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Mr Jai Thomas
Coordinator of Energy
Energy Policy WA
Department of Mines, Industry Regulation and Safety

Submitted by email: energymarkets@dmirs.wa.gov.au

6 June 2023

Dear Mr Thomas

RE: Reserve Capacity Mechanism Review Consultation Paper (Stage 2)

Thank you for the opportunity to provide feedback on the *Reserve Capacity Mechanism Review Consultation Paper (Stage 2)*.

Enel X works with commercial and industrial energy users to develop demand-side flexibility and offer it into capacity, energy and ancillary services markets worldwide, as well as to network businesses. In Western Australia, Enel X helps energy users minimise their capacity charges through the IRCR mechanism. We also built a 22 MW portfolio of supplementary reserve capacity for the 2022/2023 hot season.

Enel X is very supportive of Energy Policy WA's intention to amend the reserve capacity mechanism (RCM) to facilitate greater participation by the demand side, with appropriate incentives and safeguards in place. Demand flexibility will have an increasingly important role to play as we transition to a future characterised by high penetration of variable renewable energy and distributed energy resources. Demand flexibility provides a relatively low-cost way to ameliorate the short periods of high system stress that are increasingly likely to occur.

This submission sets out Enel X's views on Energy Policy WA's proposals, and where we consider the proposals could be clarified to strengthen their intended effects. In summary:

- We do not believe that a strong case has been made to change the interval selection methodology for IRCR. However, Energy Policy WA's proposal is workable and we support some of the other amendments to the IRCR framework.
- Reducing the 200 hour dispatch limit to a more reasonable level is key to increasing participation in demand side programmes.
- We propose some changes to the DSP testing regime to incentivise participation whilst providing assurance that DSP capacity is real.
- We generally support the flexible capacity measures proposed, provided that demand side resources can participate.

We look forward to continuing to work with Energy Policy WA on these issues. If you have any questions or would like to discuss this submission further, please do not hesitate to contact me.

Regards

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Introduction

Like many energy markets tackling the shift to decarbonisation, the generation mix in WA is expected to be increasingly dominated by variable renewable energy and aging, less reliable fossil fuel plants. Demand response will play an important role in maintaining reliability not just because of peakier loads associated with widespread uptake of rooftop solar and electric vehicles, but also to manage fluctuations in supply. Providing a framework that enables effective participation by a wide range of loads will be crucial to managing the transition to a low carbon energy system in a way that is cost effective and continues to deliver a reliable electricity supply to customers.

Demand response offers several unique benefits compared to generation in providing additional capacity. In particular, demand response is relatively low cost to set up. While there are costs associated with installing the necessary hardware and software, these costs are dwarfed by the capital required to construct a new generator, and potentially the additional network investment required to connect it. Further, enabling participation is relatively fast.

There is latent demand response capability in WA. With a challenging macroeconomic environment pushing costs up, businesses are open to innovative opportunities to bring in new revenue and help manage their energy bills. On the east coast, commercial and industrial businesses are using their demand flexibility to participate in a range of market programs to help decrease their energy costs and support their decarbonisation goals. The latent demand response capability available in WA could support system reliability if opportunities to participate, similar to those in the east, are put in place. Enel X was able to activate 22 MW of this latent capability, in a relatively short period of time, for the purposes of providing supplementary reserve capacity in the 2022/2023 hot season.

If existing barriers to increasing demand response in the Reserve Capacity Mechanism (RCM) are addressed, we consider there could be a strong uptake in demand side participation to the benefit of both the market and consumers. As such, we strongly support EPWA's recognition of the role the demand side can play in supporting a lower cost and reliable market and its proposals to amend the way the demand side programme (DSP) operates to enable greater participation.

This submission responds to the specific proposals and questions set out in EPWA's consultation paper.

Individual Reserve Capacity Requirements

EPWA has identified a number of problems with the current IRCR approach, including:[1]

1. "in some years, the highest demand intervals are spread across six or seven days. The current IRCR method only considers four days in the Hot Season.

[1] EPWA, Reserve Capacity Mechanism Review, Information Paper (Stage 1) and Consultation Paper (Stage 2), 3 May 2023, p. 48.

2. in some years, the highest demand intervals are concentrated on one or two days. The current IRCR method would include only three intervals on each selected day, meaning that high demand intervals are excluded in favour of lower demand intervals; and
3. sometimes, system stress occurs in lower demand intervals where lower available capacity means a lower reserve margin. The current IRCR method does not consider the size of the reserve margin."

While there are some flaws with the current mechanism, overall we are not convinced there is a strong case to make significant changes to the IRCR to address the first two issues identified above. It is not clear that amending the IRCR will deliver significant benefits to the system and customers. However, we consider EPWA's proposal to be workable.

The third issue identified by EPWA is unlikely to be resolved through amending IRCR, since the mechanism is designed to take effect on high demand days. However, we consider the improvements to the RCM (discussed below) will go some way to addressing system stress during lower demand intervals with lower available capacity.

Response to consultation questions:

	Question	Enel X response
1	Do stakeholders support determining IRCR based on contribution to high demand intervals?	We agree that the existing approach to determining IRCR based on contribution to high demand intervals is appropriate. Alternative options are more complex and/or will be more costly to implement, without a clear benefit. We particularly do not support options 1 or 2 for these reasons.
2	Do stakeholders support the proposed interval selection methodology?	We consider the proposed interval selection methodology does not provide a significantly better representation of load than the existing methodology. The proposed methodology may provide a slight benefit over the existing methodology where it incentivises responses on more high demand days. However, overall, it is not clear that the benefits of changing the methodology would outweigh the costs. Large energy users typically operate conservatively to avoid additional charges. This means they are already likely reducing or minimising demand on all high demand days, given the uncertainty about which days will be identified as the peak demand days under the IRCR.
3	Do stakeholders support the removal of TDL and NTDL multipliers?	We support the removal of temperature dependent load and non-temperature dependent load multipliers for the reasons set out by EPWA in the consultation paper.
4	Do stakeholders support the changes to the treatment of new loads?	No comment

5	The settlement cycle is weekly, not monthly. Do stakeholders see any issues with the use of monthly peaks where IRCR is calculated daily?	No comment
6	Do stakeholders support determining flexible IRCR based on consumer contribution to the ramp during high ramp periods?	Enel X does not have a strong view on the preferred option. Option 1 is likely to have more impact in delivering a reduction in the ramping effect by allowing large industrial loads, that do not usually contribute to the ramp, to help deliver a demand reduction and so offset the ramping. On the other hand, option 2 is fairer because it adopts a causer pays approach whereby those that contribute to the ramp are targeted. However, option 2 is likely to be more complex and so more costly to implement.
7	Do stakeholders support the proposed interval selection method?	Enel X supports the proposed interval selection method for flexible capacity provided there is a reasonable way for DSPs to offer the flexible ramping product. DSPs must be able to respond to an AEMO direction to reduce load. The alternative approach, where participants have to conservatively anticipate when the high ramping intervals will be, requires participants to dispatch many times to reduce their exposure to flexible IRCR. This is highly costly and inefficient, as unnecessary dispatches do not contribute to a system need. If AEMO provides better instructions on when high ramping times will be, DSPs will be better able to respond.
8	Do stakeholders agree that it is necessary for AEMO to publish the forecast ramp?	Yes, Enel X supports AEMO publishing the forecast ramp. This will improve predictability around when demand reductions are most needed and valued. As noted above, DSPs will be better able to respond where more timely information is available.

Demand Side Programme

Overall, Enel X is strongly supportive of EPWA's proposed amendments to the DSP framework. We consider that EPWA's proposals will achieve the overarching goal of bringing additional, reliable and relatively low-cost capacity into the market to support the system at times of high stress.

There are two key barriers to load participating in a DSP under the current framework:

1. The current approach undervalues the potential contribution of load. The way in which DSP participants are allocated Certified Reserve Capacity (CRC) and a participant's "relevant demand" – the estimate of counterfactual demand when it is dispatched – is calculated will determine the

financial viability of a customer providing demand response. Undervaluing a DSP's relevant demand level means that a DSP participant will be certified for a much lower amount of capacity credits than it is capable of providing.

2. The current requirement to provide up to 200 hours of demand response per year to participate in the RCM is a high barrier for many potential customers. Reducing the hours that DSPs can be dispatched for would support participation in the RCM by a wider range of industries.

We are pleased to see EPWA's recognition of these issues and support the proposals to amend these elements of DSP. We are also supportive of amendments to other aspects of DSP design. There are a couple of areas where we consider the proposals would benefit from greater clarity, including:

- Under proposal G, clarifying edge cases for aggregators that may have a mix of customer types, some with the same Associated Loads as the previous year and others with different Associated Loads. We put forward a proposal in our response below.

- Under proposal H, clarifying the basis on which consumption records may be adjusted.

In the next section we also put forward an alternative approach to testing for DSP that we consider better achieves a consistent package of reforms.

Response to consultation questions:

	Question	Enel X response
9	Do stakeholders support the proposed DSP CRC allocation method?	We agree with EPWA's proposal that where a DSP has different Associated Loads from the previous year, CRCs will be assigned based on a value nominated by the Market Participant (option 2). However, it would be helpful to provide some clarifications for cases that do not clearly fall into the two options identified in EPWA's proposal G. For example, as an aggregator we are likely to have a mix of large industrial loads that, by themselves, may fall into option 1. However, these will be combined with many smaller loads that, aggregated by themselves, would fall into option 2. Further, when aggregators are certifying capacity three years in advance, we are unlikely to have certainty about the NMIs that will ultimately be included in our portfolio. As identified by EPWA, "For DSPs made up of many aggregated loads, the specific NMIs involved may not be identified at the time of certification, and only identified closer to the start of the Capacity Year".[2] Therefore, while we can commit to an aggregate level of capacity, we will not necessarily know exactly which loads will be delivering the capacity and therefore the specific NMIs involved.

[2] EPWA, Reserve Capacity Mechanism Review, Information Paper (Stage 1) and Consultation Paper (Stage 2), 3 May 2023, p. 71.

		Our view is that all aggregators should fall under option 2 regardless of the size of the loads in the aggregations or if the Associated Loads have changed from the previous year. Allowing all aggregators to nominate a value for the purposes of assigning CRCs will remove barriers on aggregators to enrol any loads to meet CRC obligations and therefore bring more capacity to the market. A prudent DSP provider will contract with more load than is required to meet its capacity obligations. It will do this so it can be certain of delivering the full quantity of certified capacity in light of natural or unexpected variations in the availability of the individual loads in the programme. Combined with an appropriate testing and refund regime (discussed below), allowing aggregators to nominate their own value for CRC will: • give confidence to the market that DSP will deliver the required capacity • enable greater participation in DSP • more appropriately value the available capacity, and • ensure the nominations for CRC are legitimate.
10	Do stakeholders support the removal of CDAs?	We support the proposal to remove CDAs on the basis that aggregators will be able to nominate their own value for CRCs and so account for maintenance days within that value. EPWA has suggested that consumption records may be adjusted “where necessary using AEMO’s records of DSP dispatch”. It would be helpful if EPWA could clarify when consumption records will be adjusted and on what basis.
11	Do stakeholders agree that sites with generation or storage should be able to be part of a DSP?	We support the proposal that sites with generation or storage should be able to be part of a DSP on the basis that: • it provides additional flexibility for customers and so supports their ability to provide demand response, and • preventing these sites from participating would simply exclude valuable megawatts from the capacity market.
12	Do stakeholders agree that measurement against a dynamic baseline would better	We strongly support the move to measuring response against a dynamic baseline. A dynamic baseline has several benefits:

	reflect the actual contribution of DSPs at times of system stress?	• It more accurately reflects the actual curtailment delivered by the DSP compared to if it were not dispatched. • By more accurately reflecting actual curtailment, it addresses concerns about potential gaming. • It shifts more risk onto the DSP provider to deliver the nominated response. • It is consistent with the approach adopted in the NEM for wholesale demand response, and in international markets. For further discussion on why we support dynamic baselines, please refer to rule change proposal RC_2019_01. We are keen to continue discussions with EPWA on which dynamic baseline approach to use. The CAISO 10/10 baseline, used by demand side resources offering supplementary reserve capacity, could be a good starting point.
13	Would reducing the 200 hours that DSPs can be dispatched for in a year meet better the WEM objectives and, if so, what would be a more appropriate number of hours?	We agree that reducing the required dispatch hours from 200 would reduce the potential costs and risks of participating and so allow more loads to participate. The current limit is too high and is one of the key barriers to demand side participation in the RCM. The new limit must achieve a balance between what the grid actually needs and what can reasonably be expected of participating loads. Limits that are too low hamper a grid operator's ability to fully utilise demand response as a flexible resource. Limits that are too high impose unnecessary costs on demand response providers and aggregators. These costs are then either passed on to consumers or serve to limit the participation of cheaper demand side resources. This balance is not easy to determine, and there is no consistent approach internationally. Dispatch limits in other capacity mechanisms range from two hours to an unlimited amount of hours. However, in general, markets with a high or unlimited number of dispatch hours do not see meaningful levels of demand side participation. Customers tend to be sensitive to the costs and risks of a high number of dispatches. The costs to customers of dispatching do not linearly increase with additional dispatches; there is usually a point at which the costs of further dispatches increase rapidly because the inherent flexibility in operations has been fully utilised. This is particularly true for customers that have never provided demand response before. Appropriately set dispatch limits help convince customers to join programs because it places an easily understandable cap on the potential costs of participating.

		We propose 20 hours, as this is more reflective of the number of hours that DSPs are likely to be dispatched and of value to the system. A higher number of hours is likely to be of decreasing marginal benefit for the grid. Requiring dispatch above 20 hours per year is also likely to significantly increase the cost as this is the point at which many customers' inherent operational flexibility is fully utilised. And, as the level of demand side participation in the RCM is currently very low, a limit of 20 hours will help to encourage new demand side capacity to participate. This reduced requirement for availability is likely to: • Increase the number of MW participating in DSP by lowering the cost of participation. • Provide significant value to AEMO at times when the system is most under stress by providing visible, dispatchable capacity. • Allow AEMO to dispatch additional demand-side capacity when the system is under stress due to generator outages rather than high demand (in contrast to IRCR, which is only effective on high demand days). In doing so, the WEM objectives are likely to be better met by: • Allowing lower-cost provision of reserve capacity via the demand side, contributing to the economically efficient supply of electricity and helping to minimise the long-term cost of electricity supplied to customers from the South West Interconnected System. • Providing additional competition to generators in the provision of reserve capacity. • Reducing discrimination against particular energy options and technologies, namely the demand side, by removing an existing barrier to the demand-side participating on a level playing field in the RCM. We would also encourage EPWA to consider the duration requirements for DSP. Currently, a facility must be available to provide reserve for at least 12 hours (Rule 4.10.1(f)(iii)). We propose this be reduced to four hours, again to be more reflective of the expected value of demand side resources during grid stress events. A twelve hour dispatch is unachievable for many loads. For example, a refrigeration warehouse can only reduce load for a few hours before their goods start to spoil. Reducing the duration requirements to four hours would allow different types of load to provide valuable capacity for the times when the system is most under stress.

Other Aspects of the RCM

As noted above, we generally support the proposed amendments to the RCM relating to DSP. This includes the proposed approaches to outage planning and refunds. However, we put forward a slightly different approach to testing.

Response to consultation questions:

	Question	Enel X response
Testing		
14	Do stakeholders see any other aspects of flexible capacity that should be included in the testing regime?	For DSPs, we consider testing for flexible capacity should be approached in the same way as for regular DSP capacity, as discussed below.
15	Do stakeholders agree that flexible characteristics can be tested by observation?	
16	Do stakeholders agree that flexible characteristics can be tested by observation?	
17	Do stakeholders agree with the changes to Reserve Capacity Testing for DSPs?	We agree that the testing regime for DSPs will need to change to reflect the use of dynamic baselines. However we believe the testing regime could be improved to incentivise DSP participation whilst ensuring the integrity of DSP capacity. In general, it is not clear how the obligations and penalties of the two existing tests for DSP (the annual test and the verification test) interact, and why two tests are necessary. As noted in response to question 13, demand response dispatches (including for tests) result in costs to the customer. Requiring two tests per year – in addition to availability requirements – comes at a significant cost to potential participants. These costs either limit the amount of hours that resources are available for dispatch and/or increase the cost of providing this capacity. The system benefits of two tests are also not clear. The testing regime must strike an appropriate balance between ensuring the capacity is "real" and incentivising DSP resources to participate. In our view, one annual test is an appropriate

		balance – this provides sufficient certainty to AEMO that a resource is capable without using too many hours of that resource's dispatch capability. In Enel X's view, one annual test, a 20 hour dispatch limit, and the other incentives and penalties in the RCM framework will sufficiently incentivise participation in the RCM whilst ensuring the integrity of DSP reserve capacity. We believe this framework will deter any participant from taking on a capacity obligation speculatively or failing to deliver contracted capacity. Regarding the treatment of failed tests as the beginning of a forced outage – we are concerned that this approach does not recognise that the primary purpose of generation and demand side resources are fundamentally different, and will unfairly penalise customer resources that may not be able to quickly remedy the unavailability.
18	What are stakeholder views on completely aligning the generation and DSP testing regimes?	We do not consider that it is appropriate to completely align the DSP testing regime with the generation testing regime. The testing framework must recognise that the way in which generation capacity and demand side capacity are used in the RCM differs, and the cost/benefit trade-off for participation differs. Alignment of the testing regime should not be an objective for its own sake – as above, testing must strike an appropriate balance between what the system operator actually needs to verify for that type of resource, and what will encourage that resource to participate.
Outage planning		
19	Do stakeholders agree with the proposed changes to AEMO's outage assessment process?	No comment
20	Do stakeholders agree with the proposed approach to flexible capacity outages?	No comment
21	Do stakeholders agree with the proposed approach to DSP outages?	We support the proposal to allow DSP owners to manage their own outage schedules, without participating in the outage planning regime. We agree with EPWA's view that because DSPs are dispatched infrequently, the cost of DSPs participating in the outage planning process are likely to be higher than the benefits. As such, we support continuing to allow participants to schedule their own outages.

		We also agree that if a dynamic baseline is implemented, the availability measurement would need to be amended.
Refunds		
22	Do stakeholders agree with the proposed approach to flexible capacity refunds?	No comment
23	If stakeholders consider that the potential refunds for flexible capacity outages should be capped, what proportion of the total payments would they suggest, and why?	No comment
24	Do stakeholders agree with the proposed approach to refund multipliers?	No comment
25	Do stakeholders agree with the proposed approach to DSP refunds?	As noted above, it is our view that the existing penalty and refund regime, combined with the testing regime proposed above, is robust enough to deter any participant from taking on a capacity obligation speculatively or failing to deliver contracted capacity. In Enel X's view the risk of losing capacity credits is sufficient incentive to ensure that capacity is available. We are not convinced that DSP participants should be more heavily penalised than generation because "participants are unlikely to have invested in significant capital expenditure to set up a DSP". We do not consider that DSP should be penalised simply for being a more economic resource. And, as noted above, DSP dispatches are not without cost. A clearer policy rationale for this proposal is needed if the change is to be made.
26	Do stakeholders agree with the proposed distribution of collected capacity refunds?	No comment
The EUE Target in the Planning Criterion		
27	Do stakeholders agree with the proposed change to a 0.0002% EUE target in the Planning Criterion?	No comment
Determination of the BRCP Technology		
28	Do stakeholders agree that the Coordinator should determine the reference technology for each of the capacity products?	No comment

29	Do stakeholders agree that the potential adoption of a net CONE approach should be considered with the reference technology?	No comment