14 September 2023

Mr Ben Davis
Director
Australian Energy Markets Commission
Level 15/60 Castlereagh St,
Sydney NSW 2000

Submitted online:

Dear Mr. Davis,

Australian Energy Council - Response to ERC0352 Integrating Price Responsive Resources into the NEM

The Australian Energy Council (AEC) welcomes the opportunity to respond to the Integrating Price Responsive Resources into the NEM consultation paper.

The Australian Energy Council (AEC) is the peak industry body for electricity and downstream natural gas businesses operating in the competitive wholesale and retail energy markets. Our members collectively generate the overwhelming majority of electricity in Australia, sell gas and electricity to millions of homes and businesses, and are major investors in renewable energy generation. The AEC supports reaching net-zero by 2050 as well as a 55 percent emissions reduction target by 2035 and is part of the Australian Climate Roundtable promoting climate ambition.

The AEMC consultation paper examines the potential benefits of better integration of distributed energy resources (DER) comprising both aggregated customer energy resources and other larger grid connected resources. The consultation paper also seeks views on the proposed AEMO mechanism for integrating price responsive DER. The AEC responds to these in turn.

Overview

As the consultation paper notes, price responsive services are already participating in electricity markets via the WDRM, contingency FCAS, the DMIS, the RERT and the NSCAS. Five Minute Settlement was also proposed as an enabler to price responsive services via a better price signal for investment in fast response technologies, such as batteries and demand response. Most of these schemes were established without a realistic assessment of likely participation, the future benefit they would bring, or of the establishment costs they would impose ultimately on end users. It is an imperative that proof of benefit should inform the AEMC in both the timing and scale of integrating price responsive resources into the NEM.

The potential benefits of better integration of DER also need a critical approach. Currently each of the VPP programs provides for either a battery subsidy or a FiT higher than the State FiT (perhaps for all practical purposes a battery subsidy). And attracting consumers to participate in VPPs is not easy, as being part of a VPP means giving up control and autonomy of their CER. In such programs, VPPs may not leave reserve storage with consumers to hedge against blackout (often one of the principal drivers behind their purchase), and battery life may also be shortened by the VPP discharge events. Even with current subsidies, the financial benefit to a small customer participation in a VPP is in the order of $100-$200 per annum, depending on the size of their battery storage. This is not a particularly compelling customer proposition at around 50 cents a day, and over time this proposition may even worsen as subsidies are removed.

As the paper notes, trials are also underway on the orchestration of hot water systems in South Australia to demonstrate whether managing hot water systems can help with grid stability and reduce energy prices. Importantly these trials will also help show whether orchestration will reduce energy prices *enough* to attract widespread customer participation in VPPs. To date this latter insight is often substituted by dogged assertions of consumer benefit but the reality is that it is still being tested.

The consultation paper breaks down the potential benefits of better integrating these resources into AEMO's system planning and management. But because AEMO cannot see or directly control energy flows of potentially price responsive DER does not mean that the benefits of their DER are not already accruing to customers. The five categories identified should therefore only be assessed on the customer benefits exclusively derived from AEMO's proposal, and not from the direct and indirect benefits that customers are already receiving from their DER. We anticipate that the order of magnitude of benefit even assuming that voluntary participation rates are high is still likely to be small until there is a far greater penetration of household batteries. There is a need for information and not haste.

QUESTION 1: DO YOU AGREE THAT PRICE-RESPONSIVE RESOURCES NEED TO BE INTEGRATED INTO THE NEM?

1. The Commission has identified five types of issues with increasing volumes of price responsive resources. Do you agree with this breakdown of the issues? What do you consider the magnitude of each issue is? How is this likely to change over time?

The AEC broadly agrees with the breakdown of the issues. The question of price responsive resources providing information regarding their price sensitivity and their ability to provide other market services that support system operation and security should not be a surprise once AEMOs proposed market mechanism is built but known well beforehand as part of this examination and as justification for the build, especially as the proposed scheme is voluntary.

We would be concerned that this is another approach to build and implement a system to test a market, as opposed to understanding the need first. In our view understanding the need would be assisted by the development of an options paper, and a better problem definition would assist directing the discovery of further information.

Dispatch costs in the NEM — knowing when these resources can be used to reduce demand (particularly at higher cost times), improves demand forecasting and reduces the resources that AEMO dispatches to meet demand.

With a VPPs participants' approval, their resources can and are being tapped by their utility providers (both distribution and energy) during times of high demand and this is scalable as an approach. Improving demand forecasting and resources dispatch may benefit AEMO but is the problem statement simply "what is the value of the decisions that AEMO couldn't make now?"

The NERA report provides a useful insight. It cites AEMO views that the growth in distributed resources is going to happen, and that Scheduled Lite is necessary to incorporate these resources into the NEM. The nexus between growth in DER and the need to schedule it is explored but the problem is still not entirely clear. The NERA report cites international experience as on a kind of continuum, from those schemes promoting growth in DER resources to those emphasising reliability. The latter, which would suit knowing when these resources can be used to reduce demand (particularly at higher cost times), improves demand forecasting and reduce the resources that AEMO dispatches to meet demand also have high barriers to entry and onerous testing and compliance requirements. Our expectation is that a scheme that could materially improve demand forecasting and dispatch would not of its nature promote growth in DER resources nor encourage voluntary participation.

We are in an energy transition that seeks to close centralised fossil fuel power stations and replace them with low emissions or renewable generation, both central and distributed. Our view us that at this stage the emphasis should be on promoting growth in DER resources, and that to achieve this then the exact performance of DER is far less important than need to encourage its uptake. There may be scope for VPP providers to provide information to AEMO on aggregated dispatchable load for VPP assets and this option could be explored in this context.

Energy prices in the NEM — by better matching supply and demand, the cost of energy would be lower, potentially reducing spot prices.

Demand response can theoretically provide competitive pressure to reduce wholesale prices, but there are still no meaningful volumes of demand-side participation (which could set the price if it is the marginal unit selected) in dispatch and associated system operation benefits following the introduction of the WDRM. In this light it seems unconvincing that a sufficient price signal to elicit a response can be found in the 5-30 MW range either, nor that this could reliably reduce spot prices.

The New Zealand Electricity Authority's Dispatch Lite, introduced in 2023, provided a notable commentary from their Final Decision that *"We do not have any particular expectation about the level of participation …, but we consider it an important option to offer."* This is a growth oriented case study that could be treated as a trial to inform the Australian understanding, and we should at this stage be watching closely.

Many of the schemes explored including the UK and Western Australia cannot directly influence the spot price. The New Zealand approach can, and so should be reviewed over time to inform future considerations. The potential to reduce spot prices should not be given too greater an emphasis at this stage in Australia. Evidence of a sustained reduction in spot prices, when it becomes available from international experience, is required.

Security of supply in the NEM — by reducing the need for additional, potentially more expensive generation reserves to balance the market, system security will be achieved at lower cost.

This (system security at a lower cost) is an interesting paradigm. The power system is secure when technical parameters such as voltage and frequency are maintained within defined limits and to maintain frequency the power system must instantaneously balance electricity supply against demand. We know that in each jurisdiction the transmission network must now grow to ensure reliable supply from increased but intermittent renewable generation capacity, with some 10,000km of new transmission needed to connect renewable generation to consumers. Understanding what would be foregone in the current forecasts that would be met at a lower cost by the proposed price responsive mechanism has not been well identified in the consultation to date, but at first glance it looks like paying for the duplication of already planned costs.

There is also a limited firmness to the demand response or load shifting of a VPP when compared to a traditional generator. VPP assets with industrial and commercial customers do cover some firmer demand shifting ability and the firmness of on-site generation, but small customer VPPs tend to provide limited firmness, with the customer retaining the ability to opt out. The assumptions about VPPs should therefore be tested more thoroughly by review of existing trial outcomes. This may be assisted by AEMO and VPP providers directly exchanging dispatch data to develop the necessary understanding. This could be used to inform an options paper before committing to any rule change consultation.

Western Australia's Backstop Reserve Capacity Mechanism proposes a limited use of DR targeted at providing some reliability at lower cost than alternatives, rather than building a more efficient and integrated system. Barriers to entry for participation in the WA mechanism are identified as high, comparable to the ERCOT (Texas) LRERS. Notably, the cost of ERCOTs reserves purchases is continuing to increase, which combined with ERCOT issuing a voluntary conservation notice to consumers on August 20, 2023, and may indicate that those generation reserves to balance the market are a worthwhile investment compared to the less firm alternatives.

All considered there is still an opportunity for DR to work, and to reduce the need for additional, potentially more expensive generation reserves. AEMO's own 2020 estimate is that there is approximately 4.3 GW of potential demand flexibility in the NEM, and that only 412 MW has been activated in the NEM over the past three years. A review of the whole WDRM mechanism may identify ways to enable a greater level of demand side participation in the wholesale market and in doing so provide valuable insights into the best approach for incorporating greater demand side participation through a two-sided market. Our view is that this needs the attention for now. We were critics of the original WDRM concept and design. The AEMCs 2016 assessment that the WDRM ..*mechanism is costly and adds little benefit to consumers, because the benefits of demand side participation can, and already are, accessible under current arrangements..* echoes with this current proposal. But given relatively low levels of non-conformance in the WDRM, participation rules could be potentially expanded to capture further classes of DR assets as an alternative to the proposed price responsive mechanism to balance the market at "lower cost".

Reliability of supply — the ability to schedule these available resources could improve planning and the use of lower-cost lower-emission generation and lower intervention costs.

There is a case at face value that benefits can be made by an ability to schedule these resources. However, it is not correct to assume that there is no coordination, nor that better coordination might not be achievable by simpler means. Responses are not guaranteed in the current market but that does not mean that they are not manageable.

The Demand Side Participation (DSP) Information Portal is an existing NER mechanism for AEMO to collect DSP information from participants that is then used to inform AEMO electricity load forecasts. Like the other schemes it was developed to encourage greater demand side participation by consumers in Australia's energy markets. In the forecast accuracy summary DSP performed well[1] when compared to other AEMO forecasts[2], and particularly when compared to consumption and installed generation forecasts.

We question whether the emphasis on CER will deliver enough at this time for the likely cost. If there are existing mismatched (or insufficient) incentives in the market to provide the desired services, then this could be addressed first.

Operation of distribution and transmission networks — longer-term accurate forecasts would improve network investments and planning, reducing network costs to consumers.

We do not dispute that longer term accurate forecasts can improve planning and ultimately reduce network costs. However, the strong case has not been made that greater visibility through increased participation in the existing schemes, schemes that were similarly justified to either improve planning or reduce costs cannot accommodate further gains.

It is also hard to understand, either in theory or in practice, that the cost to consumers of incentives to get greater participation in existing schemes such as the RERT and WDRM will be substantially or materially different to the cost to consumers of the incentives required to get participation in the approaches proposed by AEMO in the consultation. The business model of aggregation in a form

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[1] The best out of 7 forecast indicators.
[2] AEMO Forecast Accuracy Report 2022, Table 1, p.3 https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/accuracy-report/forecast-accuracy-report-2022.pdf?la=en

such as the VPP is in its infancy, and participants are still trialling technologies and incentives to determine whether the benefits will exceed the costs.

One example which if reviewed may assist understanding of the economics of aggregation is the Small Generator Aggregator (SGA) reform, which allows a large customer with a small generating system to have that system aggregated by an SGA, for supply into the NEM. The SGA was designed to reduce the barriers to small generation being able to directly participate in the NEM. We are unsure of its success. Similarly, if an SGA cannot provide market ancillary services, then should that be addressed first? The SGA has been in place for a decade now, initially justified by AEMOs assessment that there would be fifty new small generators in the NEM with a combined capacity of 150 MW to participate in the SGA by 2016 (within the first three years). This submission has been unable to validate that claim, nor what proportion participates in the SGA, nor whether this has improved AEMO forecasting, or reduced pool prices as originally hypothesised.

Finally forecasting is by its very nature inexact and whilst improvement may be desirable the alternative approaches have not been considered here as they may have been in, for example, an options paper. There is for instance software that can use existing data and algorithms to improve forecasting, and this could be considered along with other options.

Conclusion

Many of the purported issues in the paper are overstated and not actually present barriers and can be potentially accommodated within existing schemes or by review and amendment to those schemes. This may not provide infinite visibility to AEMO but could well be sufficient to ensure the greater part of the stated objectives in the consultation are met, and at lower cost and with less disruption.

Concerns that these existing schemes have not stimulated additional market entry by small generation or demand response consistent with their original assertions remains. An examination of the incentives to participation may be warranted for the RERT, the WDRM and the SGA, along with broader DSP on how they might be altered to accommodate greater participation by aggregators and large CER should be undertaken in an options paper. This, combined with AEMO and VPP providers directly exchanging dispatch data to develop the necessary understanding, should be completed before committing to any rule change consultation.

Please contact the undersigned at David.Markham@energycouncil.com.au should you wish to discuss.

Yours sincerely,

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