Transmission Access Reform – Updated Technical Specifications and Cost-Benefit Analysis

Response to AEMC

19 October 2020

Energy Networks Australia

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

Key messages

- Energy Networks Australia (ENA) recognises the extensive amount of consultation and stakeholder engagement that the Australian Energy Market Commission (AEMC) has undertaken on the reform so far.
- ENA supports the principle of improving congestion arrangements and locational signals for generator investment. However, it is critical that the true incremental benefits of these reforms positive and over and above the benefits of generator locational decisions being driven already through the Integrated System Plan (ISP), Renewable Energy Zone (REZ) reforms and government policies.
- The reform should proceed if it is:
  1. Demonstrably in the long-term interests of consumers and
  2. Supported by most market participants and stakeholders.
- ENA query the inclusion of the wealth transfer benefits in the cost benefit analysis. The AEMC has historically had a major focus on efficiency benefits and has strongly opposed the inclusion of wealth transfers in regulated investment tests.
- ENA welcomes the additional work on the implementation costs as they appear on the low side for the whole of industry. It is not in customers' interest to repeat the implementation of five-minute settlement, where the true implementation costs have been orders of magnitude higher than originally estimated.
- If the Coordination of Generation and Transmission Investment (COGATI) proposals proceed then ENA:
  - Supports ensuring pragmatic phasing of these reforms in alignment with REZ and ISP developments, as well as other likely outcomes from the Energy security Board's (ESB) Post 2025 Review such as Essential System Services;
  - Support Financial Transmission Rights (FTR) pooled auction revenue being returned at regular intervals to offset consumer Transmission Use of System (TUOS) combined in addition to any excess settlement residue. Auction designs that incorporate increased competition for FTRs could increase consumers benefits. ENA welcomes further discussion on timing of the auction proceeds being paid out to offset TUOS and benefit consumers. The firmness and length of FTRs should be balanced against the volatility of pricing to consumers;
  - Notes there is a need for a clear transparent process for the initial selection of nodes within each region and the adoption of further nodes in the FTR horizon (10 years or less). ENA suggest that this be undertaken by the

    - AEMC or the Reliability Panel in a similar manner to managing region changes under Chapter 2A;
    - Notes there is a need for a clear methodology in the rules for the calculation of the quantity of FTRs available for a given node. These calculations need to be determined in consultation with the Transmission Network Service Providers (TNSPs). The interactions of thermal constraints and the post 2025 market reform needs to be considered: will the new market provide assurance that the needed power system services will be there to fill all gaps?
    - Supports no change to the strength of the Service Target Incentive Performance Scheme (STIPS), however further consideration of the move to value of congestion without a tolerance is required. The STIPS should focus on operational activity of the transmission network for activities that are within the TNSPs control. A focus purely on value of congestion is suggesting that transmission assets are built to support any poor location decisions made by generators, this is unlikely to meet the National Electricity Objective (NEO).
        - In addition, the STIPS approach should adopt an incremental reward/penalty over a year and better take into account the need to manage the high volumes of new connections and transmission commissioning. It is not efficient for there to be no congestion, efficient levels of congestion should not result in a penalty.
    - Notes that FTR's would only be sold up to a portion of network capacity, however thermal and non-thermal constraints may be difficult to quantify with any certainty.
    - Support FTRs not including losses, this is consistent with the approach in overseas markets. ENA welcomes further clarity on how the congestion only portion of Locational Marginal Pricing (LMP) is calculated for use in the FTR payout and STIPS.
- ENA supports a move to dynamic loss factors even if COGATI reform did not proceed and it were efficient to align with other post 2025 decisions. This would improve dispatch efficiency and provide a better locational signal than the current static loss factors.

Overview

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

ENA appreciates the opportunity to respond to the AEMC Interim Report on Transmission Access Reform – Updated Technical Specifications and Cost-Benefit Analysis. This submission is on behalf of ENA transmission members.

ENA looks forward to engaging with the AEMC and other stakeholders on the development of the rules drafting and detailed design.

ENA recognises the extensive amount of consultation and stakeholder engagement that the AEMC has undertaken on the reform so far. The numerous briefing sessions and technical working group meetings with robust stakeholder engagement are appreciated.

Overall, ENA is supportive of improving congestion arrangements and locational signals for generator investment. However, it is important that the predicted benefits are over and above the benefits of generator locational decisions being driven already through the ISP, REZ reforms and government policies. Any reform needs to be in the long-term interests of consumers and supported by most stakeholders before it progresses.

If the COGATI proposal proceeds, then ENA provides comments on the design of the reform in the following sections:

- An auction design that maximises return to consumers;
- The approach to determining operational network capacity for FTRs;
- Support for FTR's not including losses;
- Appropriate changes to the STIPS scheme that are within the TNSPs operational control;
- Identification and roll out of the predefined nodes using a process similar to the management of regional boundaries;
- Support for a move to dynamic losses; and
- Support a realisable incremental benefit case above the current reforms.

1 Balanced FTR design to maximise return to consumers

The Interim Report proposes that the use of FTR auction revenue in addition to settlement residues helps to ensure that FTRs are reasonably firm and are unlikely to be scaled back. Any revenue remaining after a period in the FTR auction pool (plus congestion settlement residue less FTR payouts) would be used to offset TUOS charges for consumers on a regional basis. This position remains unchanged from the AEMC's March 2020 report.

ENA agrees that the quantity of FTRs made available should be determined such that we are commonly dealing with excess revenue, and only rarely dealing with a settlement shortfall. A conservative approach should be adopted (this is particularly important when the reforms are first introduced and reflects a pragmatic approach that can be revisited once the arrangements have become more established). A lower level of FTRs than the maximum calculated through the simultaneous feasibility auction should be considered to introduce a level of conservatism.

For revenue adequacy to be workable, the network capacity each 5 minutes on the day will need to match the FTR's allocated in the auctions. ENA's concerns regarding the allocation of transmission capacity to FTRs is outlined in section 2 below.

ENA support FTR pooled auction revenue being returned at regular intervals to offset consumer TUOS combined in addition to the intra-regional settlement residue. If FTR units were auctioned for a quarter, ideally excess funds after the payout for that quarter should be used to offset customer TUOS rather than be allowed to grow unchecked in the fund. The excess accumulated funds above a reserve should be credited to TUOS at least by March each year to be included in transmission charges publication on 15 March[1]

Auction designs that incorporate increased competition for FTRs, possibly by including non-physical participants, could increase consumers benefits. ENA welcomes further discussion on timing of the auction proceeds being paid out to offset TUOS and benefit consumers. The firmness and length of FTRs should be balanced against the volatility of pricing to consumers.

2 Approach to determining operational network capacity for FTRs

The Interim Report states that the Australian Energy Market Operator (AEMO), with input from TNSPs, will set the parameters of how many FTRs could be sold. This will need to consider the incumbent generator transitional FTRs and the roll off of those FTRs and the likely congestion, both thermal and non-thermal, for each trading interval and FTR tranche.

The Interim Report suggests that small quantities of FTRs up to 10 years out could be sold in 3-month tranches. However, NZ and ERCOT offer 26 months and 24 months respectively. PJM offer up to 36 months in advance. California (CASIO) is the only market where small quantities are offered up to 10 years out for a long term FTR product.

While ENA note that only a small portion of the total quantity of FTRs would be made available well in advance, it may be challenging for TNSPs to forecast how both thermal and non-thermal constraints might bind in the future FTR tranches released.

The level of transmission investment stemming from the ISP has not been seen for decades. ISP project delivery and staged commissioning (including REZs) can and potentially will vary from plans, there is substantially less certainty on network

[1] This will allow the values to be included and off set in the TUOS calculations for the tariffs applying from July.

capability 10 years in advance. Future ISPs could also alter existing actionable ISP project timings or possibly scope.

Leaving aside thermal constraints, generator dispatch may also be constrained in other ways – system strength, inertia etc. It is not immediately clear how these constraints can be assessed with any certainty 10 years out and with a range of reforms which may impact the depth of market or delivery of these services at the needed locations. This may be challenging to forecast even for the next three months.

ENA welcome further discussion with the AEMC on the process to determine the portion of capacity available to FTRs and the portion of capacity sold by year.

3 Support FTRs not hedging marginal losses

AEMC has noted that FTR products that hedge losses in overseas markets are unusual. NZ is the only LMP/FTR market which includes losses in its hedge products. Despite investigating the inclusion of losses in the FTR product, the AEMC has found it challenging to ensure that there would be adequate funding of FTRs to support hedging marginal losses.

ENA support the AEMC's position that FTRs should only hedge congestion related price differences. This will provide greater certainty that the FTRs auction will have a high degree of firmness and that the quantity of FTRs made available to manage congestion risks can be maximised (within the limitations of the transmission system). This will help to maximise the FTR auction value proceeds used to benefit consumers.

ENA welcomes further discussion with stakeholders on the appropriate choice of a slack node within the national electricity market and how the congestion only portion of LMP is calculated for use in FTR payout and STIPS.

4 Any changes to STIPS need to be appropriate

ENA broadly supports the AEMC's proposal that the Market Impact Component of the STPIS be reviewed for alignment with transmission access reform and matters that are within the TNSPs control. ENA also supports the AEMCs position that the expected strength of the incentive scheme (i.e. the revenue at risk) would remain unchanged (at 1 per cent of Maximum Allowable Revenue (MAR)).

The proposal to move away from the threshold approach is not supported. A focus purely on value of congestion implies that transmission assets are built to support any location decision made by generators, this is unlikely to meet the NEO. Further, ENA consider that seeking to have no congestion is not efficient.

Some TNSPs have incurred penalties to connect new generation under previous versions of the parameter. Further the historic view of data currently used is not appropriate for the significant transition ahead both connecting new generation and the phased commissioning of new transmission for ISP projects. ENA also recommend further consideration of a more enduring incentive scheme across a year where the reward or penalty is capped on a more frequent basis within the year.

ENA consider that the STIPS should focus on the outages on the transmission system that are within the TNSP control and be based on material congestion. The incentive scheme is intended to incentivise a TNSP to improve and maintain reliability of the transmission system and needs to focus on matters within the TNSPs operational control. The ISP has significant forward investment in new transmission infrastructure, managing delivery dates and complex commissioning with AEMO and other impacted parties should not be underestimated.

Where non thermal constraints impact LMP and these are subject to sufficient delivery of essential services in the needed locations via a de-centralised market mechanism these should be excluded from the TNSPs incentive framework. The adequacy of these services is not within the TNSPs control.

Similarly, constraints imposed by AEMO to handle the adverse interactions of connected generator assets should not be included within the STIPS scheme.

ENA note that any such modifications to the scheme will need to go through the normal Australian Energy Regulator consultation process and will allow fuller consideration of the changes that could be implemented. An enhanced operational incentive scheme for TNSPs could only be applied as part of the TNSPs next revenue determination and after the LMP/FTR reform takes effect.

5 Identification and roll out of pre-defined nodes

ENA has previously considered that it is too early in the design to conclude that certain FTR configurations should be excluded from the access model. The choice of FTR configurations offered should be pragmatic, and subject to what can be achieved computationally and what market participants want.

Of the two types of FTR approaches;

» An FTR that relates from a local price to another local price; or
» Financial transmission rights that relate to a few pre-defined nodes or hubs,

the AEMC has opted for the latter.

ENA consider there is a need for a clear transparent process for the initial selection of nodes within each region and the adoption of further nodes in the FTR horizon (10 years or less). ENA welcome the AEMC initiative to develop a process by which the available routes are determined this year. This process would seek to balance sufficient locations for market participants to manage basis risk and the complexity of more FTR routes.

ENA suggest that the identification and roll out of nodes be undertaken by the AEMC or the Reliability Panel in a similar manner to managing region changes under the rules chapter 2A. This would provide a clear process, including stakeholder consultation.

The identification of the pre-defined nodes will need to consider;

- *Initial node identification to support transitional FTRs* -the transitional FTR approach where incumbent generators at the time the final rule is made will be granted FTRs for up to five years based on an allocation of transmission capacity at the time the final rule is made;
- *New nodes identified to support pre- commencement date new generation* - in the intervening period new generation will be commissioned and may need FTRs available from the start of the LMP/FTR regime, these may also need new FTR nodes;
- *Nodes to support FTR auction* - where the FTR auction makes available FTRs up to 10 years into the future then a view of new nodes may need to be considered.

The AEMC may want to consider the timing implications of any new node identification ahead of first release of auction for those FTRs and the relevant FTR period. For example, is the first auction of FTRs for quarter 1 held two years prior to day 1, implying that any additional node other than those supporting the transitional FTRs would already need to have completed chapter 2a identification process. Further consideration of the timings for staging the implementation ahead of commencement and frequency of node updates is needed.

6 Support a move to dynamic loss factors

The Interim Report proposes a move to dynamic marginal loss factors which are incorporated in the LMP. ENA supports a move to dynamic loss factors even if COGATI did not proceed and it were efficient to align with other post 2025. This would improve dispatch efficiency and provide a better locational signal than the current static loss factors.

ENA notes that the issue of dynamic loss factors is a separable issue from the introduction of FTRs and is supported in its own right as having a net benefit and being consistent with international practice.

The Interim Report notes that the NERA modelling may have overstated this benefit and has noted that the implementation of dynamic losses would require a replacement of National Electricity Market Dispatch Engine (NEMDE). Hard Software's evaluation of the change to dynamic marginal losses suggests an incremental cost of approximately $15m. ENA note that AEMO is undertaking a major systems replacement project and is likely to need further changes to facilitate post 2025 reforms, these changes may be able to be incorporated with any other changes to NEMDE for minimal additional cost. ENA support further development of a more robust cost estimate by AEMO this year to confirm the benefits case to move to dynamic marginal losses.

7 Supportive of a realisable incremental benefits case above current reforms

ENA recognises the extensive amount of consultation and stakeholder engagement that the AEMC has undertaken on the reform so far.

Ultimately AEMO's and registered participants' costs of the reform are borne by consumers. While ENA is supportive of improving congestion arrangements and locational signals for generator investment, it is, however, important that cost benefits are over and above the benefits of generator locational decisions being driven already through the ISP, REZ reforms and government policies.

Any reform needs to be in the long-term interests of consumers and supported by most stakeholders.

ENA note the work undertaken to identify preliminary costs by HARD software, SW Advisory and Intelligent Energy Systems. The report notes that it was a quick assessment of costs in the time allowed.

ENA welcome the additional work on the implementation costs as they appear on the low side for the whole of industry. ENA note estimated costs for distribution network service providers, however any costs for TNSPs should also be considered. AEMO and participant categories should provide their views on the appropriate costs for implementation. It may be useful for a consultant to interview or survey participants to seek a measured view on forward costs.

It would be useful for AEMO to clarify their view of the capital budget and total program costs for COGATI across the implementation period and the underlying assumptions. The preliminary cost report suggests that an off the shelf security constrained energy dispatch system (SCED system) may be an option. NEMDE is old and AEMO are already considering options to replace the existing short-term projected assessment of system adequacy (ST PASA) systems. The likely packages would require nodal load forecasts. In addition, any revisions to frequency control ancillary services (FCAS) to better integrate variable renewable energy may require an upgrade to NEMDE or replacement with a new SCED system.

An AEMO forward IT strategy that underpins the systems work currently being undertaken and the forward IT work program to support various reforms and program costs would be beneficial. Changes to frequency services could occur and require system changes in 2023 or with elements of the post 2025 reform ahead of COGATI, capability to support LMP may largely exist.

On the benefits side, ENA query the inclusion of the wealth transfer benefits in the cost benefit analysis. The AEMC has historically had a major focus on efficiency benefits and has strongly opposed the inclusion of wealth transfers in regulated investment tests.