23 May 2019

10 Eagle Street
Brisbane QLD 4122
T 07 3347 3100

Mr John Pierce
Chair
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Dear Mr Pierce

Investigation into intervention mechanisms and system strength in the NEM – AEMO Submission

Thank you for the opportunity to contribute to the AEMC's investigation into intervention mechanisms and system strength in the NEM. With increasing rates of system strength directions in the NEM, AEMO believes this is an important and timely investigation.

AEMO welcomes this opportunity to comment on relevant issues in a holistic way. The consultation paper addresses various components of the intervention and system strength frameworks and has highlighted linkages between these components. AEMO has previously submitted 4 rule change requests to the AEMC which relate to this investigation and this submission is an opportunity to consolidate some of the content of these submissions. It is also an opportunity to provide general comment on intervention and system strength in the NEM.

AEMO's submission below outlines our views on the issues raised in the consultation paper. It draws on our experience in implementing directions and other forms of intervention, and our expertise in the regulatory and technical aspects of system strength.

Should you have any questions on the matters raised in our submission, please contact Brian Nelson, Manager Electricity Market Monitoring on 02 9239 9132.

Yours sincerely

Peter Geers
Chief Strategy and Markets Officer

1. Introduction

1.1 Regulatory considerations

AEMO believes market intervention should only be used as a last resort and should not be relied on for essential power system services such as system strength and inertia. AEMO recognises that the NEM has seen intervention with unprecedented frequency in recent years. During this time, intervention has predominantly (but not exclusively) been in the form of directions to synchronous generators to aid system strength in South Australia (SA).

The AEMC's investigation is an important opportunity for AEMO to share its insights into the directions process and its views on how surrounding frameworks can be developed to support efficiency of intervention in the short term. It is also an opportunity to inform the process of system strength shortfall assessment for the medium to long term. AEMO believes any changes to regulatory arrangements should consider:

- The scope of the potential impact. For example, whether the implications of a change to NER are confined to a particular:
  - NEM region
  - Time period
  - Intervention mechanism
  - System security service
- Historical outcomes in the NEM under current arrangements
- Implementation costs, especially in cases where the impact of a regulatory change is likely to be small
- Operational and financial risks
- All value streams of existing assets or new investments

1.2 Technical considerations

The need for security services is informed by an understanding of the stable technical operating envelope of the power system. Power system stability is determined by the highly complex interaction of many electrical and mechanical elements. The strength and resilience of a system to recover from a disturbance relates to all network components, including synchronous and asynchronous generation, as well as network and generator protection systems.

Stability in the context of traditional power systems (predominantly based on synchronous generation) is well understood, informed by an extensive power engineering knowledge base and operational experience globally over several decades. Increasing penetrations of asynchronous generation have led to the emergence of other forms of instability (such as adverse control system interactions) and the need for re-examination of previously well-understood forms.

Like other grid operators worldwide, AEMO's understanding of the technical envelope continues to evolve as the generation mix becomes increasingly asynchronous. This is informed by our experience operating parts of the NEM already at high levels of penetration, learnings from actual system events, and transitioning to modelling tools that can better capture the fast-acting control systems associated with asynchronous technologies, such as PSCAD™.

AEMO believes that regulatory arrangements should be sufficiently flexible to accommodate this evolution and the opportunities and challenges it presents.

1.3 Nature of system strength

System strength is an umbrella term for a range of interrelated factors that together contribute to the stability of the power system. System strength reflects the ability of network voltages to withstand small and large disturbances. It affects the stability and dynamics of generating systems' control systems, and the ability of the power system to remain stable under normal conditions and return to steady-state conditions following a disturbance.

The current system strength arrangements in the NEM rely on simplified metrics commonly used to assess system strength under different operating conditions, including:

- Fault level: for system strength requirements and shortfall assessment
- Short circuit ratio: for the 'do no harm' assessment of the system strength impact of connecting generators

While AEMO understands the need for consistent metrics within the system strength framework, we emphasise the need for flexibility to allow for all aspects of system strength to be appropriately considered. With respect to shortfall assessment and requirements, the current system strength framework and the AEMC's consultation paper use the terms "system strength" and "fault level" interchangeably. AEMO suggests the current framework be revised to remove references to "fault level" unless this is the absolute intention rather than "system strength."

2. Hierarchy of intervention mechanisms

AEMO views the three intervention mechanisms - directions, RERT and instructions - as a suite of options which can be used to ensure the security and/or reliability of the power system. AEMO supports changes to the hierarchy such that RERT is not preferred to directions. However, an ideal hierarchy is one that maximises operational flexibility, allowing AEMO to select the option it expects will deliver security and/or reliability at the lowest cost to consumers, accounting for the risks associated with different outcomes. This is equivalent to removing the hierarchy and having the choice between different intervention mechanisms informed only by expected costs and risks in each instance. It is not possible to conclude that one particular type of intervention will always be more efficient than another in any set of circumstances. AEMO therefore does not support a hierarchy which prescribes the use of a particular intervention mechanism where another mechanism may be available to it at lower cost.

The benefits to consumers of a Rules framework which maximises flexibility are illustrated in the example below. The example also highlights how AEMO assesses the expected cost of different intervention mechanisms in real time, and the challenges associated with this.

Example 1 - Addressing supply scarcity

Suppose it is expected that the NEM will experience a supply scarcity event, that a combination of fast start units and slow start units are available for direction, and that RERT is available. For simplicity, assume there are three times at which a decision to intervene could be made by AEMO:

1. The time slow-start units would need to be directed
2. The earliest time RERT contracts would need to be activated or pre-activated
3. The time fast-start units would need to be directed

At time 1, if it is forecast that the impending supply scarcity can comfortably be addressed by fast-start capacity alone, then there is no need to start any slow-start units. Conversely, if it is forecast that fast-start capacity will be insufficient to address the issue, then the slow-start units would be directed to provide energy. If it is forecast that fast-start capacity will be sufficient to address the issue, but only by a small amount, then AEMO would need to assess whether the likelihood and expected cost of having insufficient fast-start capacity at time 3 warrants issuing directions to slow-start plant at time 1. Directing slow-start plant at time 1 would typically be a more expensive option than directing fast-start plant at time 3. However, directing slow-start plant at time 1 allows the flexibility of fast-start units to be retained until time 3, since a choice can then be made at time 3 as to whether fast-start units need to be directed. AEMO's assessment of whether to direct slow-start units, even though they may not be needed, effectively places a value on the additional flexibility of fast-start units above slow-start units.

A similar decision is made at time 2, this time assessing whether the likelihood and expected cost of having insufficient fast start capacity at time 3 warrants activating RERT.

The box above describes lowest expected cost deployment of intervention mechanisms, accounting for uncertainty. As described, this may involve directions (to slow-start plant), followed by RERT activation, followed by directions (to fast-start plant). AEMO supports a hierarchy which facilitates this deployment. That is, one which does not prefer RERT to directions. Conversely, AEMO does not support a hierarchy in which directions are necessarily used in preference to RERT. By using 'slower' options such as RERT before 'faster' options such as directions to fast start plant, AEMO can retain the flexibility of the faster options for longer. This flexibility has a value which may offset the additional cost of, for example, using RERT.

In many circumstances, eliminating the preference for RERT over directions effectively removes the need for a hierarchy altogether, because both RERT and directions will often be lower cost options than instructions to shed load. However, as is addressed in the AEMC's final determination on enhanced RERT, RERT will not always be a cheaper option to consumers than instructions to shed load. Therefore, a hierarchy of intervention mechanisms which prioritises RERT (or directions) over instructions may limit AEMO's ability to secure the power system at least cost.

Variability and unpredictability inherent in forecasts, supply-scarcity profiles and the plant mix available for direction complicate decision making in real time. From AEMO's perspective, this further highlights the benefits of a rules framework which maximises the flexibility of intervention. AEMO also notes that, in practice, it can be difficult to intervene in a way that strictly minimises expected cost accounting for the value of flexibility. Intervention, by definition, is outside the market and hence cost optimisation with the same level of sophistication as within the market via NEMDE is not possible. Though AEMO endeavours to make decisions following the logic described in the example earlier in this section, AEMO believes that strict obligations to minimise expected costs are inappropriate.

3. Mandatory restrictions

AEMO considers that the mandatory restrictions framework should not be retained. Jurisdictions have not exercised mandatory restrictions powers since the framework was introduced into the Rules in 2001. By different means, the Victorian, South Australian and New South Wales state governments have provided funding in support of RERT, indicating this is a preferable means of managing supply shortfalls. AEMO suggests that retaining the complex process in rule 3.12A to reflect jurisdictional rationing in NEM pricing is not justified given the very low probability of occurrence.

4. Counteractions

AEMO considers the counteractions framework should not be retained. Rules clause 3.8.1(b)(11) requires AEMO, as far as reasonably practical, to minimise the number of affected participants and the effect on interconnector flows resulting from a direction. Under current processes, AEMO attempts to do this through counteractions. AEMO notes that its obligations specified in Rules clause 3.8.1(b)(11) may conflict with the requirement to minimise the cost of directions, as specified in Rules clause 4.8.9(b)(1).

It is not generally practical for AEMO to apply counteractions during directions to synchronous generators for system strength in SA. Hypothetically, if counteractions were possible, they would likely result in increased output from thermal units in Victoria. This is because counteractions to reduce interconnector impact would be implemented by reducing the output of the highest bid generator in SA which is not contributing to system strength. This is likely to be a wind generator. As a result, Vic-SA interconnector flows would likely tend more towards SA than without the counteraction. This means additional generation would need to be sourced within the Victorian region. This is likely to be thermal generation. Under the current rules, affected participant (and eligible person) compensation would put SRD unit holders in the same position regardless of whether counteraction occurred. Thus, the tangible difference between counteracting and not is that counteracting displaces SA wind generation with higher fuel cost generation in other regions, resulting in higher prices.

If counteractions were to remain, and the premise of applying intervention pricing to system security directions is accepted[1], then AEMO believes that intervention pricing should still apply when directions are counteracted. In general, the more closely a counteraction is matched to a direction, the smaller the impact on physical dispatch resulting from the direction and counteraction combination. However, this is not guaranteed and is difficult to predict. If the impact on physical dispatch is significant, and intervention pricing is applied, NEMDE's outturn and pricing runs would be materially different. In this case, applying intervention pricing is valuable because it retains the same signals for energy and FCAS that would have occurred but for the direction. If the impact on physical dispatch from a direction and counteraction combination is small, applying intervention pricing does not materially improve or worsen the economic efficiency of dispatch. In such cases, NEMDE's outturn and pricing runs would not be materially different. Applying intervention pricing is thus at little or no cost to consumers. As the benefit of applying intervention pricing when it is needed is high, but the cost of applying when it is not are low, AEMO considers it prudent to apply intervention pricing regardless of the precision of counteractions.

5. Intervention pricing

5.1 Market-traded and non-market-traded services

AEMO believes it is inefficient to apply intervention pricing during directions whose purpose is to address scarcity of non-market-traded services. Applying intervention pricing according to this principle would greatly reduce the number of intervention pricing events, as system strength (for example) is not a market-traded service. Applying intervention pricing in this manner would also largely eliminate many of the concerns raised in this consultation.

Intervention pricing during supply scarcity directions ignores any energy which is provided as a result of the direction. This preserves an energy price which would efficiently meet demand if no direction occurred. In this way, intervention pricing induces efficient commercial behaviour (investment, planning

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[1] AEMO believes counteractions should not remain and, as per section 5.1, intervention pricing should not apply to all system security directions.

or operation) consistent with the direction not occurring. This behaviour is more likely to address similar reliability issues in the future[2].

In contrast, NEM spot prices cannot signal the scarcity of services, such as system strength, that are not market-traded. Therefore, AEMO does not believe it is efficient to preserve the energy or FCAS prices which would have occurred with no system strength directions. Intervention pricing in this context would generally lead participants to believe a similar future scenario would result in higher energy and/or FCAS prices than would have occurred without intervention pricing. This induces commercial behaviour which will likely provide more energy and/or FCAS. Intervention pricing does not, however, induce the provision of system strength.

In practice, intervention pricing during system strength directions may worsen system strength by inducing additional investment in generation capacity which does not aid system strength. Instead, it is preferable that the energy price reflect the level of scarcity of energy on an operational timeframe. Thus, the energy price should be based on 'residual energy demand' that is not met by plant directed to aid system strength. In general, where there is a shortage of a non-market-traded service, the energy price should account for the provision of any 'free' energy provided to the system as a by-product of directions.

5.2 RERT

AEMO does not support changes to the current pricing approach employed when RERT is activated. Broadly, the purpose of RERT is to provide additional reserves to the market and thus it is not activated exclusively in scenarios where a supply shortfall would have occurred and the price would have been set to MPC[3]. By applying intervention pricing while RERT is activated, the energy price is only set to MPC at times when in-market generation (as distinct from RERT provision) would have been insufficient to meet demand. This ensures that RERT does not influence the spot market's signal of energy scarcity.

To set the spot price to MPC whenever RERT is activated would conflate a lack of reserves with a lack of energy and incorrectly imply the energy market should explicitly value reserves. RERT may be activated to provide reserves in response to an LOR2. If LOR3 is not reached, it is likely that no load shedding would have occurred even if no RERT had been activated. In such a case, it would be inappropriate to set prices to MPC.

6. Changes to the RRN test

The intent of AEMO's proposed changes to the wording of the RRN test in Rules clause 3.9.3(d) is captured in its rule change request. This section clarifies AEMO's intent in relation to observations in the AEMC's consultation paper.

AEMO intends that the RRN test would be considered for all interventions where the Rules provide for intervention pricing to apply. Under the current intervention pricing framework, all directions would continue to be subject to the RRN test regardless of the purpose of the direction. For example, system strength directions in SA would continue to be subject to the RRN test. Conversely, if the intervention pricing framework proposed in section 5.1 were introduced, the RRN test would only need to be considered for interventions to address scarcity of market-traded services (energy and FCAS).

The AEMC has noted that AEMO's proposed redrafting of the RRN test carries new implications for periods affected by multiple directions. AEMO intends for the RRN test to be applied separately to each AEMO intervention event, even where multiple interventions are effective simultaneously. AEMO does not ascribe the same meaning as the AEMC to the phrase "any direction which constitutes the AEMO

[2] There have only been two reliability directions since 2010.

[3] Price may be at the MPC without a supply shortfall, reflecting participant bids. During a supply shortfall, Rules clause 3.9.2(e)(1) requires that the price be set to MPC.

intervention event"; it considers the only purpose of those words is to differentiate between a direction (which is subject to the RRN test) and an exercise of RERT (which is currently not).

The example below illustrates how AEMO currently applies the RRN test for periods when multiple directions are in effect.

Example 2: Simultaneous directions

> Suppose that two directions are effective at the same time. However, only one direction passes the RRN test. To implement the directions, two constraints would be invoked, for example specifying the minimum loading of two generators. The constraint relating to the direction which passes the RRN test would have an intervention flag attached to it, whereas the other constraint would not. The constraint with an intervention flag would then be removed from NEMDE's intervention pricing run. In this way, intervention pricing ignores the direction which passes the RRN test and hence intervention pricing in the NEM would cease whenever this direction ends. AEMO notes this interpretation reflects current processes and AEMO's proposed wording of the RRN test was intended to support the continuation of these processes.

7. Compensation

7.1 Compensation reporting

The AEMC's consultation paper raises the prospect of more explicit reporting requirements with respect to compensation following directions. There are presently conflicting indications in the Rules that indicate confidentiality of individual amounts, yet a requirement for the independent expert report to include total direction compensation will reveal an individual amount where there is only one directed participant. AEMO welcomes certainty in the Rules as to the level of detail to be published on compensation amounts.

7.2 When should affected participants be compensated?

Consistent with AEMO's view on intervention pricing, affected participants (and eligible persons) should only be compensated for the effects of directions to address scarcity of market-traded services.

During system strength directions, and assuming intervention pricing is not applied, some energy bid above the clearing price would have been dispatched had the direction not occurred. This energy is not part of the generation mix that most efficiently meets the NEM's combined energy and system strength needs. It is therefore not efficient to compensate for this energy not being provided.

More generally, it is not appropriate to compensate when directions are for scarcity of non-market-traded services. This means the same test proposed in section 5.1 for intervention pricing should also be used to determine whether affected participants should be compensated.

7.3 How should participants be compensated?

90th Percentile compensation of directed participants

The current practice of compensating directed participants using the 90th percentile spot price is resulting in very few claims for additional compensation from directed participants (6 claims across the NEM since the beginning of 2017). This suggests that this level of 'automatic' compensation is rarely insufficient to cover the costs of directed participants. If compensation payments are consistently greater than directed participant costs, there is merit in lowering the level of these automatic payments.

Some participants may view being directed as an alternative to remaining in service and receiving the spot price. A potential consequence of adopting the intervention pricing approach proposed in section

5.1 is an increase in the number of directions required to secure non-market traded services. With lower spot prices during direction, the incentive for synchronous generators which are not being directed to remain in service would be lower, and participant preference for being directed would be stronger. This may result in AEMO needing to direct more synchronous generators than under the current approach to intervention pricing. Lowering the payoff of being directed by lowering the directed participant compensation percentile may reduce the incentive to withdraw and help contain the number of directions.

AEMO believes that the level of compensation could be set at a lower level while still being sufficient to cover directed participant costs in most cases, noting that participants will retain the right to claim additional compensation if the percentile-based compensation is insufficient.

However, there are two additional complexities to 90^{th} percentile compensation that warrant consideration. First, spot prices are likely to be lower if intervention pricing is no longer applied during system strength directions. The 90^{th} percentile price would likely be most affected in SA. It would gradually fall within the first year of not applying intervention pricing to system strength directions.

Secondly, if 90^{th} percentile compensation is insufficient, participants may claim additional compensation to ensure a reasonable rate of return on the capital employed in the provision of the service[4]. With frequent directions, a lower compensation percentile may be sufficient to ensure a reasonable rate of return. Therefore, the frequency of direction should inform the selection of the spot-price percentile.

Framework for compensation of directed participants

The question of whether a spot price percentile is an appropriate framework for directed participant cost recovery is closely tied to the frequency of direction. Though it imperfectly reflects costs, AEMO believes that a formulaic approach to cost recovery, such as using a spot price percentile, is appropriate where the frequency of direction is high. A formulaic approach allows compensation amounts to be published soon after directions, which is of high value to participants with frequent directions. Further, if compensation were to be customised, each instance of compensation sets a more powerful precedent for the next instance than if directions were infrequent. This also suggests a formulaic approach is more appropriate if directions are frequent.

With infrequent directions, precedent is less powerful and the value of publishing compensation soon after a direction is lower. Therefore, a customised approach to compensation is more appropriate in this context.

$5,000 Threshold for affected participant compensation and additional compensation claims

The smallest directed and affected participant compensation claims received by AEMO since the beginning of 2017 have been approximately $20,000. It could be inferred that this represents an upper bound on the minimum cost of submitting an additional compensation claim. In the context of AEMO's rule change request to have the compensation threshold apply per event instead of per trading interval, the consultation paper questions whether the $5,000 claim threshold should be adjusted upwards. This question assumes that most events would span more than one trading interval, and on that basis an increase would be needed to effectively maintain the minimum threshold at a similar aggregate level.

The primary purpose of a threshold claim amount is to prevent or limit claims for which the processing and determination costs are likely to exceed the compensation payable. AEMO's compensation determination costs are approximately $5,000 per event. As the AEMC notes in its consultation paper, "the rationale for the threshold is that, if the amount is less than $5,000, this amount is immaterial and does not justify the costs of determining compensation payment." These costs are unlikely to increase

[4] Rules clause 3.15.7B(a1)(2)

with the number of trading intervals of direction, supporting AEMO's proposal that the compensation threshold should apply on a per-event basis.

The $5,000 threshold currently applies to both directed and affected participants. AEMO's administrative cost of determining compensation to/from affected participants is not materially different to the administrative cost of processing additional compensation claims from directed participants. Therefore, AEMO does not believe that different compensation thresholds should apply to directed and affected participants.

8. Approach to setting system strength requirements and identifying shortfalls

8.1 Assessment undertaken in 2018

AEMO published its inaugural system strength requirements methodology and determination of minimum fault level requirements in June 2018.[5] This assessment was undertaken for the state of the power system as at 30 June 2018 and did not assess potential fault level shortfalls beyond this point.[6]

8.2 Five-year assessment

AEMO's 2018 National Transmission Network Development Plan[7] projected system strength adequacy in the NEM over a five-year horizon. This considered system strength under the neutral scenario generation and network development outlook projected in the Integrated System Plan against the minimum requirements determined in 2018.

Over the last year or so, some parts of the NEM have observed significantly reduced synchronous generator unit commitment, as well as fast uptake of new asynchronous generator connections. These changes, together with changes in the operating profiles of existing generators, are driving rapid changes in power system conditions.

AEMO is currently developing a methodology to undertake the five-year ahead assessment in 2019 over a wider range of plausible future scenarios. In particular, AEMO is considering a number of "bookend scenarios" to assess the need for different system services under these scenarios. It is critical that the framework can respond flexibly to new issues as they emerge, and enable proactive action based on an economic assessment of risks.

Level of specificity

AEMO's approach to assessing system strength requirements is consistent with the AEMC's proposal for an initial higher-level shortfall assessment, serving as a trigger for more detailed investigation. AEMO believes this is appropriate as EMT studies to assess system strength needs beyond a two-year horizon are likely to be of limited value. This is due to the range of assumptions required to develop coherent PSCAD™/EMTDC™ models on inherently uncertain inputs, such as the future generation mix and advancements in generation technology. As such, AEMO's assessment up to five years ahead will be based on screening methods similar to the stage 1 assessments in 2018.

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[5] AEMO (June 2018) *System Strength Requirements Methodology and System Strength Requirements & Fault Level Shortfall*, Available: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf

[6] The methodology involved the following stages:

- Determination of fault level nodes: in consultation with the TNSPs.
- Stage 1 assessment: power system studies undertaken in PSS®E applying RMS analysis methods to assess three phase fault level at fault nodes within regions not considered at risk of a fault level shortfall in 2018 (all except SA).
- Stage 2 assessment: detailed EMT simulations in PSCAD™/EMTDC™ studies only for regions likely to approach a fault level shortfall in 2018 (only SA).

[7] AEMO, *2019 National Transmission Network Development Plan,* available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2018/2018-NTNDP.pdf

Dispatch scenarios

AEMO's 2019 assessment of system strength shortfalls will consider a broad range of plausible dispatch outcomes. This will include the Integrated System Plan scenarios, as well as others capturing potential risk of unexpected early retirement, mothballing or changing operating patterns of synchronous plant in the short term. This is likely to include the 2020 Integrated System Plan scenarios, and potentially other 'bookend' scenarios built to consider the range of requirements for different system services.

Three-phase fault levels will be calculated in PSS®E for each time interval in the market simulations (based on synchronous generating units online) and compared to minimum fault level requirements. This will provide an indicative profile of available system strength margin in excess of the minimum requirements over the course of each modelled year – which would then be used to determine potential shortfalls (or the elevated risk of shortfalls) as well as when and how often these might be expected.

8.3 Distribution networks and distributed energy resources

AEMO recommends the AEMC consider how some form of system strength framework might apply to distribution networks so that system strength requirements continue to be met at this level. This is especially important as penetrations of behind-the-meter rooftop PV and larger scale embedded asynchronous generation continue to grow. Ideally the framework would facilitate co-optimisation of system strength provision between the distribution and transmission level.

Distribution network operational needs may be the key factor that sets system strength requirements in parts of the NEM in the near future. This is likely to be more efficiently addressed through solutions within the distribution network.

Sufficient system strength is required at the distribution level to ensure:

- Stable operation of rooftop PV inverters that synchronise to the grid using phase-locked loop control
- Effective operation of current-based protection schemes
- Reactive plant switching continues to comply with voltage requirements[8]
- Power quality at the customer connection point within requirements[9]

Increasing penetrations of residential rooftop PV systems impacts system strength in two main ways:

- As rooftop PV systems interface with the power system via inverters, they reduce system strength in the distribution network and, in turn, the transmission network. As the AEMC has noted (unlike utility scale solar installations) small scale PV installations are not subject to the 'do no harm' requirements to mitigate their adverse impact on system strength.
- Continued reduction in operational demand during daylight hours. Coupled with the ongoing increasing levels of large-scale asynchronous generation, this results in the continued reduction of synchronous generation dispatched.

There are currently designated fault level nodes in metropolitan areas remote from synchronous generation in order to maintain sufficient system strength in these areas as penetrations of rooftop PV increase.

[8] Required to comply with Australian Standard AS61000.3.7.

[9] Required to comply with Australian Standards AS61000.3.6 and AS61000.3.7.

Rooftop PV's lack of controllability also has implications for the design of system strength solutions. Solutions relying on the dispatch of synchronous generation will not be feasible when most or all load is being served by rooftop PV.

9. Interaction between short and long term solutions

Under the current system strength framework, unexpected changes in the power system may result in system strength shortfalls being identified with insufficient time for the TNSP to address them. In these situations, there are operational measures to achieve secure minimum levels of system strength. Available options in this regard are specific to the given location and situation, and include:

- Directing synchronous generating units online and/or constraining the output of asynchronous plant. This is how system strength is currently maintained in SA.
- Constraining interconnector flows or the output of asynchronous plant, or both, to encourage unit commitment from synchronous plant. This is how inertia and fault level are currently maintained operationally in Tasmania. The ongoing suitability of this arrangement (as more asynchronous generation connects) is currently being reviewed. The use of constraints to achieve synchronous generator unit commitment may not be feasible in other regions.
- Constraining the output of asynchronous plant alone. In parts of the NEM electrically distant from existing synchronous generation centres, the system strength improvement from directing additional synchronous generating units online is marginal. This is how system strength was maintained during recent prior outage conditions in north west Victoria. [10]

AEMO supports a proactive, risk-based approach to considering system strength requirements. This would minimise the need to use operational measures and hence reduce market distortion.

10. Declaring shortfalls that vary over time

10.1 Shortfalls that vary in magnitude over a year

AEMO believes there are benefits to reporting on variations in system strength shortfalls over a year. This may give an indication of times of elevated shortfall risk. This could be examined by presenting available system strength profiles under a range of scenarios.

System strength shortfall assessments based on market simulations should be interpreted in the same way as market simulations undertaken to assess reliability (such as MT PASA and the ESOO) – namely, only as an indication of when and how often there may be shortfalls. The variation in shortfalls across different scenarios could then inform risk-based, economic assessment of potential solutions.

10.2 Flexibility of current arrangements

AEMO continues to work proactively with TNSPs as part of the joint planning process to monitor possible system strength issues on an ongoing basis This includes reporting on potential shortfalls as and when they are identified, rather than only once a year through the NTNDP/ISP process.

AEMO supports the AEMC's proposal for the TNSP to be able to address part of an identified system strength shortfall as soon as practicable, as an interim measure, while solutions to address the entire gap are being considered and implemented.

TNSPs should be encouraged to pre-emptively explore potential contracting solutions prior to any formal determination of a shortfall. This would help to reduce implementation lead times and costs for interim

[10] AEMO (2019) *Planned outages in North Western VIC and South West NSW transmission network, Industry Communique*, Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2019/Planned-outages-in-the-North-Western-VIC-and-South-West-NSW-transmission-network-industry-communique.pdf

solutions, by reducing the need for directions. It would also assist to inform the TNSP's economic assessment of how the risk of shortfall should be addressed:

- In situations with relatively few providers contracting costs may be high enough to justify addressing potential shortfalls in advance.
- In other parts of the NEM, there may be sufficient contestability for lower cost outcomes and potentially innovation in capability across providers.

Such flexibility would also be beneficial for managing the economic impacts of managing system strength during planned outages TNSPs and other asset owners are required to undertake the safe maintenance and upgrade of network infrastructure.[11]

11. TNSP meeting the shortfall

AEMO considers that there are potential efficiency gains from better coordinating the implementation of 'do no harm' obligations for connecting generators with the system strength needs of the overall power system.

Substantial economies of scale could be achieved through the optimised, coordinated provision of system strength to support clusters of asynchronous generator connections – rather than remediating system strength in an uncoordinated manner, one connection at a time. AEMO has assessed this to be the case for system strength remediation in western Victoria. This will be especially important for the development of renewable energy zones (REZs) as identified in AEMO's Integrated System Plan. It may be helpful for a streamlined connection assessment and approval process for system strength remediation works, acting as a 'bridge' to enable development of REZs.

AEMO's recent experience has highlighted that impacts are significantly influenced by equipment capability and how well plant has been tuned for the connection point conditions. This indicates that system strength could be maintained at a lower cost by co-optimising generator control systems.

[11] AEMO recently identified that there would be insufficient fault level and system strength in the event of a credible contingency on other network sections during planned outages in Victoria. Power system security has been maintained by applying constraints reducing the output of generating systems in the affected area. For further information refer to: AEMO (2019) *Planned outages in North Western VIC and South West NSW transmission network, Industry Communique*, available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2019/Planned-outages-in-the-North-Western-VIC-and-South-West-NSW-transmission-network-industry-communique.pdf