# Post 2025 Market Design

## Response to the Energy Security Board's Post 2025 Market Design Consultation Paper

19 October 2020

Energy Networks Australia

# Contents



Energy Networks Australia www.energynetworks.com.au
Unit 5, Level 12, 385 Bourke Street Melbourne VIC 3000
P: +61 3 9103 0400 E: info@energynetworks.com.au
Energy Networks Association T/A Energy Networks Australia
ABN: 75 106 735 406

## Key messages

- **Efficient integration of DER is a critical issue for customers, for the electricity system and for the delivery of sustainability goals. It should be addressed now through a variety of cost-effective technical, regulatory and economic solutions.**
  In order to unlock value for customers, ENA supports a focus on addressing system issues now through changes to the current framework, such as reviewing the scope of network services provided from grid-connected batteries.
- ENA is supportive of the outcomes that the ESB's two-sided market design is looking to achieve. However, to ensure a net benefit for customers, a **move towards two-sided market arrangements needs to be confirmed by robust cost benefit analysis, and the design should be strongly informed by consumer behavioural insights.**
  Progression to each subsequent milestone should be undertaken when there is a clear customer benefit, and the desired end state should be adaptable to lessons learnt in previous phases.
- ENA supports the principle of improving congestion arrangements and locational signals for generator investment. However, **it is critical that the true incremental benefits of the COGATI reforms are positive over and above the benefits of generator locational decisions being driven already through the ISP, REZ reforms and other related government policies.**
- ENA supports a **more proactive and coordinated approach to solving system strength issues now**. TNSPs, as the single source of accountability, should be responsible for planning and procuring system strength on the transmission network.
- **ENA strongly encourages the ESB to consider whether non-market alternatives may most efficiently address some of the opportunities & challenges being considered as part of the Post 2025 market review**. The NEO seeks to best meet the long-term interests of electricity customers, and unless a market is clearly beneficial, consideration should also be given to alternatives such as bilateral contracts, definition of standards, or obligations placed on monopoly service providers as means to best deliver services.

# 1 Overview

Energy Networks Australia appreciates the opportunity to provide a response to the Energy Security Board's Consultation Paper on the Post 2025 Market Design.[1]

Energy Networks Australia (ENA) is the national industry body representing Australia's electricity transmission and distribution and gas distribution networks. Our members provide more than 16 million electricity and gas connections to almost every home and business across Australia.

[1] Energy Security Board, Post 2025 Market Design Consultation Paper, September 2020.

Australia's energy system is undergoing a significant transition, moving away from large centralised coal and gas generation to smaller scale dispersed generation that is increasingly renewable generation, with the transformation occurring both at grid scale and at the individual customer level.

The existing National Electricity Market (NEM) design has to adapt and change to ensure that large and small scale renewables are better integrated into the system and meet the changing needs of the system and customers. ENA supports a proactive approach that actions a series of 'no-regret' incremental changes to the current framework, while also robustly considering potential market design elements for the future.

In a future of decentralised energy, networks will have an even greater part to play in enabling market transition. This is evidenced by the many projects that networks are proactively undertaking now in collaboration with State/Federal governments, Australian Renewable Energy Agency (ARENA), academia and commercial companies. Some of these include the Evolve Project[2], the South Australian Virtual Power Plant (VPP)[3], Increasing Visibility of Distribution Networks[4], various Distributed Energy Resources (DER) Hosting Capacity studies[5].

ENA has been actively involved in the Energy Security Board's (ESB) Post 2025 program, including participation in advisory and technical working groups, and via formal submissions to the ESB.[6]

This submission to the ESB's Post 2025 Market Design Consultation Paper focuses on the following four Post 2025 market development initiatives (MDIs):

- MDI-C Essential System Services,
- MDI-E Two-Sided Markets,
- MDI-F Valuing Demand Flexibility and DER Integration, and
- MDI-G Transmission Access and the Coordination of Generation and Transmission

ENA welcomes this stage of consultation, acknowledges the work undertaken by the ESB, and looks forward to continued engagement as the reform program progresses, including the scheduled release of the Market Design Options Paper for stakeholder consultation in December 2020/January 2021.

[2] https://arena.gov.au/projects/evolve-der-project/

[3] https://arena.gov.au/knowledge-bank/virtual-power-plant-south-australia/

[4] https://arena.gov.au/projects/increasing-visibility-of-distribution-networks/

[5] https://arena.gov.au/assets/2020/08/jemena-der-hosting-capacity-interim-knowledge-sharing-report.pdf

[6] Energy Networks Australia, Energy Networks Australia Response to Moving to a Two-Sided Market, 18 May 2020.

# 2 Essential system services MDI

**Key messages**

- **ENA supports a more proactive and coordinated approach to system strength and the desire to realise economies of scale for the benefit of customers**.
- **TNSPs, as the single point of accountability, are best placed to plan and procure system strength** on the transmission network due to their familiarity with local planning issues, their independence and existing incentive structures.
- ENA generally support the checks and balances approach outlined by the ESB (ESB's Figure 24); however, **we query the controls, oversight and efficiency incentives in a centrally procured model.**
- **There needs to be an appropriate independent governance framework to address the timing of any long term future move to a spot market-based approach for system strength and possibly inertia**. In the case of system strength, ENA query whether there would be a sufficient price signal to make the needed investment in a spot market approach.

## 2.1 Background

The NEM has traditionally relied on thermal generators to provide frequency control, inertia and system strength as a by-product of providing energy. However, as a result of the renewable energy transition, these additional power system characteristics can be short at times as these are not provided by non-synchronous generators. The Australian Energy Market Operator (AEMO) is therefore increasingly intervening in the market to maintain system security, at a significant cost to customers.

The ESB, through the *Essential System Services MDI*, is considering options through the Post 2025 initiative to create markets for these services so that there are price signals for investment and the services are valued. The ESB's Consultation Paper proposes a preference for real time markets for these Essential System Services (ESS) where possible. However, there is acknowledgment that some services, such as system strength, appear more suited to structured procurement such as Transmission Network Service Provider (TNSP) provision, bi-lateral contracts between AEMO or NSPs and providers, and generator access standards or mandatory technical limits.

## 2.2 Overarching position on system services

ENA's overarching position on system services is as follows:

- ENA supports reforms to the frameworks for delivery of system services that are in the interests of electricity customers with appropriate independent oversight.
- The framework needs to provide increased clarity of demand for services and financial obligations. For the services market to be effective, the price signals need to be sufficient to provide confidence to invest in the assets needed.
- ENA acknowledges the problems expressed regarding the essential power system services and the desire to create markets and value the services (other than for system strength) which are not currently valued. The approach to create alternative revenue streams for energy market participants would be expected to drive down wholesale prices and realise a benefit for customers.

- The Australian Energy Market Commission's (AEMC) system strength investigation and the suite of system service rule changes have significant overlap with this Post 2025 market design initiative. The ESB should therefore work closely with the AEMC in order to implement appropriate reforms now.
- ENA agree with the view of ESB and FTI Consulting that system strength is not well placed to be a spot market essential service. TNSPs are best placed to plan and procure system strength due to their familiarity with local planning issues, their independence and existing incentive structures.
- ENA is also supportive of an effective Fast Frequency Response (FFR) market which needs to be in place before the sunset of Mandatory Primary Frequency Response (MPFR), in line with the proposed sequencing outlined in Figure 36 of the ESB's Consultation Paper (*Phased Market Development*).

## 2.3 Immediate need to focus on system strength

The energy mix is rapidly transforming, and system strength is an issue now, but solutions require sufficient time to deliver. Therefore, the requirements to forecast and plan for system strength should be addressed ahead of the Post 2025 process.

The AEMC's system strength investigation and the suite of system service rule changes have significant overlap with this Post 2025 market design initiative, and ENA encourages the ESB to work closely with the AEMC in order to implement appropriate reforms now. The AEMC, in its system strength investigation, recognises that the reactive minimum system strength framework and the do no harm framework should be improved. While the current framework has allocated responsibilities for system strength between AEMO and TNSPs that address the immediate security issues, a new framework is needed to more efficiently provide system strength services over the long term.

The current short-term reactive approach to deliver a theoretical minimum system strength level does not sufficiently enable holistic planning for the long-term management of system strength and related system security requirements.

Adverse interactions between distinct facilities are increasingly observed (such as north west Victoria); due to the complexities involved, it is difficult to relate these interactions to simple metrics. There is no agreed definition of the system strength service that enables commoditising the service in a de-centralised market. Where it is not technically or economically feasible to create new markets to deliver system services, due to the technical complexity or locational nature of the services which limits the scope for effective competition, efficient arrangements should be put in place to plan, procure, value and fund the delivery of these services.

ENA therefore supports a more proactive and coordinated approach to system strength and the desire to realise economies of scale for the benefit of customers. TNSPs are best placed to plan and procure system strength on the transmission network due to their familiarity with local planning issues, their independence and existing incentive structures. The option value of TNSPs specifying system strength solutions with inertia at low marginal cost may lead to further efficiencies.

System strength should be considered a network service on the basis that it is a necessary pre-condition for meeting a range of transmission network performance standards and licence obligations, including proper operation of protection systems and quality of supply to customers. The role of TNSPs is to provide a network capable of reliable and secure operation – TNSPs have the single point of accountability. AEMO's role is to reliably and securely operate the NEM. TNSPs are therefore best placed to provide system strength.

System strength is a locational requirement, not a global service. It should, in the main, be provided as a network service managed by the Jurisdictional Planner as the party accountable for shared transmission network service outcomes. Jurisdictional Planners are well placed to coordinate system strength planning and procurement as they conduct joint planning with each other and with the distribution networks in their jurisdictions.

Both the ESB Consultation Paper[7] and the FTI Consulting Report[8] also confirm that system strength is difficult to define and measure, is typically localised and has a narrow scope for competition. There is no international precedent for a system strength service and there is uncertainty about the potential for co-optimisation with bulk energy and other ESS. This would suggest that the power system should not be put at risk with a take or pay spot market service for system strength.

In Figure 23 of the Consultation Paper (*A Possible Roadmap of Procurement and Scheduling Options for Essential System Services*), the system strength demand curve is described as a long-term ambition with respect to spot market-based ESS. ENA suggest the inertia demand curve should also be described as a long-term ambition (with respect to spot market-based ESS) rather than a potential future design.

ENA supports the intent of TransGrid's proposed system strength rule change[9] that a more proactive and coordinated approach to system strength is required, and the desire to realise economies of scale for the benefit of customers. The current approach where individual generator proponents must meet do no harm provisions and TNSPs can only procure to meet a shortfall of system strength —or inertia — once it is declared by AEMO creates inefficient investment in system strength services, increases the cost of generator connections and increases the cost and risk of operating the power system securely.

ENA supports an independent body, such as the Reliability Panel, setting the approach to system strength and the standards to ensure appropriate evaluation of cost and risk.

Other options considered by the AEMC system strength investigation included mandatory service provision (build to meet the specified technical performance standards) or access standards (imposing obligations on generators to install equipment that is capable of operating stably during low system strength). These options by themselves are unlikely to meet the system strength requirements but could be considered with a TNSP procurement model.

To the extent that there are system strength shortfalls identified from within the distribution network, the distribution network service providers (DNSPs) should be able to plan and procure system strength.

## 2.4 Allowing regulatory adaptability

The ESB is seeking stakeholders' views on possible regulatory approaches, where both market design and regulatory flexibility evolves through the transition, possibly with clear decision points. One proposed approach in the Consultation Paper is to provide AEMO with flexibility to make specific adjustments without any ex-ante external review or approval (while other changes would be subject to more extensive scrutiny and formal regulatory consultation and approvals).

Any long-term ambition to move to a spot market-based system strength service should only proceed if the issues are clearly overcome and there is a net benefit to customers. There needs to be an appropriate independent governance framework to address the timing of such a move to a spot market-based approach for system strength and possibly inertia.

[7] Energy Security Board, Post 2025 Market Design Consultation Paper, September 2020, page 70.

[8] FTI Consulting, Essential System Services in the National Electricity Market: A Report for the ESB, 14 August 2020.

[9] TransGrid, Rule change proposal on a new system strength framework for the NEM, 27 April 2020.

In the case of system strength, ENA query whether there would be a sufficient price signal to make the needed investment in a spot market approach. A necessary precondition would be certainty that a liquid forward contract market would evolve to support investment. Further, any consideration of a move to a spot market may have adverse impacts for investment and contracting in Phase 2 of Figure 23 of the Consultation Paper (*A Possible Roadmap of Procurement and Scheduling Options for Essential System Services*).

Structured procurement of system strength by the TNSP would be subject to oversight by the Australian Energy Regulator (AER). TNSPs are required to consider credible options to meet the system strength requirements in the Regulatory Investment Test Transmission (RIT-T), which does not preclude third party solutions to meet the identified needs. Testing and sandboxing may be suitable to trial new technologies subject to the ability to fund the needed capital requirements. Use of the AER's Demand Management Incentive Allowance or ARENA funds could also be considered to trial more innovative service approaches.

ENA generally support the checks and balances approach proposed by the ESB Figure 24 of the Consultation Paper (*Possible Checks and Balances of Regulatory Oversight, Allowing Regulatory Adaptability*), however, we query the controls, oversight and efficiency incentives in a centrally procured model.

# 3 Two-sided markets MDI

**Key messages**

- ENA is supportive of the outcomes that the ESB's two-sided market deign is looking to achieve. However, before introducing new market mechanisms, **clear identification of the barriers and shortcomings with current market arrangements that are impeding DER participation is required.**
- To ensure a net benefit for customers, any **move towards two-sided market arrangements needs to be confirmed by robust cost benefit analysis, and the design should be strongly informed by consumer behavioural insights.** Progression to each subsequent milestone should only be undertaken when there is a clear customer benefit, and the desired end state should be adaptable to lessons learnt in previous phases.
- **Customers must retain sufficient and appropriate levels of protection** and be kept well informed during the development phases.

## 3.1 Background

Australia's energy system is undergoing a significant transition, moving away from large coal and gas centralised generation to smaller scale dispersed generation that is increasingly renewable generation. This transformation is occurring both at grid scale and at the individual customer level, with increasing levels of DER connected to the electricity network.

A two-sided market is a market model that promotes direct interaction between suppliers and customers. The ESB's *Two-Sided Market MDI* is exploring framework changes to make it easier for new types of participation in the market, or for customers with flexible demand to participate, with the dual objective of:

- Designing a market that supports the most efficient balance of supply and demand, and
- Enabling all customers to realise the value of their demand and supply.

ENA supports and agrees with the outcomes that the market design is looking to achieve. The linear relationship between networks, retailers and customers is changing, and this necessitates the role of the network in more direct engagement with communities.

The ESB released its *Moving to a Two-Sided Market* consultation paper in April 2020[10], which provided a high-level overview of what a two-sided market could look like and its key foundations for stakeholder feedback.

ENA made a submission to the consultation[11], supporting a staged approach, and highlighting the need for rigorous and comprehensive cost-benefit analysis of the two-sided market framework being undertaken at key decision gateways to ensure a net benefit for customers.

The submission also highlighted learnings from the joint ENA and AEMO's Open Energy Networks (OpEN) project, which investigated solutions to optimise and manage DER on the distribution network, and to facilitate DER participation in the wholesale energy markets.

## 3.2 Staged approach to reform

The ESB's September 2020 Consultation Paper proposes a long term approach towards two-sided market arrangements, with a staged suite of reforms to facilitate an expanded two-sided market implemented over the following timeframes:

» Short term (now to two years),

» Intermediate term (two to five years), and

» Long term (five years and beyond).

The staged approach is intended to:

» Allow customers to choose if and how they participate in the wholesale market,

» Better reward the value provided to the system by flexible demand and supply,

» Facilitate new types of participation in the market, remove barriers and provide incentives for traders to participate in dispatch, enabling greater innovation and choice to customers,

» Work out how best to incorporate price responsive supply and demand into the operation of central dispatch and the forecasting that leads into real time, enabling better informed quantity and price inputs from both the demand and supply sides in market processes, and

» Establish an evolved consumer protections framework that makes sure all customers have fit-for-purpose protections.

ENA notes that the benefits to two-sided markets are not only to the wholesale market. More dynamic management at the distribution level will also bring benefits, however, we need to make sure that we take a measured approach to reform. ENA therefore strongly supports a staged approach, informed by rigorous cost benefit analysis, to developing and implementing two-sided market arrangements. Incremental and measured solutions that take into consideration the design and implementation factors outlined below will be in the long-term interests of customers.

---

[10] Energy Security Board, Moving to a Two-Sided Market, April 2020.

[11] Energy Networks Australia, Energy Networks Australia Response to Moving to a Two-Sided Market, 18 May 2020.

## 3.3 Design and implementation considerations

Customers' primary desire is for safe, reliable electricity supply at an affordable price and any changes should seek to improve this.

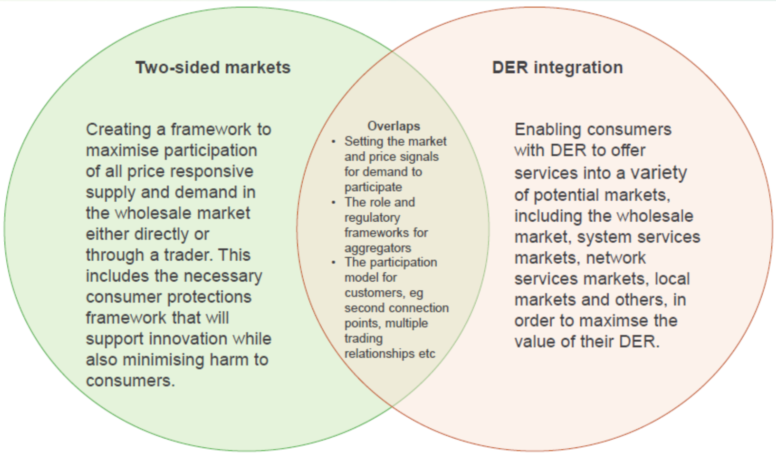
ENA considers that clear identification of the barriers and shortcomings with current market arrangements that are impeding DER participation is required before introducing new market mechanisms. Each potential solution should be assessed against the costs, benefits and trade-offs of that solution, and ensure that it addresses any barriers in the current framework, recognising that changes may need to be made to the regulatory framework to give practical effect. Cost benefit analysis of options must be undertaken to ensure a net benefit for customers. Progression to each subsequent milestone should only be undertaken when there is a clear customer benefit, and we support a focus on end customer outcomes when assessing options.

The design of two-sided market arrangements should be informed by insights into consumer behaviour to ensure realistic assessments of the likely level of response of consumers, particularly small customers, to market signals. Some past reforms assumed a far more active customer response than eventuated, most notably metering competition. Customer research should also be used to ensure that the proposed market design corresponds with customers' expectations of a two-sided market.

## 3.4 MDI integration

The two-sided markets MDI and the DER integration MDI are interrelated, and ENA recognises that there are areas of overlap, as shown in **Figure 1**, between the two MDIs that would be useful to be considered collectively by the MDI teams. ENA supports collaboration between the MDI teams on these areas of overlap.

**Figure 1: Two-sided markets and DER integration interactions**




*Source: Energy Security Board*[12]

ENA, however, does not support the integration of two MDIs into one, and considers that there is value in them remaining as separate MDIs at this stage.

[12] Energy Security Board, Post 2025 Market Design Program: Deep dive on two-sided markets and DER integration, Briefing to Energy Networks Australia, 23 September 2020.

# 4 Valuing demand flexibility & integrating DER MDI

**Key messages**

- **Efficient integration of DER is a critical issue for customers, for the electricity system and for the delivery of sustainability goals. It should be addressed through a variety of cost-effective technical, regulatory and economic solutions.**
- A range of related policies will be required to integrate the ever-growing levels of DER into the grid. **A key capability required under all successful paths is DNSPs improving visibility of DER at the local level.**
- **In order to unlock value for customers, ENA supports a focus on removing inefficient barriers in the current structure,** such as reviewing the scope of network services provided from grid-connected batteries, and the network access and pricing arrangements rule change process currently underway.
- **As DNSPs transition to a DSO role they will unlock value through new services and more effective asset utilisation. While the speed of this transition is not uniform across Australia, DNSPs are preparing by implementing a range of no-regrets actions**.
- **Consumer equity, protections and preference must be maintained through the co-design of future markets for all customers, both with and without DER.** It will be important to demonstrate clear customer benefit at every stage.
- Formal distribution level markets may be justified post-2030 with some jurisdictions with high penetrations of active DER seeing opportunities earlier than others. **Until this time, we should seek to make the most of the current system through no-regrets changes to manage issues and unlock opportunities.**

## 4.1 Background

The level of DER penetration Australia-wide is expected to significantly increase driven by falling costs, government incentives and customer preferences. The ESB observes that this may also open additional opportunities to better optimise and integrate the use of these assets for decreasing costs, emissions, and improving reliability.

The ESB's *Valuing Demand Flexibility and DER Integration MDI* looks at how DER could be embedded more seamlessly into electricity markets, eventually forming distribution-level markets when active DER penetration reaches a certain threshold (post 2025) and what foundational capabilities are required to enable this to happen.

Networks will continue to play an increasingly critical role in unlocking the value of existing and future DER. They are at the very forefront of this evolution and are seeking to deliver societal and political expectations, namely lower cost, more reliable and sustainable power.

Some examples include the South Australian VPP trial, which is a partnership between the South Australian Government, ARENA, Tesla and South Australian Power Networks that is seeking to maximise export capacity of existing networks. After a successful phase one, they are beginning the next phase scaling up the size of the VPP from 1,000 to 5,000 installations.

## 4.2 Managing passive solar PV

To date, only a small percentage of solar PV (and other forms of DER) is, or has the ability to be, actively managed. This means that a large proportion of Australia's current fleet of unconstrained solar PV is exporting in an uncontrolled manner into the grid (i.e. exported as it is produced).

Until "active" management enabled by customers, their designated representative, networks or aggregators becomes the norm, it will continue to remain a challenge to their efficient participation in markets.

AEMO's Electricity Statement of Opportunities 2020[13] shows a high risk to power system security as a result of rapidly reducing system minimum demand (caused by excess unconstrained solar PV output) in the short term for South Australia and increasing likelihood in other parts of the country such as Victoria and Queensland. Unconstrained solar PV output is also increasingly causing localised issues on distribution networks. It is important to note here that issues are occurring at different rates across Australia and not uniformly.

ENA believe that managing the impacts of passive solar PV until such time it becomes active will require a holistic strategy incorporating technology (customer, networks and standards), regulation (economic and technical), tariff reform and customer engagement. There is no one silver bullet solution, but a holistic combination of cost-effective actions should be considered.

Network service providers (NSPs) are subject to the AER's ring-fencing framework, which limits their ability to provide certain services. Some NSPs have noted that network batteries represent an increasingly efficient option to address local network issues such as peak/minimum demand and voltage regulation. However, NSPs are precluded from increasing the viability of these options by leasing out spare capacity or offering customers access to a shared storage service regardless of their retailer (and therefore maintaining retail contestability). ENA supports the AER's forthcoming review of the ring-fencing guideline to ensure that the framework is fit-for-purpose and allows batteries to be deployed where that is in the long-term interests of customers.

## 4.3 Customer DER accessing wholesale markets

It is clear that there is an increasing appetite from some customers to participate in the market. While it is unlikely that all DER-owning customers will want to actively trade their own assets, instead opting to delegate this management to retailers, aggregators and the like, we should be mindful of incorporating their increased participation in future design.

Demand response and allowing customers DER access to current wholesale and ancillary services market should be prioritised in the near term. Removal of inefficient barriers in the current structure should be identified and explored first, such as network tariff reform, before more comprehensive market redesign is warranted.

As the ESB's Consultation Paper notes, the AEMC is currently considering three rule change requests on network access and pricing that aim to better facilitate the efficient integration of distributed energy resources for the grid of the future[14]; an outcome of the ARENA led distributed energy integration program (DEIP) initiative.

---

[13] Australian Energy Market Operator, 2020 Electricity Statement of Opportunities, August 2020.

[14] Australian Energy Market Commission, Distributed energy resources integration - updating regulatory arrangements, Consultation paper, 30 July 2020.

ENA is actively involved in this rule change process, and is strongly supportive of regulatory reform that explicitly recognises the changing role of the electricity grid; from one of traditionally providing consumption services to one of facilitating the two-way flow of energy. This reform is key to ensuring that DNSPs can continue to enable the customer-driven transition to distributed energy.

Finally, we note that many customers, via retailers and aggregators, are now actively participating in wholesale markets. For example, in South Australia there are already nine active virtual power plant operators. We need to be clear what additional access to the market we are trying to enable.

## 4.4 DNSPs transitioning to DSOs

As DNSPs transition to DSOs, they will unlock value through new services and more effective asset utilisation. These include providing dynamic operating envelopes and optimising DER and existing network assets to maximise customer access to the wholesale market.

There are a number of factors influencing this transition, including the level of DER penetration, topology of the network, maturity of technology and differing customer expectations due to temporal differences of when solutions are needed, and jurisdictional specific factors such as state government solar PV rebate schemes.

While the speed of this transition is not uniform across Australia, networks are preparing by investing in a range of no-regrets actions. ENA supports a continued focus on implementation of the 'least regrets' milestones proactively identified jointly by networks and AEMO through the OpEN project, being:

- Distribution network service providers defining network visibility requirements and network export constraints,
- Defined communication requirements for operating envelopes, and
- Establishing an industry guideline for operating envelopes for export limits.

These 'least regrets' actions will be required regardless of the timing of the development of distribution level markets. Further to this, establishing a nationally consistent number of DER technical standards will be beneficial to all networks, including those jurisdictions that do not expect high levels of DER penetration in the near future.

At present we agree with the ESB that there is no current need to implement formal distribution level markets while penetrations of *active* DER are still very low. While this may change depending on technological developments, for now we support a continued focus on making the most of the current system through incremental changes where opportunities are identified, and barriers removed.

## 4.5 Customer equity, protections and preferences

It is positive to see the ESB consider how customers might participate in future markets, however ENA considers that there should be more focus on the equity, protections and preference of all customers now and during the transition to those future market designs (nominally 2030).

A majority of customers (either by choice or circumstance) do not currently own DER and while this may drastically change by 2030, the question of customer equity and protections between now and then is still topical and important.

To ensure the continued support of all customers, there needs to be evaluations at key points to ensure that benefits to all customers still outweigh the costs to deliver them. Progression to each subsequent milestone should only be undertaken when there is clear, additional customer benefit or value to be unlocked.  We note and support the ESB's staged approach and believe this could provide some guidance in determining evaluation points.

Continually incorporating customer preferences also allows optionality to account for technological development or cultural change, ensuring that we are adapting to deliver solutions that meet continually evolving customer needs.

# 5 Transmission access and coordination of generation & transmission MDI

**Key messages**

- **The actionable ISP framework and ISP guidelines provide a comprehensive governance framework to implement ISP projects.** Safeguards are in place to ensure that only efficient transmission (or a non-network option) is built.
- **TNSPs, including AEMO as a TNSP, already use industry best practice approaches to tender for the detailed design and construction, representing the vast majority of the total project costs for ISP projects**. This competitive process achieves the lowest cost outcome for customers.
- By facilitating the efficient and timely connection of future generator investment, **REZ development has the potential to lower overall system costs in the long-term interests of electricity customers.**
- It is **important that before the jurisdictional planning body (JPB/TNSP) is subject to regulatory obligations in relation to the RIT-T for a REZ, there is firmer commitment to the REZ from government and connecting generators, and the TNSP's role and responsibilities are clear.**
- In relation to the AEMC COGATI work, **ENA supports the principle of improving congestion arrangements and locational signals for generator investment. However, it is critical that the true incremental benefits of these reforms are positive over and above the benefits of generator locational decisions being driven already through the ISP, REZ reforms and other related government policies.**

## 5.1 Background

The generation mix is rapidly changing as old thermal generators are gradually retiring from the NEM.  By 2040 there is expected to be an additional 31,140MW of renewable generation added to the transmission system and an additional 11,737 MW of storage.[15]  These large quantities of generation are not necessarily built where existing generation is retiring, and therefore there is insufficient transmission capacity in the right locations to support the additional generation.

To address the challenges, the ESB has developed the actionable Integrated System Plan (ISP) framework in the Rules.  The 2022 AEMO ISP will be the first full plan under these new rules.  The ESB is also looking to create interim arrangements to support the development of several Renewable Energy Zones (REZs). The AEMC is also undertaking a review of the Coordination of Generation and Transmission Investment with the introduction of locational marginal pricing and financial transmission rights.

[15] Energy Security Board, Post 2025 Market Design Consultation Paper, September 2020, Page 109.

This ESB's *Transmission Access and Coordination of Generation and Transmission MDI* is considering how the existing grid and transmission access frameworks need to be updated to accommodate the increasing levels of renewable generation and energy storage connecting to the power system.

## 5.2 Actionable ISP framework

The actionable ISP framework and ISP Guidelines provide a comprehensive governance framework to implement ISP projects. Safeguards are in place to ensure that transmission (or a non-network option) is not built at any cost.

The ISP optimal development path has been developed and evaluated as robust to a range of possible future scenarios. Transmission is an important enabler for the transition to a low emissions economy. As large thermal generators retire, they will be replaced by renewable or intermittent generators at different locations on the grid. To enable renewable energy to be transmitted to load centres, new transmission is required to lower constraints in dispatch.

The consequential Regulatory Investment Test for Transmission (RIT-T) undertakes further stakeholder engagement, robust consultation and net benefits at the individual project level. Future ISPs will also be developed in conjunction with a consumer panel established by AEMO to further improve consumer confidence in the ISP.

The ESB's actionable ISP rules framework has sought to streamline the ISP and RIT-T process. However, many of the actionable ISP projects in the Final 2020 ISP have completed or are well progressed in the regulatory investment test process. ElectraNet and TransGrid have submitted contingent project applications to the AER in respect of Project Energy Connect to seek funding approval for the interconnector between SA and NSW.

The development of the ISP should be able to be fine-tuned over time to make it more timely and efficient. The 2022 ISP will be the first full ISP to be developed under the new rule framework and the streamlined RIT-T process through to ISP funding approvals is expected to be shorter.

The ISP identifies needs for new interconnectors between states to share generation resources and encourage competition. In the last decade or more, transmission investment has been limited to reinvestment in existing assets, which is essentially work on existing brownfield transmission lines. Community expectations and engagement for large greenfield ISP projects, that is new transmission lines, is not the same as upgrading or maintaining existing network. Managing community expectations and engagement for ISP projects is therefore critical.

It is important that social licence is sought, and communities educated about the transmission infrastructure required to enable the transition to renewable energy generation. There can be added benefits for local communities in terms of employment and additional income sources.

It is unsurprising that, as projects are progressed with a clear identified need and a preferred option, detailed design and route analysis, that the costs change. This is evident for most projects, including those in Victoria managed by AEMO. As the National Cabinet seek to stimulate the economy, infrastructure spend will be at the top of the list. Government investment in infrastructure projects and major renewable projects will be seeking many of the same resources, as will renewable generators, e.g. civil and electrical. Governments around the world will be looking for economic stimulus with a focus on moving economies towards lower emissions. Broader economic conditions impacting the labour and capital markets will impact large ISP projects but also ongoing network capital programs.

TNSPs already use industry best practice approaches to tender for the majority of the work for ISP projects through competitive procurement processes in order to achieve the best price in the market. This competitive process achieves the lowest cost outcome for customers. A portion of the total cost relates to TNSP oversight and governance of the contracting arrangements, project and works management etc. TNSP's project costs are also subject to rigorous scrutiny by the AER under the economic regulatory framework.

## 5.3 Efficient development and connection of REZs

### 5.3.1 REZ planning regime is broadly supported

The ISP has improved the ability to plan transmission network for committed and reasonably expected generation connections. The development of REZs will further improve the coordination of transmission and generation investment as the power system transitions away from coal-fired generation. By facilitating the efficient and timely connection of future generator investment, REZ development has the potential to lower overall system costs in the long-term interests of electricity customers.

The REZ planning framework is an important step in this development process and ENA is supportive of it and of the broad proposals set out in the REZ Stage 1 Consultation Paper.[16] In particular, ENA supports the role of the Jurisdictional Planning Bodies (JPB) in preparing REZ design reports and the ESB's recognition of the importance of maintaining system security.

ENA considers that a number of safeguards are required to prevent consumers bearing inefficient costs:

» there should be support from both the JPB and the relevant jurisdictional Government, with the JPB confirming any known local issues impacting the suitability of the REZ for development, and

» there also needs to be genuine and sufficient interest from multiple proponents expressing a willingness to connect to that REZ.

### 5.3.2 We need flexibility in the engagement process to ensure it is fit for purpose

The REZ design report and development process should not be prescriptive in the Rules and should avoid duplication. There should be flexibility to allow Governments to lead certain aspects of REZ delivery where they consider it is appropriate (e.g. consultation with local communities and generator proponents), and flexibility over the planning timeframes and staging so that the preparatory activities undertaken for the REZ design report are proportionate. This is necessary to accommodate the significant diversity that will exist between REZ design reports – while some will be quite preliminary and relate to projects ten years into the future, others will be very detailed and relate to imminent projects. Further, JPBs are best placed to determine the appropriate approach and time required to undertake consultation and engagement with proponents and communities.

### 5.3.3 Need to ensure that the whole REZ framework is workable end to end

The step two implementation arrangements will be subject to a later consultation and cover the commercial and regulated aspects of the REZ delivery and access protections. It is important that before the JPB/TNSP is subject to regulatory obligations in relation to RIT-T for a REZ, there is firmer commitment to the REZ from Government and connecting generators, and the TNSP's role and responsibilities are clear.

---

[16] Energy Security Board, Renewable Energy Zones Planning (Step 1) Consultation Paper and Draft Rules, August 2020.

## 5.4 Investor funding in the shared transmission network

The AEMC as part of COGATI review[17] has previously consulted on a number of REZ models and is currently working on arrangements to improve the connection to dedicated connection assets.

The ESB's Consultation Paper notes a complementary mechanism to that currently being considered by the AEMC COGATI process, where investors fund incremental development of the shared transmission network between two points and receive a right over additional transfer capacity.

Such a model would have more limited applicability but would nevertheless provide an avenue for generators to pay for transmission investment that would not otherwise occur.

ENA has several concerns with such a model that we have expressed previously in response to the AEMC 2019 COGATI Review – Renewable Energy Zones.[18] This type of arrangement is unlikely to address incentives for efficient infrastructure, as the arrangements proposed to facilitate investment in incremental 'spare' capacity (including the application of the RIT-T to this incremental portion of the investment only) are likely to be unworkable in practice. It is also not appropriate for a generator to obtain a right or capacity all the way back to the regional reference node rather than to the 'other side' of the augmentation associated with the REZ development. This is reminiscent of the AEMC's earlier Optional Firm Access proposals, with its associated practical difficulties.

There are aspects of this proposal that appear to again raise the prospect of a future link between the sale of hedges and transmission investment planning, along the lines that the AEMC has now rejected in its separate Discussion Paper on the access framework.

ENA understand that the ESB's REZ arrangements intend to complement the actionable ISP and only be in place until the congestion access regime is implemented. ENA would be concerned if generator investment sought to lead transmission planning and investment which is unlikely to be efficient and could serve to undermine the ISP. As the AEMC has noted, there is no international precedent for this approach. The ESB interim REZ arrangements need to provide a workable, practical end-to-end framework, noting the models that have previously been dropped.

ENA looks forward to further engagement with the ESB on the REZ implementation paper as this will be key to infrastructure development and cost recovery, roles and responsibilities and access protections available.

## 5.5 Transmission access reforms

ENA recognises the extensive work and stakeholder engagement that the AEMC has undertaken on the COGATI reform so far.

Any reform needs to be in the long-term interests of customers and be supported by most market participants and stakeholders. ENA supports the principle of improving congestion arrangements and locational signals for generator investment. However, it is critical that the true incremental benefits of these reforms are positive over and above the benefits of generator locational decisions being driven already through the ISP, REZ reforms and other related government policies.

---

[17] Australian Energy Market Commission, Renewable Energy Zones, 14 October 2019.

[18] Energy Networks Australia response, AEMC Discussion paper, 2019 COGATI Review – Renewable Energy Zones, 8 November 2019.

ENA welcomes the additional work proposed by the AEMC on the implementation costs as they appear on the low side for the whole of industry.

ENA has provided a separate response to the AEMC's Interim Report on Transmission Access Reform and refers the ESB to that submission. In summary, if the COGATI proceeds then ENA:

- Supports ensuring pragmatic phasing of these reforms in alignment with REZ and ISP developments, as well as other likely outcomes from the ESB's Post 2025 Review such as Essential System Services.
- Supports Financial Transmission Rights (FTR) pooled auction revenue and excess congestion related settlement residue (after FTR payouts) being returned at regular intervals to offset consumer Transmission Use of System (TUOS) combined in addition to loss related settlement residue. Auction designs that incorporate increased competition for FTRs, possibly with a reserve price if needed, could increase customers' benefits. ENA welcomes further discussion on timing of the auction proceeds being paid out to offset TUOS and benefit customers.
- Notes there is a need for a transparent process for the initial selection of nodes within each region and the adoption of further nodes in the FTR horizon (10 years or less). ENA suggest that this be undertaken by the AEMC or the Reliability Panel in a similar manner to managing region changes under NER Chapter 2A.
- Notes there is a need for a clear methodology in the Rules for the calculation of the quantity of FTRs available for a given node. These calculations need to be determined in consultation with the TNSPs. The interactions of thermal constraints and the post 2025 market reform needs to be considered.
- Supports no change to the strength of the Service Target Performance Incentive Scheme (STIPS), however further consideration of the move to value congestion without a threshold is required. Currently STIPS reward or penalty only accumulates when the price exceeds $10/MWh. The STIPS should be limited to aspects under the TNSPs' control. A focus purely on value of congestion is suggesting that transmission assets are built to support any poor location decisions made by generators, which is unlikely to meet the National Electricity Objective.
  - In addition, the STIPS approach should adopt an incremental reward/penalty over a year and better take into account the need to manage the high volumes of new connections and transmission commissioning. It is not efficient for there to be no congestion; efficient levels of congestion should not result in a penalty.
  - Notes that FTRs would only be sold up to a portion of network capacity, however thermal and non-thermal constraints may be difficult to quantify with any certainty
- Supports a move to dynamic loss factors even if COGATI did not proceed and it were efficient to align with other Post 2025 reforms. This would improve dispatch efficiency and provide a better locational signal than the current static loss factors.
- Supports FTRs not including losses, which is consistent with the approach in overseas markets. ENA welcomes further clarity on how the congestion only portion of Locational Marginal Pricing (LMP) is calculated for use in FTR payout and STIPS.

## 5.6 Need for improved locational signals for generators

ENA agree with the ESB that the optimal level of congestion is not zero. There is a balance of the costs of congestion and the cost of augmenting the network. The level of congestion has been increasing as renewables locate in areas of good renewable resources, which is often in areas where the transmission network has reached or close to its limits. The wholesale price is the same for each unit of generation in the region no matter where it is located, and the marginal loss factor reflecting the losses to transport the electricity to the load centres is a relatively poor locational price signal.

The current framework is limited to marginal loss factors which are static for a year, and therefore any changes occurring within a year are generally not taken into account. Marginal loss factors can decline with increased generator or REZ connections over time. Dynamic marginal loss factors may provide better, more timely, locational price signals.

A range of information is available to improve due diligence and assist generator locational decisions:

» The AEMO Generator Information Page contains all generation projects, even those in the development stage. The page includes generator location, capacity and type and the expected commercial date,

» The Transmission Annual Planning Reports are produced each year by 31 October by the TNSPs and published on their websites. These reports highlight the network constraint locations and augmentation/upgrade timing, and opportunities for non-network solutions,

» The ISP provides a national plan to alleviate transmission constraints through projects that are part of the optimal development path. AEMO also declares gaps for minimum levels of system strength or inertia that are required by the power system which may also help to alleviate constraints on generator dispatch, and

» Increased due diligence on shadow prices would also be a useful sign of current congestion on the transmission network.

As the AEMC's COGATI work has noted, there is significant international experience with implementation of LMP and FTRs to further improve locational price signals to generators.

Where generators make poor location decisions, they should pay for augmentation to alleviate constraints, not customers.