5 October 2023

Nomiky Panayiotakis
Australian Energy Market Commission
GPO Box 2603
Sydney NSW 2000

Dear Ms Panayiotakis

RE: Improving security frameworks for the energy transition

Shell Energy Australia Pty Ltd (Shell Energy) welcomes the opportunity to respond to the Australian Energy Market Commission's (AEMC) second directions paper on the Improving Security Frameworks for the Energy Transition rule change.

About Shell Energy in Australia

Shell Energy is Shell's renewables and energy solutions business in Australia, helping its customers to decarbonise and reduce their environmental footprint.

Shell Energy delivers business energy solutions and innovation across a portfolio of electricity, gas, environmental products and energy productivity for commercial and industrial customers, while our residential energy retailing business Powershop, acquired in 2022, serves households and small business customers in Australia.

As the second largest electricity provider to commercial and industrial businesses in Australia[1], Shell Energy offers integrated solutions and market-leading[2] customer satisfaction, built on industry expertise and personalised relationships. The company's generation assets include 662 megawatts of gas-fired peaking power stations in Western Australia and Queensland, supporting the transition to renewables, and the 120 megawatt Gangarri solar energy development in Queensland.

Shell Energy Australia Pty Ltd and its subsidiaries trade as Shell Energy, while Powershop Australia Pty Ltd trades as Powershop. Further information about Shell Energy and our operations can be found on our website here.

General comments

Shell Energy considers that one of the key features of the previous draft determination was the AEMC's preference for essential system services (ESS) to be unbundled and valued separately from energy. With the retirement of large synchronous generators, the provision of some essential services like system strength and inertia alongside energy generation is no longer a given. With the right signals, inverter-based resources (IBR) and specifically designed flexible synchronous generators could deliver these services provided there is a signal

[1]By load, based on Shell Energy analysis of publicly available data.
[2] Utility Market Intelligence (UMI) survey of large commercial and industrial electricity customers of major electricity retailers, including ERM Power (now known as Shell Energy) by independent research company NTF Group in 2011-2021.

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to do so, and the value of providing the service can be forecast over the longer term. The Operational Security Mechanism (OSM) draft determination sought to achieve this.

The AEMC's second directions paper does not appear to place the same importance on unbundling these services. Shell Energy sees this as a drawback in the proposed approach. Given the scale of change from the draft determination to this second directions paper, Shell Energy recommends the next stage in this consultation process be a revised draft determination rather than moving straight to a final determination.

We consider that allowing continuation of unit configuration bundles results in opaque outcomes to the market where there is a real risk that what are market supplied services are contained within a bundle. We note AEMO has released details on the South Australian minimum synchronous generation requirements[3] where services such as adequate energy reserves, energy ramping services and frequency control reserves are all included in the determination of the unit configuration bundle. Shell Energy considers all these services fall within the boundaries of the energy and FCAS markets or if required, the reliability and emergency reserve trader provisions. AEMO also details all the currently known ESS including grid reference, voltage control, inertia and system strength. As such it is unclear to us why the AEMC has determined the process to unbundle ESS is too difficult. We believe the AEMC should prioritise the development of unbundled ESS by reducing the timeframes set out in the directions paper from 10 years to 5 years, where it is currently proposed ESS would be provided either by contracts or directly procured by transmission network service providers (TNSP).

Also, any proposed solution must only address the essential systems shortfalls i.e. the cause, and not just the symptoms. Limits associated with transient, voltage and angular stability are symptoms, not causes. Inertia, voltage control or support, grid reference and system strength are the services which improve the limits of operation for the secure powers system envelope. In our view, the AEMC must therefore ensure it addresses the ESS requirements and not allow this to get confused with symptoms. ESS should only be procured to allow secure operation of the interconnected Mainland or islanded Tasmanian power systems.

Under the AEMC's proposed approach, TNSPs would be the sole procurers of essential system services like inertia over the next 10 years. The creates a risk that TNSPs may look to find options that deliver the service over a long period, for which they will receive a long term guaranteed return through their Regulated Asset Base (RAB) regardless of eventual need. Such an outcome prevents alternative, lower cost solutions from being delivered as they are needed over the long term. Even if a market were to eventuate, TNSPs would have the advantage of already having assets in place that have been effectively subsidised by energy consumers.

From our perspective, the crucial timeframes to deliver ESS for the energy transition is in the early stages. If, for the next ten years, only TNSPs procure (or install) the necessary ESS, the AEMC's proposed approach will reduce the incentives for incoming generators to consider providing ESS as they connect to the grid. This risks crowding out efficient investment over the long-term and locking in higher cost approaches. In our view, it would be preferable and more efficient to reduce the timeframe to 5 years, with annual reviews analysing whether the unbundling of services and implementation of a market-based solution is feasible.

Further, Shell Energy considers that there should be stronger guardrails around any long-term contracts initiated by TNSPs including potentially limiting the length of contracts or limiting what can be provided. For instance, should TNSPs be required to procure services via contracts or unregulated assets rather than building regulated assets? We also suggest that any contracts than TNSPs enter into, be limited to a timeframe of three or four years. This would ensure that incentives remain over the long-term for other potential providers of ESS to efficiently deliver these services and be appropriately rewarded for doing so.

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[3] AEMO, SA minimum synchronous generator requirements – Stakeholder update package, September 2022 **Error! Hyperlink reference not valid.**and SA minimum synchronous generator requirements – Update, May 2023.

Changes to directions compensation

Shell Energy notes the AEMC's proposed approach to changing the compensation arrangements for direction to align it with the market suspension compensation framework. We recognise the AEMC has identified potential benefits from making this change, we consider there are several key issues the Commission has not examined at this stage. We agree with the AEMC's view that the 90th percentile approach currently used is not entirely appropriate and may over-compensate some generators while under-compensating others, leading to additional compensation claims.

Firstly, the benchmark prices used in the market suspension framework are currently inadequate and have not resulted in provision of adequate compensation – claims for additional compensation are frequently lodged. Duplicating this framework for the directions compensation framework risks increasing rather than reducing the frequency of claims for additional compensation.

While the AEMC's proposed approach is undoubtedly simple, using benchmarks for fuel costs, efficiency and variable operating costs, it only appears to be relevant for some but not all gas, diesel or coal-fired power plants. As the AEMC acknowledges, the proposed benchmark calculation does not factor in the opportunity costs involved for energy-limited plant such as pumped hydro and BESS and also, some gas, diesel and coal fuelled plant. The AEMC's proposed approach to explicitly reject opportunity costs for directions payments creates a strange form of discrimination, whereby thermal plant would be compensated based on a benchmark fuel cost, whereas hydro and BESS would be treated on a different basis, which would likely leave the exposed to losses. Even if the AEMC were to determine a different approach for batteries, it would create a different kind of technology-based discrimination.

We also strongly reject the AEMC's implied view that participants seek to be directed. Our view is that, by and large, generators would rather be dispatched as per their dispatch offer prices. In many cases, where participants are directed, the real driver is clause 3.9.7(b) which states that a generator that is constrained-on is not entitled to receive any compensation due to its spot price being less than its dispatch offer price. Consequently, a generator concerned it will be constrained on, is likely to choose to bid as unavailable to avoid being constrained-on and potentially running at a loss. If it is then directed to operate, it can receive compensation for its costs. Had this clause been modified earlier to allow for compensation for participants dispatched for essential system services to receive compensation, we consider that most, if not all, directions for system strength in South Australia may not have been required.

Shell Energy strongly argues that changing this clause to allow generators constrained on to receive compensation, would largely eliminate this problem, where generators are left with no other choice than to bid as unavailable. We consider that changes to this clause could involve adding a new sub-clause to allow generators constrained on for the purposes of providing essential system services, to receive compensation for being dispatched below their dispatch offer price. Additionally, clause 3.15.7B should be altered to allow Directed participants constrained on to apply for compensation for opportunity costs.

Cost recovery arrangements for NSCAS

The AEMC proposes applying the current NSCAS cost recovery provisions for TNSP procurement to inertia service and system strength procured through the NSCAS framework. This would mean that cost recovery for all services procured through the NSCAS framework is consistent. NSCAS costs are currently recovered from consumers through the TNSPs' regulated transmission charges. In our view, costs should not simply be imposed on market customers (effectively consumers) but should be based on user or beneficiary pays cost recovery using methodology determined by AER.

Changes to reporting requirements

The Paper outlines a series of changes relating to reporting with two key areas: reporting on directions, and reporting on the enablement of system security contracts. At a high level, Shell Energy believes that the reporting obligations should operate more or less in parallel, with similar information published on similar timeframes.

Shell Energy welcomes the AEMC's intention to improve transparency regarding the reporting of directions information. The AEMC proposes requiring AEMO to publish a market notice when issuing a direction. Further, directions reporting for specific events would be replaced by quarterly reporting.

We agree with the need for quarterly reporting to outline the costs of issuing directions, the system services required, the volume of MW directed and the circumstances which necessitated the direction. While the AEMC indicates a brief description of the circumstances that necessitated the direction would be required in a market notice, we consider that more detailed descriptions should be required in the quarterly reports.

For AEMO's reporting on the enablement of system security contracts, we consider that the proposed timeframes of "at least annually" is insufficient. We argue that quarterly reporting would be more effective as the reports would complement the quarterly reports on the costs and circumstances of directions reporting. This would allow participants to consider the two sets of actions alongside each other, and understand how an absence of a system service contract for instance, influences the costs and need for a direction.

We recommend that AEMO's reports on the enablement of system security contracts also be required to explain the circumstances surrounding each instance of contract dispatch and discuss how the costs of dispatching ESS contracts relate to the benefits provided. We argue that this would complement the directions reporting obligations by demonstrating how costs compare between ESS contracts and directions compare on the same timeframes.

ESS reporting

At present, AEMO publishes annual reports on inertia, system strength and NSCAS requirements and shortfalls. Shell Energy wishes to understand to what extent the new reporting requirements, including requirement to report at least annually on enablement processes, will be included with these reports or within a separate report. Additionally, we believe the AEMC should consider whether a single report would offer a clearer and more accessible approach than multiple ESS requirements and dispatch outcomes reports potentially published on different timelines.

We firmly believe that the aggregated costs of enabling contracts for ESS be included in these reports, alongside an analysis of enablement processes and potential reporting. Though we recommend that reporting of the aggregated costs should be done on a quarterly basis, to provide greater clarity to the market. We acknowledge the AEMC has proposed daily reporting of enablement outcomes, but an aggregated quarterly report would provide significant benefits to market participants (and consumer advocates in particular) to assess the costs over time.

Shell Energy also contends that these reports should include an assessment on how AEMO is progressing towards unbundling the services to allow markets to develop. In our view, AEMO should report on progress annually, with a more comprehensive assessment at year 3 and year 4 of our proposed 5-year timeline. This reporting timeframe would allow AEMO and the AEMC to assess the potential for markets for unbundled ESS markets to be implemented sooner than the 10-year timeline (with a review after 7 years) set out in the AEMC's directions paper.

Enablement principles

The AEMC proposes that AEMO's enablement decisions would be guided by principles in the Rules. These principles would include:

- enable a combination of contracts that meet the required level of the security services at lowest cost
- not enable contracts more than 12 hours ahead of time
- aim for efficient outcomes when enablement contracts ahead of time – balancing more accurate forecasts closer to real-time with unit commitment constraints
- enable contracts only when energy spot market outcomes are not expected to provide the required level
- only enable contracts to meet security service gap, not always enable for the full amount of the required service
- enable contracts for stable voltage waveforms only where the enablement of system strength contracts results in an overall increase in dispatched IBR and the total increase in dispatched IBR is greater than the total energy provided by additional system strength contracts.
- aim to – but not be required to – use contracts specifically for their contracted purpose (for example, system strength contracts to meet system strength needs).

Broadly, we see that these principles aim for the right results. However, we consider some amendments may be required. Firstly, we consider the principle that contracts should not be enabled more than 12 hours ahead is too long. While start up times of plants do vary by technology, the 12-hour limit appears to sit in between the approximate start times for some but not all gas plant of around 4 hours, and for coal-fired plant, of around 24 hours. In our view, this timeframe runs the risk of contracts being enabled earlier than they could and therefore imposing costs on consumers when they may not ultimately be necessary. We argue that reducing this time to 4 hours is likely to have little if any impact on the plant that may participate, would still allow ample time for contracts to be enabled and reduces the risk that contracts would be enabled when not ultimately needed. Such that there may be plant that would not be able to participate with 4 hours' notice, then there may be a case to extend this out to something more appropriate. However, we do believe that it is incumbent on the AEMC (or AEMO) to outline the need for whatever time frame is chosen with reference to what additional plant (in general terms) could be able to participate at different timescales.

We are also concerned that the principle that AEMO must aim to use contracts specifically for their contracted purpose, but is not required to, may provide too much leeway for AEMO to use ESS contracts for other reasons. To avoid this risk, we note the AEMC may need to clarify the first principle to "enable a combination of contracts that meet the required level of the security services at lowest cost". We consider that "lowest cost" could refer to total cost of energy plus the enablement of ESS contracts. We consider that this principle should be amended to ensure that lowest cost refers to the total cost of enablement of these contracts.

Inertia procurement

The AEMC has proposed changing the current inertia requirements to have AEMO set a mainland NEM inertia floor. AEMO would still be able to procure additional inertia in sub-networks that may still be at risk of separation and therefore require higher levels of local inertia to maintain system security when operating as an island.

Shell Energy believes that this change requires clarity as to what volume of inertia would be procured in the case of islanded sub-networks. We contend that the minimum level of inertia required to support an islanded sub-region would be the most appropriate value but this is unclear in the Paper at this stage.

We also consider that the AEMC should seek to define in the Rules how to determine whether a sub-region is at risk of islanding. At present, clause 5.20B.1 is relatively open as to how sub-networks are defined, and there is currently no methodology or process document setting out how AEMO defines sub-regions. The 2022 Inertia Report[4] contains some limited information in this area but lacks detail. Shell Energy also suggests that where AEMO identifies the risk of sub-regional or regional islanding, the at-risk network assets should contained in AEMO's List of Vulnerable Transmission Lines.

There are a range of potential ways that a sub-network could be defined as being at risk of islanding, depending on the level of risk AEMO is willing to accept. A greater appetite for risk may entail lower costs to procure inertia (if any) but does increase the risk of there being insufficient levels of inertia should an islanding event occur. A more cautious approach would reduce the risks of inertia shortfalls but could increase costs. Whatever approach is taken, Shell Energy considers there to be a need for transparency around how these decisions are made. We propose that the definitions should either be explicit within the NER or require consultation with the Reliability Panel, AEMO's technical advice and that of other independent experts.

Enablement levels to support system security

Under the AEMC's proposed approach, AEMO would be allowed to enable system strength contracts to meet the projected level of dispatch from IBR, but only if it results in an overall increase in the level of IBR dispatched. The AEMC gives examples of what it wants to avoid, such as a 50MW thermal generator being dispatched that would allow an extra 1 MW of IBR to be dispatched, or the dispatch of 50 MW of system strength that enables 50 MW of IBR to be dispatched, but it displaces 100 MW of IBR elsewhere.

We recognise the AEMC's goals with this proposal and agree that at a basic level they are reasonable. It would make little sense to enable system strength contracts that do not result in an overall increase in the volume of IBR dispatched. An increase in the level of IBR such as wind and solar could reduce spot prices and emissions.

Yet, the requirements set out in the directions paper do not appear to consider the possible cost impacts of achieving this. If the cost of enabling a system strength contract exceeds the reduction in spot market costs (potentially including a value for emissions) then consumers will be worse off.

Nor does an increase in IBR guarantee the dispatch of lower-cost energy. While wind and solar make up the bulk of IBR in the NEM, BESS are also IBR, and as such it is feasible that a system strength contract, when enabled, displaces coal-fired or gas-fired generation, which may or may not have an emissions benefit, only to result in an increase in higher cost BESS generation. This could result in both a higher spot-price plus the costs of the system strength contract being imposed on consumers.

The AEMC does recognize the cost impact in principle, stating that:

> *"Over time, if cheaper IBR is able to be dispatched more often through enablement, then the wholesale energy price is likely to reduce, outweighing the costs of system strength contracts"*[5]

Shell Energy agrees that this may be the case in theory but will depend on the total costs of IBR generation and enabling of system strength contracts as well as the uncertain impact this has on wholesale spot prices and potentially, the level of emissions reduction that is also achieved. There is no certainty that such outcomes will flow through to financial contract prices which will include not just the total costs of IBR generation but also the costs of firming variable renewable energy resources.

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[4] AEMO, 2022 Inertia Report, December 2022.

[5] AEMC, *Improving Security Frameworks for the Energy Transition, Directions Paper*, 24 August 2023, p82.

We recommend the AEMC to consider ways to ensure that any system strength contract enabled for IBR purposes delivers more benefits than the cost of enabling the contract. We also seek clarification from the AEMC as to how such contracts would operate alongside the proposed Transmission Access Reform (TAR) model which may favour dispatch of some resources through the priority queue model, or allow for increased IBR dispatch through the Congestion Relief Market (CRM).

Acquisition of transitional services by AEMO

To incentivise newer technologies to participate in the new Non-market Ancillary Services (NMAS) framework, the AEMC has drafted rules allowing AEMO to enter into bilateral agreements with "transitional service providers". Shell Energy supports AEMO having the ability to do this, but considers that the rules as drafted do not provide sufficient protections to the transitional service providers.

Our concerns stem from draft clauses 3.11.11(e) and 3.11.11(f), the former of which gives AEMO powers to determine whether the tenders are competitive and engage in good faith negotiation with the provider if AEMO determines that the offers are not competitive. The latter clause allows for disputes on any aspect other than price to be handled using the existing dispute resolution rules.

As AEMO determines whether offers are competitive in terms of price, but potential transitional service providers have no opportunity to dispute AEMO's views on price, this creates an imbalance of power in contractual terms. We consider that the AEMC should allow for transitional services providers to engage an independent expert to determine fair pricing in the event that AEMO and the provider are unable to reach an agreement on pricing for the service.

In addition, we recommend that the rules contain clear provisions that AEMO's use of transitional services only be for the time required to meet any identified shortfall. The use of transitional services contracts by AEMO should be limited to meeting short lived but critical needs and no more. Where the intent is to allow use of these transitional services contracts to improve AEMO's ability to operate the power system, such outcomes must be fully transparent, and our preference is that an operability standard be developed and set out in the rules. Operability must be treated like any other market element with set parameters representing efficient levels.

Pricing of services

We consider there is a degree of ambiguity in the proposed rules regarding the pricing of services. When offered as a dollar per hour based on a min dispatch level or $/MWh of dispatch, the rules should be clear that this price is net of spot price. The ESS dispatch price would act as a floor that the service provider should receive.

Routine review of AEMO's guidelines, methodology and process documents

The proposed rules set out in a number of places where AEMO must develop guidelines, methodology and process documents in accordance with the rule's consultation procedures. However, once developed these requirements are not subject to review unless AEMO determines a change is warranted. We consider this to be a substandard outcome and consider that these guidelines, methodology and process documents should be subject to routine two or four yearly review to facilitate improvements where warranted.

Conclusion

Shell Energy welcomes the additional analysis the AEMC has undertaken to understand how to ensure there are sufficient ESS delivered in the NEM as part of the energy transition. Given the significant changes from the draft determination to the second directions paper, we suggest the AEMC releases a revised draft determination as the next stage of consultation rather than moving straight to a final determination. We consider that further changes to the AEMC's draft position are needed to deliver better incentives for markets to deliver ESS as traditional providers such as thermal generators retire from the NEM. Shell Energy recommends the following changes:

- Reducing the timeframe of the new framework to 5 years rather than 10 years
- A review of the progress towards unbundled markets for ESS services after 3 and 4 years
- Changing clause 3.9.7(b) of the NER to improve the directions compensation framework
- Quarterly reporting on the costs of ESS contract enablement
- Ensure that the benefits of enabling system strength contracts to enable greater IBR generation exceed the costs
- Reduce the ahead time for enabling ESS contracts to 4 hours.

For more detail on this submission, please contact Ben Pryor, Regulatory Affairs Policy Adviser (0437 305 547 or ben.pryor@shellenergy.com.au).

Yours sincerely

[signed]

Libby Hawker
GM Regulatory Affairs & Compliance