almost three years based on learnings and customer feedback. Lessons learnt from this activity have been presented in prior knowledge sharing reports and are summarised below:

- **The upfront cost of the battery was the most sensitive variable in attracting sales leads.** Targeted marketing campaigns at lower price points demonstrated much higher conversion rates.
- **Overall lead to sale conversion rates were high at ~26%,** supported by the relatively low cost to customers of participation in the program.
- **Conversion rates were highest for existing AGL solar customers,** likely driven by the relative ease for customers of persisting with AGL as their energy retailer.
- **Initial interest in the program was dominated by early solar adopters.** Customers who receive the PFIT were over-represented in the cohort of customers that expressed an early interest in project participation.
- **Premium feed-in tariffs a barrier to battery adoption.** As outlined in Milestone Report 1 a high fraction of prospects chose not to continue with a battery installation because they would lose their Premium Feed-in Tariff (PFIT) by participating in the program.
- **One to one sales discussions are key to explaining the value of batteries,** the VPP concept and how it works for customers.
- **Customers were largely unfamiliar with the concept of voltage and its impact at their site.** This can make estimating the value of a battery to customers challenging.
- **Direct email communications to AGL target customers was the most cost-effective channel,** followed by digital marketing approaches.
• **Customers want back-up power as part of a battery purchase.** The majority of sales conversations began with customer expecting that the installed energy storage system would provide backup power. Many customers placed a high value on the backup functionality.

### 2.5.2. Installation lessons learned

Through the installation and maintenance of multiple asset types the VPP-SA project identified multiple installation improvement areas, relating to installation costs, technical knowledge requirements and installer management. Key installation lessons learned are presented below.

• **AC-coupled battery systems support more cost-effective battery installations.**
  - As noted in previous reports, AGL opted to use AC-coupled battery systems for the VPP-SA project to simplify the installation methodology and eliminate the need to upgrade existing solar arrays and cabling. This choice was maintained to the end of the project.
  - Based on early site visits, AGL estimated that more than 50% of existing solar PV systems would require some form of modification to make them compliant with current Australian standards, and that the likely cost of modification is typically in the order of $500-$1000 per system. This necessitates a costly variation to a customer quote. To avoid the cost of modifying existing solar PV systems, AGL chose to use only AC-front coupled energy storage systems in the VPP-SA program. This removes a significant uncertainty from retrofit ESS installations and eliminate these costs.
  - Milestone 1 report includes a detailed explanation of this AC-coupled architecture.

• **The concept of “back-up” power provided by a battery is detailed and requires a degree of technical understanding.**
  - There are multiple components to back-up power, including whether or not solar can charge the battery and the customer load that can be supported by a battery providing back-up power.
  - Understanding and explaining these differences required a nuanced, technical conversation with customers to ensure they had clarity on the capability prior to accepting the quote.

• **Pre-installation site inspections are key to achieving safe, ‘first time right’ installations – AGL continued to employ pre-installation site inspections for battery installations throughout the VPP-SA project. Site inspections are key to:**
  - Identify any reasons that would prevent installation proceeding (e.g., unsafe access or excessive additional costs due to site conditions).
  - Identify any constraints on battery location options to comply with AS/NZS5139 and battery manufacturer requirements, and to agree the battery location with the customer.
  - Confirm and plan safe access and site establishment.
  - Identify pre-works that need to be agreed with the customer before battery installation can proceed (e.g., switchboard upgrades or asbestos removal).
  - Confirm cable sizing for compliance with voltage rise limits.
  - Confirm how the internet connection with the battery system will be installed.
  - Confirm customer selection of circuits to powered from backup power.
  - Identify any variations required to complete the installation.

• **Individual sites present varied installation challenges that each require consideration and management.** Key site-specific installation challenges experienced throughout VPP-SA include:
  - **Proposed locations in direct sunlight** that conflict with battery manufacturer installation requirements.
  - **Identifying appropriate wall materials for wall-mounted installations.** AGL commissioned a third-party engineering review of wall materials that can facilitate wall-mounted battery installations.
Age and condition of switchboards, particularly in older suburbs where the need for a complete switchboard upgrade affects a high percentage of sites. Specific challenges with switchboards include the presence of asbestos, lack of space within the switchboard cabinet for metering devices and CTs and a lack of lack of available space to segregate circuit breakers and wiring for backup power.

Integration of generators used by customers for backup power. This integration can be complex and expensive to integrate into the site fixed wiring in a safe manner.

Mechanical protection of battery locations in garages and carports. Mechanical protection of the battery is required by AS/NZS3000. AGL has employed bollards and curb strips which are relatively cheap and easy to install.

Internet connection quality. AGL has standardised on installing a hardwire connection between the battery and the customer’s modem/router whenever cost-effective.

Use of batteries as Uninterruptible Power Supply. VPP-SA battery inverters do not comply with the requirements of an uninterruptible power supply (UPS), and as such, AGL was not able to install a battery where a UPS was required (to power an essential medical device, as an example). The distinction between a UPS and a BESS with backup capability was difficult for some customers unfamiliar with the Australian Standards governing UPS systems to appreciate.

Presence of solar diverters and power conditioners.
- Solar diverters are devices that send excess solar energy to hot water storage tanks. As these divert power away from the battery system charging, AGL required the devices to be disconnected.
- AGL encountered two sites where the customers had installed “power conditioners” (essentially power factor correction devices) intended to reduce bills. In some instances, these devices may need to be removed to install a BESS as they may interfere with the inverters normal operation.

- Battery vendor training and accreditation, and vendor changes to installation instructions
  - AGL required all installers complete hardware vendor accreditation programs. While these provided an introduction, there are limits on how much information can be imparted via online learning techniques. AGL found that hands-on guidance was still needed for the first few installations to ensure the installers became familiar with the technology and achieved consistent successful completions in a timely manner.
  - BESS vendors published updates to their installation methodologies several times through the project. AGL needed to update our training materials each time and ensure the installers were aware of the changes.

- Dedicated installers for specific technologies can support installation quality.
  - AGL has maintained and continuously improved its installer induction training and the clarity of its “installation overlay” instructions.
  - Dedicating installers to one type of battery system improved efficiency and quality of installs. Overflow capacity was utilised from another company using just one installation team.

2.6. HSE tracking and performance

AGL’s target for health and safety is zero harm to our people. For the VPP-SA project, as in all projects, the safety of staff, contractors, customers, and members of the public was of the utmost importance. AGL managed a strong focus on health and safety throughout the program, and this resulted in 0 Medical Treatment Injuries (MTI) and 0 Lost Time Injuries (LTI) being recorded. There were however four High Potential (HP) incidents recorded.
2.6.1. Key HSE Insights

Working at heights

Ensuring safe and compliant practices relating to work at height is an ongoing challenge in the small-scale renewables sector. Many installers, particularly small businesses and sole traders, operate on lean margins and can view fall protection measures as an unnecessary use of their limited time and resources while on site. This challenge is amplified during home battery installations, where the installer might spend less than 30 minutes on the customer’s roof as distinct from a solar installation requiring hours of rooftop work. It was our observation that these short periods of rooftop work more often resulted in a tendency to cut corners on safety.

This issue was managed to good effect through risk awareness activities, constant reinforcement of AGL’s requirements and in-field HSE assurance and auditing. While just under 12% of total installations on the program were subject to formal HSE audit, many more ad-hoc safety observations were conducted by field technical personnel who were empowered to stop work on any installation if unsafe practices were observed.

2.7. Summary of project media

Given the topical nature of energy in South Australia and the innovative nature of the project, VPP-SA has attracted media attention and AGL has provided frequent communication updates.

A summary of key media coverage is presented in Table 4.
**Table 4 Summary of key media coverage**

<table>
<thead>
<tr>
<th>Event</th>
<th>Coverage</th>
<th>Key Themes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Launch and Stage 1</td>
<td>All TV networks in Adelaide</td>
<td>Benefits of VPPs</td>
</tr>
<tr>
<td></td>
<td><strong>Renew Economy</strong> - <em>AGL invests in world’s largest battery storage virtual power plant</em>, 5 August 2016</td>
<td>Scale of VPP-SA (1000 batteries)</td>
</tr>
<tr>
<td></td>
<td><strong>The Australian Financial Review</strong> - *AGL Energy to harness power of 1000 batteries in ‘virtual power plant’, 5 August 2016</td>
<td>ARENA support</td>
</tr>
<tr>
<td></td>
<td><strong>Energy Storage News</strong> - <em>South Australia to get ‘world’s largest virtual power plant’, 9 August 2016</em></td>
<td></td>
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<tr>
<td></td>
<td><strong>ABC News</strong> - <em>Virtual power plant links solar and battery storage in hundreds of Adelaide homes</em>, 15 Dec 2016</td>
<td></td>
</tr>
<tr>
<td>Stage 2</td>
<td><strong>The Advertiser</strong> – <em>Major Projects Conference attendees to get AGL power plant update in Adelaide</em>, 25 July 2017</td>
<td>Benefits of VPPs</td>
</tr>
<tr>
<td></td>
<td><strong>ABC News</strong> – <em>AGL suspends household battery installations for Adelaide’s cutting-edge Virtual Power Plant</em>, 7 September 2017</td>
<td>Deployment of next generation battery technology</td>
</tr>
<tr>
<td></td>
<td><strong>Renew Economy</strong> – <em>AGL hits pause on virtual power plant in technology “rethink”, 29 August 2018</em></td>
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<td><strong>Renew Economy</strong> – <em>AGL switches to Tesla and LG Chem for virtual power plant</em>, 13 March 2018</td>
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<td><strong>The Conversation</strong> – <em>The unholy alliance that explains why renewable energy is trouncing nuclear</em>, 20 March 2018</td>
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<td>Stage 3</td>
<td><strong>The Advertiser</strong> - <em>Negatives, positives on battery</em>, 20th September 2019</td>
<td>Benefits of VPPs</td>
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<td><strong>The Advertiser</strong> – <em>Price rise for all if solar stays squeezed, says power rule setter</em>, 27th September 2019</td>
<td>Expected battery uptake</td>
</tr>
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<td></td>
<td><strong>Energy Magazine</strong> - <em>AEMO: VPPs can alleviate operational challenges</em>, July 27, 2020</td>
<td>AGL connecting 1000 households</td>
</tr>
</tbody>
</table>

AGL announced the Virtual Power Plant project at a joint press conference with ARENA on 5th of August, 2016. South Australian Treasurer and Minister for Energy, Tom Koutsantonis, ARENA CEO Ivor Frischknecht, and AGL CEO Andy Vesey were present. The announcement generated significant media attention, focused largely on the potential benefits of VPPs and the significant scale of the VPP-SA program, noting the VPP was set to become the world’s largest. Stage two media covered included commentary on the deployment of next generation battery hardware across VPP-SA.

More recent incidental media coverage has been driven by broader coverage of home battery subsidy schemes and the related coverage of AGL’s broader VPP market offers that were launched in July and August 2019. As the project has spanned more than 4 years since the initial announcement, the detail and tone of the reports has evolved significantly over that time. Initial reports focussed on the innovation of VPP technology and the nascent residential energy storage market, while later reports have focussed more on competitive nature of the VPP market (recognising that new VPP’s had launched in Australia) and industry forecasts for battery uptake.
3. Customer experience

3.1. Consumer savings in context of the VPP

Financial savings from BESS are typically considered through the lens of simple payback periods by consumers, defined as the upfront costs of the battery and installation to the customer divided by the ongoing annual benefit - the expected bill reduction as well as any additional benefits from joining a VPP (though in this program those benefits were realised in the upfront purchase price of the BESS). Figure 4 sets out the range of payback periods VPP-SA customers could expect if they were to install a battery under either a flat retail electricity tariff or a ‘solar sponge’ retail tariff. The left-hand panel shows the payback periods for a battery installed at a subsidised price of $3,500 incl. GST (reflecting the customer offer pricing in this project). The right-hand panel shows payback periods for battery pricing of $5,499 (the customer offer price of a Tesla Powerwall 2 under current South Australian Home Battery Scheme for customers participating in AGL’s orchestration offer at the time of writing). The range provided is the inter-quartile range based on the load profiles of customers participating in the VPP-SA project. Customer savings were calculated based on the load profiles of VPP-SA customers and AGL’s Essentials plans available in South Australia as of August 2020.

Under the VPP-SA pricing, customers could expect an average ~9 year payback under a flat tariff (interquartile range 8-12), or an average ~8 year payback with a solar sponge tariff (interquartile range 7-10). Under the SA Home Battery Scheme pricing, including the AGL orchestration discount, customers on a flat tariff would expect a payback period of ~15 years, or ~12 year on the solar sponge tariff. Importantly, in assessing the savings under the solar sponge tariff, the BESS systems were operating in a solar self-consumption mode that assumed a flat tariff. That is, a BESS controller that is able to effectively optimise the use of the storage system to maximise savings under that tariff structure may be able to improve savings and reduce the payback accordingly.

It is also relevant to note that VPP-SA customer load profiles may not be representative of the general consumer load profile across Adelaide, and that tariffs are expected to vary during the term of the program, which will influence these results.

The Flat and Solar Sponge reference tariffs are outlined in Table 5.
The introduction of a solar sponge time of use tariff improves the economics for households to install battery storage while the economics of installing solar PV without storage become less attractive. Based on AGL’s Essentials tariff and the load and solar generation profiles for customers participating in the VPP-SA a ‘Solar Sponge’ tariff would have improved the payback period of installing battery storage by on average 17%, assuming the customer had an existing solar system.

3.1.1. Tariff optimisation in context of the VPP

A review by the Australian Energy Regulator (AER) in June 2020\(^2\) found that in South Australia 96.2% of residential and small business customers are on a flat tariff. As part of its determination for the 2020 to 2025 regulatory period the AER approved a Tariff Structure Statement that sees South Australian Power Networks (SAPN) charge retailers a time of use tariff as the default tariff for smart and interval metered customers. For customers with smart meters an alternative “prosumer” tariff which includes peak demand charges is also available. Table 6 sets out SAPN’s tariff for 2020-21.

### Table 6 SAPN 2020-21 Residential Network Use of System (NUOS) Charges

<table>
<thead>
<tr>
<th></th>
<th>Residential Flat</th>
<th>Residential TOU</th>
<th>Residential “Prosumer”</th>
</tr>
</thead>
<tbody>
<tr>
<td>Daily rate $/day</td>
<td>0.4658</td>
<td>0.4658</td>
<td>0.4658</td>
</tr>
<tr>
<td>Peak rate $/kwh (all/remaining time)</td>
<td>0.1378</td>
<td>0.1723</td>
<td>0.1033</td>
</tr>
<tr>
<td>Shoulder $/kWh (1:00am to 6:00 am)</td>
<td>n/a</td>
<td>0.069</td>
<td>0.0414</td>
</tr>
<tr>
<td>Off-peak $/kWh (10:00 am to 3:00 pm)</td>
<td>n/a</td>
<td>0.0345</td>
<td>0.0206</td>
</tr>
<tr>
<td>Summer peak demand $/Kw/day</td>
<td>n/a</td>
<td>n/a</td>
<td>0.7661</td>
</tr>
</tbody>
</table>

The key feature of SAPN’s new time of use network tariffs is that usage prices are lowest in the period from 10:00 to 15:00 pm, reflecting periods of high solar generation. The continued strong uptake of roof-top solar has led to the emergence of a daytime off-peak period and led to the introduction of a ‘Solar Sponge’ period in the middle of the day.

---

\(^2\) AER, Understanding the Impact of Network Tariff on Retailer Offers, June 2020
Figure 5 shows what the network cost to supply component of a VPP-SA customers energy bill would be using SAPN’s different network tariffs. The range provided is the inter-quartile range based on the load profiles of customers participating in the VPP-SA project.

On average customers in the VPP-SA would have incurred the lowest cost under the flat tariff $470 per year versus $477 per year on the ‘TOU Solar Sponge’ tariff while most customers would have incurred the highest network costs under the ‘Prosumer’ tariff (which includes a demand charge component). Figure 6 presents a histogram of the change in expected network costs for each customer moving from the flat tariff to the ‘TOU Solar Sponge’ and ‘Prosumer’ tariff. Generally moving from flat to ‘Solar Sponge’, most customer network costs would increase by a $0-25, with some decreasing by the same amount. Moving from flat to ‘Prosumer’ most customer network costs would increase significantly, often by more than $100. This analysis demonstrates that changes to more complex tariff regimes produce a range of customer outcomes that can be difficult to predict. Indeed, a customer with an energy storage system that was offsetting their evening load would be expected to be well suited to a tariff regime with both a time of use and demand charge component, though the results of this study demonstrates that most of the customers in the VPP-SA cohort would be paying considerably higher network charges under such a tariff regime.

We note that the analysis of network cost doesn’t include any behaviour change a customer may undertake in response to facing a different tariff structure. Customers could actively change their behaviour, set their batteries to respond to the changed network tariff or let a third party like a retailer control the battery to respond to the changed price signal.
Under the prosumer tariff peak demand during the summer months from 17:00 to 21:00 has large influence on total network cost. On this tariff, network cost within the sample of customers in the VPP would have been between $175 and $3,264 per year with peak demand charges representing on average $354 per year and up to $2,287 per year.

When customers face more sophisticated tariff structures like the ‘Solar Sponge’ or ‘Prosumer’ tariff the relative savings of installing solar versus installing a battery change. Under tariffs with time of use or demand charge features, the savings from installing solar are lower than the savings from installing battery storage.

Figure 7 shows the average network costs and savings from installing battery storage under SAPN’s flat, ‘Solar Sponge’ and ‘Prosumer’ tariffs.
Figure 7 Average network cost and savings from solar and battery installation under different tariff regimes

Network cost savings from installing solar are highest under the flat tariff i.e. $352/year and decline to $221/year under the ‘Prosumer’ tariff. Network cost savings from installing battery storage are $291/year under the flat tariff and increase to $364/year under the prosumer tariff.

Overall network costs for customers in the VPP-SA would have been lowest under the flat tariff which is a result of the load characteristics of customers in the VPP-SA.

3.1.2. Impact of orchestration events on customer value

Under emerging VPP models customers typically receive benefits from participating in the VPP. Orchestration events may charge or discharge energy from these customers BESS’ and so have some impact on underlying solar self-consumption savings. For customers on standard single-rate tariffs\(^3\) (i.e.: flat consumption tariff and flat feed in tariff, as per the “Flat tariff” outlined in Table 6), orchestration events will typically have a net subtractive impact on the customer energy bills, and thus it’s important that all orchestration customer offers have both clear boundaries on the frequency and volume of orchestration events, and a mechanism for remuneration to the customer for participation in those events. In the VPP-SA program, customer benefit for participation was provided in the large upfront subsidy on the cost of the BESS.

The savings impact of orchestration events can be separated into two components\(^4\):

- Value generated for the customer during the orchestration event due to increased export to grid (from feed-in tariff).
- Cost incurred by the customer some time after the event due to either:

\(^3\) Impact to customers on TOU tariffs are not considered in this analysis.

\(^4\) This only applies to orchestration events that involve battery discharge (relative to the self-consumption baseline). Impact to customer may differ for charge events.
i. Foregone self-consumption from battery (due to the lower state of charge of the battery from the orchestration event meaning that the customer must draw from the grid instead of from the battery).

ii. The exports being “brought forward” to the orchestration event rather than some subsequent export event (during which time the energy is instead used to charge the battery), meaning these exports incur only efficiency losses.

The net impact to customer value is largely determined by the proportion of cost that is incurred due to foregone self-consumption (i. above) versus “brought forward” exports (ii. above).

The net impact of an orchestration event to customer value cannot be calculated until the costs of foregone self-consumption and/or brought forward exports have been realised. In some cases, these costs may only be realised days after the event has concluded. However, at the time an orchestration event is completed, the impact to customer can be bounded as follows:

\[
\text{energy discharged} \times \left( \frac{\text{feed in tariff}}{\text{battery efficiency}} - \text{feed in tariff} \right) \leq \text{net impact} \leq \text{energy discharged} \times (\text{consumption tariff} - \text{feed in tariff})
\]

This bounding of customer impact is demonstrated in the two example scenarios outlined below.

**Scenario 1 – Exports being “brought forward”, incurring efficiency losses**

Consider a scenario in which under an orchestration event a battery is discharged at maximum power from 16:30 to 17:00, with a total of 1.9 kWh discharged (relative to the expected solar self-consumption baseline). This scenario is presented in Figure 8, demonstrating the battery state of charge, battery power and grid power for both the orchestration event and the latter battery charging event the next day.

The value generated for the customer due to the feed-in tariff is the product of the energy discharged and the feed-in tariff, equating to $0.2356. Under this scenario there is a cost incurred by the customer the next day from 11:00 to 12:30; energy that would be exported is instead used to charge the battery – essentially the exports have been “brought forward” to the day prior.

This cost to the customer equates to $0.2618, calculated according to the equation below.

\[
\text{Cost incurred} = \text{energy discharged} \times \left( \frac{\text{feed in tariff}}{\text{battery efficiency}} \right)
\]

The net impact to the customer therefore for this event would be $0.026. Note that the net impact to the customer would be zero if the battery was 100% and did not incur round trip losses.

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5 In fact, the time for costs to be incurred is unbounded. However, we typically see that the cost is incurred within 24 hours of the event concluding.
Consider a scenario in which under an orchestration event a battery is discharged from 16:30 to 17:00, with a total of 1.6 kWh discharged (relative to the expected solar self-consumption baseline).

The value generated for the customer due to the feed-in tariff is the product of the energy discharged and the feed-in tariff, equating to $0.1984.

Under this scenario there is a cost incurred by the customer the next day from 04:30 to 07:30 due to foregone self-consumption from the battery (1.6 kWh is consumed from the grid that otherwise would have
been self-consumed from the battery). The cost incurred is the product of the energy discharged and the consumption tariff, equating to $0.5190.

The net impact to the customer therefore for this event would be $0.321. This scenario is presented in Figure 9.

*Figure 9 Scenario 2 Customer impact due to forgone self-consumption*
3.2. Customer demographics and satisfaction metrics

3.2.1. Customer Demographics

The figure below presents the location of the VPP-SA customers across metropolitan Adelaide. The VPP-SA customers are relatively dispersed between postcodes, with exception of the beachside suburbs south of Adelaide city where AGL undertook very targeted marketing, and which, as a result has approximately 10% of the total number of VPP-SA customers.

Figure 10: Geographic spread of VPP-SA customer sites across metropolitan Adelaide
3.2.2. Customer Satisfaction and Feedback

AGL sent NPS and customer satisfaction surveys to all customers as part of the VPP-SA project. AGL recorded an overall NPS of 46, regarded as an excellent score. There were 333 responses (33% response rate), also an excellent completion rate, reflecting the highly engaged nature of the VPP-SA customers.

Survey responses suggest that customers appreciated the professionalism and commitment of the AGL support personnel and that their experiences were challenged by installation and process delays.

![Figure 11: Summary of AGL-VPP NPS responses](image)

Taking a more granular view, specific questions asked of customers about their experience reflected a similar trend. AGL asked five customer satisfaction questions, outlined in Table 7 – the NPS scores based on the responses range from 78-84, with the exception of the Information question that recorded a lower score of 24. Customer responses regarding Information were impacted by the delays in receiving information regarding battery upgrades to next generation technology, and the lower score is largely reflective of customer frustration regarding these delays.

<table>
<thead>
<tr>
<th>Customer Feedback Area</th>
<th>Question</th>
<th>Score</th>
</tr>
</thead>
<tbody>
<tr>
<td>Battery Options</td>
<td>How satisfied were you with the battery options made available to you?</td>
<td>79</td>
</tr>
<tr>
<td>Information</td>
<td>After selecting your battery, how satisfied were you with the information you received through the upgrade process?</td>
<td>24</td>
</tr>
<tr>
<td>Site inspection</td>
<td>How satisfied were you with the service provided during the site inspection?</td>
<td>84</td>
</tr>
<tr>
<td>Sales Consultant</td>
<td>How satisfied were you with the service provided by your sales consultant?</td>
<td>78</td>
</tr>
<tr>
<td>Installation</td>
<td>How satisfied were you with the service provided during your installation?</td>
<td>82</td>
</tr>
</tbody>
</table>

Customer Drivers

The VPP concept was communicated to customers through direct marketing communications including emails and direct mail. These communications directed customers to digital channels where they could interact with more detailed content, including an animated explainer video6 and the ability to ask questions in AGL community chat forums. This insight was supported by one to one customer conversations with sales agents who would explain in the project in detail, including how the concept of a VPP works, the battery product and the installation process (usually completed over 2-3 conversations). This information was reinforced by the quote that was provided to interested customers.

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6 An example of a current marketing video explaining the VPP can be found here: [https://www.youtube.com/watch?v=mRhWngSilQw8](https://www.youtube.com/watch?v=mRhWngSilQw8)
Understanding customer motivations to purchase a BESS was a key area of interest for the program. As described in previous knowledge sharing reports, customers with an ‘early adopter’ mindset were well represented amongst the cohort, and this predictably meant an interest in the technology aspects of the program as a priority. There were also a significant number of retirees and near-retirees seeking an investment that would continue to provide savings for the duration of its warranted life, which led to a focus on savings.

Many customers were motivated to provide their feedback on the program to AGL and other participants (or those considering participation) and used AGL’s Community forum for this purpose. Other customers posted about their experiences on personal blogs or other public message boards.

3.3. Suggestions for regulatory change to improve customer experience within a VPP

AGL believe that a competitive market underpinned by customer choice has the greatest potential to realise the benefits of DER for the broader energy market system. As the market for DER products and services matures, ensuring a high quality of customer experience within a VPP will be critical to empowering customers with choice and enabling them to assess the benefits of participating in orchestration.

In our view, participant models that entail a retailer function have greater visibility of customers’ billing arrangements and are better placed to manage system security and customer protections. AGL’s experience of direct interaction with customers is that calculating and communicating the impact to customers from orchestration activity is an essential function. That is, where a single party is responsible for both energy billing and orchestration, there are clearer consumer protections, and a single party responsible for the impact of orchestration on a customer’s bill. The risk of misunderstanding and misalignment in the Market Ancillary Services Provider (MASP) as VPP operator model is significantly increased. The MASP as VPP operator may result in customer costs that are not easily managed, or in some instances, even visible to customers.

AGL is currently developing further technical capabilities to provide more transparent information on orchestration events to our VPP customers through our customer app and MyAccount web portal that will enable our customer to better understand the impact of participating on AGL’s orchestration service on their system and billing arrangements.

As VPP services continue to scale, we would recommend that policymakers consider the need for consistent consumer protections to ensure customers benefit from appropriate visibility with respect to the costs and benefits associated with orchestration services. Indeed, as we recently observed in the context of the AEMC’s review of Consumer Protections in an Evolving Market for both New Energy and Traditional Retailers, consumer protections should be designed towards an outcomes-based model that ensures a consistent customer experience, regardless of the energy service provider.

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9 http://www.geoffperkins.com/technology/power-to-the-people
4. VPP Functionality and Performance

The VPP-SA project was successful in demonstrating, at a commercial scale, the ability for energy storage systems to provide multiple services, including reducing customer bills, managing network peak demand, wholesale market arbitrage and provision of FCAS services.

4.1. Fleet performance profiles

4.1.1. Aggregate State of Charge profile

Aggregated state of charge across the 1,000-battery VPP fleet is presented below in Figure 12, averaged each half-hour by season. Winter has the lower aggregated state of charge, reflecting lower solar PV generation, though even in winter the average state of charge does not fall below ~22%. This may be in part due to the backup reserve levels set by consumers for their own BESS. Summer and spring have similar state of charge profiles, reflecting higher solar PV generation, though there is some divergence in the evening due to higher customer load in summer.

The aggregate state of charge peaks at 5pm NEM-time for each season except summer, in which the peak occurs at 4pm.

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4.1.2. Aggregate Charge and Discharge profiles

The four figures that follow present the average charge and discharge profile per battery of the 1,000-battery VPP fleet, averaged each-hour with each season illustrated with a separate figure. Figure 13 illustrates that in summer, the peak of battery charging typically occurs at approximately 13:00, and that in aggregate, the fleet moves from charging to discharging at approximately 18:00, with the BESS systems effectively stretching that pivot point into the early evening. These observations are based on a fleet with an average battery size of 12.7kWh, broadly representative of current home battery sizes. It worth noting also that these observations don’t exhibit a ‘second solar peak’ at midday that was feared to occur when all batteries were full and site solar would begin exporting to grid.

The figures illustrate the benefits that a battery can bring to reducing both solar exports and peak demand. Table 8 and Table 9 outline the key characteristics of each charge and discharge profile. Across summer the addition of a battery to a household with solar reduces the average maximum solar export from 2.6kW to 2.1kW and reduces the average maximum demand from 1kW to 0.4kW.

These results are based on a flat tariff solar self-consumption mode on each battery. There are two potential options for further improvement, either through (i) a local BESS mode that manages the battery to shape solar export through the peak period (perhaps by flattening it) and to flatten evening peak demand, or (ii) active orchestration of the battery through these two periods to provide the same benefit. The first option is most likely to be the most effective, though this approach is reliant on accurate forecasts of both local solar production and household load being available at the device itself, whereas normal (flat tariff) battery operation doesn’t require any forecasting.
Figure 14 Autumn charge and discharge profile of VPP

Figure 15 Winter charge and discharge profile of VPP

Figure 16 Spring charge and discharge profile of VPP
Table 8 Maximum export of charge and discharge profiles by season

<table>
<thead>
<tr>
<th></th>
<th>Underlying Load</th>
<th>Site Load after PV</th>
<th>Site Load after PV + Battery</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Maximum Export</td>
<td>Time</td>
<td>Maximum Export</td>
</tr>
<tr>
<td>Summer</td>
<td>n/a</td>
<td>n/a</td>
<td>2.60</td>
</tr>
<tr>
<td>Autumn</td>
<td>n/a</td>
<td>n/a</td>
<td>1.75</td>
</tr>
<tr>
<td>Winter</td>
<td>n/a</td>
<td>n/a</td>
<td>1.35</td>
</tr>
<tr>
<td>Spring</td>
<td>n/a</td>
<td>n/a</td>
<td>2.70</td>
</tr>
</tbody>
</table>

Table 9 Maximum demand of charge and discharge profiles by season

<table>
<thead>
<tr>
<th></th>
<th>Underlying Load</th>
<th>Site Load after PV</th>
<th>Site Load after PV + Battery</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Maximum Demand</td>
<td>Time</td>
<td>Maximum Demand</td>
</tr>
<tr>
<td>Summer</td>
<td>1.09</td>
<td>17:00</td>
<td>1.05</td>
</tr>
<tr>
<td>Autumn</td>
<td>0.86</td>
<td>18:00</td>
<td>0.98</td>
</tr>
<tr>
<td>Winter</td>
<td>1.46</td>
<td>19:00</td>
<td>1.62</td>
</tr>
<tr>
<td>Spring</td>
<td>0.79</td>
<td>19:00</td>
<td>0.94</td>
</tr>
</tbody>
</table>

4.2. Solar Utilisation

Apart from any market participation revenues, BESS’ create value for residential customers by allowing them to store excess solar generated during day and use this energy later in the evening. Effective use of a battery depends on high solar utilisation, which is in turn impacted by the nature of solar generation and household load.

The figures below (Figure 17, Figure 18 and Figure 19) outline the solar, household load and battery state of charge for three different customers over a week in mid-April 2020. In the example of the first customer the solar system generates enough energy to fill the battery, at which point solar generation is exported to the grid. The household load is not sufficient to deplete the battery, which results in limited cycling of the battery, demonstrated in the third panel of Figure 17 in which the battery state of charge does not fall below ~70%.
Figure 17 Customer example: Low utilisation of battery due to low household load
In the example of the second customer the solar system does not generate enough energy to fill the battery, driven in part by the household load coincident with this generation. The battery state of charge does not increase above 20%, meaning a significant proportion of household load is met by the grid.

In the example of the third customer the solar system generates enough energy to meet coincident household load and fill the battery. The evening household load is also significant enough to drawdown energy from the battery. This results in the battery effectively cycling on a daily basis, moving between 100% and 30% state of charge.
Figure 19 Customer example: High utilisation of battery due to excess PV generation and appropriate household load

Figure 20 illustrates the utilisation of solar for the VPP-SA Tesla batteries by season, using all available data since March 2018. Solar utilisation to offset load via the battery is broadly consistent across each season at ~7kWh – this consistency is driven by two competing limits that result in similar solar-battery utilisation. In summer, the battery utilisation is limited as the average battery is more often full, given the high levels of solar generation, and in winter the battery utilisation is limited to limited solar generation.
Figure 21 illustrates average daily household load by energy source across the seasons, using the same dataset as outlined above.

4.3. Voltage Observations

4.3.1. Voltage standards

Under the National Electricity Rules, distribution network businesses are required to maintain low voltage network voltages within +/- 10% of the nominal voltage in each jurisdiction (AEMC, 2017). Australian Standards (AS 61000.3.100), which is the standard most widely adopted by DNSPs, specifies a nominal voltage requirement of 230V +10%/-6% (216V – 253V) to be met under steady state conditions. The steady state voltage limits are measured at the point of connection and V1% and V99% limits are used to evaluate compliance based on one weeks’ worth of continuous 10-minute average measurement data.

By design, DNSPs typically operate networks so that for most of the year grid voltages range toward the upper end of the allowable range. There are a number of potential reasons a network may do this, including:

- Networks were historically designed to accommodate only one-way power flows. Voltages are typically set to be higher towards the distribution transformer and decrease along the length of the feeder. Higher voltages at the start of the feeder allow customers connected at the end of the lines to remain within the lower end of the allowable range (i.e. 216V); and
• Transformer tap settings have limited range. Voltage control on the LV network is typically managed by augmenting LV conductors (to limit the voltage drop) or by manually setting the off-load tap changers on distribution transformers at a different position. While modifications to the tap changers of distribution transformers are effective at boosting the voltage for customers located at the end of the feeder, this can create a problem for customers located at the start of the LV network (i.e. close to the distribution transformer) as their voltages can exceed legislated limits.

• Dynamic control of network voltages requires a level of operational visibility at the LV circuit level that may not exist in all network contexts.

The University of New South Wales (UNSW) recently published a paper on voltage management which concluded that network voltages are generally high across all jurisdictions and that increasing levels of solar penetration require solutions to bring voltages back down to a 230V median to create headroom for solar export, in order to facilitate a high penetration of DER.

4.3.2. AGL VPP Voltage Data

AGL’s voltage observations align broadly with those of UNSW. AGL’s first knowledge sharing report confirmed that grid voltage levels across the South Australian grid sat generally at the higher end of the allowable range, regardless of whether customers were exporting solar or not. A more detailed view of voltages, broadly consistent with methodology described in AS 61000.3.100, and broken down by season in 2019/20, is presented below. The charts presented the V99 and V1 for the majority of the fleet (each vertical slice represents the upper and lower bound for a single unit) as well as the upper and lower bound of allowable voltages.

![Figure 22 - Fleet Voltages in Summer (1st January to 7th January 2020)](https://prod-energycouncil.energy.slicedtech.com.au/sites/prod.energycouncil/files/200502%20ESB%20cover%20note%20on%20UNSW%20Voltage%20Report.pdf)
Figure 23 - Fleet Voltages in Spring (1st September to 7th September 2019)

Figure 24 - Fleet Voltages in Autumn (1st March to 7th March 2020)
One can see from the plots that the voltages of the fleet sit at the higher end of the range throughout the year, with even $V_1$ voltages in winter for the bulk of the fleet staying well above the 230V nominal level. In spring when solar generation is high, and household loads are generally low, the $V_{99}$ voltages experienced by the fleet are especially high with approximately 40% of the fleet of Tesla systems seeing voltages in excess of the 253V limit. It is noted that there are a small number of devices that have relatively low $V_{99}$ and $V_1$ readings, with a wide range between them. There is thought to be a specific issue at these sites causing the wide gap between high and low voltages.

4.3.3. VPP-SA Customer Impact of Higher Voltages

Higher voltages both limit the operational power band in which the DER are able to operate, and in some instances, trigger a reactive power response from the inverters, both of which impact customer value.

Volt-VAr Mode

Volt-VAr control provides dynamic reactive power output (absorption or injection) in responses to voltage measurements from the energy storage or solar device. For grid connected systems, the voltage is a reflection of the grid voltage as well as the voltage rise between the inverter and the point of supply (which per the Australian Standard AS4777.2 must be less than 2% of the nominal voltage at the site).

The Volt-VAr curve has a defined dead band (where no reactive power is supplied) and trigger points at which reactive power is either injected or absorbed. An inverter has limited headroom to supply reactive power (governed by the kVA limit of the inverter) without curtailing active power. The supply of active power will be curtailed if the total apparent power (VA) limit of the inverter is exceeded when reactive power is required to be supplied to the network. Where the active power output of an inverter is curtailed due to this mode when it ordinarily would have been discharging for another purpose, the customer value would be impacted. As an example, if the inverter was offsetting a customer’s household load when the mode was activated, then the customer will be forced to draw power for that curtailed proportion of their load from the

\[ \text{https://www.sapowernetworks.com.au/public/download.jsp?id=9561} \] Volt-VAr Curve used by SAPN is found on page 18
grid, rather than from their stored solar. If the customer was participating in a VPP event, then the value that can be accessed in that event will be limited. Importantly, the generation of VArS is required from the inverters in order to help reduce network voltage, providing a *de facto* network service. This is however a service for which customers are not remunerated, and for which the impact to consumer savings is not visible. AGL supports a thorough investigation into the frequency, scale, and impact of real power curtailment as a result of these modes, as well as a review of their effectiveness in helping to manage grid voltage to ensure that the cost of the impact to consumers is valued, and the service to the network verified.

**Volt-Watt Mode**

Volt-Watt control dynamically curtails inverter active power in response to voltage measurements from the inverter. Similar to the Volt-VAr curve, Volt-Watt curves have a defined demand band and operate to curtail output when measured grid voltages exceed a specified point. The Volt-Watt curve will cause an inverter’s real power output to ramp down under conditions of high voltage such that, ideally, the voltage does not reach the upper limit of the allowable range which would require the inverter to disconnect. Again, the curtailing of real power output of the inverter has a real impact on customer value, and like Volt-VAr modes, that impact is typically invisible to customers as most inverter monitoring systems do not meaningfully report on their real power curtailment and the resulting impact to a customer’s solar production (in the case of a solar PV system), or load offset (in the case of an energy storage system).

Under the current version of the governing Australian Standard AS4777, the activation of both Volt-VAr and Volt-Watt modes is left to the local DNSP to specify in their inverter connection standard. At the time of writing, the latest version of AS4777 was out for public comment and was proposing that the modes be mandatory for all new grid connected residential inverters. Importantly, no analysis of the impact on customer value (or indeed the practical effectiveness) of those modes was undertaken by either the proponents of the changes to the standard, even though these setting again provide a *de facto* network service without a clear rationale for whether this is an effective mechanism to manage voltage on distribution networks, or the impacts to customer value is appropriate.

### 4.3.4. Voltage Management Solutions

Networks typically remedy voltage constraints by prioritising according to the number of customers in each cluster and the duration for which the voltage excursions are occurring, then utilise the least-cost augmentation solution to remedy these situations which typically include:

- Phase balancing
- Adjusting the tap position on the distribution substation to a lower setting to create headroom for voltage rise from the export of solar PV, provided the transformers still have lower tap settings available.
- Augmentation – older LV substations can be upgraded with newer ones which will have a greater range of tap settings available allowing better voltage control by optimally setting the tap setting of the distribution transformer to accommodate the wide spread in voltages that can be experienced between summer peak (low voltages) and spring/autumn (high voltages).

In some scenarios, it is thought that VPPs could be used in place of traditional network solutions provided the batteries are installed in a part of the network where they could provide a meaningful impact and there is

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a suitable concentration of batteries installed with the right technical capability. Batteries can provide voltage management services in the following way:

- Charging from the grid – In a high DER penetration scenario, voltage management and reverse power flows could present challenges to the operation of networks which charging DER from grid can simultaneously help solve. Charging batteries from the grid can add load to the network during peak solar export times (thereby reducing voltages) as well as absorb solar exports from other passive (uncontrolled) solar customers to limit the risk of reverse power flows through the distribution transformer.

- Reactive Power Modes – Reactive power modes can, in the correct context, be used for providing a voltage management service. There are three ways in which reactive power modes can be provided through modern inverters:
  - Direct reactive power dispatch: involves absorbing or dispatching a fixed amount of reactive power from each inverter
  - Power factor settings: the inverter will vary the reactive power output to ensure that the target power factor is met when the inverter power output changes.
  - Volt-VAr modes: the inverter will dynamically vary reactive power (absorption or injection) from the solar or battery inverter in response to measured voltages at the customers inverter

### 4.4. Key VPP Use Cases

#### 4.4.1. Network Services

Historically, networks have built new electricity infrastructure to meet the increasing demand for electricity by customers. This may involve augmentation of the network by installing new transformers and building new powerlines which are considered traditional ‘network solutions’.

The establishment of these assets is capital intensive and so to the augmentation, upgrade, or replacement, it may be more economical in some cases to implement a ‘non-network solution’. These non-network solutions may be temporary or permanent, but serve to defer or replace the building of the traditional network assets. Orchestration of DER can provide a range of services to distribution network businesses including thermal and voltage management services to accommodate localised demand constraints, higher penetrations of DER, or to assist in manage quality of supply compliance. Further, in its report seeking to value the services that a coordinated fleet of DER could provide, Oakley Greenwood has identified the following cost drivers for networks which could be used to provide a network service via DER:

- Direct connection cost
- Extension/augmentation/replacement of existing shared network
- Cost of managing voltages within required levels in a shared network
- Managing bushfire risk

AGL has been working collaboratively with DNSP’s to understand the practical implementation of network service use cases and explore how network services could be stacked and co-optimised to operate with other value pools into the future. It is noted however that the market for distribution network services

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provided by residential, behind the meter DER remains nascent, with most examples of such services taking the form of demonstrations and trials\(^\text{15}\).

In order to reliably deliver a network service from a fleet of behind the meter DER, the DER obviously needs to both be installed in the service region of the network, and a minimum ‘critical mass’ of batteries be deployed. As this section of the report demonstrates, the ‘critical mass’ varies based on the network type and topology, the service to be provided, and the location of the DER.

The bulk of AGL’s SA-VPP batteries are geographically dispersed across the SA Power Networks (SAPN) distribution region in the Adelaide metropolitan region. However, as part of the VPP-SA project, AGL undertook a targeted deployment of solar and energy storage systems on substations/circuits within SAPN’s network that were identified as sites that could be subject to thermal and voltage constraints in the future, or had an existing metering capability that would allow the impact of the network service to be monitored. In the final operational phase of the project, AGL sold and deployed approximately 130 batteries in 20 distribution network zones (consisting of both high voltage and low voltage feeders) identified by SAPN with total customer connection points ranging between 27 and 2,570.

## Table 10 AGL VPP SA Energy Storage Installations in Constrained Network Areas

<table>
<thead>
<tr>
<th>Network Area</th>
<th>Customers Connected</th>
<th>Type of Constraint</th>
<th>Solar Edge</th>
<th>Tesla</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Network Area 1</td>
<td>70</td>
<td>Voltage</td>
<td>2</td>
<td>0</td>
<td>2</td>
</tr>
<tr>
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<td>Thermal</td>
<td>1</td>
<td>0</td>
<td>1</td>
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<tr>
<td>Network Area 3</td>
<td>62</td>
<td>Voltage</td>
<td>2</td>
<td>1</td>
<td>3</td>
</tr>
<tr>
<td>Network Area 4</td>
<td>55</td>
<td>Voltage</td>
<td>1</td>
<td>0</td>
<td>1</td>
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<td>Voltage</td>
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<td>0</td>
<td>2</td>
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<td>Network Area 6</td>
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<td>2</td>
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<tr>
<td>Network Area 7</td>
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<td>Voltage</td>
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<td>0</td>
<td>1</td>
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<td>Network Area 8</td>
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<td>0</td>
<td>1</td>
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<td>Network Area 9</td>
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<td>Thermal</td>
<td>1</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>Network Area 10</td>
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<td>Thermal</td>
<td>3</td>
<td>0</td>
<td>3</td>
</tr>
<tr>
<td>Network Area 11</td>
<td>1894</td>
<td>Thermal</td>
<td>31</td>
<td>0</td>
<td>31</td>
</tr>
<tr>
<td>Network Area 12</td>
<td>2047</td>
<td>Thermal</td>
<td>30</td>
<td>7</td>
<td>37</td>
</tr>
<tr>
<td>Network Area 13</td>
<td>2570</td>
<td>Thermal</td>
<td>27</td>
<td>3</td>
<td>30</td>
</tr>
<tr>
<td>Network Area 14</td>
<td>38</td>
<td>Voltage</td>
<td>1</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>Network Area 15</td>
<td>93</td>
<td>Voltage</td>
<td>2</td>
<td>1</td>
<td>3</td>
</tr>
<tr>
<td>Network Area 16</td>
<td>77</td>
<td>Voltage</td>
<td>3</td>
<td>1</td>
<td>4</td>
</tr>
<tr>
<td>Network Area 17</td>
<td>82</td>
<td>Thermal</td>
<td>1</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>Network Area 18</td>
<td>87</td>
<td>Voltage</td>
<td>1</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>Network Area 19</td>
<td>62</td>
<td>Voltage</td>
<td>2</td>
<td>0</td>
<td>2</td>
</tr>
<tr>
<td>Network Area 20</td>
<td>90</td>
<td>Voltage</td>
<td>2</td>
<td>0</td>
<td>2</td>
</tr>
</tbody>
</table>

### Network Services Use Cases Trialled

This section of the document sets out the network service use cases that were trialled by AGL for the VPP SA fleet. An overview of the use cases trialled by AGL is provided below:
### Table 11 - VPP SA Project Network Service Use Cases Trialled by AGL

<table>
<thead>
<tr>
<th>Category</th>
<th>Use Case</th>
<th>Network Services Application</th>
</tr>
</thead>
<tbody>
<tr>
<td>Active Power</td>
<td>Peak Demand Management</td>
<td>Demand Management for Thermal Constraints</td>
</tr>
<tr>
<td>Active Power</td>
<td>Charge from Grid</td>
<td>Voltage Management</td>
</tr>
<tr>
<td>Reactive Power</td>
<td>Fixed Reactive Power Dispatch</td>
<td>Voltage Management</td>
</tr>
<tr>
<td>Reactive Power</td>
<td>Power Factor</td>
<td>Voltage Management</td>
</tr>
</tbody>
</table>

#### Peak Demand management

AGL tested the peak demand management function using the Enbala platform’s Peak Demand Management (PDM) feature. AGL created a ‘dummy’ 1MVA transformer load profile\(^\text{16}\) reflective of a high temperature day and set the peak load to be 4%\(^\text{17}\) higher than 1MVA nameplate rating of the transformer. AGL set the VPP power threshold to just below 1MW to trigger the VPP platform to bring the net load on the substation back to its nameplate rating using a defined sub-fleet, consisting of 60 energy storage systems (assumed to be collocated on the same feeder).

The event results are shown below in Figure 26:

![Figure 26 Ten-minute average demand in Enbala's Peak Demand Management Mode overlaid on AGL's dummy transformer load profile](image)

The test results show that a fleet of behind the meter energy storage systems are indeed able to manage aggregate demand in a specific network location, though it’s worth considering that the devices themselves were dedicated to the provision of that service not just during the peak demand period, but in the lead up to the event as well (as they were required to retain sufficient charge to see the event through). This means that they were not able to participate in other value generating functions at the same time, such as participation in frequency markets, or dispatching against a wholesale price trigger. Greater penetration of


orchestratable storage systems to provide these services, will bring greater fleet diversity that should allow for less impact on the operation of individual devices, with little or no impact to the firmness of the service.

Voltage Management – Charge from grid and direct reactive power dispatch

AGL performed a series of real and reactive power notch tests to observe and isolate the specific impact of real and reactive power on local site voltages. The objective of the notch tests was to understand the magnitude of voltage change that could be achieved via a maximum 5kW real power and 5kVAr reactive power (using the direct reactive power mode) charge and discharge across the full VPP SA fleet. The test methodology follows:

- The test time of ~3:30am was chosen as a time when general site loads are low and solar production is zero. Importantly also, overnight loads tend not to vary significantly, noting that volatility in load affects voltage.
- Direct reactive power mode was used for the 5 kVAr reactive power dispatch. This is more than double the maximum VAr dispatch that could be expected under Volt-VAr modes, in order to maximise the observable voltage impacts, noting that impacts on local voltages from VAr dispatches are relatively modest.
- Each energy storage system was sequenced to charge from grid at 5kW, then discharge at 5kW, followed by 5kVAr charge and discharge.
- The notch test sequence was repeated several times to isolate the impacts of the orchestration over and above the natural variability of customer loads. The results presented are an average of the repeated notch test sequence used by AGL.
- Each power step was performed for exactly 1 minute, where the measured data used for calculation was the numerical average of readings across the 1 minute period
- AGL calculated the inferred resistance (R) and reactance (X) of the network at the connection point of each VPP SA asset using notch test results and the following formula:

Real component of voltage is \( \Delta V_r = R \frac{\Delta P}{V} \) where:
- \( R \) is the Thevenin resistance seen at the connection point
- \( \Delta P \) is the magnitude of real power change
- \( V \) is the line voltage (measured)
- \( \Delta V_p \) is the change in voltage observed due to the real power change

Reactive component of voltage is \( \Delta V_q = X \frac{\Delta Q}{V} \) where:
- \( X \) is the Thevenin reactance seen at the connection point
- \( \Delta Q \) is the magnitude of reactive power change
- \( V \) is the line voltage (measured)
- \( \Delta V_q \) is the change in voltage observed due to the reactive power change

The R and X values calculated as part of the notch tests were used to infer relative impedance and \( X/R \) ratios (which is a measure of network construction and strength of the network) at each VPP SA customer energy storage system site. Theory suggests that the sensitivity of voltage change from energy storage system active and reactive power flows is highly dependent on the fundamental electrical impedance characteristics \( Z = R + jX \) of the network that the inverter is connected to, with high X value indicating the network has a higher reactance and therefore will be more sensitive to voltage change from reactive power flows and high R value indicating the network has a higher resistance and therefore will be more sensitive to
voltage change from real power flows. Voltage sensitivity will be a function of the impedance characteristics at the customer’s site. AGL applied the following notch test sequence to 764 assets in fleet:

![Figure 27 - 5kW Active and 5kVAr reactive power notch test sequence](https://electrical.eng.unimelb.edu.au/power-energy/projects/pv-rich-distribution-networks)

![Figure 28 - Distribution of voltage change by inferred impedance across the VPP SA fleet as part of the reactive power notch tests (averaged over two notch test cycles).](https://electrical.eng.unimelb.edu.au/power-energy/projects/pv-rich-distribution-networks)

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Figure 28 and Figure 29 show the results of the reactive and real power notch tests, respectively. Clearly however, the response of network voltages to changes in real or reactive power is not uniform. Higher impedance networks are more sensitive to voltage change from changes in active and reactive power flows and are potentially better suited to the use of inverters for voltage management services. Important also is the wide range of responses seen across the fleet with some responses to real power changes as much as seven times those of the less sensitive sites. For reactive power dispatches, the range spanned a factor of more than five. This is particularly relevant in the discussion of power quality response modes, as it is evidence that the impact these modes have on consumer value may not be matched by a commensurate impact on network power quality. That is, when Volt-VAr and Volt-Watt modes are mandated consistently across all grid-connected inverter devices, there will be a large proportion of systems that are not contributing meaningfully to the actual improvement of network voltages due to the characteristics of the network they are on or their position within the network.

It is also important to note that AGL could not establish just how the voltage changes at individual sites would contribute to the overall voltage change across an LV circuit. That is, the change in voltage at a distribution transformer is not simply the arithmetic sum of individual site voltage changes due to these tests. The actual change visible at the distribution transformer would be function of, for example, the voltage change at the individual sites, the load and generation dynamics on the circuit, the position of the DER sites along the circuit, etc. This is important, as it requires the development of bespoke solutions for voltage management for each circuit, and indeed, calls into question the mandating of uniform power quality response modes across diverse networks.

Figure 28 also shows that charging from grid can reduce network voltages. As with peak demand management, the number and size of the batteries used to charge from grid will vary based on location, with larger fleets providing greater diversity and smaller impact to each individual unit providing the service.

**Voltage management – Power factor mode**

AGL notched the power factor (PF) between 0.8 and unity (at one minute intervals) under solar self-consumption mode (SSCM) as well as a full 5kW charge and discharge cycles to understand the voltage impact that could be achieved by enabling power factor mode across our fleet of assets.

AGL applied the following notch test sequence to 764 assets from the VPP-SA fleet:
Figure 30 - Power factor notch test sequence

Figure 31 - Box plot of fleet voltage change with PF notched from 0.8 to unity for solar self-consumption (SSCM) mode and 5kW charge and discharge cycles.

Figure 31 shows box plots of the range of impact on voltages when inverter power factor is set under SSCM mode as well as the maximum impact achieved by PF mode across full 5kW charge and discharge cycles. When setting the power factor of an inverter, the actual reactive power delivered is a function of the charging and discharging cycles of the inverter, and so unsurprisingly, the voltage response from the fleet under solar self-consumption operation is varied and spans a wide range. While this response could become predictable across a large fleet with sophisticated forecasting capability, it adds a layer of complexity to the use of power factor modes as a voltage management tool. Setting power factor for charge and discharge events compromises the power delivered during those events for other services.

As with other reactive power modes, power factor, will have limited impact to network voltages on more inductive networks and will be limited in its effectiveness as a voltage management tool in practice. The targeted use of direct reactive power, Volt-VAr, Volt-Watt and charge from grid modes on selected sites are likely to be more effective tools for voltage management in practice.
LV Substation Impact Measurement

AGL sought to leverage SAPN’s existing monitoring to see whether an observable impact on substation demand and voltages could be seen through orchestration of the BESS fleet. AGL selected the LV substation which had the highest concentration of BESS systems (3 BESS on a LV circuit with 77 connections), though it was not known how the 3 BESS assets were distributed across the three phases of the LV network.

AGL ran three notch tests, each lasting 10 minutes (selected to line up with the maximum data granularity of the SAPN meters) where each battery under control was notched between 5kW and 0kW. The time of the test was 3:30am to 4:30am, chosen to maximise the network impact of energy storage assets dispatching as loads were expected to be lowest in this period with no interference from solar.

The load on the substation during the test period was 57.3 kW, which averages to approximately 740W/customer. Through controlling 3 energy storage assets, AGL was able to dispatch 15kW, likely distributed across multiple phases. The ratio of real/reactive power to assumed overall load on the LV circuit was 0.26.

Metering at the transformer did pick up a change in demand, however could only pick up a very small 0.5V change in voltage on some of the phases. Clearly the penetration of BESS systems across the three phases has to be higher for a more meaningful impact. It is also noted that phase mapping is historically not well documented at the LV circuit level and this is likely to be increasingly important to understand which systems are on which phase so the impact of energy storage orchestration can be measured by networks on a phase by phase basis.

4.4.2. Contingency FCAS

AGL has begun to demonstrate the potential for virtual power plants to provide contingency Frequency Control Ancillary Services (FCAS) through enrolment in the Virtual Power Plant Demonstrations, an innovation trial led by Australian Energy Market Operator (AEMO)\(^{19}\) (AEMO), in collaboration with the Australian Renewable Energy Agency (ARENA) aimed at understanding how VPPs can integrate into the future energy landscape.

FCAS are secondary services to the National Energy Market and consist of 8 market services for Frequency Control. Frequency control markets are used to support balancing the physical supply and demand in the NEM, to ensure the efficient allocation of generation resources.

There are two distinct types of FCAS services:

- FCAS Regulation services are for making small adjustments to supply and demand when the NEM frequency is inside the normal range. These are normal, expected levels of adjustments required to account for the normal variations of load, and the normal variations of generators not exactly meeting their energy targets set from AEMO. There are two markets for FCAS Regulation Services – Regulation Raise and Regulation Lower.
- FCAS Contingency services are for when there is a large system contingency event, for example a large generation plant or transmission line trips and disconnects, which causes a large instantaneous mismatch in supply and demand in the NEM. This mismatch will be too large for the FCAS Regulation service to control, and so FCAS Contingency services consist of generation and

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load enabled to respond in these situations. There are six distinct FCAS Contingency services – three Raise services (increasing generation/reducing load) and three Lower services (decreasing generation/adding load).

In order to participate alongside traditional generation, AEMO developed an amendment to the Distributed Energy Resource addition to the Market Ancillary Service Specification, which relaxed the metering requirements for verifying the delivery of FCAS Contingency services from 50ms reporting to 1s, allowing use of the DER device metering capability, and avoiding the need for a high-speed meter alongside each BESS installation.

Tesla Powerwall 2 batteries are delivering FCAS contingency through the setting of a configurable frequency-Watt droop curve, that has been configured to deliver a linear ramp of increase or decrease in power based on how far the frequency is outside of the normal range.

**Availability**

AGL is required to bid the FCAS availability of the fleet to AEMO with very high levels of confidence based on the real time availability of the fleet. For the AGL VPP-SA, the battery systems are primarily performing their regular solar self-consumption mode day to day, storing excess solar energy during the day, and discharging to offset load in the evening. FCAS Contingency availability is the power capacity available over and above the normal battery cycling, and as such, the availability of the fleet needs to be calculated in near real time, and consider customer load, solar power, site export limits and battery state of charge.

**Baselining**

As the FCAS availability is the additional power over and above the normal BESS daily cycle, the method for baselining that underlying operation is critical to measuring the actual response of the device. There are two main approaches for baselining:

1. Using the normal solar self-consumption profile as a baseline (i.e. what the battery would ordinarily be doing if it were in its normal mode) and providing a response over and above that profile
2. Using the position of the BESS at the start of the event as a baseline and then respond purely to the frequency deviations according to the frequency-Watt droop curve, and ignore any solar and load variations that occur during the event.

Both approaches are valid, noting that large scale generators do not consider any variations in underlying solar or demand changes when they respond to contingency frequency events, supporting in part the latter method. AGL’s approach was however to use the solar self-consumption baseline.

**Voltage Impacts**

High voltage levels observed across the fleet cause power quality response modes (Volt-VAr and Volt-Watt) to be invoked more frequently, limiting the ability of the VPP fleet to be operated in FCAS mode.

Fleet voltages average around 245V median (ref. Figure 22 through Figure 25). Once a large dispatch begins, voltages can be raised at each site above 250V, which is beginning to enter the range were voltage response modes will begin to meaningfully curtail real power output, and curtail the FCAS response of the device. This situation leads to a clear conflict between the two modes and the services that they are providing (with only the FCAS service being remunerated). Further, as site voltages can be noisy and will fluctuate at a sub-second frequency, it can be difficult to accurately determine the impact of site voltage and the power quality response modes on the availability of the fleet. For sites that are experiencing high voltages at the start of an event, and where a contingency event triggers an inverter discharge, the site voltage could rise to over 258V, causing the BESS system to disconnect entirely and not be able to contribute to FCAS contingency events.
**Policy and regulation considerations**

Given that FCAS contingency services are intended to support the ongoing security of the grid in circumstances entailing large contingency events, AGL would encourage further assessment of the impact of the application of network regulations that could otherwise limit the provision of these services. AGL would recommend an independent assessment of:

- Whether Volt-VAr and Volt-Watt modes should apply in circumstances where a fleet is providing FCAS contingency services, balancing the benefits of power quality response modes against the benefits associated with the provision of FCAS services in supporting the grid in times of imbalance;
- Whether distribution networks’ site export limits should be tailored to enable greater provision of FCAS services by excluding FCAS contingency services from the constraint of the export limits

**FCAS Event Example**

Figure 32 shows an example response to an FCAS event on the 23 August 2020. When the frequency dipped below 49.7Hz and out of the normal operating band, the VPP provided an extra 1.9MW into the grid to help arrest the frequency dip, and did so very accurately and according to the defined proportional droop curve that was set.

![Figure 32 FCAS event example (23 August 2020)](image)

**Customer Impact**

While large contingency events triggering large power responses from BESS systems are infrequent, there can be several small events each day where the frequency leaves the normal range for only a matter of seconds. Batteries in a VPP will respond to even these small events, and while individually small, their impact in aggregate over a long period of time can be meaningful and should be tracked to assess impact to customer value.

As an indication of the relative value and impact of a BESS system enrolled in contingency FCAS markets, analysis was undertaken to determine the potential revenue from VPP operations and the average financial impact to customers of batteries operating in FCAS mode. This analysis covered a 3-month period over June, July, and August 2020, outlined in Table 12. It is estimated that over this period the average impact to the customer would have been $0.18, with the potential for over $20 of FCAS revenue which would be shared with the customer.
AGL has undertaken fleet wide studies with the VPP-SA fleet and determined that even with multiple large contingency events in a row (an extremely unlikely scenario), there will be no more ~$0.50 impact per customer in a single day.

Table 12 SA raise/lower impact to customer and revenue from 2020-06-01 to 2020-08-31 (based on 1s frequency data measured by AGL VPP-SA batteries)

<table>
<thead>
<tr>
<th>Service</th>
<th>Total time spent out of bounds</th>
<th>Average excursion</th>
<th>Max excursion</th>
<th>Total frequency response</th>
<th>Impact to customer</th>
<th>AGL FCAS revenue</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(minutes)²⁰</td>
<td>(Hz)²¹</td>
<td>(Hz)</td>
<td>(kWh/battery)²²</td>
<td>($/battery)²³</td>
<td>($/battery)²⁴</td>
</tr>
<tr>
<td>Raise</td>
<td>263</td>
<td>0.01</td>
<td>0.27</td>
<td>0.86</td>
<td>$0.17</td>
<td>$13.12</td>
</tr>
<tr>
<td>Lower</td>
<td>24</td>
<td>0</td>
<td>0.04</td>
<td>0.03</td>
<td>$0.01</td>
<td>$10.79</td>
</tr>
<tr>
<td>Total</td>
<td>287</td>
<td>0.89</td>
<td></td>
<td></td>
<td>$0.18</td>
<td>$23.91</td>
</tr>
</tbody>
</table>

Regulatory Change to support the use of VPP’s in FCAS markets

In order to support the use of VPPs for FCAS and synthetic inertia services into the future, we recommend regulatory reform in the following areas:

- Network regulation in the application of power quality response modes to FCAS and the regulation of site export limits during FCAS contingency events; and
- Uniform technical specifications governing the provision of these services, through the revision of AEMO’s broader Market Ancillary Services Specification (MASS).

As elaborated above, given that FCAS is intended to support the ongoing security of the grid in circumstances entailing large contingency events, we encourage an independent review on the extent to which network regulations (in regulated power quality response modes and export limits) may impact upon these services. Policymakers should consider varying network regulations to enhance the operational ability of BESS’ to provide FCAS.

In order to integrate VPP FCAS services into regular market operations, the Demonstrations should ultimately inform the revision of AEMO’s broader MASS. Although it was AEMO’s intention to test a new approach to measurement and monitoring of contingency FCAS to promote more competition for these services²⁵, we note that the technical specifications have proven challenging for a range of DER hardware providers to develop for a limited term trial with no guarantee of application beyond the trial.

In developing fit-for-purpose technical specifications for regular market operations, we would encourage AEMO to consider:

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²⁰ Where bounds are 50.15Hz for lower services and 49.85Hz for raise services
²¹ Where the excursion is measured relative to the bounds
²² Assumes an ideal battery that always has capacity to respond to every frequency excursion at 0.7% droop
²³ Assumes $0.30 consumption tariff and $0.10 feed in tariff
²⁴ Actual AGL revenue from all contingency services
• The need to facilitate market integration whilst also supporting continued innovation in the performance of these services. Given that the competitive market for the performance of these services is still in its infancy, regulating the capability at this time may stifle further innovation. Rather, the standardisation of protocols should focus on interconnection between the vendor, AEMO, and network systems whilst leaving scope for the development of novel performance capabilities.

• The need to establish a common open technical standard framework for the provision of these services to facilitate open access for a range of participants. In our experience with the development of other technical standards we have observed risks in locking operations into one technical compliance pathway. By way of example, the AS/NZS 4755 demand response framework for electrical products in Australia currently includes the requirement to provide a physical interface on AS/NZS 4755.3-compliant electrical products, so that products can receive operational instructions from an external 4755.1-compliant Demand Response Enabling Device (DRED). The DRED control methodology has resulted in many practical issues in our operations. AEMO should seek to mitigate the risk of similar technology lock-in occurring in the context of FCAS service provision.

4.4.3. Wholesale Energy Market

One standard use case for a VPP is discharging the fleet when the energy market spot prices are high, on behalf of the Financially Responsible Market Participant (FRMP) which is responsible for the load or generation at that metering point in the wholesale energy market. In such high price scenarios, there is typically a tight balance in the supply and demand of energy. VPPs dispatching additional power serves to first offset the underlying site load, and then add additional supply through export to the grid.

It is anticipated that in the future VPPs will be of sufficient scale that they will be required to be both visible to the market and participate in the bid-dispatch process managed by AEMO. Currently however, VPPs can be operated as a behind the meter load, whereby they are operated as required by the aggregator relatively independent of AEMO. As part of the AEMO VPP Demonstrations program, VPPs are required to submit forecast and actual of the operational data of the VPP fleet to support AEMO in understanding how VPPs currently behave in the energy system.

Analysis below illustrates the performance of the VPP operation over a series of hot and volatile market days in South Australia in January 2020. The analysis demonstrates how VPPs can be effective at supporting the grid when there is a tightening energy supply-demand balance.

Figure 33 illustrates solar generation and underlying household load of a subset of the VPP-SA fleet. On 30 January there was a peak load of 2.5MW, which was more than double the peak load of only two days earlier of 1.1MW. These subsequent days of heat draw down on battery state of charge, meaning without intervention to charge the batteries from the grid, there may not be a fully available fleet if there are high energy market spot prices. Additionally, to achieve net export of the VPP into the grid, the battery inverters first need to supply the underlying higher loads. This means that there is potentially both a reduction in power capacity for net export, and energy capacity available from the VPP in times of most need, without effective forecasting and preparation.

Figure 33 VPP-SA solar and customer load for select days in January 2020

Figure 34 VPP-SA wholesale dispatch example

Figure 34 illustrates an example wholesale dispatch event. On the 30 January, a subset of the VPP-SA fleet was dispatched during a period of sustained high wholesale energy prices. Energy prices exceeded $300/MWh for six consecutive 30 minute trading intervals – from period ending 16:30 to 19:00 NEM time. The VPP was dispatched for a total of one hour, from 17:00 to 18:00, and was performing solar self consumption through the remainder of the high prices.
Figure 35 provides further detail on the timing of the discharge event. This dispatch included approximately 750 sites with Tesla Powerwall 2 BESS. The actual number of units that participated was a function of both the availability of those systems at the time, the VPP software platform used to enable the dispatch and how it prioritised individual units for participation.

The fleet was dispatched through two of the early high price 30 mins trading intervals, ending at 17:30 and 18:00. During this discharge event energy prices were at $2,093/MWh and $4981/MWh across these two periods. In the subsequent intervals, when the VPP returned to solar self consumption, the energy price moved higher to $11,200/MWh and then to $12,217/MWh. This outcome wasn’t predicted by the predispatch price forecasts. It can be seen that even though the VPP wasn’t intentionally dispatching, there was still substantial battery power contribution to the grid, covering the site loads and reducing the underlying load on the grid during this time. The discrepancy between the total energy dispatched over the 2.5 hour period (3.1 MWh) compared to the net site export over the same period (0.5 MWh), demonstrates this difference clearly.

Table 13 summarises the average power and financial flows for that event, where VPP site power is represented as a positive for import to the sites in aggregate, and negative for export to the grid. When there is site import when wholesale market spot prices are positive, this is energy that must be supplied, or bought...
The billing impacts to individual customers as a result of this dispatch is relatively complex, and is best described by the discussion of customer billing impacts in Section 3.1.2 which discusses some of the complexity in assessing that impact. At an aggregate level, while it’s tempting to calculate the total site export over the time attributable to battery discharge across the fleet and use this as a measure of customer losses, it’s not a meaningful estimate for a number of reasons:

- The mechanism for remunerating a customer for participation in the VPP will form part of this calculation
- The impact of the event is assessed against a baseline BESS performance that considers what the system would have been doing, if not for the event. For simple battery control algorithms optimised for a flat tariff this is straightforward, but for more sophisticated BESS solar self-consumption algorithms, this calculation is non-trivial
- The aggregate powerflow for the fleet is often not a an accurate reflection of the position of individual systems that make up the fleet, and there is always a relatively wide range of variability. As an example, a fleet with 50% of systems discharging at 5kW and the other 50% charging at 5 kW will appear to be sitting idle, in aggregate
- In AGL’s VPP, customers are free to choose the underlying energy tariff that suits them best, and the financial impact of an event is a function of this tariff which is not uniform across the fleet

As a result, it’s clear that customer impacts of orchestration events is a complex calculation that needs to be performed at unit level rather than at a fleet level. This example is also intended to highlight the complex nature of the operations of the VPP, and the inherent complexity in managing resources that are primarily serving customer loads, and also seeking to participate in multiple markets. Accurate production, load and price forecasting, as well as fleet monitoring and control are required to successfully operate VPPs through days of complex activity in the market. Further, accounting for the customer impacts of orchestration is critical for customer visibility, and requires a sophisticated counter-factual method, and it’s own monitoring.
5. Stakeholder and Network Engagement

5.1. Stakeholder Reference Group review

AGL created a Stakeholder Reference Group (SRG) at the start of the project both to share insights with, and seek feedback from key industry stakeholders through the course of the development and deployment phase of the program. The members of the initial Stakeholder Reference Group (SRG) and their respective organisations for this project were:

<table>
<thead>
<tr>
<th>Organisation</th>
</tr>
</thead>
<tbody>
<tr>
<td>AGL (Chair)</td>
</tr>
<tr>
<td>AGL project representatives</td>
</tr>
<tr>
<td>ARENA</td>
</tr>
<tr>
<td>SAPN</td>
</tr>
<tr>
<td>ElectraNet</td>
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<tr>
<td>AEMO</td>
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<tr>
<td>AER</td>
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<td>AEMC</td>
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<tr>
<td>SA Department of State Development</td>
</tr>
<tr>
<td>SACOSS</td>
</tr>
<tr>
<td>Uniting Communities</td>
</tr>
<tr>
<td>AECOM (observer)</td>
</tr>
<tr>
<td>Energy Consumers Australia</td>
</tr>
</tbody>
</table>

The membership of the group largely remained the same, though the representatives from each organisation changed as the project progressed. The terms of reference, meeting minutes, and key insights from previous SRG meetings were published in previous knowledge sharing reports.

The SRG meetings were paused at the same time that AGL paused installations in late 2017. In mid-2018, a meeting was held to update the group on the progress with the relaunched installation program, and at the time a number of new working groups had formed seeking to explore many of the same areas that the VPP-SA program was focussed on – the Distributed Energy Integration Program group and SAPN had formed their own Distributed Energy Integration Working Group, are two key examples. AGL was requested by ARENA to temporarily pause the SRG meetings to make sure that content discussed through the various groups was appropriately targeted. AGL has since decided to inform these separate working groups and consultations with the insights and learnings from the VPP-SA program, rather than continue a project-specific SRG for this program.

5.2. Specific network location targeting

As detailed more extensively in previous knowledge sharing reports, AGL has undertaken ‘hyper-local’ targeted sales twice within the VPP-SA project. The results of the first campaign are detailed in AGL’s Milestone 2 Knowledge Sharing Report. This campaign had only limited success but demonstrated the factors that would contribute to the success of such a campaign, with upfront cost of the battery being the primary issue.
Acknowledging that the upfront cost of the battery was the primary determinant in developing sales leads that could convert to a sale, a successful local marketing campaign would need to consider a compelling price point as a prerequisite for a successful sales campaign. Through a very small trial within two low voltage feeder zones in late 2018 AGL, offered eight homes batteries at a sub-$1,000 (incl. GST) price point, and found that take-up rates were significantly higher than in the previous targeted marketing campaign, and set a similar price point for the second major targeted sales campaign in the beachside suburbs south of Adelaide identified by SAPN as being suitable locations for the testing of VPP network services.

SAPN has provided information relating to a number of individual LV feeders or zone substations, as detailed in Section 4.4.1. In total, approximately 8,500 NMIs were identified within areas to target, with 100-130 sales (~3% of full market) within that cohort representing a challenging but achievable outcome, noting that a number of factors may rule out eligibility for some customer’s, including:

- Whether they have solar and sufficient household load to be able to accommodate a battery
- Size and age of their existing solar system
- Whether they currently received a premium Feed-in Tariff for grid exports form their existing solar system (which would be lost if they install a battery)
- Whether they own their home and intend to live there for the following 5 years
- Whether they have a suitable location to install the battery
- Whether they are already an AGL customer or are prepared to churn to AGL for the duration of the 5-year trial

A short window was set for development of a marketing campaign and sales operations (late January to mid-April 2019). It was decided that a combination of direct mail (DM), electronic direct mail (eDM), and outbound telemarketing (OTM) would be used to achieve the required sales targeting. As the South Australian Governments Home Battery Scheme had been launched at this stage, AGL was aware of a number of marketing campaigns around subsidised batteries in the Adelaide market, which would likely result in a high probability of customer confusion, or suspicion regarding the veracity of competitive battery offers that may have appeared ‘too good to be true’.

The second targeted campaign was a success with 120 BESS systems sold into the target areas, and which form the bulk of the fleet that was used for many of the tests described in Section 4.4.1.

5.3. Regulatory changes required to unlock network services value

Through our experience in the project, AGL has identified a range of regulatory reforms that could better enable the provision of non-network solutions as a cost-effective alternative to network augmentation.

AGL continues to explore regulatory reform options to better enable the provision of network services from aggregated DER assets, such as VPPs, through the development of a more mature distribution marketplace. As elaborated in the stakeholder engagement section we have been actively involved in a range of policy discussions to progress trials to test new market structures and inform key reforms including with respect to distribution market design (including access and pricing), network planning and operations and technical standards reforms.

While some progress has been made to improve DER integration since the Australian Energy Market Commission (AEMC) undertook its annual Electricity Network Economic Framework Review in 2019, we believe that further work is required to test a market-based framework that:

- Enables DER to bid as scheduled resources for wholesale and ancillary services;

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• Opens the network value pool to the competitive market through enhanced transparency and opportunities for non-network solutions for the benefit of all consumers;

• Provides greater accountability for network constraints management to support improved investment certainty for DER customers; and

• Enables DER owners to be rewarded for services provided by default to resolve issues caused by historical circumstances of distribution network operation.

The potential savings associated with DER providing network services remains substantial. Indeed, as the Energy Networks Australia and CSIRO Electricity Network Transformation Roadmap estimated, potential savings of more than $100 billion could be achieved by 2050 from deferring network investment through efficient use of DER as an alternative. However, further reform is required to realise these benefits.

Although the Open Energy Networks consultation sought to address the potential associated with network value through an assessment of new market roles and responsibilities, Energy Networks Australia’s (ENA) position paper28 fell short of supporting the necessary reforms to enable a more mature distribution market to develop. The paper suggests that there is no strong case to adopt any of the frameworks for distribution markets in the near term, given that the benefits and costs to consumers of a distribution market are highly dependent on DER deployment rates being high. ENA’s conclusion also appears to discount the potential cost to customers of adopting control approaches, with respect to customer’s DER assets, that could be better managed through competitive market incentives.

We also envisage a range of complementary reforms that could be progressed in the short to medium term:

1. Reforming network connection and access arrangements to incentivise networks to support DER participation

AGL has been actively involved in the access and pricing rule change proposals currently before the Australian Energy Market Commission (AEMC), including through membership to the Distributed Energy Integration Program Access and Pricing Reference Group and the AEMC’s Technical Working Group.

AGL in principle supports the proposed changes to provide a clearer mandate to distribution networks to provide export services to customers and to align network incentives to reflect that new remit. We consider these incremental reforms appropriately reflect the need to facilitate new operational modes for distribution networks to ensure that networks effectively facilitate the interaction of DER with the energy market system.

We also support exploring further opportunities for pricing reform, given the absence of any network pricing signals for energy exports. Nevertheless, the question of export pricing entails a complex equity dimension that will need to be carefully assessed, both in terms of customers who do not currently have access to DER and the need to mitigate any impacts to current DER customers with novel pricing arrangements into the future.

As we have observed above, high voltage levels observed in the LV distribution network remain one of the key impediments to aggregators providing a range of services, with the frequent invocation of power quality response modes impacting upon customers’ ability to participate in orchestration programs that could otherwise provide support to the grid as an alternative to costly network

infrastructure. AGL considers that the proposed reforms being progressed through the AEMC may also necessitate broader consideration of the regulatory framework governing voltage management on low voltage (LV) networks including state jurisdictional arrangements and their interaction with the network expenditure regulatory framework.

2. Standardising the valuation of network services in the AER’s network investment assessment framework

As we have observed above, while there is substantial potential to provide cost effective non-network solutions, there is no accepted framework for valuation of thermal and voltage services on the LV network. In our view, this impedes the ability of the contestable market to provide these services for the benefit of the broader energy market system. We consider that standardising the valuation of non-network services would support greater opportunities for the procurement of these services into the future.

AGL does not consider that the AER’s Expenditure Forecast Assessment Guideline is fit for purpose to assess DER integration expenditure as the latest revision was in November 2013 and the EFA Guideline did not contemplate DER integration needs. In particular, the AER’s assessment framework should provide greater transparency to ensure it does not bias network solutions. The AER should come up with incentive schemes and standard methodologies that can be used by all networks to value.

We also consider that the introduction of a ‘net market benefit’ test as a guiding principle for distribution networks’ planning and investment decision-making, as proposed in the access and pricing rule changes currently before the AEMC could act as a complement to the current economic efficiency test to ensure that networks fairly evaluate the benefits of DER in assessing network infrastructure.

3. Transitioning towards dynamic export limits

Our project has provided a range of insights on the interaction of DER with the low voltage distribution network, including on voltage management, that should inform distribution network business’ transition toward dynamic export limits and the nature of regulatory oversight that will be required in that function to ensure fair outcomes and to protect consumer value.

Among a range of insights, we have observed that voltage levels across the grid are generally high, regardless of whether customers are exporting solar. We note that the ESB and AER’s commissioned UNSW report29, also found that high voltages are due to a range of factors, especially historic circumstances of distribution network operation, with implications for compliance and consumer losses. Accordingly, we support network businesses’ approach to engaging with the overvoltage issue and seek to understand a range of potential solutions that support customer value.

AGL in principle supports the transition towards dynamic export limits, provided it enables more transparent management of network constraints and provides DER customers with greater access than would otherwise be possible with fixed limits on the size or export limits of the system. In our view, this will require a greater level of regulatory scrutiny from the Australian Energy Regulator (AER) over distribution networks’ expenditure proposals to ensure network investment facilitates the interaction of DER with the broader energy market system. To ensure consistent customer outcomes, the AER’s assessment of dynamic export operating envelopes will need to be

informed by an established customer export value methodology that appropriately values customer impacts and differentiates between historic circumstances of distribution network operation and issues associated with higher DER penetration.

We also consider that dynamic export limits should not be permitted to enable distribution networks’ mandating the provision of network support services from DER assets, such as power quality response modes, in the absence of a market-based mechanism that incentives customers.

4. Reducing the regulatory investment test for distribution (RIT-D) threshold to better support non-network solutions.

The RIT-D threshold (i.e. threshold whereby the network is required to go to market to invite responses from non-network solution providers) is currently set at $6M. This threshold is set too high as typically augmentation projects that exceed this threshold require many MW/MWh of controllable storage in a concentrated area to defer the network solution making critical mass for a single aggregator very difficult to achieve. AGL supports the rule change proposal taken forward by the Australian Energy Council to reduce the RIT-D threshold to $1m.

5. Improving network visibility on the low voltage distribution network to facilitate DER participation.

Part of the challenge of providing competitive non-network solutions is accessing relevant information on available opportunities in particular LV networks. In the context of the VPP SA trial, SAPN provided AGL with useful LV network constraint data upon request to assess the suitability of VPP's to provide non-network solutions on their network. The kind of information that AGL relied upon in the trial is not generally available to the market.

To expand the potential for the market to provide non-network solutions at the LV network level, regulators and policymakers should consider ways to mainstream the provision of relevant constraint and value information to support competitive market participation. Smart meters have given networks visibility of the Low Voltage (LV) Distribution Network. The LV network is the most dynamic part of the network and is where constraints are likely to emerge in the future due to the adoption of solar, batteries and electric vehicles by residential customers. Most networks today however do not publish constraints on the LV Distribution Network as part of their Distribution Annual Planning Reports. The power and energy required to defer augmentation as well as the annual deferment value that can be paid to an aggregator for services within a geographic area need to be transparent and made available to the market.

6. Technical standards should serve as an enabler of the market by promoting open access and interoperability.

AGL has observed that technical standards reform is increasing focused on establishing a *de facto* voltage management service by requiring new solar and energy storage system customers to have Volt-VAr and Volt-Watt modes active. In the absence of appropriate voltage management by individual distribution networks regulated by state regulators, there is a substantial risk that customers assets would be required to provide power quality response modes for the vast majority of the time. This impacts the ability of DER assets to provide network support services where consumers are remunerated for the use of their asset. AGL believes a market-based solution would provide better outcomes, whereby consumers can proactively decide to self-consume or, if appropriately rewarded, offer their DERs to stabilise the network system or provide other energy system services.

In the longer term, widespread, blanket application of Volt-VAr and Volt-Watt curves as part of Australian standards and the connection process is not an efficient approach that in many cases will unduly impact customer and market value with minimal network benefit. Volt-VAr and Volt-Watt
modes could be optimized for each solar and energy storage asset to match the electrical characteristics of the network via the provision of a network service.
6. VPP Commercial Model

6.1. Achievable Value

In this section, estimates are provided of the realistic, retrospective maximum achievable quantum of each value stream accessible by a VPP. Each VPP value stream is assessed in isolation, and the costs or impacts to other value streams are not subtracted from each of the value estimates. For example, the maximum achievable FCAS value does not take into account any customer billing impacts of the participation of their system in FCAS, nor the costs associated with customer recruitment, sharing of orchestration benefits with customers, or operational costs associated with access to orchestration software platforms.

It is also important to note that the revenue estimates are a function of the individual trading strategy of the VPP operator. Using wholesale energy value as an example, a BES system that is programmed to dispatch at a $5,000/MWh spot price trigger is expected to access less wholesale revenue than a battery that has a lower wholesale price trigger, but will also have a less significant impact on the customers solar self-consumption value. In this sense, it’s not possible to estimate the absolute value of each value pool (noting also that it’s a function of the generation of the associated solar systems in the fleet and the underlying customer load), but these estimates provide a useful guide of the approximate values.

6.1.1. Customer

The achievable customer value is closely linked to both the customer tariff and the tariff that the BESS system is optimising its performance against. These factors and the observed customer payback metrics through the course of the trial, are described in detail in Section 3.1.1.

6.1.2. FCAS

Assessing the maximum achievable FCAS revenue for a fleet of batteries is a complex proposition that needs to consider both the underlying control algorithm for the BESS systems that will determine (along with the underlying load and solar generation) the availability of the fleet.

As an illustration of the potential value, AGL has undertaken an analysis of the availability of the VPP-SA fleet for the entire FY20 at 5-minute granularity (averaged by month and weekday/weekend). In order to estimate the potential revenue that could be accessed by a fleet of 1,000 5kW BESS participating in all six contingency FCAS markets, the average profile was applied to the average pricing of the contingency raise and lower offers for 10 years from 2010 through 2019, before applying a rounding factor to account for the fact that FCAS can only be bid in rounded MW (and thus 3.8MW of capacity can only be bid as 3MW).

Importantly, this analysis did not take into account the impact of site export limits on individual site availability (which would have reduced the aggregate fleet availability), nor the available energy left in the BESS systems for dispatch, and as such, the analysis will tend to over-estimate fleet availability. Acknowledging those two assumptions, the analysis presents an upper bound on the accessible value where the normal fleet operational profile is used as the availability baseline, and the fleet availability is known and bid in real time.

Table 14 and Figure 36 describe the estimated revenues per BESS from the 6 FCAS contingency markets.
Table 14: Estimation of FCAS market revenues for a 5kW BESS system for financial years 2010 through 2019

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<th>Year</th>
<th>Total</th>
<th>Raise</th>
<th>Lower</th>
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<tbody>
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<td>Min</td>
<td>$103</td>
<td>$43</td>
<td>$23</td>
</tr>
<tr>
<td>Ave</td>
<td>$354</td>
<td>$243</td>
<td>$111</td>
</tr>
<tr>
<td>Max</td>
<td>$797</td>
<td>$761</td>
<td>$331</td>
</tr>
</tbody>
</table>

Figure 36: Estimated annual FCAS market revenue for a single BESS in financial years 2010 through 2019

6.1.3. Wholesale Energy

To provide a similar estimate of achievable fleet value through energy dispatches to maximise wholesale energy revenue, AGL undertook a similar back-cast of fleet availability during FY20, and estimated accessible wholesale market revenue using a $5,000/MWh trigger price for dispatching based on the available fleet capacity. Importantly, this approach assumes perfect foresight of the fleet operator during these dispatches – that is, it’s assumed that the half-hourly settlement price is known at the start of the half-hour settlement period. On this basis the annual per BESS revenue was $206 with around half coming from December 2019 and January 2020. Figure 37 illustrates the estimated monthly breakdown of revenue.
6.1.4. Network

Non-network solutions are typically valued against the cost of rectifying the thermal or voltage constraint via the traditional augmentation solution. As a result, the network service value which may be available to non-network service providers is typically based on the savings accessible by deferring the proposed thermal or voltage management augmentation. A non-network solution provider can capture this value as long as the cost of the non-network solution addresses the energy at risk and is more prudent and efficient than the traditional augmentation solution on an annualised basis. Other jurisdictions have implemented additional financial incentives for networks to implement non-traditional approaches to managing network issues, such as the New York REV\textsuperscript{30} program.

AGL notes that there are a number of publicly available studies that seek to quantify the market value that could be achieved through controllable DER assets providing network services. Notable studies include:

- Pricing for the Integration of DER – A study by Oakley Greenwood\textsuperscript{31}
- DER Enablement Project\textsuperscript{32} - A discussion and options paper by Energeia
- Networks Renewed \textsuperscript{33} - and ARENA funded project led by the University of Technology Sydney

While these studies provide a guide as to the overall market value that could exist for behind the meter DER services, there is no accepted framework for valuation of thermal and voltage services on the LV network. As a result, AGL used the RIT-D framework coupled with low voltage augmentation deferral and voltage management costs listed in the Energeia Report\textsuperscript{34} to quantify the annualised deferral value proposed below in this report.

\textsuperscript{30} https://www.nypa.gov/innovation/initiatives/rev
\textsuperscript{31} https://arena.gov.au/assets/2020/06/pricing-for-the-integration-of-distributed-energy-resources.pdf
Thermal management services value

The demand reduction required from a non-network solution must address the energy at risk and typically provide enough demand reduction on the LV substation to bring the loading on the distribution substation and LV circuits back to 120% of the cyclic rating. For a typical thermal constraint on the LV network, the non-network solution provider will have to:

- respond to thermal constraint events triggered by a temperature – typically greater than 35°C
- provide up to a maximum of 25kW of demand response to bring the LV substation back to its cyclic rating.
- The aggregator will be responsible for having sufficient power and energy capacity from batteries to provide between 1kW and 25kW of demand reduction for between 2-5 hours on all days where the ambient temperature threshold is exceeded.

The cost of LV network augmentation can range from $50,000 for overhead networks to $150,000 for underground networks. Using a weighted average cost of capital (WACC) of 6%, the equivalent value that could be used to contract a VPP provider to provide a service to defer the proposed augmentation by one year will therefore be $3,000/annum to $9,000/annum. This would obviously need to cover all components of the service provision, from the customer recruitment through to activation and reporting of the actual service.

This deferral value is based on the aggregator controlling sufficient power and energy capacity to achieve the demand reduction required from between 30 to 150 customers connected to a circuit. Achieving that level of targeting within a limited network area of that scale is a challenge, however AGL’s VPP SA project has shown that retailers are well placed to be able to identify the most appropriate customers and provide them with incentives to join an aggregation program.

Voltage management services value

Valuing voltage network services that can be provided by a fleet of behind the meter DER devices is complex for a number of reasons, including:

- The ability of a DER devices to provide a service is influenced by the network topology, the DERs location within the circuit, and the characteristics of that network (impedance in particular)
- The proposed change to AS4777.2 that would mandate both V-VAr and V-Watt modes on solar and battery inverters which could limit the value in the provision of those services, over and above what is currently mandated. In the absence of the market mechanism, regulating the provision of these services risks foreclosing the ability of customers to be financially remunerated for these service in future.

AGL provides the following range that could be used as a guide as to the value that could be paid to an aggregator for deferring the traditional network solution to manage voltages by one year. AGL has based the

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36 The exact demand reduction required will vary by substation depending on its load profile. The typical demand reduction required on the LV network can range from 1kW to 25kW.
39 AGL note that for the 2021 – 2025 regulatory period, the WACC for most distribution network businesses has been reduced to between ~3% and 4%. If an aggregator is providing a network service in the 2021-2024 regulatory period the annualised deferral value that could be paid to an aggregator will reduce to between $1.5k and $4.5k with the lower WACC.
value calculation on the costs incurred by the network for the traditional voltage management solution\textsuperscript{40}, and
the same assumptions around the valuation of the service based on the network’s WACC.

\textit{Table 15: An estimate of voltage management network services value for a VPP}

<table>
<thead>
<tr>
<th>Traditional Network Voltage Management Solution</th>
<th>Network Solution Cost\textsuperscript{41}</th>
<th>Value that could be paid to an aggregator for deferring the proposed network solution by one year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Adjusting the tap position at the distribution substation</td>
<td>$1,000 - $2,000</td>
<td>$60/annum to $120/annum</td>
</tr>
<tr>
<td>Phase balancing</td>
<td>$1,500 - $2,000</td>
<td>$90/annum to $120/annum</td>
</tr>
<tr>
<td>Augmentation</td>
<td>$50,000 to $150,000</td>
<td>$3,000/annum to $9,000/annum</td>
</tr>
</tbody>
</table>

\textsuperscript{40} AGL has used the United Energy 6% WACC from the 2016-2020 regulatory period as reference for this report \url{https://www.unitedenergy.com.au/wp-content/uploads/2016/05/20160526-EDPR-Final-decision.pdf}
AGL note that for the 2021 – 2025 regulatory period, the WACC for most distribution network businesses has been reduced to between ~3% and 4%. If an aggregator is providing a network service in the 2021-2024 regulatory period the annualised deferral value that could be paid to an aggregator will reduce with the lower WACC.

\textsuperscript{41} AGL has used Energeia as the reference for cost of traditional voltage management solutions. \url{https://renew.org.au/wp-content/uploads/2020/06/Energeia.pdf}
7. Conclusion and future opportunities for VPPs to be deployed at scale

This report has described in detail the various value streams that are available to a VPP operator or aggregator, as well as some of the complexities both in recruiting customers and managing the DER once it is installed. The report has also described regulatory changes that could help to unlock network services and FCAS value for VPP operators, as well as improve customer experience within VPP programs.

Considering those insights from the program, for VPP's to be deployed at scale, AGL proposes that the following challenges need to be addressed:

- VPP’s (apart from those supported by public funding) are primarily made up of customer owned assets. Enabling those assets to support the customer’s needs first - rather than the network or aggregator - is critical in building customer trust in having a third party control their DER.
- Many customers support the concept of a community of batteries supporting the grid, but their lived experience in VPP’s that are operated for aggregator value only (as opposed to shared value with the customer) could erode customer trust in the VPP industry. A robust framework of consumer protections for customers in VPP programs will be essential to build customer trust and increasing participation in aggregation programs.
- While DER prices continue to fall, batteries in particular remain a significant household investment, and don’t currently provide an attractive payback for most customers without additional government support. It is anticipated that as battery costs reduce, the case for government subsidy or loan support will diminish.
- Further, as regulatory reforms support the participation of VPP’s in new markets, more orchestration value can be shared with customers, which will further reduce the need for any additional subsidies.
- While many distribution networks monitor the rapid uptake of DER on their networks, the response from many is still focussed on curtailment and management, rather than developing an approach that supports DER deployment and embraces the services that they can provide. The role of the retailer as aggregator here is key, as the single point of coordination to manage customer participation and advocacy at the consumer/network interface.