ENERGY SECURITY BOARD

Post-2025 Market Design

Final advice to Energy Ministers

Part C - Appendix

27 July 2021

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List of Abbreviations

ACCC	Australian Competition and Consumer Commission
ACL	Australian Competition Law
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
C&I	commercial and industrial
CoAG	Council of Australian Governments
DER	distributed energy resources
ECA	Energy Consumers Australia
ENA	Energy Networks Australia
ESB	Energy Security Board
ESS	Essential System Services
ESOO	Electricity Statement of Opportunities
FCAS	frequency control ancillary services
FFR	fast frequency response
GW	Gigawatt
ISP	Integrated System Plan
MT PASA	Medium Term Projected Assessment of System Adequacy
MW	Megawatt
NECF	National Energy Customer Framework
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NSP	Network Service Provider
PFR	Primary frequency response
PRRO	Physical Retailer Reliability Obligation
PV	Photovoltaic
RAMs	Resource Adequacy Mechanisms
RERT	Reliability and Emergency Reserve Trader
REZ	Renewable Energy Zone
RRO	Retailer Reliability Obligation
ST PASA	Short Term Projected Assessment of System Adequacy
SSM	System Services Mechanism
TNSP	Transmission Network Service Provider
UCS	Unit Commitment for Security
VPP	Virtual Power Plant
VRE	Variable renewable energy
WDRM	Wholesale demand response mechanism

1. Resource Adequacy and Ageing Thermal Generator Retirement

1.1. Design choices for a capacity mechanism

Below, the ESB has outlined the key features of a potential certificate capacity mechanism and the spectrum of design choices or settings. These design choices and their impacts will be consulted on during a detailed design process. Some of these design choices have been considered through the P2025 process. Other design choices – including integrating a NEM-wide, common approach to jurisdiction investment schemes to work alongside the new capacity mechanism – will require further consideration and stakeholder input in a detailed design phase.

Box 1 Recap - The Physical Retailer Reliability Obligation

The PRRO – proposed as part the April Options Paper – is a straw proposal for a capacity mechanism achieved through physical certificates. It leverages existing market arrangements under the RRO to work as an adjunct to the current market. It borrows features from other decentralised capacity markets, such as the French Capacity Mechanism, and applies them as they are practical in a NEM context. Its key design features are described below:

- Change the nature of the current obligation so that liable entities (retailers and large customers and other customers who opt in)[1] would be required to hold sufficient qualifying capacity certificates rather than sufficient qualifying financial contracts to cover their share of actual peak electricity demand. Liable entities would hold certificates for RRO-compliance purposes. However, they will remain incentivised to purchase existing financial contracts to continue to manage price risk in the spot market.
- It would operate as an ongoing obligation, without either the T-3 or T-1 Reliability Triggers that exist in the current RRO design. Under a certificate scheme, these two time points remain important for the purpose of certifying resources [T-3], or for the purpose of AEMO procuring out-of-market resources in the event of a reliability shortfall[T-1].
- Physical resources would need to be assessed and certified by AEMO in advance
- Liable entities would not be required to submit their certificate positions in advance of a potential shortfall. Instead, reporting on certificate positions would become an ex-post obligation at T, not T-1, contingent on the triggering of a compliance assessment.
- Compliance assessment and enforcement would be dependent on a reliability shortfall having occurred, namely RERT activation or dispatch, or unserved energy. This shortfall would need to occur during a predefined period of time and demand level that would align with the certification assessment time period.
- The volume of required capacity is determined by liable entities, leaving the risks for forecasting with these entities, who are best placed to forecast their demand requirements. Liable entities would be required to hold a certificate position to cover their actual demand. Requiring retailers to cover their full load, as opposed to a share of P50, or P10 levels, creates a decentralised market demand for certificates. Market customers would decide how risk averse they want to be in avoiding compliance penalties if assessment periods are triggered, in turn creating a demand that reflects risk sensitivities of different load business models.

[1] The current RRO incorporates specific measures to safeguard competition, and to enhance liquidity and pricing transparency in the retail and wholesale markets. To the extent practical, such safeguards would remain or be modified as needed to reflect the need to safeguard competition and liquidity. This is discussed in Part B.

- The forward value of certificates would reflect any perceived risks of scarcity (high prices). Certificates would be expected to have minimal value where energy market price settings were adequate to drive the investment needed.

Assessing and certifying the supply of certificates

The certificate creates an expectation on suppliers that their capacity will be available. The certification process needs to be continuously available, so new resources can be certified. Key design choices for this feature concern who should certify the resources (generation, storage or demand response). Certification of certificates can be centrally determined e.g., by AEMO (the ESB's preference), or de-centrally determined by resources seeking them. If the latter is chosen, it will need strong monitoring and/or compliance of certificate obligations to ensure that the sale of certificates by a resource reflects their actual capability. Additionally, arrangements could be designed so a certificate scheme acts as a conduit between investment supported by jurisdictions and market arrangements (see right hand column below).

A certificate scheme will need to determine a method for creating a supply of certificates which are eligible. Certificates would be assessed for all types of resources which contribute to reliability, including renewable and conventional generators, demand side and storage. The certificates need to be fungible and additive; to represent an equivalent amount of capacity delivered during "at risk" periods. There are a range of ways that resources can be assessed and the number of certificates allocated to each participant.

Detailed choices in the calculation will make a difference to different types of resources and to the assessed value of local versus inter-regional resources. While the calculation process involves choices and some complexity, there are a number of operating examples internationally from which alternatives can be drawn. These include certification processes in decentralised capacity mechanisms like those in France and California and centralised mechanisms like those in Western Australia, the United Kingdom and North-east USA.

There are also a range of choices with respect to who undertakes the certification of resources; choices which differ in their relative centralisation (i.e. does AEMO certify, or do liable entities self-certify?) and their time horizons over which these processes occur. The approach proposed under the straw proposal reflects the 'centralised certificate creation' choice (AEMO certifies) described in the table below, alongside a timeframe for 'longer frequency of reassessments.'

This differs from the current framework for recognising physical resources under a financial RRO which allows participants to 'self-determine' their methodology based on guidelines provided by the AER. That is, rather than liable entities needing to consider the relative firmness of each financial contract in meeting their obligations, this adjustment process could be done by AEMO through 'de-rating factors' applied to the different technology types that are eligible for a certificate for the 'at-risk' time period.

Under the PRRO straw proposal, eligible resources (e.g. generators, storage, demand response providers) would apply to AEMO to be assessed and allocated certificates. Capacity is accredited for their capability to contribute to reliability during 'at risk' periods. Each certificate represents a firm quantity of MW in a region for defined 'at risk' periods. AEMO would need to evaluate the availability of these resources for these 'at risk' times, de-rating their availability based on the 'firmness' of each resource relative to the period specified by the certificate (see granularity feature below). This would be done with an objective evaluation methodology that AEMO would maintain and publish. The methodology for determining de-rating factors is complex, and will differ depending on the technology. As has been developed in schemes like Western Australia's Reserve Capacity Mechanism or the French Capacity Market, eligibility criteria would be developed for all plant, with particular interest in renewables and demand side participation. Determining an accurate methodology – and keeping it up to date as fleet ages, technology evolves and business models change – will require comprehensive consultation.

Resources assessed as being very likely to dispatch electricity in 'at risk' intervals during the relevant period would be allocated certificates corresponding to their capacity with limited de-rating, whereas less 'firm' resources would be allocated certificates on a de-rated basis relative to installed capacity. Resources would be reassessed annually; on the basis they can provide the MW capacity in three years' time for the predefined 'at risk' time period (see certificate allocation).

Alternative approaches are described in the table below (green indicating the preferred option in the straw proposal throughout the tables, orange noting design choices relevant to integrating jurisdictional schemes).

Table 1 Alternative Design Approaches for Assessing and Certifying the Supply of Certificates

Potential design settings		
Decentralised supply assessment and certification	***Centralised supply assessment and certification***	***Jurisdictional supply assessment and certification***
Resources are eligible to self-certify up to their MW nameplate capacity. [2]	Eligible resources (e.g., generators, storage, demand response providers) would apply to AEMO to be assessed and allocated certificates. [3]	Jurisdictions could ask AEMO as a central buyer to certify and purchase government-backed investment in advance of it being 'committed' under the ESOO. This arrangement is additional to either of the adjacent columns.
Analysis		
• A decentralised approach will have less up-front assessment costs, as described in the central assessment adjacent. • Enforcing this obligation may require costly ex-post compliance assessments. • Without sufficient ex post penalties, self-certification may overestimate the supply the market can expect to be available in real-time. • Conversely, if ex post penalties are too high, resources may self-certify over- cautiously, leading to underestimates of supply,	• Central assessment of certificate creation could provide the market with more confidence in the certificates. • There will be administrative costs for AEMO to establish an assessment facility although a similar assessment is undertaken in preparing the ESOO. • A rigorous ex ante assessment could negate the need for ex post assessment, and could provide certified resources certainty that they will not	• A NEM-wide certificate scheme could prove an appropriate 'vessel' by which to coordinate jurisdictional investment and to better integrate it into the market. • Jurisdictions could run competitive reverse auctions for projects at the lowest certificate price per MW at a point in time that extends beyond AEMO's typical assessment process (T-3 to T-10). • AEMO, operating as a central buyer, then buys certificates from the jurisdiction's successful

[2]Resources would be expected to match their real-time availability with the volume of certificates sold. If short, they would need to buy 'from spot' to fulfill their obligation. By decentralising the decision-making about capacity supply, an after-the-fact, ex post assessment is needed to ensure resources are incentivised to self-certify accurately, or to buy certificates in real-time when they are short.

[3] Resources remain incentivised by spot prices to be available during periods of reliability risk. This option is more likely to limit resources from over-selling capacity certificates, strengthening the link between physical resource availability and certificate volumes issued.

<table>
<tr><td colspan="2">higher certificate prices and over-procurement.</td><td colspan="2">face penalties from force majeure events.
• The certification decisions will impact the supply and demand for certificates, and hence their value for investors. Risks associated with over procurement and under procurement are likely to be passed on to consumers.</td><td colspan="2">projects, with a commitment from the jurisdiction to underwrite the price of certificates when they are later centrally auctioned to liable entities (see certificate trading).
• If jurisdictional schemes are ill-timed and enter projects into an oversupplied market, certificates risk being auctioned for less than their tender price.</td></tr>
<tr><td colspan="6">Potential design settings</td></tr>
<tr><td colspan="3">Shorter frequency of reassessment (under a centralised certificate creation model)</td><td colspan="3">Longer frequency of reassessment (under a centralised certificate creation model)</td></tr>
<tr><td colspan="3">Resources would be reassessed each year. AEMO would re-evaluate the de-ratings of each resource selling certificates.</td><td colspan="3">Resources would be reassessed over longer term horizons. A de-rating factor applied at T would remain constant for a set period of time (3-5 years) and would not be revised without a material change to the resource’s availability. Resources would be obligated to advise AEMO of material changes to its availability and adjust their certificate sales, accordingly.</td></tr>
<tr><td colspan="6">Analysis</td></tr>
<tr><td colspan="3">• Reassessing resource capacity ratings each year ensures their tradeable volume of certificates reflects their actual capacity factors and changes over time (e.g ageing thermal fleet).
• Thoroughly reassessing resources annually may be a costly exercise for AEMO.
• Reassessment process costs could be mitigated by standardising de-rating intervals (thermal fleet past certain ages discounted at standardised rates), or certain plant only reassessed per year if certain plant advise AEMO through an obligation of any material availability changes.
• If there are no material changes, the cost of reassessment is expected to be low relative to the initial assessment application.</td><td colspan="3">• Reassessing resource capacity ratings less frequently will be less costly for AEMO’s assessment function.
• There is a risk of not accurately certifying resources for their capacity, namely fleet whose MW capacity may be degrading (ageing thermal fleet) or improving (hydro exiting a drought period) significantly within the period.
• Resources could be obliged to inform AEMO of material changes to their availability between assessment periods or be allowed to lodge a request for reassessment if their capacity improves.</td></tr>
</table>

Certificate allocation

Once resources are assessed for their MW capacity, resources need to be allocated with certificates, which they can then sell to liable entities (see certificate trading). Allocation designs differ in the time horizon over which they are allocated.

Under the PRRO straw proposal, certificates would be allocated three years out of their delivery period. This is described with the 'allocated annually with a 3 year horizon' option in the table below, alongside an alternate approach. Using a three-year horizon mirrors the current RRO structure and provides some forecast certainty over periods where certificate positions may be necessary and be assessed. The longer the horizon (the period between when certificates are allocated and the 'at risk' period for which they are dated) the longer the investment signal is, and participants can trade certificates more freely. With a shorter horizon, certificate allocations may better reflect an asset's availability, but the trading period is shorter, as is the investment signal.

Table 2 Alternative Design Approaches for Certificate Allocation

Potential design settings	
Allocated annually with a three year horizon	***Allocated annually on longer or shorter horizon***
Resources are allocated certificates annually, which are dated as being valid three years from their allocation.	Resources are allocated certificates annually, which are dated as being valid for or more less than three years out from their delivery date.
Evaluation	
• Longer periods between a certificate's issue and the compliance period to which it is dated provide a longer horizon over which liable entities can cover their positions. It also allows for better quality information for AEMO to incorporate into reliability forecasts. • Resources or investors can derive certainty from revenue streams by selling certificates to liable entities interested in managing risk over both longer (3 years) and shorter periods (<1 year) of time. • Longer periods between allocation and validity of certificates requires the MW capacity of the resource to be assessed on its likely capacity of a three-year period. This may not adequately capture a seller's MW capacity, in the event their reliability changes in this time. • However, a three-year period can provide the opportunity for AEMO to revise allocations, and return quantities to AEMO. This may mitigate this risk.	• Shorter periods between certification allocation and the compliance period to which they are dated gives liable entities less time to cover their positions, and disadvantages smaller retailers in procuring certificate positions by forcing them to compete for certificates in a shorter period against larger vertically integrated incumbents. • Allocating shorter dated certificates allows AEMO to assess resources on their capacity over the forthcoming 12-36 months, rather than 36+ months, leading to more accurate de-ratings. • Allocating longer dated certificates provides a longer period for counterparties to settle positions, and creates a longer investment signal for prospective projects. Allocating certificates longer than 3 years from delivery puts pressure on AEMO's assessment process to allocate the right volume to match liability further into the future, and may require more stringent 'rebalancing' measures throughout the horizon to take into account any unforeseen changes in availability.

Certificate definition and granularity

Certificates must have a vintage, meaning they must be dated for a period over which they are valid. In the event of a compliance assessment, liable entities must hold certificates of a vintage that includes the time of the event that triggered the compliance assessment. The certificates will need to be homogenous and to support fungibility and liquidity. Certificates will also be specific to the market region in which the resource is located. A process for assessing firm imports across an interconnector

– as there is now under current arrangements, such as interregional contracts set out in the AER's interim Contracts and Firmness Guidelines – will need to be maintained and updated.[4]

Under the PRRO straw proposal, certificates must pertain to a defined 'at risk' period of reliability risk (for example, after 4pm on February weekdays) identified at T-3 when certificates are allocated (see certificate allocation). This is similar to the current RRO where a forecast reliability gap is defined and eligible contracts are procured for that gap period in order to drive investment to reduce the gap. It is described in the third column of the table below.

An alternative approach is to require certificates for a longer time period – outside of reliability 'at-risk' periods. This is different to the current RRO and more akin to a centralised capacity market. The granularity of certificates (or the length of time which they are valid) has implications for the range of technologies that effectively participate in a certificate market. For example, an annual certificate that aggregates a resource's likely availability over a 12-month period may be easily tradeable and accurately represent the availability of fleet with a consistent MW output. However, aggregation over longer horizons may discount the value of certificates sold by flexible fleet, whose capacity availability may be significantly more valuable at some points of the year compared to others (such as a battery for four hours on a summer afternoon). While a seasonal or monthly definition comes with higher administration costs and risks to fungibility, it would better reflect any seasonal availability variations (such as seasonal maintenance cycles) or seasonal participation in the market (for example, demand response availability) of different resources.

Potential approaches and their impact are described in the table below.

Table 3 Alternative Design Approaches for Certificate Definition and Granularity

Potential design settings		
12 month certificates	***Quarterly Certificates***	***Defined periods of reliability risk***
Certificates are dated as valid for a 12-month period	Certificates are dated to a specific quarter, or seasonally, in a specific year.	Defined periods of reliability risk are identified in advance at T-3 by AEMO. Liable entities must hold certificates dated to these periods in order to be compliant, in the event of an assessment period being called.
Analysis		
• Certificates are more easily procured, managed, and traded by liable entities. • Increased risk applies to liable entities as they are liable and therefore can choose to procure their actual demand at all times (see demand side obligations). This assumes	• Liable entities must procure, manage and trade four different types of certificates over a period of 12 months, adding to costs and complexity. • The availability of certificates for liable entities to procure better reflects the availability of	• Certificates are more easily procured, managed, and traded by liable entities within that region. • Defining periods in advance provides certainty to liable entities over the periods which they need to hold certificates for.

[4] Things to consider include whether the purchase of inter-regional settlement residue rights qualifies as an eligible certificate for a liable entity, and if so whether derating the likely import capability from a neighbouring region during the 'at-risk' period is required, and if there is a need to also purchase capacity certificates from that neighbouring region (noting the 'at-risk' period is not likely to coincide).

assessment periods are triggered by any days which exceed POE50, and there is either RERT activation of dispatch, or Unserved Energy is incurred (see assessment periods) • This may limit the ability for some resources (such as storage and demand response) to participate either due to compliance obligations or average annual certification that is likely to favour resources that are available to firm at all times throughout the year and for a wide range of durations of shortfalls that could occur. • Liable entities can choose whether to purchase certificates to be compliant or not, depending on their private assessment of the reliability gap materialising	resources in the specific quarter, as opposed to it being averaged over a 12-month period. • Resources which have a comparative advantage in providing more MW capacity in some quarters than others are better able to derive value from certificate market. • Liable entities can choose whether to purchase certificates to be compliant or not, depending on their private assessment of the reliability gap materialising	• However, defining periods in advance (as with the current RRO) shifts risk away from liable entities. Assessment periods are constrained to both the assessment period criteria (see assessment periods) and the defined periods of reliability risk • Liable entities will procure certificates only for defined periods of reliability risks, leaving the spot market incentives alone to deal with other periods of reliability risk • Liable entities can choose whether to purchase certificates to be compliant or not, depending on their private assessment of the reliability gap materialising.

Supply side compliance (that the resource was available when it said it would be under the certificate)

The existing RRO assesses compliance for liable entities only. Financial contracts incentivise compliance for suppliers (resources) primarily via the potential for being short in the wholesale market (that is, not being available in the market to defend against the strike price in the contract). The regulator (AER) can increase confidence in the reliability and availability of resources by adding penalties to this price risk.

The PRRO straw proposal is characterised by the first and third columns below. The risk of a resource overstating its reliability can be adequately managed in advance through discounting their MW capacity when they apply for assessment (see supply creation and certification). Further, the price risks resources face for unavailability in real time to manage derivative contract risk would continue. High market price settings might remain a sufficient incentive to ensure plant reliability and availability. This approach may be preferable to an ex-post resource compliance assessment, which would prove a costly exercise for the industry. The PRRO straw proposal adopts a 'lighter stick' approach to incentivising compliance. If resources are consistently underperforming in relation to the MW volume of certificates sold, this can be monitored by the AER and fed into AEMO's next reassessment period. Poorly performing resources would be expected to be assessed as being able to sell fewer certificates. In addition, if there is a material change in plant availability or capability post certification (for example between T-3 and T-1 there is a permanent plant reduction in capacity) this may require resources to advise AEMO and, if a reassessment finds it necessary, AEMO may require return (buy back) of certificates.

Table 4 Alternative Design Approaches for Supply Side Compliance

Potential design settings		
Ex ante availability assessment	***Ex post resource compliance assessment***	***Monitoring of performance to feed into to revise future availability assessments***
Resources are derated in advance during AEMO's assessment process to probabilistically reflect the likelihood of a seller of certificates not being available on the day.	The AER conducts a periodic review to investigate whether resources are making themselves available in dispatch in the same MW volumes as those they have sold in certificates. Penalties are applied for non-compliance.	In the event of a concern a resource is consistently underperforming on the certificate volumes it has sold into the market, despite AEMO's capacity assessment, this performance is factored into AEMO's next volume reassessment, and the resource's capacity is de-rated in the next allocation.
Analysis		
• Ex ante availability assessments put the onus on AEMO's assessment function to accurately de-rate resources ahead of time. • It is a simpler approach, and avoids the cost of a robust ex post compliance assessment. • However, a lack of a severe penalty for not being available on the day may mean more reliable technologies are not rewarded as much as they could be, as they compete with more unreliable fleet for the same periods (assessment de-rating not withstanding).	• An ex-post resource compliance assessment may support a certificate scheme's ability to be 'sharper' in incentivising fleet in a more granular way to cover gaps with certain characteristics. • Ex post compliance assessments are likely to be a costly exercise, and burdensome for market participants due to the likely legal disputes about compliance, especially force majeure and other exceptions.	• The risk of de-rating of MW capacity following lower- than-allocated availability performance can prove a suitable 'light touch' stick to incentivise resources to make themselves available in dispatch according to their certificate volumes. • The AER would have to develop a monitoring function that is cost-effective, while also sufficiently active so as to ensure resources respond to its efficacy.

Demand for certificates

Considerations of demand side safe harbours under a decentralised model will change the risk associated with compliance and the demand there is for certificates. The more certificates liable entities are expected to hold during 'at risk' periods, the more demand for certificates there will be, and the certificate scheme will do 'more work' in incentivising capacity availability or investment.

Alternatively, demand for certificates could be shifted away from being determined in a decentralised way. Demand determinations for 'at risk' periods could be forecast in advance by a central body. Retailers would be allocated a share of total forecast demand for which to hold certificates. This procurement could either be mandatory and assessed regardless of at at-risk period emerging, or compliance could be assessed only if an at-risk period arose.

The PRRO straw proposal recommends liable entities should cover their actual demand during at-risk periods, corresponding with the third column in the table below.

Table 5 Alternative Design Approaches for Demand Assessment

<table>
<tr><th colspan="3">Potential design settings</th></tr>
<tr><th>Liable Entities must cover demand scaled to P50</th><th>Liable Entities must cover demand scaled to P10</th><th>Liable Entities must cover actual demand</th></tr>
<tr><td>When assessment periods occur, liable entities must hold enough MWs of certificates to cover their demand scaled to a P50 level, similar to the current RRO framework with firm contracts.</td><td>When assessment periods occur, liable entities must hold enough MWs of certificates to cover their demand scaled to a P10 level.</td><td>Liable entities must hold enough MWs of certificates to cover their actual load as occurring during the assessed ‘at risk’ period.</td></tr>
<tr><th colspan="3">Analysis</th></tr>
<tr><td>• Represents a lower obligation on liable entities (because it is a defined risk) but may be insufficient in normal to lower supply periods to incentivise availability or new build of capacity.</td><td>• Represents a lower obligation on liable entities (because it is a defined risk) but may be insufficient in normal to lower supply periods to incentivise availability or new build of capacity.</td><td>• This option is most likely to incentivise compliance and demand creation for certificates, but places higher costs on retailers – particularly smaller ones – to procure the last few MWs of certificates compared to P10 levels (given current penalty levels under the RRO).
• Risks over procurement of MWs if ‘at risk’ periods are anticipated more frequently by liable entities than they occur.
• Can be mitigated by accurate ex ante forecasting and real time demand response contracts.</td></tr>
<tr><th colspan="3">Potential design settings</th></tr>
<tr><th colspan="3">Central determination of demand for certificates</th></tr>
<tr><td colspan="3">A central body such as AEMO determines the demand levels for certificates that retailers would have to procure. This option exists as an enabling design feature for central auctions, discussed below in ‘certificate trading.’ While requirements under the current RRO (procure to P50) can be considered a ‘central determination’ of demand, specific, deterministic numbers of actual MWs would need to be defined in order to enable central auctions to make available an appropriate volume of certificates.</td></tr>
<tr><th colspan="3">Analysis</th></tr>
<tr><td colspan="3">• This approach provides certainty to participants, consumers and jurisdictions that liable entities have purchased sufficient levels of certificates that align with system demand.
• Different compliance options are available for this design choice. Liable entities can be required to purchase enough certificates for all identified at-risk periods irrespective as to whether they eventuate. Or, liable entities will only be assessed for the allocation of demand it an at-risk period materialised.</td></tr>
</table>

• Whilst providing certainty of capacity, this option is likely to come with significant implementation and ongoing costs, and risks a suboptimal allocation of risk by shifting decision-making about likely loads away from liable entities – who may be best placed to manage them, with a central authority instead.

Certificate trading

Trading of certificates creates an investment signal. Certificates – once allocated – will need to be sufficiently liquid to ensure that they are accessible to all market participants. The more tradeable a certificate is, the easier it is for liable entities to optimise their positions according to their risk profile, with the hope of delivering efficient outcomes for consumers.

As discussed previously under 'assessing and certifying the supply of certificates', arrangements are feasible that allow for jurisdictions to meet their scheme targets by selling and trading certificates in ways which integrate government-backed certificates (physical or financial) with those that would otherwise be created by market participants.

Under the PRRO straw person, certificates were proposed to be traded bilaterally over the counter, and with the support of a central exchange. Alternative approaches are also described in the table below. None of the options proposed below are mutually exclusive.

Table 6 Alternative Design Approaches for Certificate Trading

Potential design settings		
Certificates traded bilaterally over the counter	***Implementing a central exchange***	***Implementing central auctions for certificates***
Two market participants agree between them on how to execute a trade.	A central exchange platform is established where certificates can be listed and traded transparently	AEMO runs auctions for certificates to further facilitate simple access to the certificate market for liable entities. This is additional to the approaches described in the columns adjacent.[5]
Analysis		
• Direct trading is likely to be the least cost and most direct trading method, namely for large incumbents that can be trading significant volumes of certificates.	• A central platform for certificate trading is likely to increase transparency to participants with less access to OTC trades Participants may trade bilaterally as well as establishing products to be traded on existing or new exchanges e.g. ASX.	• If longer term investment signals beyond 3 years are preferred, then central auctions for certificates could be held by AEMO. • Further, central auctions could help facilitate the entry of fleet supported through jurisdictional schemes (see supply certification and creation), and be the mechanism that integrates certificates from market participants

5 • Participation in auctions by liable entities could be voluntary to facilitate opportunities for liable entities to manage the risk in the longer-term if that is a preference. Unsold certificates can then be returned to sellers or reauctioned the following year. Alternatively, central auctions could be compulsory for liable entities, where market customers are made to purchase a proportion of their likely positions at T ahead of time.

		with those supported through investment schemes. • Auctions held exceeding T-3 will need to extend AEMO's certification and allocation horizons.

Compliance, enforcement, and penalty regime

Under financial contracting structures, participants settle contracts against the spot price. Certificate arrangements are not settled against the spot price. They are settled on the basis of a demand created artificially by regulatory arrangements, and the assessed availability of supply. With no associated price risk deriving from the market that needs to be managed, liable entities must be incentivised to purchase certificates, that is, to create a quantity risk of ensuring sufficient capacity is procured. However, there must be consequences for not managing their obligation to cover their actual demand at times during the 'at risk' period that exceed a demand of POE50, RERT is activated or dispatched, or unserved energy occurs. The scale of the penalty is proportional to the value seen by liable entities in creating a demand for certificates to insure against periods of increased reliability risk occurring.

Under the PRRO straw proposal, the penalty regime is proposed to remain consistent with that which is under the existing RRO, with non-compliant entities facing wholesale market price outcomes, the AER's civil penalty provisions, as well as paying a portion of the RERT (PoLR) costs[6]. Compliance will be assessed by the AER. The AER will identify the compliance intervals, which are intervals in which a reliability shortfall is found to have occurred, and then establishing whether each liable entity met the reliability requirement.

An alternative option is described below.

Table 7 Alternative Design Approaches for Compliance, Enforcement, and Penalty Regime

Potential design settings	
Wholesale market outcomes, allocation of RERT costs and civil penalties	***Additional explicit penalty price***
As is applied under the current RRO.	An additional penalty price could be introduced to incentivise liable entities further to ensure demand is created for certificates.
Analysis	
• This approach provides consistency for liable entities with the current penalty regime.	• *Liable entities*: Higher penalties encourage liable entities to ensure they hold sufficient certificates. However, greater penalties and compliance burdens increases liable entity risk and the value of certificates. If set too high this could impact on electricity prices. • An explicit penalty price could provide a clear and scalable penalty for non-compliance, but would need to be set appropriately to deter under-contracting.

6 The penalty amounts would require reconsideration of the penalty / risk balance in the final design.

Market power

A certificate scheme as a capacity mechanism requires arrangements to ensure market power is not abused in the certificate market.

Without T-3 and T-1 Triggers, the current Market Liquidity Obligation (MLO) under the RRO cannot be directly applied. However, an MLO-equivalent could be considered, to ensure that liable entities were confident that they can buy the certificates they need. As per the existing arrangements, this is particularly relevant for regions in which ownership of 'firm' resources is dominated by vertically integrated retailers. As such, the detailed design of a certificate scheme or other capacity mechanism will need to include rules to eliminate gaming of the mechanism. Liquidity, competition and market power concerns in the NEM may ultimately lead the design towards a centralised auction approach, if they cannot be appropriately managed with an MLO equivalent and central exchange.

Considerations of market power under different power system conditions may lead to the compulsory accreditation and allocation of certificates to all resources, rather than a voluntary participation model. The benefits of mitigating market power concerns will need to be traded off against the additional costs of universal accreditation of resources.

Potential approaches and their impact are described in the table below.

Table 8 Alternative Design Approaches for Market Power Mitigation

Potential design settings		
Voluntary assessment and allocation of certificates	***Compulsory assessment and allocation under some circumstances MLO***	***Compulsory assessment and allocation of certificates***
Participation would be voluntary for eligible resources, given the RRO is an obligation on Market Customers/load-serving entities.	In the event not enough resources seek assessment and allocation of certificates at a point in time – leading to shortfall in certificates – resources in a region where there are shortfalls can be forced to participate.	Participation in the assessment and allocation of certificates is compulsory for all scheduled and semi-scheduled units all the time.
Analysis		
• This option is least intrusive from a regulatory point of view • In concentrated market power circumstances, sellers may artificially inflate certificate prices by constraining supply of certificates and not certifying all resources.	• As per the existing arrangements, this is particularly relevant for regions in which ownership of 'firm' resources is dominated by vertically integrated retailers. • As opposed to compulsory assessment, this can be triggered via independent assessment (perhaps by the AER) regarding market power concerns.	• Considerations of market power under different power system conditions may lead to the compulsory accreditation and allocation of certificates to all resources, rather than a voluntary participation model. • The benefits of mitigating market power concerns will need to be traded off against the additional costs of universal accreditation of resources.

Competition/market power mitigation measures will need careful consideration in a detailed design process as detailed in Part B.

1.2. International development

International electricity markets are facing similar issues to those in the NEM. It is notable that most international markets have some method of valuing capacity separately from electricity generation.

However, the NEM's transition will be unlike the experience of other markets in the world. While it makes sense to borrow from the successful elements of capacity mechanisms implemented elsewhere to the extent they are relevant, it is apparent that a fit-for-purpose capacity mechanism must reflect power system conditions unique to the NEM and the characteristics and capabilities of its existing assets, as well as inducing allocative and dynamic efficiencies that help steer the NEM towards a least-cost transition.

Put simply, other markets where capacity mechanisms exist benefit from interconnection and greater access to existing flexible resources. The challenge for the NEM as aging thermal generation exits is ensuring the confidence in the adequacy of the investment signals required to replace these resources with new variable, firm and flexible resources in a timely fashion. The relative scale and speed of the transition in the NEM creates a greater test on resource adequacy than is being experienced elsewhere in the world.

We also note the number of years it took to develop and implement these mechanisms (5 years in the UK, at least three in France) and the ongoing need to regularly review and adjust aspects of the mechanism to facilitate timely entry and orderly exit at least-cost to consumers.

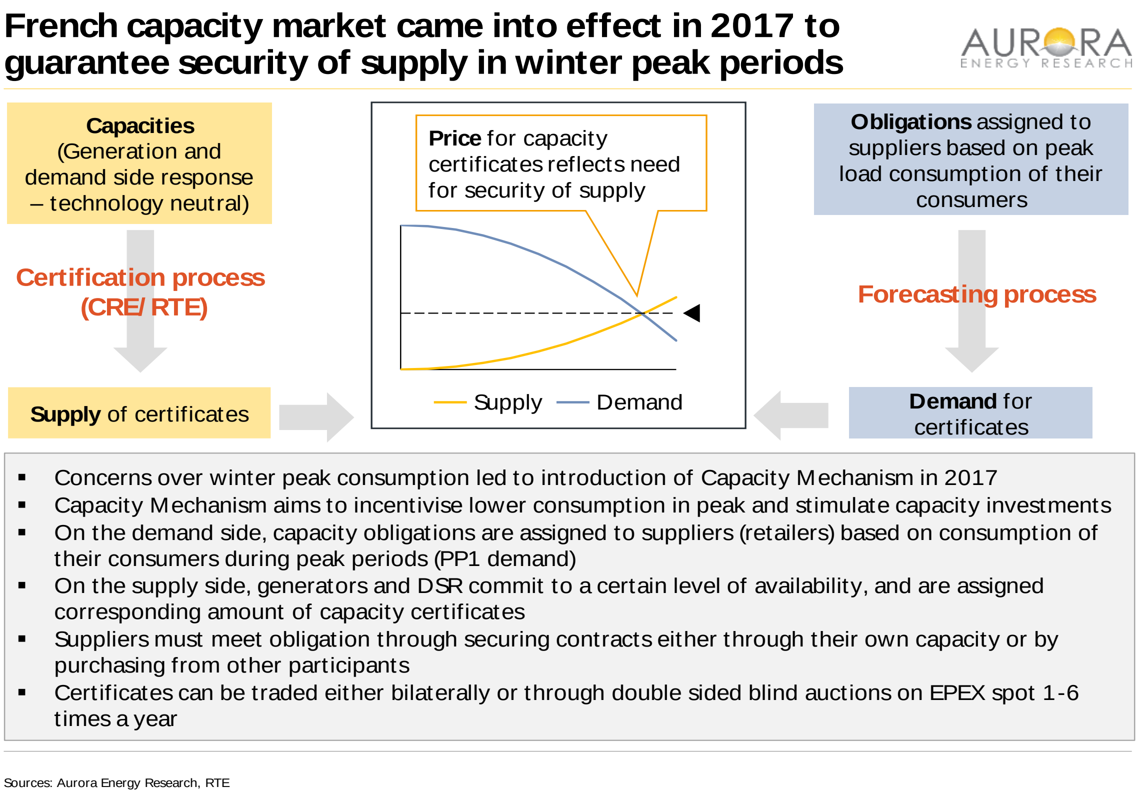
The United Kingdom and Europe have been investing heavily in new variable renewable generation and adapting their market designs along the way. The UK developed a central capacity market over a period of five years and introduced it in 2014 as part of a wider program of reform to decarbonise the UK's electricity supply while maintaining reliability and affordability. The capacity mechanism is used to procure capacity sufficient to meet their reliability standard of less than 3 hours (equivalent to 0.034% USE) with any loss of load expected each year on average.

Prospective capacity providers bid into the market to secure monthly availability payments for keeping generation capacity ready within each tendered year. Auctions are held yearly ,1 and 4 years ahead of delivery, to assign capacity contracts. Contracts are awarded and costs recovered by customers as incurred.

France was an energy only market with a €3,000/MWh price cap, but a capacity mechanism was developed and introduced in 2017 to tackle the security of supply concerns brought about by the need to meet a falling capacity factor on the system, with lower average consumption but rising winter peak demand. The mechanism aims to drive demand response during peak periods while also encouraging adequate investment in generation. [7]

7 Introducing a capacity mechanism in France also supports the public authorities' objective of making the load curve more flexible, set forth in Law 2013-415 of 15 April 2013 ("Brottes Act").

Figure 1 The French decentralized capacity market.



The capacity market and need for demand flexibility is expected to be increasingly important with the rise in intermittent renewables as France diversifies from nuclear. Capacity certificates can be traded bilaterally or through the French capacity certificate exchange on EPEX Spot.

Prior to 2017, the Irish electricity market included a traditional capacity mechanism based on administratively determined availability payments. Through the integrated, single electricity market (I-SEM) reform process that began in Ireland in 2007, the regulator determined that an 'enhanced' capacity mechanism was required to reduce the costs of funding capacity relative to their pre-existing approach. The Irish 'capacity remuneration mechanism' (CRM), was introduced to issue Reliability Options to eligible capacity from 2018 onwards.

Following an initial transition period of near-term auctions, the Irish CRM runs central auctions four years ahead, issuing one year contracts to existing generation and up to 10 year contracts for eligible new generation. The Irish market operator has initially set the contract strike price based on a hypothetical low efficiency peaking unit.

The Irish Reliability Options must have physical backing by a specific generating asset – meaning they are used exclusively to contract physical capacity. The Irish model includes a participant qualification process to determine the capacity rating of each unit – capacity is de-rated with a methodology reflecting its anticipated marginal contribution to reliability. All qualified capacity is required to bid into the auction.

In the United States, the ISO in California operates an energy only market which has had a number of enhancements over the years to operate efficiently with a high penetration of renewable generation. Outside of the energy market, the California Public Utilities Commission operates a Resource Adequacy Program which aims to:

1. ensure the safe and reliable operation of the grid in real-time providing sufficient resources to the California Independent System Operator (CAISO) when and where needed.
2. incentivise the siting and construction of new resources needed for future grid reliability.

The CPUC establishes resource adequacy obligations on all electricity providers (called load serving entities and equivalent to retailers in the NEM) within its jurisdiction. Electricity providers must report monthly and annually on how they are meeting their obligations so that capacity is available to the CAISO when and where needed. CAISO provides information to assess the firmness and deliverability of resources.

The Texas market run by ERCOT remains an energy only market but now incorporates a "Reserve Price Adder" to the spot market reflecting the economic value of reserves that are available for energy dispatch in real-time; i.e. adding a capacity value to the value determined in the 'energy only' market.

On the other hand, the traditional capacity markets of northeast USA have been challenged by the growth of variable renewable generation and the lack of real time signals. For example, PJM operates a centralised capacity market, but it introduced an operating reserve market in 2017 to better reflect shortage pricing when reserves are low. Reserves are procured according to an Operating Reserve Demand Curve (ORDC) which causes reserves to increase in price the closer the market is to being short. These prices 'cap' at a penalty price significantly above the normal energy market price cap in PJM. As reserves get tight, and especially when they are short, higher prices in the reserve market spill over into the energy prices through co-optimisation.

International experiences reveal a trend towards developing energy markets with complementary capacity mechanisms or capacity markets with mechanisms that emulate energy only markets in real time. These examples are consistent with the ESB's recommendations. As expert Peter Crampton summarises:

> "one approach to reliability is to rely solely on spot prices but to include administrative scarcity prices at times when reserves are scarce. The preference for reliability is imbedded in the scarcity prices. Setting higher scarcity prices enhances reliability in providing stronger investment incentives. An alternative approach is to more directly coordinate investment with a capacity market, although this is best done as an addition to, not a substitute for, administrative scarcity pricing, since it is the scarcity price that motivates capacity to perform when needed."[8]

8 Oxford Review of Economic Policy, Volume 33, Issue 4, Winter 2017, Pages 589–612, https://doi.org/10.1093/oxrep/grx041

2. Integration of Distributed Energy Resources and Demand Side Participation

2.1. Evolving roles and responsibilities

Overall, the future system roles and responsibilities reflect a set of assumptions about how customers will interact with the system including:

- Many customers are likely to have a preference for 'set and forget' arrangements and some customers may want to choose not to do anything differently in the future
- All customers will continue to have choice in the products and services they want to take up, and how much flexibility they make available
- Greater involvement could unlock greater value, but is balanced by greater responsibilities
- Customer protections will need to remain fit for purpose and risks will need to be regularly assessed to guard against potential harm
- Opportunities and safeguards for both DER and non-DER customers
- Secure and reliable system operation, by AEMO and networks
- Efficient market design that drives down costs for all customers (both with and without DER)
- Facilitation of beneficial innovation by service providers
- DER devices will transition from 'passive' devices (e.g., where PV systems generate purely based on the amount of solar radiation received), to 'active' devices (where they can moderate their output in response to system and market signals). System signals could include network constraints, network service requests, or minimum system load alerts, while market signals would include spot price from energy and ancillary services markets.

To provide further clarity regarding directions set out in Part B, the following tables set out an evolution for roles and responsibilities for different actors as the Post-2025 reforms are delivered.

Table 9 The role of the Customer

Role	Current	Proposed	Timing and Implementation
Customer	Payment to Retailer for connection and supply of energy	Pay/receive payment from trader/aggregator for services provided (e.g., registered agent for DOE or Emergency backstop) (fees deducted for energy connection and supply from the value earnt). Customer nominates relevant trader/aggregator when signing connection agreement. If not nominated, DNSP will manage connection as a passive customer until customer engages a trader/aggregator.	DER owners require additional relationship with trader/aggregator to manage responsibilities with DOE. Workstream: Customer protections
	Investment/ownership of behind the meter devices/appliances	Investment/ownership of behind the meter devices/appliances but making more informed choices based on expectations around ability to export and make a return on their investments.	AEMC Access and Pricing Rule change, DEIP Dynamic Operating Envelopes
	When installing DER assets, e.g., Solar PV or Battery, compliance with DNSP connection agreement, including static import and export limits. In practice this is usually managed by the DER installer.	When installing DER, signing dynamic connection agreement with DNSP – delegation of responsibility for compliance of export limits to trader. In practice, the trader will offer products that customers value and take into consideration the most suitable dynamic connection agreement)	DEIP - Dynamic Operating Envelopes Workstream: Customer protections
	Compliance with standards for devices, e.g., inverters. In practice this is usually managed by the DER Installer.	Compliance with standards for technology, communications and emergency operation requirements. In practice this will most likely managed by the DER installer. The development of devices with remote disconnection functionality will help address the issues with noncompliant inverters.	DEIP – Interoperability Stream, AEMC DER Standards Governance

Table 10 The role of the Trader (Retailer / Aggregator)

Responsibilities	Current	Proposed	Timing and Implementation
Trader	DER market participation (e.g., delivery of energy / FCAS services)	Operation of DER appliances in energy, FCAS, WDR, or any other appropriate market on behalf of customers	Current, and participation to evolve over time through flexible trading arrangements, scheduled lite, trader services and consumer protections
	Establishment of contracts with customers to operate DER devices	Establishment of contracts with customers to operate DER devices, drawing on DOEs, new markets for services, cost reflective pricing and tariffs, selling new products to reflect new services required by the network.	Current, and participation to evolve over time through flexible trading arrangements, scheduled lite, trader services and consumer protections
	Payment from or to customer in accordance with contracts, and DER device operation	Payment from or to customer in accordance with contracts, and DER device operation,	Current, and participation to evolve over time through flexible trading arrangements, scheduled lite, trader services and consumer protections
	Set up, or operation of DER device in compliance with static network limits	Responsibility for meeting Dynamic Operating limits as published by DSO/DNSP	DOE work is currently progressing through DEIP
	DER market enrolment	DER device registration in accordance with market requirements	Current, in the short term, change to registration and participation through the *Integrating energy storage systems in to the NEM rule change*. participation to evolve over time through flexible trading arrangements, scheduled lite, trader services and consumer protections
		Technical and operational compliance with comms and cyber standards	Work is currently progressing through DEIP
		Provision of data to MO to allow appropriate forecasting	Current, and processes between the MO and DSO to evolve over time to support participation of traders via flexible trading arrangements, scheduled lite, trader services and consumer protections
		Scheduled Lite – compliance with scheduling lite requirements	Design and rule change to be developed over 12 to 18 months. Models for visibility and dispatchability to be progressively introduced.
		Operation of non-essential service (pool pumps, air-conditioning)	

Table 11 The role of the Distribution Network

Responsibilities	Current	Proposed	Timing and Implementation
Distribution Network	Provision of connection agreements with static export limit.	Provision of dynamic connection agreement with dynamic export and import limits, managing capacity allocations per NMI	Immediate via DEIP DOE workstream
	Management of network capacity via static export limits in connection agreements	Allocation and publishing of dynamic limits /envelopes, managing capacity constraints per NMI	Immediate via DEIP DOE workstream
	Interface with AEMO as System Operator to register DER with new basic metadata requirements as part of connections process	Interface with AEMO as System Operator to register DER with advanced metadata requirements as part of connections process to support DOEs.	Immediate via DEIP DOE workstream
	Provision of connection agreements in line with existing DER technical standards	Provision of connection agreements for active DER (active solar panels, storage, EV's, smart appliances) in accordance with future technical standards, including proposed interoperability standards	Transitional arrangements
	Management of the network to reliability and quality standards at least cost, by either augmentation of the network or non-network options	Management of the network to reliability and quality standards at least cost, by either augmentation of the network or non-network options, and any future mechanism for energy service procurement.	post AEMC review
	Direct procurement of network services, under RIT-T and RIT-D processes	DER energy service procurement via both direct procurements, and any available DER network services markets or shared procurement platforms that may be introduced	post AEMC review
	Operation of load control to provide low cost hot water, by managing the timing of the hot water for network and system benefit	Default direct load control operation, hot water provision as essential service, and existing network assets provide this service. Responsibility to provide tariffs to these default hot water customers that recognise the network and system benefits appropriately	Transitional arrangements
	Network tariffs, postage stamp, and time-of-use	Support more dynamic network tariff designs, to better facilitate tariffs that will result in automated responses from DER	post AEMC review
	Static data on DER via DER Registry	Registration and sharing of new DER connection metadata, to AEMO to allow for the development of both short and long term forecasts.	Transitional arrangements
	Disconnection of load under UFLS processes to maintain the safe operation of the network.	Disconnection of load, or DER devices under the direction of the System operator to maintain the safe operation of the network.	Transitional arrangements

Table 12 The role of AEMO

Responsibilities	Current	Proposed	Timing and Implementation
System Operator	System limits and directions	Publishing system security limits and envelopes from DSO	Incorporate DOEs into Wholesale - transitionary and enduring arrangements
	Directions to TSNP to ensure minimum system security level maintained	Communication and operational data sharing arrangements with DSO to ensure minimum system security level is maintained	Immediate
		Operational notification of minimum system load for DER device management	Immediate
	Provide standards for DER to operate on System		
	Create short and long term forecasts for the operation of the system	Using DER data provided and other relevant information (including scheduling Lite information) develop short and long term forecasts to safely operate the system	Existing process
	LOR, and UFLS operation as required	Review and update LOR, UFLS, and LOL (Lack of Load) operation as required.	Immediate
Market Operator	DER registration	Registration of Traders into market services including existing and new market participants	IESS and Flexible Trader
	Operation of markets including FCAS, WDR, Energy	Operation of markets as defined by the Post 2025 design including new services and integration of DER	
		Facilitate the Trader Services, Scheduling Lite, Interoperability, and Dynamic Operating Envelope functionality.	
		Manage DER compliance, and conformance to market participation rules, provide minimum standards for DER participation in specific markets	
		Facilitate new market services, and data exchange processes	
	System restart or Black start capability	System restart or black start capability in zero inertia, highly decentralised energy system	Immediate

2.2. Consumer Risk Assessment Tool

As explained in section 5.4 of Part B, one of the immediate reforms is for the market bodies to use the below, updated version, of the consumer risk assessment tool. This will be the process to ensure consumer benefits and risks are explicitly considered as part of, and alongside, design and development of market reforms.

The tool requires consideration of benefits against the "consumer protection principles" that have been developed through the Post-2025 process. In addition, the risk-based approach identifies where new consumer protections or other measures may be needed, reflecting the potential of a new arrangement, product or service to cause harm.

Table 13 Consumer Risk Assessment Tool

Context

The foundation of the national electricity market's energy consumer protections framework is the Australian Consumer Law (ACL), National Energy Customer Framework (NECF, set out primarily in the National Energy Retail Law and Rules) and Victorian Energy Retail Code (Victorian Retail Code). As more consumers move to distributed energy resources (DER), and digitalisation and better data are increasing control and communication options, we need to consider what consumer protections and other measures are needed to ensure customers do not bear unreasonable risks. The market bodies will use this tool to consider consumer risks and benefits in policy development, including rule change requests (as part of considering the National Energy Retail Objective), reviews of guidelines and processes that would impact consumers. It will also be used through the maturity plan releases to help ensure solutions identified appropriately consider risks and benefits.

Communicate and Consult

Benefits Assessment

- How would the change, or new product/service deliver benefits to different types of consumers? Are there individual, customer-side or system-wide benefits? How do consumers with DER benefit compared to those without? What are the impacts on vulnerable and disengaged customers?
- How are these benefits likely to change as the future energy system changes? Will these benefits only be realised in the future?
- How will consumers find out about the benefits?
- What evidence is there that consumers want this? And whether it solves current problems?

Map out how it achieves the following consumer protection principles:

- **Access to energy**: Recognising that energy is an essential service, customers should have access to at least one source of electricity
- **Switching providers**: Customers should be able to change retail providers when they choose
- **Access to information**: Customers should have access to information that is sufficient, accurate, timely, and minimises complexity and confusion to allow them to make informed decisions
- **Vulnerable consumers**: The needs and circumstances of vulnerable consumers will need to be explicitly considered
- **Dispute resolution**: Customers should have easy access to no cost dispute resolution mechanisms when things go wrong.

Identify Risks

- What are the barriers to consumers receiving the benefits?
- What risks or issues could arise for consumers considering the multiple aspects of the consumer experience, situations, and the diverse range of customers?
- What consequences could arise if the risk is not addressed, or the barrier is not removed?

Monitor and review

Evaluate

Evaluate the magnitude of the risk or issue:

- Consider whether it is a significant risk of harm or an inconvenience
- Rank the risks based on severity of consequences and the likelihood of it occurring

Evaluate how the market bodies can address the risk or issue:

- Can they **act**? Is it within their regulatory powers to address? For example, can it be addressed through changes to the National Energy Retail Rules or to the retailer authorisation/exemption process?
- Can they **influence**? Can market bodies influence actions by jurisdictions or the ACCC to address the risk?
- Should they **monitor**? Is the risk beyond the scope of energy policy or a risk that is not yet imminent and would benefit from ongoing monitoring?

Treat risks

- What are the mitigation options? Are the options proportional to the impacts?
- Which option is best considering the consumer protections principles in combination with the National Energy Retail Objective?
- Re-analyse risk after selecting treatment to determine if there are any residual risks that require action?
- Who is responsible for progressing the risk mitigation?
- How will it be done and by when?

2.3. DER Implementation Plan

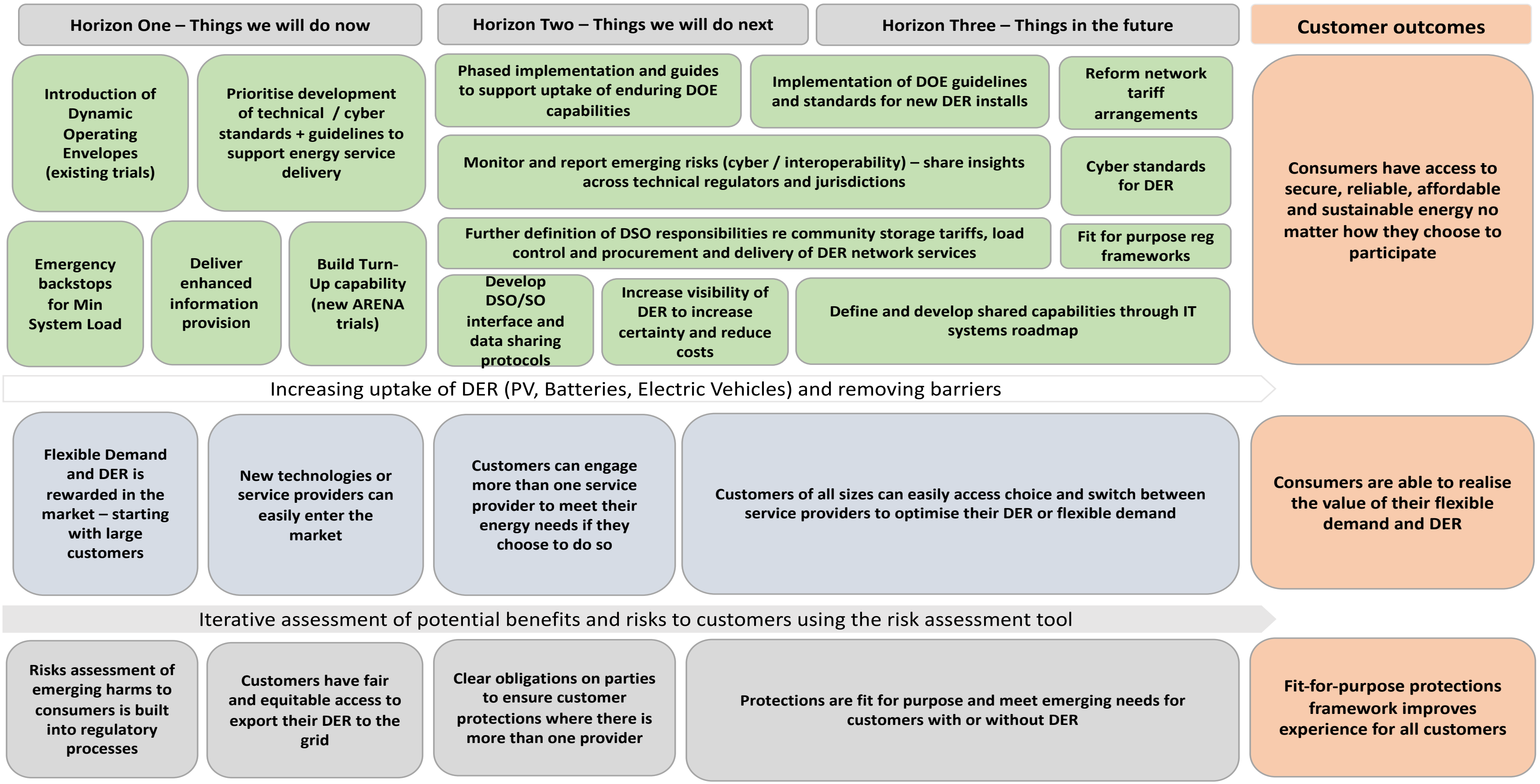
The ESB has developed a DER Implementation Plan (the 'Plan') to integrate the evolution of roles and responsibilities into a suite of technical, market and regulatory reforms from now until 2025.

Reforms are intended to leverage technology and data, improve access and efficiency, enhance market participation and strengthen customer protections and engagement.

Recognising the different stages in the elements of reform, the Plan sets out activities across new and existing workstreams, including contributions from market and industry bodies. The Plan sequences key dependencies to ensure these reforms are introduced quickly, and timed to address urgent needs associated with the rapid take-up of DER. It highlights where interim measures may be introduced to support the industry through the reform process.

A summary page view of the Plan is set out in Figure 2 below and the anticipated outcomes of the Plan are set out in Figure 3.

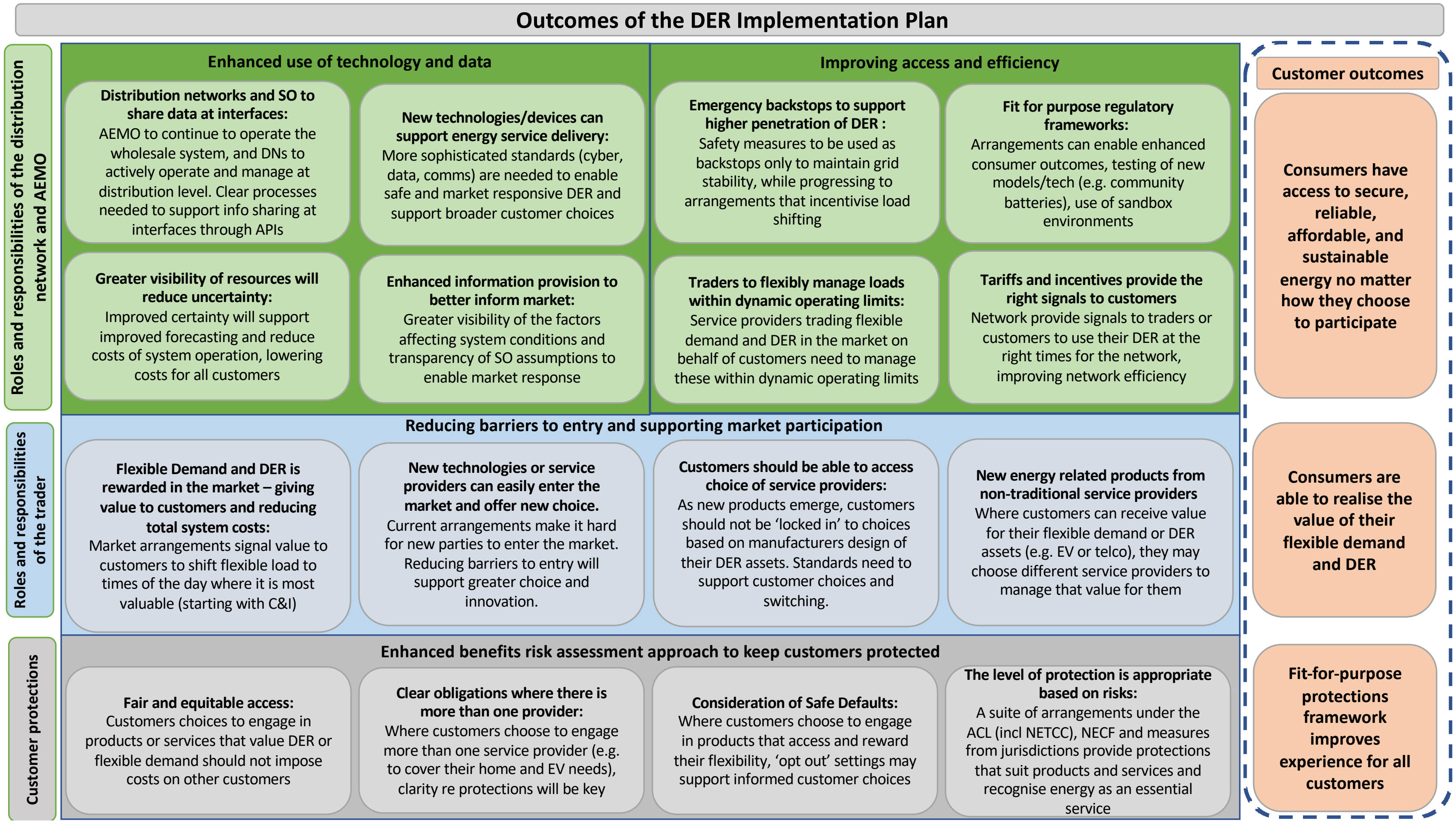
Figure 2 DER Implementation Plan – Summary View



Effective implementation of these reforms will support achievement of the following outcomes for all energy consumers:

- Consumers have access to secure, reliable, affordable and sustainable energy no matter how they choose to participate
- Consumers are able to realise the value of their flexible demand and DER
- Fit for purpose protections framework improves experience for all customers

Figure 3 Outcomes of the DER implementation plan



Leveraging technology and data:

- Participants and market operators share more data through programming interfaces, allowing a greater use of real time automation and AI, and utilise higher fidelity of information from DER to make operational decisions.
- Updated standards for communications and interoperability with DER, making it simple for new operators, cheaper technology, and ease of switching between providers.

Improving access and efficiency:

- Implementing emergency backstops across all jurisdictions to provide last-resort protections from the system security risks associated with emerging minimum load conditions, which will be transitioned with the introduction of dynamic export limits for DER customers.
- Enhancing tariffs to ensure they meet the needs of growing DER technologies, are cost reflective, improve the efficiency of network and lower costs for customers.
- Fit for purpose regulation, allowing for new technologies and innovation.

Enhancing market participation:

- New options for DER to participate in markets, such as Flexible Trading Arrangements.
- Encourage new products and service providers to enter market by reducing entry barriers, giving more choice of providers and making switching easy.
- Encouraging non-traditional players alongside new technology innovation, such as EVs.

Strengthening customer protections and engagement:

- Ensuring fair and equitable access for customers to export energy back to the grid.
- Safe defaults for customers, and clear guidelines for the introduction of more advanced products and services.
- A risk-based approach to regulation, and ensuring customers are not exposed to increased risks.

The implementation plan describes the activities and workstreams over three horizons. These are set out below.

Horizon One

Activities that will be commencing immediately, to be underway or complete by mid 2022.

- Completion of first phase of technical interoperability, communications, and cyber standards for DER, and definition of interoperability polices.
- Emergency backstops in place orin progress for jurisdictions to address system security challenges associated with low minimum system load events, alongside enhanced information provision from AEMO and early trials to promote price-responsive turn-up load in markets.
- First steps towards phasing in of dynamic operating envelopes (DOEs) as the long-term feature of the NEM DER ecosystem, with mandatory compliance for new solar PV and storage systems by 2025.
- First step mechanisms for increased DER participation, including new Flexible Trading Arrangements rule changes, including co-design through the Maturity Plan processes.

Horizon Two

The second horizon of activities in the plan will include:

- Implementation of scheduled-lite, to promote opt-in visibility for large C&I flexibility.
- Complete review of DSNP responsibilities in relation to the DSO transition, community storage, DUoS and DER energy service procurement, with a clear timetable for further reforms.
- Introduction of Trader services reforms, providing clarity on the various services and obligations for Traders in respective service categories.
- Commence work on EV smart charging standards and policies, including co-design with consumer and industry groups through the Maturity Plan process.
- Continued work on phased rollouts of DOEs with certain networks and jurisdictions to lead the adoption of active DER participation in markets.

Horizon Three

For reforms to be completed by 2025 or bringing forward long-term issues, the third horizon expects:

- Rollout of interoperability and cyber technical standards needed for active DER participation, mandatory compliance with DOEs, and processes for switching between providers.
- Introduction of the Trader services models and flexible trader metering arrangements, encouraging new providers into the market.
- Introduction of reforms to network regulation that drives network efficiencies through improved tariffs, and mechanisms to enable structured procurement of DER services by networks.
- Consumer protections frameworks have evolved to capture the risks associated with new products and services entering the market alongside the Post-2025 reforms.

Figures 4-6 sets out the activities associated with each time horizon.

Figure 4 Horizon one: things we will do now

Horizon One – Things we will do now

Introduction of Dynamic Operating Envelopes:

- Develop interim guidelines on metering and DOEs for installers together with industry bodies,
- Market trials underway are to inform guidelines on best-practice capacity allocation rules prior to AER regulation.

Prioritisation of Standards for new technologies/devices:

- ESB / market bodies to provide clear policy directions and timeframes to steer DEIP work program on DOE, Interoperability and EVs standards,
- Support phased development of technical guidelines / handbooks to drive early adoption,
- Identification of related capabilities needed for interop alongside standards,
- ESB / market bodies to complete interoperability policy and provide pathway to implementation.

Development of DER Cyber standards

- ESB / AEMO to provide clear scope and need ahead of Commonwealth (DISER) standards,
- Risk identification via DEIP interoperability workstream,
- Identify and inform market bodies of interim measures needed by mid 2022,
- AEMO to maintain coordination with DISER, and oversight of interim workplan.

Emergency backstops:

- Backstops for Minimum System Load to be put in place across jurisdictions.

Trial front stop measures

- AEMO to develop trials with ARENA and jurisdictions to build capability in 'turn up' response.

Greater visibility of resources:

- Development of Scheduled Lite arrangements,
- DER marketplace trials (Project Edge),
- SAPN Flexible export trials.

Enhanced info provision:

- Improved market visibility of emerging system security risks flowing from minimum system load,
- AEMO to develop guidelines and enhanced transparent market reporting (incl min load market notices).

Ongoing Tariff Reform

- Tariffs will transition to be more cost-reflective. Trials to test out tariff structures will supplement the ongoing tariff reforms.

Flexible Demand and DER are rewarded in the market:

- C&I customer access via WDRM
- Further design of residential customer participation in markets
- DER marketplace trials (Project Edge)

New technologies or service providers can easily enter the market :

- Integrating Energy Storage RC provides choice
- Consumer protections will need to be assessed

New energy related products from non-traditional service providers

- Flexible Trading Arrangements (Model 1 and 2) – assess potential risks to consumers,
- Review retailer authorisation process.

Customers should be able to access choice of service providers:

- Flexible trading arrangements (Models 1 and 2).

Further definition of DSO responsibilities

- ESB / market bodies to provide clear policy directions and timeframes to steer DEIP programs, provide forward clarity for DNSPs.

Define and develop shared capabilities through IT systems roadmap

- AEMO to publish NEM IT systems roadmap to enable shared view of future market system needs.

Implement Risk Assessment Tool:

- Risk assessment tool to be built into processes across market bodies,
- Iterative consideration of potential risk and harm to customers as part of policy design and decision making.

Fair and equitable access:

- DER Access and Pricing rule change

Clear obligations where there is more than one provider:

- Review of retailer authorisation process,
- Flexible Trading Arrangements (Model 1 and 2).

Maturity Plan MP1

How to remove barriers for customers to be rewarded for their flexible demand:
Use cases: C&I turn up loads + In home devices such as smart hot water systems, air conditioning loads or pool pumps.

Maturity Plan MP2

How do customers receive and give signals to the market?
Use cases: Smart appliances + Process automation.

Year One: mid-2021-2022

Figure 5 Horizon two: things we will do next

Horizon Two – Things we will do next

Standards for new technologies/devices:

- Move interoperability work into formal Australian Standards process,
- AEMC to commence rule changes associated with mandatory interoperability standards,
- AEMO to leverage pilots as an interim DOE repository for systems limits as step allowing opt-in compliance.
- Commence work on EV smart charging standards.

Trial front stop measures

- Continued pilots to test front stop "turn-up" measures to inform market changes needed,
- Learnings from pilots to be integrated in policy decisions.

Introduction of Dynamic Operating Envelopes:

- Market bodies to work with first networks commencing the use of DOEs and flexible connection limits to better understand the customer challenges,
- Phased introduction of guidelines,
- AEMO to make available system level DOEs for min demand,
- AER to consult on capacity allocation and dynamic connection agreement details.

Fit for purpose reg frameworks:

- Further detail on options for LUoS tariffs needed to support community battery storage,
- Clarifications on DSO responsibilities, direct load control, storage, and system security participation,
- Develop up structured procurement / DER network market details for market consultation,
- AER to encourage new work on new tariff structures under tariff reform agenda with DNSPs

Greater visibility of resources:

- Scheduled Lite Visibility Model,
- Operational data published by participants.

Flexible Demand and DER is rewarded in the market:

- Remove barriers to residential customers accessing DR products,
- Scheduled Lite Dispatch model.

New technologies or service providers can easily enter the market :

- Streamline process for DER integration in ESS markets (S-Lite Dispatch model),
- Streamline processes for DER registration in ESS and RAMS.

Customers should be able to access choice of service providers:

- Development of interoperability policy, and phased introduction of corresponding standards and processes for retailers and aggregators.

New energy related products from non-traditional service providers

- Review of retailer authorisation process,
- Flexible Trading Arrangements (Model 1 and 2)

Clear obligations where there is more than one provider:

- Review of retailer authorisation process to review,
- Flexible Trading Arrangements (Model 1 and 2), and interactions with DOEs

Protections are fit for purpose and meet emerging needs:

- Iterative assessment of emerging risks – e.g. including review of cooling off periods, use of safe defaults, penalty /product design / other contract restrictions,
- Proactive assessment of where grey areas may emerge with customers / stakeholders,
- Does the scope of the NECF remain fit-for-purpose,
- Assessment of need for new levels of retailer licenses.

Maturity Plan MP3
How do customers want to use smart charging?
Use cases: smart charging infrastructure away from primary premises + EV smart home charging.

Maturity Plan MP4
How do customers choose and switch providers?
Use case: enrolment in VPPS + upgrading of existing systems.

Year Two: mid-2022-2023

Figure 6 Horizon Three: Things in the future

Horizon Three – Things in the future

Standards for new technologies/devices to support energy service delivery:
- Completion of Australian Standards process on DER interoperability and comms,
- Publication of Cyber standards (DISER) for use alongside Interop standards,
- Implemented policy and associated interop standards to support switching,
- Finalise policy on EV smart charging standards and inclusion in interop.

Introduction of Dynamic Operating Envelopes:
- Rule changes completed requiring new solar / storage installations to comply with DOEs,
- Several DNSPs publish DOEs to protect network limits in congested regions.
- Phase in of full compliance for aggregators / retailers to apply dynamic limits,
- AEMO publishing min load signals through market notices and system DOE repository,
- Guidance released by AER on connection agreement conditions, capacity allocations,
- Compliance mechanisms in place to monitor aggregator obligations for meeting dynamic limits.

Fit for purpose reg frameworks:
- Reg sandbox / Maturity Plan to consider scaling and integration of community batteries,
- Tariff reform continues, with more cost reflective (TOU) tariffs,
- Regulatory changes to drive structured procurement for DER Network service uptake,
- Publishing of network visibility data to improve planning and locational DER investment.

Flexible trading and DOE pilot
- ARENA led pilot to better understand smart devices and multiple providers,
- Test interactions of home energy management tech, flexible trading and DOEs.

Greater visibility of resources:
- Scheduling arrangements continue to evolve as DER and flexible demand supplies a greater share of energy and services to the power system.

Flexible Demand and DER is rewarded in the market:
- Large and small customers can easily choose products and services that value their flexibility .

New technologies or service providers can easily enter the market :
- More technology companies and service providers active in the market,
- Value streams across Energy, ESS, RAMS, Networks.

Customers are able to engage with more than one service provider to meet their energy needs at home – without this being too costly or complex:
- Flexible Trading Arrangements (Model 1 and 2),
- Tariffs and connection policies to support EVs and community storage products.

Future System Architecture provides the markets and services required to effectively integrate and value DER and flexible demand
- Reforms provide the functionality, systems and processes to facilitate customers DER choices,
- Shared capabilities designed where these support future needs.

Customers should be able to access choice of service providers:
- Clarity on interoperability policy, and minimum compatible functionality,
- Full introduction of standards across retailers, aggregators and tech providers.

Protections are fit for purpose and meet customer needs:
- Customer input via Maturity Plan supporting co-design of fit for purpose frameworks that better meet customer needs,
- Customers can switch DER providers without lots of cost or complexity,
- Customers can easily access choice to leverage flexibility from their DER assets (e.g. solar PV, batteries or EVs) and flexible load (e.g. air conditioning units, pool pumps or smart hot water devices)

Maturity Plan MP5
Priorities to be informed by earlier releases and customer + stakeholder input.

Maturity Plan MP6
Priorities to be informed by earlier releases and customer + stakeholder input.

Year Three: mid-2022-2023

2.4. Maturity Plan Framework

Further to proposals set out in the April Options paper, the ESB has worked with stakeholders to design a mechanism intended to identify insights on key customer facing issues in the DER Implementation Plan. The Maturity Plan is intended as an approach that will streamline engagement by bringing multiple stakeholder interests together and build an evidence base of customer insights to inform reforms (and related activities) in the DER Implementation Plan. The proposals in this appendix reflect updates made to proposals in April based on stakeholder feedback in submissions and as part of the Maturity Plan pilot process (carried out April-June).[9]

The intention of the Maturity Plan is to provide a coordinated process to collaboratively explore the customer issues associated with the integration of DER. These issues have impacts across a range of factors including technical, market, regulatory, digital, communications and various dimensions of customer experience. This will enable insights to inform decisions being made by market bodies and jurisdictions, supporting decisions on appropriate system architecture and associated roles and responsibilities.

Considerable efforts across the sector have been invested to consider DER integration issues. However, the pace of uptake of DER and customer owned assets highlights the need for clear processes and timing of activities. Initial priorities have been set out as detailed in the DER Implementation Plan.

The Maturity Plan framework is intended to enable insights to be shared and to inform cohesive decision making and adjacent regulatory processes, giving greater clarity to parties making investment decisions, and to unlock the value and benefits of integrated DER for consumers in a staged but timely manner.

Implementation of the Maturity Plan

Further to stakeholder feedback, a revised framework has been developed for the Maturity Plan that will see this operate as a tool to support delivery of the reforms across the DER Implementation Plan.

In developing reforms to integrate DER and flexible demand, customer input will be key to test assumptions and to understand how customers might want to engage with different service providers or products. While the DER Implementation Plan will not be developing energy products or services, feedback from a customer perspective as to how they need or intend to use their customer owned assets, will inform development of standards to support effective switching, or inform where risks or harms may emerge with new services becoming available. The Maturity Plan will provide a vehicle to centre these cross-cutting customer issues in the development of these reforms.

The Maturity Plan will leverage these efforts including alignment with the Distribution Energy Integration Program, Energy Consumers Australian (ECA) work, rules changes, policy decisions and data strategy.

In overseeing delivery of the Post-2025 reforms, and delivery of the DER Implementation Plan, the ESB (together with market bodies) will lead and coordinate the Maturity Plan activities. It is proposed that the Maturity Plan will run for three years, consistent with delivery of the DER Implementation Plan activities.

The Maturity Plan will focus on key cross-cutting customer issues for each release (typically 6-months in length), that will be investigated alongside technical workstreams. Insights emerging from each release will inform activities across the reform program. The first four priority issues have been

[9] Further insights from the Maturity Plan Pilot can be found here: https://esb-post2025-market-design.aemc.gov.au/32572/1626317976-esb-mpp-codesignknowledge-share-reportfinal.pdf

identified below. These priorities may however evolve to adapt with emerging priorities in the DER Implementation Plan.

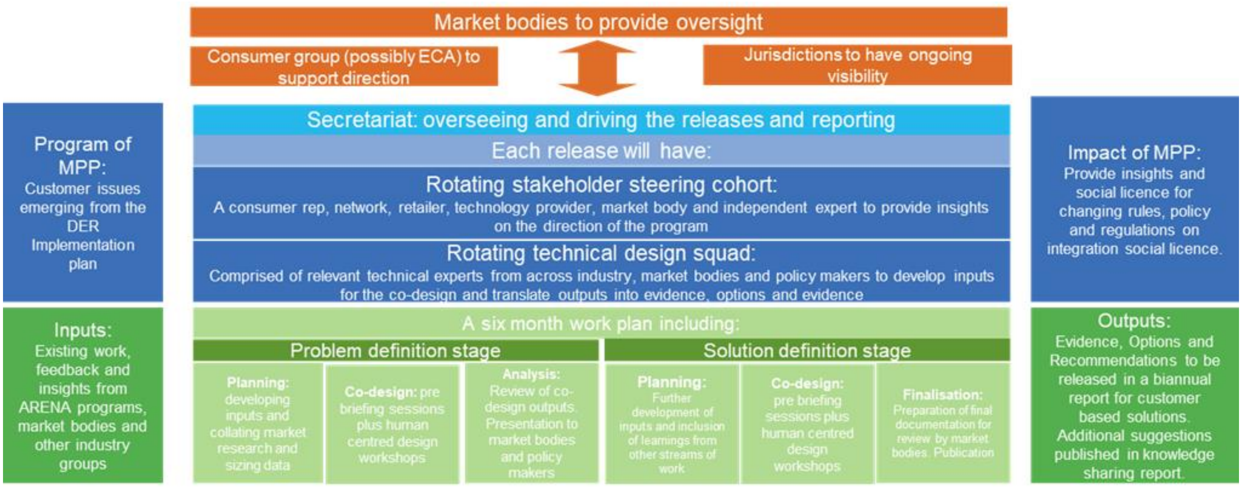
The framework would involve active engagement with stakeholders four times a year, over a 2-week window of iterative co-design workshops. These workshops will be framed with human-centred design principles to support customer centric thinking from those participating and will leverage use cases to test practical implementation issues. A new stakeholder steering cohort will be established for each release following an expression of interest (EOI) process with stakeholders. The same process would be followed to seek interest for the Design Squad. Market research and direct customer engagement will be incorporated into the program as well as any additional technical work to inform the process.

Each release will have two stages, a problem definition stage and a solution definition stage.

The problem definition stage is intended to bring stakeholders together around common understanding to move into the solution stage.

At the end of each release, a knowledge sharing report will be published to detail the insights and possible solutions emerging from the work. At that stage, the next Release will begin.

Figure 7 Overview of Maturity Plan framework



Governance and decision making

As noted in the April Options paper, the Maturity Plan is not a decision-making body and does not replace existing governance process. The Maturity Plan instead will provide decision and policy makers with insights on cross cutting issues facing customers today. Where potential solutions emerge, such as those delivered in the Maturity Plan pilot, these may be taken forward as initiatives by the Market Bodies, stakeholders or other parties.

The Stakeholder Steering Cohort will change for each release. The Cohort is intended to support a diverse stakeholder input and is tightly structured to include input from each of the following: network, market bodies, consumer advocates, retailers, technology providers and experts. Appointment to the SSC for each release will be made following an expression of interest (EOI) process with stakeholders.

Priority issues and publication

Recommended priorities for initial releases of the Maturity Plan have been set out below and reflected in the DER Implementation Plan (over Horizons One and Two of its delivery). These initial priorities were surfaced in the Maturity Plan Pilot run between April and July 2021.

As set out in the diagram above, the Maturity Plan provides for quarterly reporting to the market bodies on identified priorities informed by stakeholder input.

Issues for future releases of the Maturity Plan will be based on progress from the DER Implementation Plan and informed by stakeholder feedback on priorities.

Initial issues

- **H1 2022: Maturity Plan Release 1: How do customers get rewarded for flexibility?**
    - Use cases: C&I turn up load + Residential Hot Water
    - Related initiatives: direct load control, flexible trader model
- **H2 2022: Maturity Plan Release 2: How do customers receive and give signals to the market?**
    - Use cases: Smart appliances + process automation
    - Related initiatives: Scheduled lite + visibility, DOEs, Scheduled lite
- **H1 2023: Maturity Plan Release 3: How do customers want to use smart charging?**
    - Use cases: Smart charging infrastructure away from primary premises + EV home smart charging
    - Related initiatives: interoperability standards, flexible trader models
- **H2 2023: Maturity Plan Release 4: How do customers choose and switch providers?**
    - Use cases: Enrolment in VPPs + Upgrading existing systems
    - Related initiatives: Interoperability standards, retailer authorisation.

Integration with DER Implementation Plan

The DER Implementation Plan looks at the full range of DER Integration. Many of the decisions involved will leverage insights from the Maturity Plan. Crucial elements include the customer risk assessment tool which can be modified for use in the Maturity Plan co-design sessions. There will be alignment between the Maturity Plan activities and the DER Implementation Plan to ensure insights and possible solutions are considered and to adapt the priorities where needed.

2.5. Flexible Trading Arrangements

Section 5.5 of Part B provides an overview of the initial reforms proposed for enabling demand-side participation. This includes the flexible trading arrangements which are a means for separating controllable loads and generation (such as solar PV, batteries, EVs and pool pumps) from uncontrollable resources (the primary source of electricity to a customer's home or business). By separating controllable resources, customers can choose additional energy services for their flexible demand or generation while remaining on their current retail plan. This means that customers can be rewarded for outsourcing the management of their flexible demand while not having to change their behaviour for their conventional energy use.

The ESB has proposed two models to enable flexible trading which are both based on amendments to features of the existing regulatory framework. These are the:

- Flexible Trader Model 1 – SGA +
- Flexible Trader Model 2 – Sub-meter connection point

Both models are outlined below.

Flexible Trader Model 1 - SGA+

Model 1 extends the existing Small Generator Aggregator (SGA) framework. The main change moves the SGA design from generation only to cater for bi-directional energy flows and participation in the ancillary services market. Doing this will enable SGAs to provide new products and services to customers.

The customer's use or production of energy services at a single site would be separated into two connections, one or both of which may be bi-directional, via two metering installations and NMIs (consistent with the current SGA model). Doing so enables the NMIs to be treated independently (e.g., for consumer protections, Metering Coordinator appointment, billing, network charging, etc.). The customer could engage different traders at each connection point and could decide, over time, to change to a new trader at either connection point in line with standard customer switching processes.

This model allows a different customer to be responsible for the second connection point, appointing their own trader. This could be useful for landlord and tenants in long-term lease arrangements to support the installation of DER such as solar PV and battery storage. This model could be well-suited to new builds and properties being rewired or re-fitted where the costs of installing a second connection point are minimal and where the distributor does allow a second connection point to be established.

However, this model might not be suitable for all customers. The requirement to establish an additional connection to the distribution network means that upfront and ongoing costs (including network connection costs and ongoing network tariff charges) may pose a material barrier to for some participants and customers. Further, we note some distributors do not allow small customers to obtain a second connection point to a premises, even though the market rules do not prohibit this.

Under this model, parties who chose to use this approach bear the implementation costs rather than spread across all customers or market participants. Therefore, parties considering this this model can assess whether it is appropriate for them, given the costs and benefits in their application.

Model 1 received broad stakeholder support, with recognition that the AEMC consultation for the Integrating Energy Storage rule change was already providing a vehicle for the model to be tested against the market objectives.

The draft changes the AEMC has made to the SGA category through the Integrating Storage rule change facilitates Model 1. It does this by establishing a clear participation category for aggregators within the IRP to be bi-directional and provide both energy and ancillary services. The ESB supports the AEMC's ongoing consideration of Model 1 within the Energy Storage rule change.

Flexible trader Model 2 – Sub-meter connection point

The second model proposed provides a specific category of connection arrangement, a Private Metering Arrangement (PMA), that enables a NMI to be established within a customer's electrical installation. The key features of Model 2 include:

- Model 2 could enable a simple additional sub-meter to be installed concurrently with a new solar PV, battery or EV charger installation. This could be delivered without additional involvement from the distributor or need to upgrade existing electrical infrastructure over and above what would have otherwise been required. The wholesale settlement process already caters for the allocation of flows of energy between a primary and secondary NMI, ensuring that the traders appointed by the customer are only ever charged for energy that is attributable to them.
- As energy flows to and from the distribution network are netted, by design, this model would reduce energy-related network charges and as all energy withdrawn or injected into the local network is measured at a single point.

- Once a NMI within a PMA is established current retail market processes such as customer switching, meter churn and metering role appointments function as they would for a traditional connection to the distribution network. Customers would have the same ability to switch providers, or to request the de-energisation or de-activation of a NMI within a PMA if it was no longer required.

A range of parties supported the benefits the ESB identified for Model 2: the potential for innovation, affordability and ease of deployment were highlighted by service providers and aggregators, some distributors and consumer representatives alike. The Lighting Council Australia went further in support of the development of Model 2 and an associated review of metering installation requirements, highlighting a broad range of additional use cases beyond small customer connections that could benefit, in particular the deployment of smart street lighting systems and other initiatives to conserve the use of energy in the NEM and increase competition.

A principal issue raised by a number of stakeholders was that the potential to adopt non-traditional types of metering installation and meter location within a PMA was critical to the take up of flexible trading. The ESB agrees this is key. Over time, the PMA requirements could provide a flexible framework for the adoption of non-traditional types of metering installation and meter location, providing device, installation and maintenance standards can be maintained.

2.6. Scheduled lite proposed implementation

The initial reforms set out in section 5.5 of Part B include the proposal to introduce “Scheduled Lite”. Since the April paper the ESB has considered implementation pathways for the scheduled lite models. A staged implementation approach is proposed enables AEMO to introduce initial reforms first that don’t require changes to the rules or AEMO’s systems. It also allows AEMO to factor in other market changes, coordinate with other DER initiatives and incorporate lessons from trials before implementing enduring models as part of the initial reforms.

The first stage introduces an “initial visibility model**”** that will introduce initial benefits that can be implemented quickly. The second stage involves developing the enduring versions of the “visibility” and “dispatchability” models of Scheduled Lite. An overview of the visibility and dispatchability models is provided in section 5.5 of Part B. The elements and timing of the staged approach is set out below.

The pathway approach is detailed as follows.

Table 14 Scheduled Lite models - design and implementation pathways’

Scheduled Lite model	Design and Implementation considerations	Indicative Timing
Initial visibility model: *to improve visibility of unscheduled resources using existing rules and market systems.*	Design considerations: • Provision of forecast information with a focus on demand side use cases (including price responsive large users and aggregated DER portfolios). • Consider lessons from VPP demonstrations and WDR implementation. Implementation considerations: • Utilise existing rules (DSPI framework) and market systems (DSPI and WDR portals). • Amendment of DSPI Guidelines.	*Immediate* Commence design immediately **Go live** is (~2022 / 23)

Scheduled Lite model	Design and Implementation considerations	Indicative Timing
Visibility model: *improve visibility of unscheduled resources through provision of incentives and enhanced market systems, delivered by rule in coordination with other DSP / DER initiatives (DER implementation plan).*	Design considerations: • Provision of forecast information from price responsive unscheduled resources. • Incentives to encourage the accurate and timely submission of forecast information. • Integration of information into AEMO demand forecasts. • Publication of demand forecast information to improve visibility for market participants. Implementation considerations: - Analysis of costs and benefits (including for consumers) and formal consideration through rule change - Changes to Procedures, market participant interfaces as well as demand forecast and settlement systems.	*Initial* Commence design (2021/22) Rule change to be submitted (second half of 2022) **Go live** is (~2024/25)
Dispatchability model: *provide incentives and reduce barriers to participation in NEM dispatch, delivered by rule change and in coordination with other DSP / DER initiatives (DER implementation plan).*	Design considerations: • Detailed analysis of design elements, including use cases and end-to-end examples. Incentives and compliance. • Dispatch model for aggregated DER portfolios. • Complement and integrate with the design of related participation reforms including Integrating Energy Storage Systems and flexible trading arrangements. • Consider lessons from DER marketplace trials (including Project Edge (VIC) and Project Symphony (WA)), implementation of WDR, unscheduled generator rule change analysis and determination. • Integration of information into AEMO demand forecasts, reliability and security systems and processes. Implementation considerations: - Analysis of costs and benefits (including for consumers) and formal consideration through rule change - Changes to Procedures and market systems (including development of market interfaces and SCADA	*Initial* Commence design (2021/22) Rule change to be submitted (second half of 2022) **Go live** is (~2024/25)

Scheduled Lite model	Design and Implementation considerations	Indicative Timing
	technologies that are expected to reduce costs for participants).	

3. Transmission and Access

This section provides more detailed information regarding:

1. The reasons why the ESB considers that there is a need for access reform and, in particular, a need to improve the way that the NEM deals with congestion; and
2. How the congestion management model adapted for REZs (or CMM(REZ)) would work, and an overview of the issues requiring further consideration.

Among other things, section 3.1 presents the findings of a study undertaken for the ESB by FTI Consulting, which examined future congestion in the NEM.

3.1. Case for reform

The ESB's package of transmission and access reform include a range of measures to overcome obstacles to getting transmission and generation built when and where it is needed. The ESB's view is that the key challenges are:

- The current market design induces generation and storage investment in the wrong places and fails to provide a stable foundation for investment decisions,
- Congestion is going to increase and the current market design deals poorly with congestion, leading to more expensive outcomes for consumers,
- We need to provide better options for storage and other flexible scheduled loads such as hydrogen to profit from locating in places and operating in ways that benefit the system most.

3.1.1. Current market design induces investment in the wrong places

In the absence of arrangements that provide clear signals to generators and storage about where it would be efficient to build and how to utilise the network, outcomes will continue to be uncoordinated and lead to higher overall costs.

New generation and storage will continue to locate and operate in ways that are inconsistent with minimising total system costs. One likely consequence is elevated congestion, which means electricity cannot be dispatched to meet demand at the lowest possible cost. In turn, this will drive the requirement for more transmission investment to alleviate the congestion, which would not have been needed if the investment and operation of generation and storage had been efficient. The cost of this additional transmission investment is borne by consumers.

These market-driven distortions are not contemplated in the ISP, which is an engineering assessment designed to minimise total system costs. The ISP model identifies the best possible places for places for new generation or storage developments from a whole of system perspective and assumes that those resources decide to locate there. Essentially, the ISP implicitly assumes that locational marginal prices (LMP) are already in place. However, under the NEM's regional pricing model, there is no commercial driver for investors to choose the efficient locations identified in the ISP. If the market design encourages patterns of generation investment that do not align with the ISP, the ISP modelling will perpetually adjust in response to developments on the ground – and the adjustments are likely to be more costly than if investment had occurred in line with the original plan.

REZs will help but they are a localised solution. Due to the way electricity flows across the grid, constraints outside the REZ will be felt inside the REZ.[10] This can only be addressed through solutions that apply across the whole system, of which REZs are a part.

10 This issue is discussed in more detail in the ESB's Renewable Energy Zones Consultation Paper, January 2021, pg 20. See: https://energyministers.gov.au/publications/stage-2-rez-consultation-energy-security-board

Under the current access regime, even an investment that causes heavy congestion may still be profitable for an investor, because the costs of congestion may be borne in part by pre-existing generators or consumers rather than fully by the party that caused the congestion. This is because the NEM's current access regime permits any generator that meets the relevant technical standards to connect – irrespective of whether the investment provides value to the broader power system – and then the new generator competes with existing generators for access to available network capacity.

The ESB's CMM(REZ) seeks to change this aspect of the access regime so that a generator whose investment decision causes inefficient congestion faces the associated costs, and a generator who locates where capacity is available is protected from subsequent connection risk.[11]

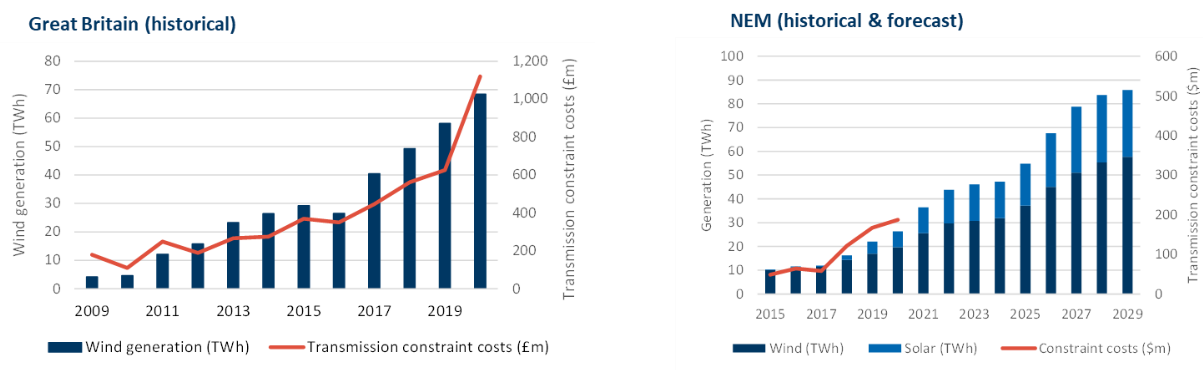
The right NEM-wide arrangements that coordinate transmission and generation will also reduce the risk of low and volatile marginal loss factors and facilitate grid connection.

3.1.2. Congestion is expected to increase, even after the actionable ISP projects are built

Most jurisdictions globally have experienced an increase in congestion costs in line with an increase in variable renewable generation. Congestion is likely to increase because the cost of building the incremental transmission infrastructure needed to allow the dispatch of variable renewable generation at the sunniest or windiest of times exceeds the benefits to reducing the cost of dispatch or reducing emissions at those times from the dispatch of VRE. It is more cost effective, and reduces emissions by a greater extent, to build more variable renewable generation than can always be accommodated by the transmission infrastructure, even if that variable generation cannot always be used.

Figure 8 compares the historical experience of Great Britain with the historical and forecast experience in the NEM. It shows a strong linkage between VRE output and congestion.

Figure 8 Trends in variable renewable generation and congestion costs



Source: FTI Consulting[12]

Congestion is a normal, everyday feature of efficiently sized transmission infrastructure to accommodate variable renewable generation – not an anomaly. It can be profitable for solar developers to build solar farms that produce surplus output during the middle of the day, so that they can produce more during the lucrative shoulder periods. It would be inefficient for the transmission network to be able to accommodate all this surplus generation.

11 Further design work is required to determine how and where rebates are made available - see section 3.4. As a high-level concept, generators that locate in REZs will receive rebates, and those who locate outside REZs will not. However, there may be instances where it is appropriate to confer rebates on generators who are locating in a part of the network with spare hosting capacity, even though it is not part of a formal REZ process. This matter will be considered further as part of any Rule change process to progress the CMM(REZ).

12 FTI Consulting, Forecast congestion in the NEM, prepared for ESB, August 2021.

The ISP does not, and should not, seek to remove all congestion from the system, given that to do so would impose significant and substantial costs on consumers. This means that issues relating to access will be common despite the transmission infrastructure expansions foreshadowed by the ISP.

To illustrate this point, the ESB engaged FTI Consulting to examine the prevalence of congestion in the NEM in 2030 assuming that transmission, generation and storage are built in accordance with the ISP step change scenario. As shown in Figure 9, the number of hours with constraints binding is expected to increase significantly in all regions except Tasmania.

Figure 9 Percentage of hours per month with at least one constraint binding by State

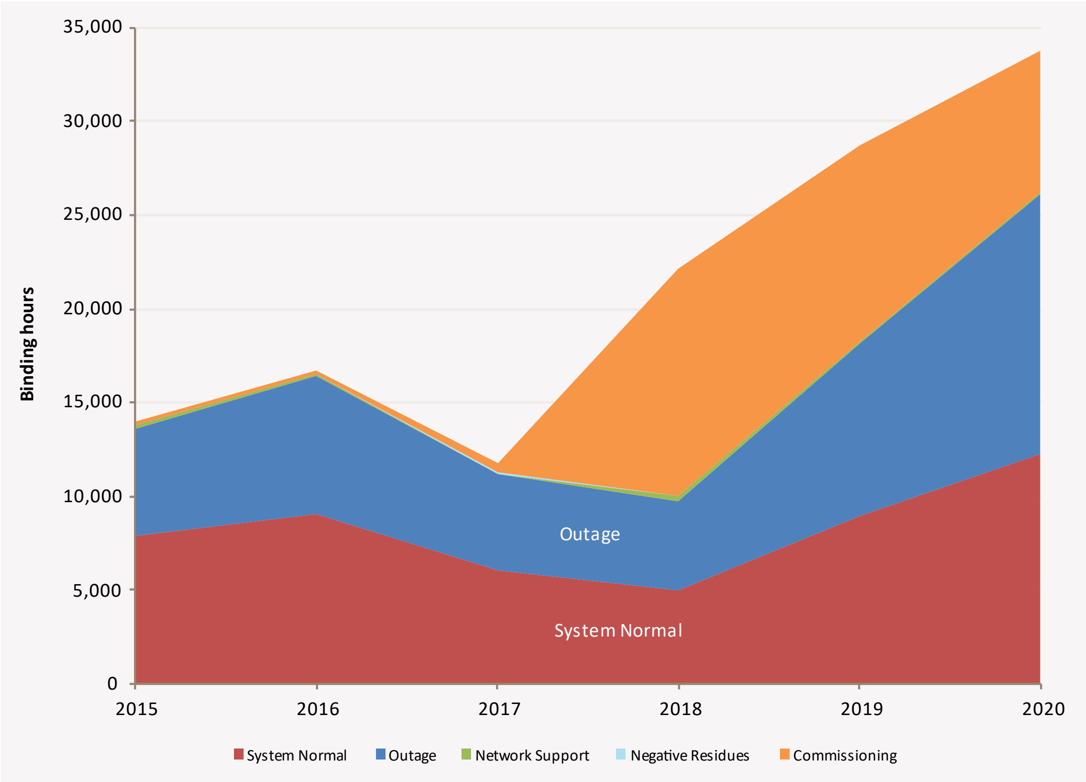
Source: FTI Consulting, Forecast congestion in the NEM, prepared for ESB, June 2021.

Note: Network constraints includes thermal and stability constraints. It does not include network outage constraints.

FTI Consulting's findings align with other studies. For instance, Cornwall Insight Australia estimates that by 2030, the NEM will have 12 GW of surplus energy available in the middle of the day on an average day (with the implication that around half the time, there will be even more than 12 GW).[13]

The level of congestion shown in Figure 10 are likely to understate true levels for a number of reasons. First, the modelling is focussed on congestion occurring during system normal conditions as the complexity of the modelling task means that it is not feasible to include network outages. However, historical experience suggests that a significant proportion of congestion arises as a result of network outages.

Figure 10 Binding hours by constraint type, NEM, 2015 to 2020



Source: AEMO[14]

The second reason why actual levels of congestion are likely to be greater than forecast is that the current market design systematically incentivises generation investment at locations that are inconsistent with the least cost development path identified by the ISP. This is because generators are paid the regional reference price, which does not reflect the marginal cost of energy at their specific location. To the extent that generation investment occurs at certain locations in excess of the level identified in the ISP, congestion is likely to further increase. When FTI ran a sensitivity to explore the impact of additional solar capacity over and above the amount modelled in the ISP, the potential incremental solar output was reduced by over 20 per cent due to constraints.

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13 Cornwall Insight Australia, *Chart of the week 74 - When less could be more – on the states' green targets*, 11 March 2021. Available at: https://www.cornwall-insight.com.au/wp-content/uploads/2021/03/AU-COTW-Issue-74.pdf

14 AEMO, NEM Constraint Report 2020 Summary data. Available at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams

3.1.3. Need for congestion management in operational timeframes

In operational timeframes, the current wholesale pricing framework can give rise to inefficient and complicated results in the presence of congestion. This is because the regional pricing model does not reflect what happens on the power system during periods of congestion. Instead, during periods of congestion the dispatch algorithm applies simplified rules that reward market participants for acting in a manner that is inconsistent with economic efficiency.

One such inefficiency that arises is an instance of 'disorderly bidding', known as 'race to the floor bidding'. In the presence of congestion, generators know that the offers they make will be unlikely to affect their regional reference price. The profit maximising behaviour of a generator is to bid at the market floor price of -$1,000/MWh. This maximises their individual dispatch quantity, and hence the revenue they receive (the dispatch quantity multiplied by the regional reference price). All generators affected by the constraints are incentivised to maximise their share of the limited transmission capacity by engaging in this 'race to the floor' bidding behaviour: not racing to the floor when one's competitors are doing so reduces the generator's share of dispatch, and hence revenue.

The NEM dispatch engine selects market participants to be dispatched by minimising total as-bid costs while ensuring that the pattern of dispatch is consistent with the physical capacity of the system. It uses as an input the bids made by market participants; it does not distinguish between the underlying actual costs of generators. As a result, in the presence of congestion and disorderly bidding, dispatch is shared based on administered rules between generation with high and lower underlying costs, all of whom are bidding at the same price. This results in productive inefficiencies – it would have been more efficient for the lower cost generation to be dispatched ahead of the higher cost generator – and ultimately in higher prices for consumers.

Analysis of dispatch inefficiencies and congestion in the grid show that over time the impact and associated costs of these issues are likely to significantly increase. NERA modelling undertaken for the AEMC[15] estimates that costs arising from race to the floor bidding could reach up to NPV $1 bn over the period from 2026 to 2040 ($2020). Analysis of international case studies suggests benefits to consumers from efficient dispatch signals could be in the order of up to $137 million per year.[16]

Risk of underutilisation of interconnectors

The current access regime also creates specific problems around the treatment of interconnectors and inter-regional flows When congestion arises between a generator and its regional reference node, if the generator can access an interconnector, they may instead be dispatched into a neighbouring region. This generator will still be paid the price that applies in its home region. If the price is high in the home region due to the congestion, then counter-price flows may occur.

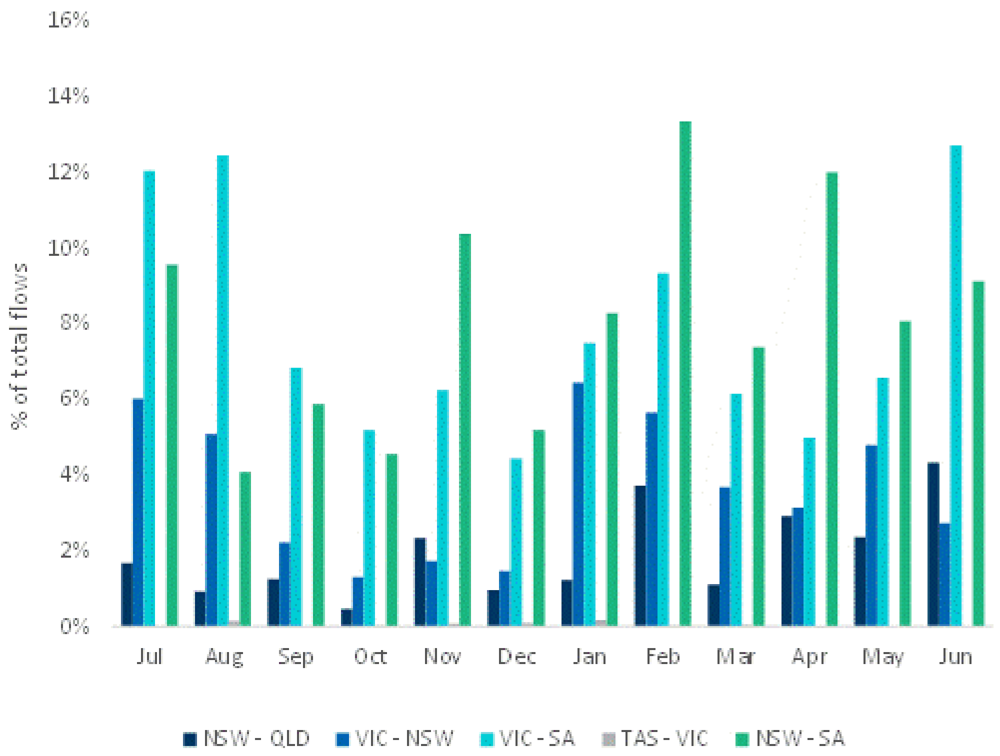
When the value of counter-price flows across an interconnector exceeds $100,000, the Rules require AEMO to "clamp" the interconnector (i.e., change dispatch outcomes so that the counter-price flow ceases). This requirement is designed to protect customers from large negative inter-regional settlement residue balances, which would manifest as an increase in transmission use of system charges. While there is a clear justification for clamping, it currently can result in a sub-optimal use of interconnector assets due to flaws in the current market design.

15 https://www.aemc.gov.au/sites/default/files/2020-09/NERA%20report%20Cost%20Benefit%20of%20Access%20Reform%202020_09_07.pdf

16 Some generators have indicated that these costs could be overstated because their trading systems are not sophisticated enough to engage in race to the floor bidding. The ESB notes that this could have the opposite effect and increase the costs of disorderly bidding. If the parties that don't rebid are the new entrant renewable generators, and the parties that do rebid are the larger thermal incumbents, then partial race to the floor bidding could result in the more expensive generation receiving a larger share of dispatch than they would if everyone raced to the floor.

Incidences of clamping are likely to increase in materiality as REZs are developed near the regional boundaries and investment in new interconnectors results in more loop flows between NEM regions. To date, the NEM is represented by a hub-and-spoke model, where limited interconnection means that there is no diversity in how power flows between regions. For instance, power flowing from South Australia to NSW must go via Victoria. This will change following the completion of Project Energy Connect, which will create the first loop flow among NEM regions. FTI Consulting's analysis shows substantial growth in the number of hours of counter-price flows in 2030, especially in the NSW-Vic-SA triangle.

Figure 11 Forecast volume of counter-price flows across NEM interconnectors, 2030



Source: FTI Consulting

To the extent that these counter-price flows give rise to clamping, there is a risk that interconnector investments will not deliver the anticipated market benefits. As the need for clamping is driven by price outcomes rather than underlying costs, they are not taken into account in the ISP and RIT-T assessments. To be clear, counter-price flows are not problematic in themselves. The problem is the flaws in the market design that give rise to a need for clamping. The ESB's proposed access reforms would reduce the need for clamping due to changes in how generators are compensated (see section 3.2).

3.1.4. Appropriate signals for storage

The right NEM-wide transmission access regime will help us to stay ahead of, and facilitate the efficient investment in, the expected dramatic increase in large-scale battery deployment and emerging technologies such as hydrogen. A large flexible load, grid connected hydrogen could be a source of demand response on the horizon, which can help make the system stable. These technologies need incentives so that they charge or use energy and discharge or not use energy at the times that are most valuable. That way they work within, and not against, a high variable renewable energy power system. Investors should have the opportunity to be rewarded for leveraging the flexibility of these technologies.

Batteries in the NEM have to date been deployed under business cases that attach greater emphasis to frequency control ancillary services (FCAS) market revenues than energy arbitrage revenues to recoup their investment costs. However, with FCAS revenues being relatively small to date and likely to reach saturation with further battery entry, it is likely that energy arbitrage along with network service provision will become a crucial component for many battery business cases at some point in the future, especially as costs of batteries continue to decline.

The current market design does not typically reward batteries for alleviating congestion.[17] Instead, batteries are incentivised to behave like a generator, even though they have a broader range of capabilities. This is because it receives the same price in its region, regardless of what congestion is near where it is located. If there is high congestion in its area, there would be system-wide benefits for the battery to charge, alleviating congestion. However, if the regional price is high at this time then the battery will not have the appropriate incentive to do so. Conversely, if there is little congestion in its area, then it should export, but again the current incentives do not create this effect. This undermines the value that batteries can offer to the system, particularly where they are needed to support flexible resources.

More granular local prices could enable batteries to compete with both generation and transmission, for instance by enabling batteries to become virtual transmission lines that earn revenue by arbitraging differences in local prices. Batteries targeting revenue from arbitrage are prevented from receiving greater intra-day price spreads than those that occur at the regional reference node (see Part B, section 4.1 of the options paper[18]).

3.2. Description of congestion management model with REZ adaptations

The CMM(REZ) uses the selective availability of congestion rebates to drive a more orderly and predictable energy transition. Box 2 outlines how the basic congestion charge-congestion rebate mechanism works.

Box 2 Description of the vanilla congestion management model

Under the status quo, generators are remunerated as follows (ignoring the effect of losses for simplicity):

$$\text{Revenue}_{\text{status quo}} = \text{RRP x dispatch quantity}$$

The revenue received by generators at the moment can be broken down into two components:

- The locational marginal price at the generator's connection point, multiplied by the dispatch quantity and
- The intra-regional settlement residue, which is the difference between the regional price and the locational marginal price, multiplied by the dispatch quantity.

Hence, the formula above could equally be written as:

$$\text{Revenue}_{\text{status quo}} = \text{[LMP x dispatch quantity] + [(RRP-LMP) x dispatch quantity)].}$$

Under the status quo, congestion risk is manifested in changes in the dispatch quantity. This drives generators to change their bidding behaviour in ways that maximises their dispatch quantity if their costs are less than the regional reference price.

17 Unless the battery enters into a non-network support agreement with a network services provider.

18 See https://esb-post2025-market-design.aemc.gov.au/32572/1619564172-part-b-p2025-march-paper-appendices-esb-final-for-publication-30-april-2021.pdf

The congestion management model disaggregates the elements of the regional reference price in a way that drives more efficient bidding behaviour and dispatch outcomes. It does this by changing the metric used to allocate the intra-regional settlement residues between generators.

$$\text{Revenue}_{\text{CMM}} = [\text{LMP x dispatch quantity}] + [(\text{RRP-LMP}) \text{ x } \textbf{allocated quantity})]$$

Generators are incentivised to bid more closely in line with their short run marginal cost because they receive the LMP for their dispatched output. Their overall profitability is protected because they still receive their share of the intra-regional settlement residues, irrespective of their dispatch quantity. Intra-regional settlement residues are given to eligible generators in order to provide them with an automatic hedge.

The CMM will change outcomes for participants in that bidding behaviours are likely to change, however, a lot of the financial impact on generators will be mitigated by the rebates. Ultimately, the impact of the CMM on an individual generator depends on what metric is used to allocate rebates between generators and (under the CMM(REZ)) who is entitled to receive the rebates.

The CMM(REZ) enhances the vanilla congestion management model by restricting the availability of congestion rebates to generators that locate in the right places from a whole of system perspective, as determined by the planning framework (as supplemented by government policies). This enhancement creates a tool to provide locational signals to generators. It also increases the investment certainty conferred by the congestion rebates to eligible generators because the total congestion rent will be divided between a limited and specified quantity of participants, as opposed to between all current and future participants. The ESB's reasons for preferring a model that restricts the availability of rebates are discussed further below.

Generators that would be eligible to receive congestion rebates would include incumbent generators and new generators that connect in REZs or other optimal locations.

As a group, generators are better off under the CMM(REZ), because they share in the efficiency gains achieved via improved dispatch outcomes and locational decisions. Customers also benefit from the efficiency gains. However, as several submissions noted, further detail is required to fully assess the impact of the CMM(REZ) on various market participants.

Table 15 outlines the ESB's preliminary thinking on a range of design features that will affect how individual generators would be affected by the CMM(REZ). The ESB notes that Table 15 is not exhaustive, and that the identified design features interact with each other and can pull in opposite directions. The necessary trade-offs associated with the various redress options will need to be considered further as part of any Rule change process.

Table 15 Preliminary thinking on winners and losers associated with various design choices under the CMM (REZ)

Issue	Concept	Winner	Loser	Alternative design to redress?
Impact on dispatch	Everything else being equal we expect lower cost generators to be dispatched more under the CMM.	Low cost generators (ie, VRE) and customers. Lower emissions.	The winnings come from the dispatch efficiency, so there is no particular loser, however actual outcomes may vary..	N/A
Out of merit order generators	In its simplest version, the CMM allocates rebates on the basis of availability regardless of whether the generator would have wanted to be dispatched (i.e., even where RRP < generator cost)	Peaking plant	Low variable cost plant eg, • baseload plant • VRE who have to share their rebates with generators who would not have been dispatched.	Preclude out of merit order generators from receiving a share of the settlement residue if the RRP is low.
Winner takes all	Current dispatch has “winner takes all” characteristics based on participation factors, while CMM could be designed to share settlement residues among eligible generators. (See section 3.3).	Generators with **high** participation factors on material binding constraints – typically those electrically “nearer” or more “behind” the constraint.	Generators with **low** participation factors on material binding constraints – typically those electrically “farther” or less “behind” the constraint.	Alternative settlement algebra which replicates winner takes all.
Network support generators	Under the CMM, it may be appropriate for generators that have an LMP > RRP to not receive a (negative) rebate. Consequently, they will be better off than under the status quo.	Network support generators (LMP > RRP)	Non-network support generators (LMP < RRP)	Provide (negative) rebate to network support generators.
Scheduled load	Under the CMM, it may be appropriate for scheduled load to be settled at their LMP and not receive a (negative) rebate, or to only receive a rebate when LMP > RRP.	Load with an LMP < RRP	Load with an LMP > RRP Generators	Provide (negative) rebate to scheduled load.
Interconnectors	CMM allocates settlement residue to generators and interconnectors on the basis of “availability”.	Depends on definition of interconnector “availability” (or other relevant metric) used to allocate residue between interconnectors and generators. Winners/ losers could be:		Alternative methodologies to allocate settlement residue to interconnectors.

	Concept of availability unclear for interconnectors and will need to be defined.	• Generators who do/do not use SRA units to hedge risk • Consumers, who receive have more/less TUOS charge offset from SRA unit sales.		
Availability of rebates	New generators wishing to connect outside designated REZs (or in a REZ but outside the coordinated process) face LMP.	REZ generators and incumbent generators	Non-REZ generators	Make rebates available for all spare network capacity.

Further consultation is required to develop the detailed design of the CMM(REZ). There are a range of outstanding issues, including:

- The metric used to allocate congestion rebates among eligible generators,
- The process used to define a REZ (where "REZ" means an area of the network where new entrants are eligible to receive congestion rebates),
- The methodology used to calculate the caps on access to the pool of congestion rebates,
- The transitional arrangements for in-train developments,
- Interaction with the connections framework,
- Impact on contractual arrangements, and
- Application of access regime to distribution level generation.

To promote understanding of the model, the remainder of this section outlines some of the outstanding issues that will need to be resolved as part of any future consultation process.

3.3. Allocation metric

A critical design choice relates to the allocation metric, as it is used to determine each generator's share of the congestion rebates. There is a range of options for the allocation metric, which can be tailored to meet various objectives, such as:

- Maintain status quo outcomes,
- Improve on status quo outcomes (e.g. by moving away from "winner takes all" outcomes, where tiny differences in participation factors have a large bearing on the profits of individual generators on a looped flow), or
- Provide revenue certainty.

There are myriad possible access allocations which meet the requirement of a feasible dispatch solution. Table 16 outlines provides some examples of possible approaches, and the objective that they are designed to achieve. Importantly, none of these options makes use of generator bids, so – unlike in today's market there is no incentive for constrained generators to adjust their bids in order to improve their access. This should encourage more cost-reflective bidding and so lower-cost dispatch.

Table 16 Examples of allocation metrics

Option	Description	Objective

Pro rata access sharing	Provides access to each qualifying generator in proportion to their in-merit availability. Where this would lead to an implied access level greater than the in-merit availability, the entitlement is equally scaled back among all eligible generators.	Simplicity/transparency Risk sharing
Winner-takes-all allocation	Reflects the dispatch outcome that would occur under the current market design where all in-merit available generators bid down to the market floor price to maximise dispatch and hence access.	Maintains status quo outcomes
Inferred economic dispatch	Uses inferred generator costs to calculate what the economic dispatch would be if generators offered these inferred costs.[19]	Minimises exposure to LMP

Based on feedback to the options paper, the ESB's initial view is that simplicity and revenue certainty may be suitable objectives to guide the choice of allocation metric, however this question requires further consultation.

3.4. Process used to define a REZ

Another key design choice under the CMM(REZ) relates to the caps on access to the pool of congestion rebates, and how this relates to the REZ framework. The ESB notes that the establishment of a cap on the number of rebate rights[20] is essential in order to confer value on the rebates. As more rebates are made available, the value of each rebate is diminished as the settlement residue "pie" is shared among more parties.

However, some stakeholders, including the Clean Energy Investors Group and Enel Green Power, have expressed concern that requiring non-REZ generators to face the LMP would entail an unacceptable level of risk.

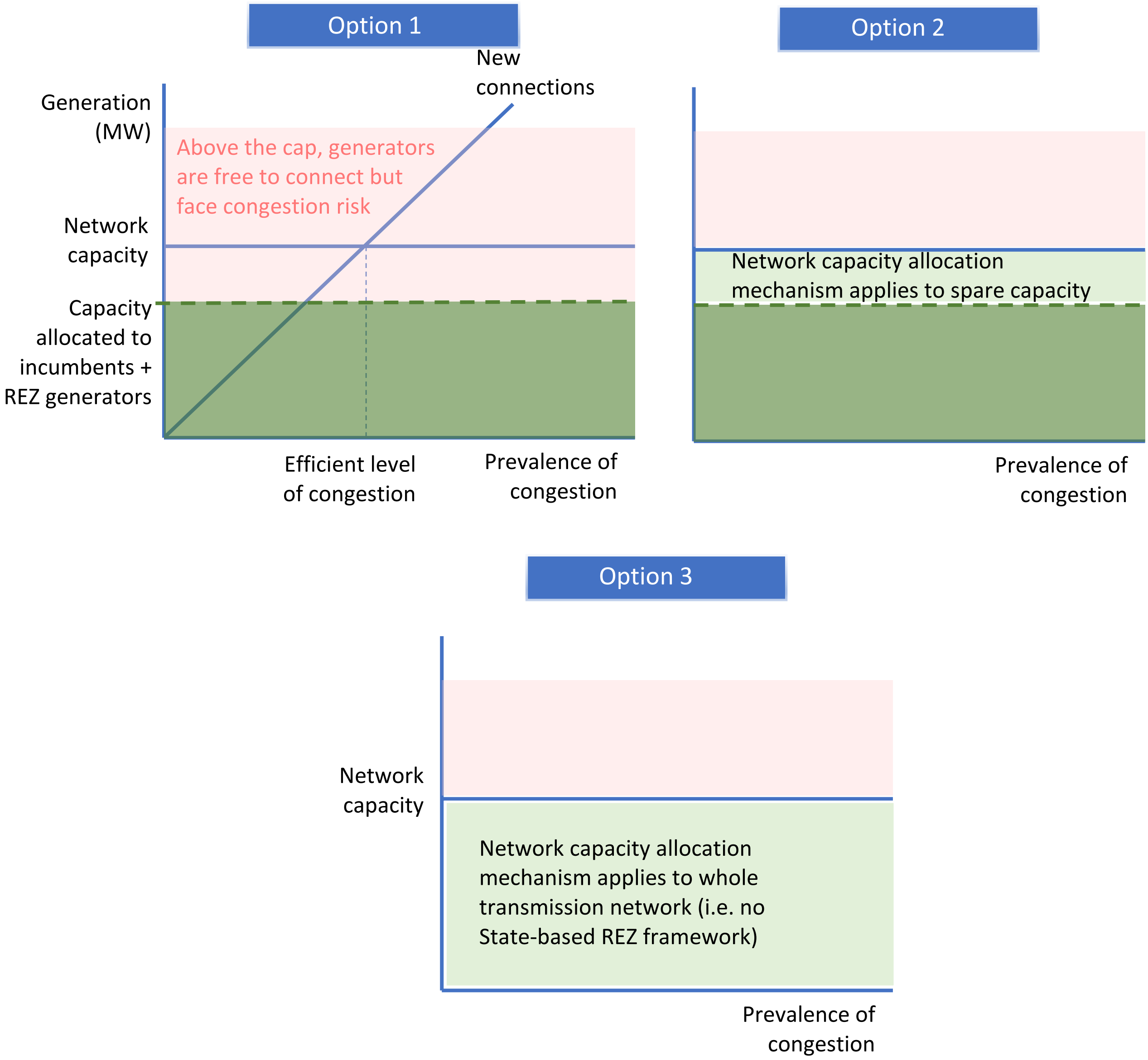
In response to these concerns, the ESB proposes to explore options to widen those parts of the network that are treated as REZs (and hence congestion rebates are made available). One option could be to release congestion rebates for all parts of the network where spare transmission capacity is available, not just those locations that are subject to government-driven or ISP nominated REZ initiatives. The ESB does not propose to make congestion rebates available to new generators seeking to connect in congested parts of the network, as that would defeat the purpose of the reforms.

This is a complex area, particularly given that it is an active area of policy development for multiple State governments. Figure 12 depicts three non-exhaustive options for the availability of congestion rebates.

[19] The methodology for inferring generation costs would need to be developed, and would be expected to be based on historical generation bidding and dispatch, rather than a bottom-up cost-analysis of each generator. Note that some inference of generation costs is needed for all the options if a design choice is made to identify and exclude out-of-merit generators.

[20] Or more accurately, the establishment of a fixed methodology for determining the availability of rebate rights.

Figure 12 Options for the availability of congestion rebates



Under option 1, rebates would only be made available to incumbent generators and new generators that locate in a REZ in accordance with the process established by the relevant State government or nominated under the ISP process. Commercial parties that identify opportunities beyond those identified by the network planners would still be able to connect, however they would face congestion risk without the benefit of a rebate (and, of course, without having to pay for the right to the rebate). This may not be a problem, for instance,

- if the project proponent intends to co-locate a battery with their VRE generator and hence is able to manage congestion, or
- if the project is in a part of the grid that is a largely uncongested now and into the future, the LMP would closely approximate the RRP.

As the firmness of the rebates increases with scarcity, option 1 would maximise REZ auction proceeds (which may then be used to offset the transmission costs borne by customers). However, this approach risks underutilisation of the existing network if – as suggested by some stakeholders – investors are risk averse and decline to invest in projects that face the LMP. In practice, RRP and LMP are likely to diverge only infrequently where there is spare network capacity but more frequently where there is less spare network capacity.

Under option 2, a network capacity allocation mechanism could be established to release any spare transmission network capacity outside designated REZs. In cases where the relevant State government does not wish to establish their own REZ framework, a further option 3 could be established whereby the network capacity allocation mechanism is applied across the whole transmission network (to the extent that there is spare capacity).

Each of these models could be applied in conjunction with the REZ framework set out in the ESB's Stage 2 REZ recommendations.

3.5. Methodology used to calculate the caps on access to the rebate pool

A further outstanding question is how to calculate the caps on access to the pool of congestion rebates. The ESB's preliminary view is that caps should be determined using a methodology that has regard to the efficient hosting capacity of the network.

The efficient hosting capacity of the network should be assessed in the context of the broader power system. As noted in Part B, a certain level of transmission congestion is efficient in a high VRE power system. Hence, an efficient cap on access to congestion rebates is likely to be an amount that exceeds the basic network transfer capability of the network.

If pursuing this approach, the methodology used to determine the cap should also recognise that the hosting capacity of the network will vary depending on the nature of the generators that connect to it and changing power system conditions. For instance, the hosting capacity of a REZ is higher if generators within the REZ have diverse output profiles compared to a set of generators who all seek to produce simultaneously.

In effecting this principle, it would also be necessary to resolve the treatment of storage. Storage differs from generation in that it has the ability to reduce congestion, so long as it receives the right market signals. Hence, there is a question as to whether the hosting capacity of the REZ should include storage, and the treatment of storage within an access regime. Some storage providers could potentially find it more profitable to connect on a non-firm basis.

The methodology used to determine the caps could use, as a starting point, the limits advice prepared by TNSPs and published on AEMO's website. There would be value in an information resource that advises connection applicants when certain parts of the network are nearing capacity.

3.6. Transitional arrangements for in-train developments

The detailed design process will also need to consider what happens to parties who are progressing developments outside of REZs prior to the CMM(REZ) coming into effect. In particular, it will be necessary to establish a mechanism to determine which developments are treated as incumbent and hence eligible to receive congestion rebates.

The approach should seek to avoid disrupting genuine projects that are being developed under the current access regime, while also ensuring that it does not incentivise gaming behaviour, such as the premature submission of connection applications to gain preferential treatment.

The ESB notes that given that the CMM(REZ) is not expected to come into effect until around 2025 (see Part B, Chapter 6). Accordingly, there is likely to be enough time for current in-train developments to come online, and hence be eligible to receive congestion rebates, before the new framework comes into effect.

3.7. Interaction with the connections framework

Further work is required to determine how any network capacity allocation mechanism (beyond the co-ordinated process used to deliver REZ) might work in practice.

If congestion rebates are made available on a first-come first-served basis, there is the risk of haphazard connections with generators racing to get connected. Given the value associated with the rebates, it may be necessary to establish a queuing or tender mechanism to ensure that capacity is not allocated to spurious projects.

Consistent with the ESB's REZ recommendations, the REZ coordinator could be responsible for deciding which generators receive congestion rebates. The REZ coordinator would be nominated by the relevant State Government Minister. The ESB considers that the most obvious candidates are AEMO, a State government entity, or the local TNSP – however this is likely to vary from State to State.

3.8. Impact on contractual arrangements

A number of stakeholders, including the Australian Financial Markets Association, the ASX, Flow Power and CS Energy expressed concern about the potential impact of the congestion management model on contracts. Stakeholders suggested that there may be additional implementation costs if the reforms trigger the market disruption clause of a contract, with the effect that the contract needs to be renegotiated. As the reforms would not be introduced for several years, this issue is most relevant to long term contracts such as power purchase agreements.

The question of whether the market disruption clause of a contract is triggered will depend on the drafting of the relevant clauses, so the ESB is not in a position to advise on whether the contracts will be affected or not. However, the ESB would observe that:

- The CMM is significantly less likely to result in renegotiations than full LMP/FTR reforms. This is because there is no change to the regional reference price, financial outcomes of incumbent generators are similar to the status quo, and other changes such as dynamic losses and FTRs are not included in the model. This was supported by AFMA in their submission to the April options paper.
- The impact of the CMM is likely to be benign for both parties. As VRE generators are low marginal cost, other things being equal they are likely to be dispatched more under the CMM than at present, and the formulation of the regional reference price paid by customers is unchanged..
- The CMM(REZ) is likely to improve the ability of generators to enter into power purchase agreements in the future, as parties who receive rebates will have more protection from the risk of inefficient congestion caused by subsequent connections than the status quo if the REZ element of CMM(REZ) can achieve effective implementation.
- To the extent that there are still concerns, the access scheme can be designed and implemented in such a way that minimises the costs. Taking such aspects into consideration is not unusual when considering changes to the NER and has been done regularly in the past (e.g. when 5-minute settlement was introduced).

More generally, the ESB would observe that contractual arrangements that incentivise generators to maximise their dispatched output, even when the value of that output is negative, is likely to result in increasingly problematic market outcomes as VRE levels increase.

3.9. Application of access regime to distribution level generation

As highlighted in Energy Queensland's submission to the options paper, the treatment of utility scale generators that are connected to the distribution network requires further consideration. The ESB's view is that the regime should seek to avoid preferential treatment for either transmission or distribution-connected plant. One approach could be to apply access model to all scheduled and semi-scheduled plant, irrespective of whether it is connected to the transmission or distribution network. In this case, congestion charges for distribution-connected generators would be calculated at the relevant transmission connection point.

However, it will be necessary to consider further how well this approach fits with the access arrangements that apply at the distribution level, as well as current system configurations and capabilities, particularly in light of rules changes currently being considered by the AEMC.[21]

21 See AEMC, Access, pricing and incentive arrangements for distributed energy resources. Available at: https://www.aemc.gov.au/rule-changes/access-pricing-and-incentive-arrangements-distributed-energy-resources

4. Enabling Implementation

4.1. Estimation of AEMO implementation costs

Given the scale and nature of the reforms, and noting that further detailed design is required, it is not possible to estimate implementation costs with any degree of certainty. In considering the scale of implementation we have developed an indicative cost estimate range for necessary changes to AEMO IT market systems and processes to implement key reforms identified in each pathway. These are planning level cost estimates only, providing a range of indicative costs for system changes. There will also be ongoing operational costs which have not been developed at this stage.

The methodology used for determining the estimates consisted of the following steps:

- Identifying the key solution requirements based on the regulatory design of the reforms as set out in this report.
- Conducting an impact assessment that identified functional areas impacted by multiple reforms and assessed the nature and size of the changes required holistically across the program. The impact assessment helps identify where the changes across the program can be accommodated by extending current capabilities and legacy systems or leveraging recently established or planned digital capabilities, or whether they require developing new capabilities.
- Identifying the main cost drivers, areas of uncertainty and limitations and assumptions for each reform.
- Identifying functional dependencies. The systems and process interdependencies of each reform was considered in the context of implementing individual reform initiatives, new pre-requisite capabilities, as well as other work AEMO has planned or has underway.

As part of this estimation process, it was necessary to make a number of assumptions in relation to the reforms themselves. An overview of these assumptions is set out below:

- Only immediate and initial reforms proposed in each pathway have been considered. The reforms included in the estimation process were those that have been put forward in these recommendations as either being underway or suggested for immediate implementation through the submission of rule changes as set out in this report.
- The scope and design of the proposed reforms were assumed to be as set out in this report and are subject to final rules and detailed design and specification. Importantly, they are limited to the scope of those reforms, indicative transaction volumes and the assumed roles and responsibilities (e.g., wholesale systems would interface with traders and not individual consumers, electric vehicles are considered as part of existing metering structures). As the design of the reforms is further refined as part of rule change or detailed design processes, the estimates may need to be revisited, particularly if reforms evolve beyond the scope set out in this report.
- Fundamental market frameworks and structures are preserved. The assessment assumes that market structures for information and settlement flows are maintained.
- The new capacity mechanism has not been costed. The final recommendations, the detailed design of which will be developed for consultation with stakeholders. The likely implementation costs of a future capacity mechanism will depend on a number of key design choices, the costs of which will also be assessed as part of this recommended detailed design process.

- The cost estimates generally assume AEMO build-own-operate. Opportunities for streamlining these costs estimates with external service providers will continue to be considered, particularly as part of consultation on the NEM IT systems and implementation processes.
- Systems implementation costs reflect one-off capital expenditure. These estimates do not include costs associated for ongoing operating costs, which will need to be determined as the designs and technology solutions are further developed.
- Program complexity and delivery timeframes. The estimates do not account for delivery risk associated with complexity of program execution. While allowances have been made for project management, stakeholder coordination and industry readiness within each project, the program itself may present execution challenges. Managing the program may introduce significant complexity that impacts the overall delivery costs, which are not possible to estimate at this stage. The delivery schedule will also be subject to regulatory imperatives rather than a sequence that optimises technology development. These factors will need to be considered into the sequencing of the reform delivery as the NEM IT Systems Roadmap is developed with industry stakeholders.

As estimates, they are of course subject to change. Changes in the policies, designs, timing and other assumptions could result in a material change to estimated costs. The extent to which the projects can be sequenced or bundled and run in parallel will be subject to more detailed planning and industry consultation.

These costs do not include ongoing operational costs at this stage. Operational costs could be significant depending on implementation details, including cloud costs, which will need to be determined as the designs and technology solutions are further developed.

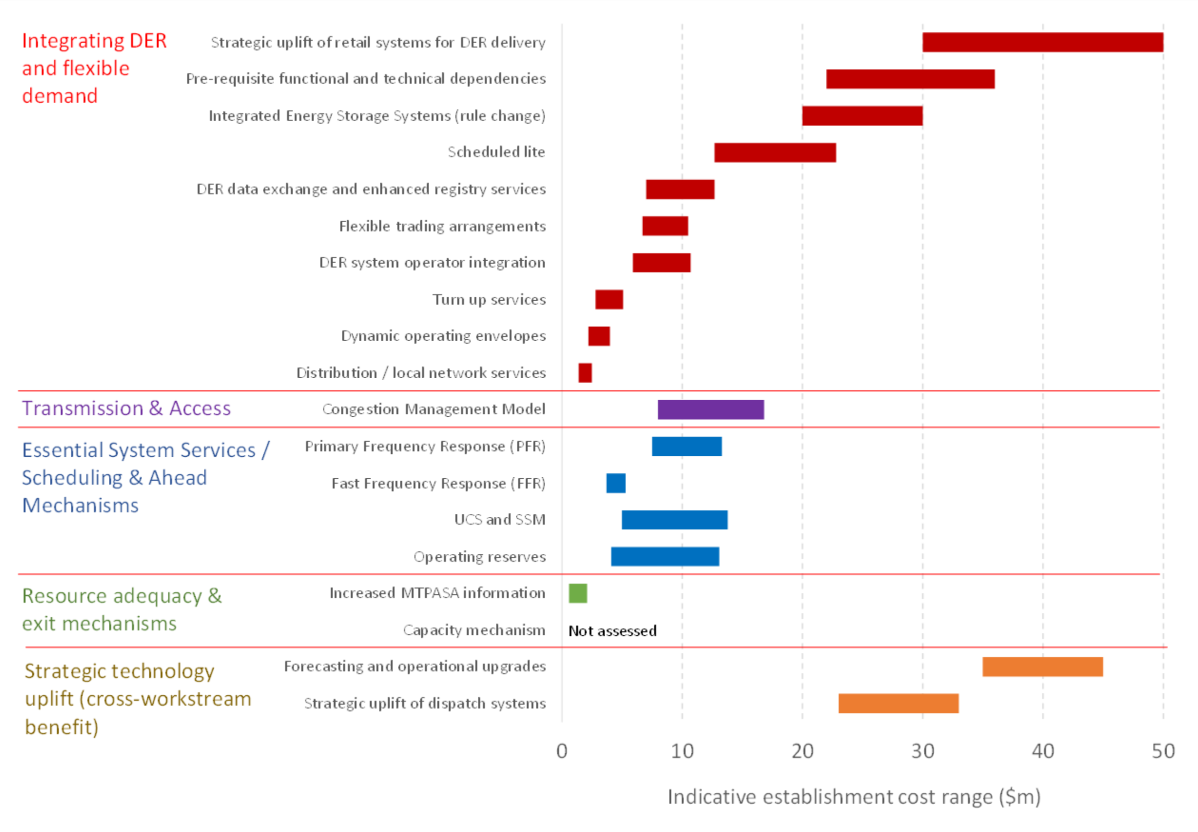
For clarity, the cost estimates have been developed for the purpose of evaluating the indicative size of the reforms. They are based on a program that would implement the reform initiatives identified in this report and contain uplifting of impacted systems so that they are on current technologies that are secure, can scale and are flexible. However, this uplift is constrained to the market framework and industry information flows and processes that exist today or are envisioned in the reform designs. A material change to market structures (e.g. trader requirements relating to settlements and prudentials or an introduction of full nodal pricing) would require a change to core systems and business processes that has not been included. Also not included is an overhaul or replacement of all legacy market systems and processes. Major upgrades of systems will still be required outside of the projects to implement the Post-2025 reforms.

Impact assessment by workstream

The following chart shows the indicative cost estimate range for the projects to implement the reform initiatives in the reform pathway. The sections that follow provide some explanation of the key basis for these estimates.

AEMO has attempted to estimate the uncertainty in the scope of the designs and how that will translate into detailed designs and system specifications by the cost estimate range. When aggregating the estimates up to a workstream or program level, the range has been expressed as 'mid-point' and 'high point'.

Figure 13 AEMO indicative cost estimates by workstream



Resource adequacy

Indicative estimate	Mid-point: $1m High point: $2m
Initiatives included	Increased MTPASA information
Key reform scope assumptions	• The capacity mechanism has not been assessed.

- <u>The capacity mechanism has not been costed.</u> As noted above, the ESB recommends that a form of capacity mechanism is developed, the detailed design of which will be developed for consultation with stakeholders. A straw-person based on a physical RRO arrangement has been developed to set out the possible design choices. Indicative implementation and ongoing costs of other certificate schemes is presented in Part B,Chapter 7as a guide. However, the likely implementation costs of a future capacity mechanism will depend on a number of key design choices, the costs of which will also be assessed as part of this recommended detailed design process.
- <u>Jurisdictional investment schemes.</u> Initial assessment has shown minimal impact on market systems.

Essential system services

Indicative estimate	Mid-point: $30m High point: $50m

Initiatives included	• Primary frequency response (PFR) ($9-15m) • Fast frequency response (FFR) ($4-5m) • Operating reserves ($8-15m) • Unit Commitment for Security (UCS) and Security Service Mechanism (SSM) ($8-15m).
Key points on solution	• Leverage existing systems as well as recent bidding and settlement system uplifts. • New solvers for Operating Reserves, UCS and SSM. • Forecasting and operational system upgrades carried out as a pre-requisite to the delivery of the ESS initiatives. • Strategic technology uplift of applications in the dispatch system set and in the forecasting and operational applications is required.
Key reform scope assumptions	• For purpose of the impact assessment it was assumed that PFR is associated with a new FCAS market and changes to causer pays. • Procurement of FFR services is similar to existing contingency FCAS services. • Operating reserve estimate assumes development of solver and co-optimisation with energy FCAS.

Insights

- Primary Frequency Response. Estimates include the replacement of the causer pays system.
- FFR. The assessment was based on the assumption that the new services will be similar to existing contingency FCAS. The implementation of the new services will require considerable technical effort to specify the new service through the Market and System Specification (MASS) as well as modifications to NEMDE and settlement systems.
- Operating reserves. There is greater uncertainty associated with the estimates for operating reserves as considerable detailed market design work is required before implementation costs can be accurately assessed.
- UCS and SSM. The main cost driver is the development of a new solver to perform the UCS and SSM functions. Concurrent SSM and UCS implementation has a lower cost by avoiding duplication of solver and integration effort.
- TNSP-led procurement of system strength. Initial assessment has shown minimal impact on market systems.
- Next reforms. Inertia spot market and integrated ahead market were not included in impact assessment.

Integrating DER and flexible demand

Indicative estimate	Mid-point: $140m High point: $185m
Initiatives included	• Integrated Energy Storage Systems (rule change) ($20-30m) • Flexible trading arrangements ($8-10m)

	- Scheduled lite ($15-25m) • DER data exchange and enhanced registry services ($10-15m) • Dynamic operating envelopes ($3-5m) • Distribution / local network services ($2-3m) • Turn up services ($3-5m) • DER System Operator Integration ($8-10m).
Key points on solution	• Implementation of initiatives requires re-development of many wholesale and retail systems. • Functional and technical dependencies on the implementation of pre-requisite projects for: o integration of DER information into core market systems. o industry data interfaces and management. o integration and automation between registries, retail and wholesale systems. • Uplift retail market systems as part of the delivery of DER initiatives.
Key reform scope assumptions	• Current market structures for information and settlement flows are preserved. • Implementation of relatively simple DER market solutions, as outlined in chapter 5.

Insights

- <u>The implementation of pre-requisite projects is required for functional and technical dependencies.</u> ($30-35m)
- <u>Strategic investment to uplift retail market systems made as part of the delivery of DER initiatives. ($40-50m)</u>
- <u>Simple DER market initiatives.</u> The proposed market system changes would have the ability to scale to support the forecast growth in active DER and market participants. However, the estimates are based on the implementation of relatively simple market solutions as outlined in chapter 8. Potential future evolution of market solutions has not been assessed (e.g. spot markets for local services, co-optimisation of local services with energy and ancillary service markets).
- <u>Current market structures.</u> A fundamental change to market structures (such as information and settlement flows) is likely to require a further uplift in core market systems than what has been estimated here. For example, if the uptake of EVs necessitates a fundamental change in who provides, how information is exchanged and settled then an uplift in core market systems is likely to be required.
- <u>Initiatives not assessed.</u> It is assumed that consumer protections initiatives, DER standards, distribution access reform, and distribution tariffs will have minimal AEMO implementation impacts.
- The Trader Services model was considered as a potential future reform path. However, amendments to market systems to support the model were not assessed.

Transmission and access

Indicative estimate	Mid-point: \$10m High point: \$20m
Initiatives included	• Congestion Management Model
Key points on solution	• No change to dispatch systems required. Dispatch retains regional model. CMM implemented by using information from constraint equation outcomes. • No change to settlement residue auction required. However, there would need to be changes to settlement of auction units.
Key scope assumptions	• While there may be value in including locational information in STPASA, MTPASA and LT forecasting, it is assumed that this is out of scope.

Insights

- Market settlement system impacts. The main cost driver for the implementation of the Congestion Management Model is associated with the market settlement system.
- REZ planning rules (stage 1), REZ implementation (Stage 2). Initial assessment is minimal market system impact.

Strategic technology uplift of applications to benefit all reforms

The impact assessment identified the need to uplift applications in the forecasting, operational and dispatch systems; benefitting the delivery of the reforms across pathways: Essential System Services, Integrating DER and flexible demand and the Congestion Management Model (CMM)(REZ) in the Transmission and access reform pathway.

- Forecasting and operational system upgrades. ESS development occurs on new forecasting and operational systems allowing better integration and avoiding subsequent rework.
- Strategic uplift of dispatch systems. These include strategic investments in various components of the dispatch systems against their lifecycle replacement. Note that this is not a replacement of the dispatch engine (NEMDE) but rather the multitude of components that make up the dispatch environment.

5. Benefits

5.1. Essential System Service Modelling (Cornwell Insight Australia)

5.2. Valuing Load Flexibility and Resource Adequacy Mechanisms in the NEM (NERA Economic Consulting)

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