Backup Boost Knowledge Sharing

Final report

1 May 2024

Overview of the trial

Enel X was proud to partner with the South Australian (SA) Government to provide support to local businesses by changing the way they use energy.

Through its Demand Management Trials Program, the SA Government provided funding to support upgrades to existing backup generators and to install new BESS at eligible businesses in SA, to test the ability to:

> create an aggregated portfolio of fast-responding, dispatchable generation

> show that demand response can bring financial benefits to participating businesses and consumers more broadly

> sell a cap product in relation to the dispatchable capacity, and assess the impact on liquidity in the contract market.

This is the eighth and final knowledge sharing report for this program. Previous knowledge sharing reports reflected on the effectiveness and challenges of engaging customers to provide demand response, upgrading backup generation, and installing BESS to operate in the wholesale market and sell financial derivative products on the ASX. This report shares knowledge on the trial period (1 November 2023 to 30 April 2024) and on the achievement of the trial outcomes more broadly.

As set out below, the program has delivered on the objectives of the program. In summary:

> It activated 19.2 MW of demand response capacity through backup generator and BESS assets at nine commercial and industrial sites across SA. Participating backup generator sites variously participated in more than 85 dispatch events over the course of the program, and the BESS projects have been dispatching on an almost daily basis since their commissioning dates. All participants remain contracted with Enel X and will continue to provide demand response services to the grid after the program ends.

> While there were technical challenges along the way, the performance of these assets was good when they were available. Customers supported the grid in exchange for market revenue when dispatched, and generally had a very positive experience of participation in the program.

> The sale of cap products against the capacity in the program provided some interesting insight, particularly as events unfolded over the June 2022 market crisis.

> The project shed valuable insight into what the path forward is for Enel X and for the activation of demand response capability more broadly. We've adjusted our focus based on what we've learned about backup generators and BESS value capture through this program.

> Beyond this, the key learning is that capable businesses need access to firm revenue in order to be sufficiently incentivised to activate their demand response capability. There are a number of regulatory changes that can be made to support this.

Assessment of how the trial performed against the purpose

The purpose of the trial program was to:

(a) show how existing backup generators or BESS can provide dispatchable demand response capacity in the NEM, and deliver value to small-medium commercial and industrial businesses in SA

(b) assess the viability of selling a cap product in relation to the aggregated capacity.

On item (a), the project contracted, enabled and dispatched 19.2 MW of demand response capacity that was not previously providing demand response. This capacity is located at nine sites for businesses in the materials manufacturing, food manufacturing, cold storage and water sectors.

Participating backup generator sites variously participated in over 85 dispatch events over the course of the program, and the BESS projects have been dispatching on an almost daily basis since their commissioning dates, providing a valuable source of capacity to the grid in critical periods.

As shown in the customer feedback section below, participants in the trial generally have positive views of their program participation, have seen real value in providing demand response, and are looking for other opportunities to expand or increase their demand response participation. With the exception of one customer, the participants in the portfolio did not show "dispatch fatigue", either in relation to the length of events (which could be for up to five hours) or the number of events they were dispatched for. Importantly, all capacity activated through the program will continue to provide demand response services to the grid beyond the completion of this program.

On item (b), we were successful in selling caps against a portion of the capacity enrolled through this trial. However, doing so was a learning experience, particularly through the market crisis events of June 2022, which saw unprecedented levels of volatility. Market prices in those quarters significantly exceeded cap premiums that were sold in advance, which had a negative impact on earnings. Fundamentally, the risk-reward calculation for $300 cap products shifted after the market crisis events of June 2022, but has recovered somewhat with lower levels of volatility recently. Overall, the amount of caps we sold against the program capacity was not enough to affect liquidity in the SA contract market.

Key lessons learned from the delivery and operation of the trial

Previous progress and knowledge sharing reports have shared a lot of insight on lessons learned from the delivery and operation of the trial. The dot points below set out our key lessons learned from the delivery of the program as a whole.

The business case for backup generator upgrades in an energy-only market is challenging

The funding received from the SA Government through this project helped the business case stack up for generator works to make sites capable of providing demand response. Without funding support, demand response providers rely on energy/FCAS market revenue to recover the costs of generator upgrades required to enable a site to provide demand response. At the moment in SA, average wholesale prices have been trending down, and there are a fewer periods of volatility than last year. As a result, it's unclear whether there will be sufficient periods of sustained high pricing to recover generator upgrade costs over a reasonable period.

The business case for BESS is also challenging, but improving

The funding support received through this project was crucial to making the business case for the BESS projects stack up. Without such support, it can be difficult to build a business case for behind the meter C&I batteries in an energy-only market, for the same reasons as above, but even more so due to the capex intensive nature of BESS assets. Nevertheless, the fundamentals of a behind the meter C&I BESS are improving, and as a business we are investing behind it to deliver more of these projects.

There is significant interest in C&I behind the meter BESS

Where a business does not have a backup generator, it is generally more interested to explore onsite BESS than a backup generator as a solution to their energy needs. The narrative around supporting the grid by enabling greater renewable penetration appears to resonate strongly, particularly with those businesses that have decarbonisation goals. However, maximising value from BESS is more complex than that for a backup generator. In general, we've found that businesses need help understanding how to create value from a BESS and determining whether a business case for onsite BESS stacks up.

Technical challenges can arise after sites enter the market

Participants in the trial have had varying levels of availability throughout the program period as technical issues arise and are resolved. In some cases it can take time to resolve technical issues, with personnel changes on site and differing business priorities affecting levels of customer engagement, particularly during the COVID-19 pandemic. Various technical issues have also arisen at the BESS sites. As a business we have learned a lot about operating BESS over the past 12 months, where previously we had limited local experience. Despite these availability challenges, all participants in the program committed to rectify the issue in order to get back into the market at some stage – that is, at no point has the technical issue become insurmountable such that the customer decides to cease providing demand response services altogether.

The challenges associated with backup generators have caused Enel X to review its business priorities

As noted above, the business case for backup generator upgrades is challenging, and sites can experience technical issues once in the market. The combination of these matters, and the range of other things we have learned through this trial program (including the cost, time and complexity of seeking export or long-term parallel approval from DNSPs), have made us redefine our business priorities and not actively pursue generator upgrade prospects outside of those contracted through this program. Our focus is now on BESS prospects, sites that do not need generators to do demand response, or sites whose generators are already well set up to provide demand response. Under the current market dynamics, the costs and risk of pursuing generator upgrade works are greater than the revenue potential.

Once a customer signs up to provide demand response, they'll likely continue to do so

It can be challenging to sell demand response services to customers. The sales cycle can be long, and many opportunities fall through for various reasons. However, when a business does sign up to provide demand response, and carries out its first few dispatches, it generally has a positive view of the experience and is the overall value of providing demand response services. All participants in this trial remain contracted and continue to provide demand response services. The lesson here is that once demand response capacity is activated, it will more than likely continue to be available (provided that sufficient incentives to do so exist).

Recommendations for policy change

What has become clear to Enel X over the course of this program is that there are two things needed to support greater participation by the demand side in the NEM's electricity markets:

1. An incentive to provide demand response
2. A workable market mechanism through which to provide demand response

On the first dot point, the funding support provided by the SA Government through this trial helped the commercial proposition for demand response stack up for six businesses across nine sites in SA. All six businesses will continue to provide demand response services to the grid even now that the trial period is over, and will continue to benefit financially from doing so.

However, beyond the program there is limited incentive for energy users to engage in forms of wholesale demand response. While there are periods of volatility and an overall increase in the daily price spread, there are currently insufficient periods of sustained high spot prices to incentivise enough C&I energy users to provide demand response. In our view, the solution to this problem is to provide demand side capacity with access to capacity-style payments for being available to respond in critical grid periods when demand response is most valuable. Capacity payments make demand response customers more immune to lower average clearing prices across the period of their dispatch. It delivers a more certain revenue stream that a business can invest against, and means that more demand response is available and likely to dispatch in those critical grid periods.

We note that demand response resources were not permitted to offer capacity into the recent Vic-SA Capacity Investment Scheme (CIS) tender. The rationale for this is not entirely clear, given there is an existing mechanism (the WDRM) that enables demand side resources to be visible and centrally dispatched, and that NSW adopted as a participation requirement for resources offering capacity in its 2023 firming tender. Enel X has been contracted to provide 95 MW of demand response firming capacity through the WDRM under the NSW firming tender. We encourage all states and territories to allow demand response resources to offer capacity into future CIS tenders and, in NEM jurisdictions, for this capacity to participate through the WDRM. This approach will deliver energy users the capacity style payment needed to incentivise them to provide demand response and make any necessary investments on site, with the energy payment received for actual dispatch allowing them to compensate for the costs of curtailing demand during those periods.

On the second dot point, the market mechanisms for demand response participation in the NEM are substantially in place, with the WDRM, SGA and FCAS frameworks now providing several avenues for customers to provide demand response services. However, improvements still need to be made, particularly to the WDRM, to encourage more providers to participate. The WDRM was established to be the mechanism by which demand side capacity is scheduled and dispatched through the NEM, and paid on equivalence with generation. It delivers on one of the original design intentions of the NEM – to establish a two-sided market - but several policy decisions and inaction by the AEMC and AEMO have meant that uptake of the mechanism is not as high as it should be. The eligibility criteria for participation in the WDRM are strict. This is partly by design – AEMO's intention when setting the eligibility criteria for the WDRM was to start strict and review the criteria over time. The solution to this is to broaden the WDRM eligibility criteria. The ability to do this mostly sits with AEMO.

Enel X's views on ways in which eligibility for the WDRM can be broadened are set out below. We have listed these in priority order, based on the additional MW the change would be expected to bring to the WDRM, and the ease of its implementation. We recommend that all four improvements be made, but even just one of these changes will have a material, positive impact on WDRM eligibility and therefore system reliability.

a) *Implement changes to allow sites with solar, and portions of variable load, to participate in the WDRM.*

Sites with solar, or that have portions of load that are highly variable, do not meet the baseline eligibility requirements to participate in the WDRM. These issues can be addressed through new baseline methodologies, and Enel X recently submitted several new baseline methodology requests to AEMO for their consideration and public consultation. Based on the timing for this process, as set out in the WDR Guideline, we expect AEMO to decide on these new requests before summer 2024/25.

b) *Review the WDRM baseline eligibility thresholds.*

In its final determination on the WDRM baseline eligibility policy, AEMO said that it would review the baseline eligibility thresholds (RRMSE and ARE) annually, starting in 2022, to "ensure that [they do] not unnecessarily restrict WDRM participation", and that it would consult publicly when it does. No such public review has been conducted to date. It is now over two years since the WDRM commenced, and thus it makes sense to review whether these thresholds are appropriate, and to do so through an open and consultative public process.

c) *Review the threshold for DNSP endorsement of aggregations (currently 5 MW).*

There is no real basis for this threshold and the endorsement process is complex to navigate. Unfortunately, the endorsement framework only serves to disincentivise aggregation and reduce incentives to participate in the WDRM.

d) *Amend the NER to enable sites with multiple connection points to participate in the WDRM.*

Sites that have multiple, electrically-connected connection points are not eligible to participate in WDRM. Enel X submitted a rule change to the AEMC to remove this restriction in April 2022, but it has not yet been initiated. Many large energy users have sites with multiple, electrically connected connection points. These sites are currently not eligible to participate in WDRM but, if the rule change was made, would bring significant MW of visible, flexible capacity into the market.

The AEMC has indicated that it will not commence Enel X's rule change while the *Integrating price-responsive resources into the NEM* rule change is underway. In the AEMC's view, the *Integrating price-responsive resources into the NEM* rule change will result in a mechanism that replaces or diminishes the need for the WDRM. However, based on the current design, we do not believe this to be the case, and in any case implementation of that mechanism is several years away, so we believe there is still merit in progressing the Enel X rule change.

We encourage the SA Government to continue working with AEMO and the AEMC to make the WDRM eligibility enhancements outlined above, to catalyse the success of the WDRM and other initiatives that may leverage it in future (e.g. future CIS tenders).

Barriers to participation in the trial

Previous progress and knowledge sharing reports have shared a lot of insight on barriers to participation in the trial. In the initial phase of the program, the main barriers to participation related to technical matters, and whether the proposition stood up from a commercial perspective, specifically:

- the technical suitability of customers' generators
- the suitability of the site in terms of its load profile (i.e. whether load would be available during periods when demand response events are likely to be called)
- what quantity of demand response the site would be able to provide
- whether the site had the ability to export excess generation to the grid
- whether the customer's retail contract prevented them from contracting with a third party to provide demand response.

The section above sets out some of the barriers to demand response from a regulatory perspective.

Beyond the technical, commercial and regulatory barriers, many business have behavioural barriers to providing demand response. Most of these are operational or organisational objections to demand response, for example concerns about what impact a demand response event will have on business output. The only way these objections can be overcome is through education, risk management, and technical solutions where needed. Delivering these is the role of the demand response service provider. This can take time, and is challenged by staff changes at site and competing business priorities, which emerged as a particular challenge during the COVID-19 pandemic. As a result, the sales cycle for demand response can be lengthy. In general, knowledge of opportunities to provide demand response remains low among commercial and industrial businesses. While addressing this is a responsibility of demand response service providers, we do believe that governments can play a bigger role in publicising opportunities for businesses to engage in demand response, and supporting them to do so.

Effectiveness of different pricing structures/incentives employed to recruit capacity and encourage participation

The trial enabled participation through three different demand response mechanisms: spot price share, SGA and WDRM, and there are advantages and disadvantages to each. The spot price share mechanism provides a relatively easy and clear way for customers on spot-priced retail contracts to manage their exposure to high spot prices by reducing demand, but value can only be created through this mechanism if the business is able to consistently and repeatedly provide demand response in each period of market volatility. Many businesses do not have the risk appetite to take up a spot-price retail contract, or the operational flexibility to provide the level of flexibility required to capture value through this framework. So, while it is well suited to some customers, the incentive structure of the spot price share mechanism is not the most effective way to recruit the majority of customers to do demand response.

By contrast, the SGA and WDRM mechanisms allow customers to stay on their fixed price retail contracts, but capture the value of price volatility at their discretion. Under these programs, there are two ways to structure the commercial offer – through capacity and energy payments, or through energy payments only. Most businesses prefer the first option, as it gives them access to a predictable and ongoing source of revenue. The second option, while potentially more lucrative, only gives value to customers when they are dispatched. In periods of high volatility, this commercial offering can pay off well. However, in the current context of lower average wholesale prices and fewer periods of sustained high pricing, the capacity + energy payment structure remains the more effective means of recruiting customers to demand response programs. It's for this reason that we support a similar pricing structure for demand response participation in future CIS tenders.

Number and nature of events during the period

Demand response dispatches tend to occur when spot prices are high because of tight supply/demand conditions across the grid. In general, high prices are driven by a combination of the following factors:

> Very hot or very cold weather. Temperature extremes tend to increase demand above forecast levels.

> Low wind and solar PV output. South Australia's generation mix is dominated by renewable sources. Spot prices often increase when renewable output is low. For example, price spikes are often seen on hot days in the late afternoon when rooftop solar PV output drops off.

> Large generator outages. Planned and unplanned outages of large generators reduce available supply and can lead led to low reserve conditions, particularly when demand is high.

> Transmission line outages. Constraints on the interconnector between SA and Victoria, and between NSW, reduce available supply to SA and can drive prices higher.

Enel X called eight dispatch events for the backup generator sites during the reporting period (1 Nov 2023 to 30 Apr 2024). Key metrics on all events are set out in the table below.

In general, the reporting period experienced lower average wholesale electricity prices and less volatility than previous summers. Average spot prices in South Australia in Q1 2024 were lower than the same quarter last year, with very low/negative average prices between 9am-3pm. In general, the quarter also saw lower price volatility than other NEM regions, with only 252 intervals priced at above $300/MWh compared to 609 intervals in Q1 2023. Nevertheless, there were several significant volatility events, which caused Enel X to dispatch the portfolio twice from 1 November 2023 and six times in Q1 2024. One of these events occurred on 21 Feb 2024, where high temperatures, high evening peak demand, a drop in solar output and constraints on the Heywood interconnector resulted in nine intervals at the market price cap of $16,600/MWh between 6-7pm.

The average spot price over all intervals during events in the reporting period was $2,643/MWh.

Event number	Event date	Event start time	Event duration (hours)	Average price ($/MWh)
1	9/11/2023	18:55	0.5	1,674.83
2	8/12/2023	11:40	0.5	2,256.92
3	23/01/2024	16:50	4	256.15
4	12/02/2024	18:10	1.16	422.07
5	21/02/2024	18:00	1.5	9,072.81
6	27/02/2024	18:20	1	3,342.67
7	10/03/2024	17:50	1.16	618.41
8	11/03/2024	18:20	1	3,501.17

The BESS are dispatched much more frequently than the BUG sites (typically once a day, when online). The table below provides detail on three high pricing events where the BESS were dispatched, and gives an indication of the MWh dispatched and value captured across the event.

Event number	Date	Event start time	Dispatch duration	Average market price
1	21 Feb 2024	18:00	1 hour	$13,500/MWh
2	27 Feb 2024	18:10	1 hour	$4,150/MWh
3	11 Mar 2024	18:25	30 mins	$6,500/MWh

Over the course of the whole program, the backup generator sites have variously participated in over 85 dispatch events, and the BESS projects have been dispatching on a almost daily basis since their commissioning dates.

Dispatch performance, and firmness of the capacity

In general, over the whole program period, the capacity was not as firm as expected, and not as high as contracted levels. Firmness levels were primarily affected by technical issues – either at the generator or battery, or other site issues that rendered it unable to participate in demand response events for a period. For example:

> Technical issues at one site rendered the generators incapable of taking on site load. These issues are in the process of being addressed, and we expect the site to be back in the market later in 2024.

> One site's generator has a break-before-make configuration, meaning that there is a short interruption to supply during a demand response event before the generator takes on the site load. While participation is still possible, the business would prefer a seamless transfer, so chose to opt out of demand response participation until it gets the necessary DNSP approvals for this.

When a site is online and opted into market participation, it generally performs to expectation.

The amount of demand response delivered in an event also depends on how much load the site is using at the time, and therefore how much load the generator will support. As none of the generator sites have export approval, the maximum amount of demand response that can be provided in an event is capped at the site load at the time of the dispatch.

The BESS sites encountered some technical challenges in the early days of commissioning. This has been a good learning experience for Enel X, and we are making technical and operational improvements all the time to increase the availability of the BESS. All BESS are now being dispatched through DER.OS, Enel X's proprietary dispatch optimisation platform. The overall performance of the DER.OS, in terms of its ability to optimise and capture value, has been fairly good. However, there is always room for improvement, and this is something that we continue to work on.

Overall, we expect the firmness of the full portfolio to increase over time as we improve our BESS engineering capability and make other necessary fixes at the generator sites to ensure higher levels of firmness, and therefore revenue.

Market, spot price share, and cap revenues earned compared to predicted

Overall market conditions were not volatile, so overall financial performance during the period was not as high as previous summer periods. Our market operations team expected this to be the case, with their forecasts indicating a milder than usual summer. Issues at some customer sites also reduced levels of availability over the trial period, either taking them out of the market completely or reducing the amount of demand response able to be provided. Nevertheless, there were some significant volatility events that our customers were able to capture.

Impact of the aggregated resource's operation during periods of high solar PV generation output

Enel X dispatched the portfolio during periods of high spot prices. High spot price events usually coincide with periods of high forecast demand (due to weather) and periods of low wind and/or low solar PV generation output. These periods tend to occur in the late afternoon to early-mid evening when there is lower solar PV output than during the middle of the day. This reflects an ongoing trend of low or negative spot prices during the day when solar PV output is high, followed by prices increasing when solar output decreases. As shown further above, all dispatch events during the trial period occurred during the late afternoon to early evening. This has been largely the case across all dispatches over the whole program period. So, the portfolio had very little impact during periods of high solar PV generation output.

Efforts to build and sell a cap product and, if successful, any impact that product has had on contract market liquidity

We were successful in selling caps against a portion of the capacity enrolled through this trial. However, doing so was a learning experience, particularly through the market crisis events of June 2022, which saw unprecedented levels of volatility. Market prices in those quarters significantly exceeded cap premiums that were sold in advance, which had a negative impact on earnings. Fundamentally, the risk-reward calculation for $300 cap products shifted after the market crisis events of June 2022, but has recovered somewhat with lower levels of volatility recently. Overall, the amount of caps we sold against the program capacity was not enough to affect liquidity in the SA contract market.

Effectiveness for participants as a hedge against wholesale price volatility

All but one customer participating in the program were on fixed price retail agreements, so were not explicitly exposed to the spot price through their retail offering. But, retailers price expected market volatility and hedging costs into their retail contract offering, so customers ultimately pay for it. While volatility signals are muted for customers on fixed price retail contracts, this program has allowed trial participants to earn revenue that indirectly offsets their exposure to these costs. The value of this to trial participants became particularly clear in the market crisis events of June 2022, when there were multiple and sustained periods of high pricing, and consequently multiple dispatch events and opportunities to earn revenue to protect against the overall increase in retail electricity prices in the months that followed.

One participating customer was on a spot-exposed retail contract, so provided demand response through a spot-price-share mechanism. This customer had positive things to say about its participation in the program, and was able to reduce its energy costs significantly through its participation. The spot-price-share mechanism provides a clear and direct means to manage exposure to spot price volatility, but is only successful in doing so if the customer is able to consistently and repeatedly reduce demand during those high price intervals. In some quarters this may be achievable, but in others, like the events seen in June 2022, it becomes very difficult for the business to provide demand response continuously over the full period of volatility.

Outcomes for customers with/without grid export capability

None of the generator sites have grid export capability. For reasons outlined in previous knowledge sharing reports, the financial benefits of exporting net generation are often outweighed by the costs, time and administrative complexity of seeking export approval from the DNSP. Consequently, in all cases, the amount of demand response able to provide by each of the generator sites was capped at the site load at the time of the demand response event, which limits the amount of demand response that can be provided and thus impacts overall revenue.

All BESS sites have grid export capability, which means they are able to capture more value than a same-sized generator (to the extent that there is excess capability to be exported). In all cases, SAPN has imposed export limits on the BESS, which do have a negative impact on a BESS business case but not to a significant extent.

Any differences in customer experience of market participation for sites participating via the SGA framework vs DRSP framework vs spot price share

Customers participating in the trial program were able to participate in the energy market in one of three ways – through the wholesale demand response mechanism, through the Small Generation Aggregator framework, or through spot price response (i.e. switching to generator supply to reduce exposure to high spot prices). One site participated via the WDRM, one site through a spot price response mechanism, and the remainder through the SGA framework.

The SGA and spot price response mechanisms are arguably the easiest market participation models for both customers and aggregators. Both methods drive changes in behaviour in response to the prevailing spot price, and there are no significant administrative hurdles or ongoing compliance obligations to participate in this way. However, there is one key difference between the two frameworks, and that is in how value is created. The SGA method earns revenue directly from the market (because all generation output is settled at the prevailing spot price when dispatched), whereas the spot price response method relies on the customer being spot exposed, and value being created through the difference between the price the customer would have paid for consuming during a dispatch interval, and what it actually pays when it reduces demand during a dispatch. The choice between these models largely comes down to what kind of retail tariff the customer is on – that is, a spot exposed retail contract or a fixed price contract. As noted further above, the customer on the spot-price-share arrangement was happy with the simplicity of this mechanism and the value generated. In general, we have found the SGA framework to be a very good fit for the BESS sites as it is a relatively flexible framework that supports daily charging/discharging activities and optimisation with other value streams.

The WDRM also encourages wholesale demand response, but does so directly through the central dispatch mechanism. The quantity of WDR provided is settled at the prevailing spot price (minus the retailer reimbursement). The challenge with the WDRM is that there are strict eligibility criteria, meaning that not all loads who wish to participate are able to. There are also strict ongoing compliance obligations and market risks that participants must comply with and that Enel X, as an aggregator, assumes on its customers' behalf. Another challenge with the WDRM is that there is a minimum offer requirement of 1 MW. This can be surmounted through aggregation (where possible) if a site does not meet this threshold itself, but this contrasts with the SGA and spot price response modes of participation where there is no minimum threshold to access value.

It is our responsibility of demand response services providers / aggregators to make demand response participation as simple as possible for customers. Ultimately, the mechanism that is best for the customer is the one that:

> works best with their retail arrangement (i.e. spot price share only creates value where the customer is on a spot-price-exposure retail tariff)

> they are eligible for (as noted above, the WDRM eligibility criteria are very strict, so SGA may be the backstop option for a customer that is ineligible for the WDRM)

> minimises market and operational risks to a level that the customer is comfortable with

> they are technically capable of participating in (e.g. the participation requirements for the WDRM are more stringent than those for the SGA program).

While the WDRM framework is strict and eligibility is constrained, we still believe it is a mechanism that provides good value for customers and that is worth improving and expanding to other customers. We also see its benefits from a grid perspective – all WDRM capacity is forecastable, scheduled and dispatched through AEMO's central dispatch mechanism, whereas SGA and spot-price-share customers are "invisible" to the broader market, and thus there is no knowledge of when or how much demand response will be provided by those customers.

Feedback from customers on experiences participating in the trial

Enel X has sought feedback from all customers participating in the trial. A summary of their experiences is set out below:

> Customers have appreciated our regular and timely communication about market conditions and the likelihood of dispatch events.

> Most customers in the portfolio have not fatigued, despite having been called to dispatch a significant number of times. Some customers raised concerns about wear and tear on generators due to multiple dispatches, particularly during the market crisis events of June 2022.

> Two site with “break before make” generators were not comfortable with multiple dispatches during periods of significant volatility. One sought to address this by limiting its participation in the short term (i.e. by increasing its price threshold for dispatch) and by seeking approval from the DNSP to set up the generator for seamless transfer in the long term.

> The BESS sites experienced a number of delays in commissioning due to flooding, supply chain constraints. Technical issues have also affected overall availability levels of the BESS. While this has delayed revenue earnings in the short term, the customer understand that this is a learning process and remains committed to the demand response participation for the long term.

> Some customers raised questions about financial performance, but in general have remain committed to program participation and investing in improvements to increase availability or levels of participation.

> On a broader level, customers see participation in Enel X’s VPP as a win-win. It enables them to access a new revenue stream and contribute to the reliability of the grid on days of high demand and / or supply shortfalls.

> The refrigeration customer requested stronger levels of communication about potential dispatches, in order to manage health and safety risks associated with shifting to generator supply during a demand response event.

All customers contracted for participation through this trial have chosen to remain under contract with Enel X and will continue to provide demand response services to the SA grid. While there still some technical and customer issues to address, the fact that all participants are keen to continue to provide demand response services is testament to the value created through this program, and the broader appeal of demand response to their business.

Any patterns in performance across industry sectors, BUG or BESS size or geographical location

We have not been able to identify any strong patterns in customer experience across industry sectors, generator size or geographic location. However, we have noted that:

> sites that have a stable and consistent load during high demand periods, in both summer and winter, are likely to be better performers in DR dispatches

> sites located in the Adelaide CBD are likely to experience greater barriers to participation if export capability is sought, given network constraints in the area

> businesses participating in this trial were generally happy to be dispatched quite frequently, which is not always the case for businesses offering demand response

> at BESS sites specifically, for sites with a fairly stable load pattern, the headroom available to charge the BESS without increasing the network demand charge is reduced and can affect the utilisation of the BESS

> sites that respond automatically to an dispatch instruction generally deliver stronger performance than sites under manual control, which means that automated sites generally capture more value.