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Project Manager
Australian Energy Market Commission
GPO Box 2603
SYDNEY NSW 2001

19th October 2020

Submitted online to: https://www.aemc.gov.au/rule-changes/

Dear Mr Pendlebury,

Transmission Access Reform Interim Report
Updated Technical Specifications and Cost-Benefit Analysis
Reference: ERP0073

The Australian Energy Council (the "**AEC**") welcomes the opportunity to make a submission in response to the Australian Energy Market Commission's ("**AEMC**'s") *Transmission Access Reform Interim Report*.

The AEC is the industry body representing 21 electricity and downstream natural gas businesses operating in the competitive wholesale and retail energy markets. These businesses collectively generate the overwhelming majority of electricity in Australia, sell gas and electricity to over ten million homes and businesses, and are major investors in renewable energy generation.

Introduction

The AEC recognises the very large exercise undertaken in this workstream to date, to which it and its members have closely engaged throughout. The AEC has separately commented upon these proposed reforms to the Energy Security Board's ("**ESB**"'s) contemporaneous consultation on the Proposed NEM 2025 ("**P2025**") Consultation Paper.

The AEC agrees the Locational Marginal Pricing ("**LMP**")/Financial Transmission Right ("**FTR**") construct is commonly used overseas and is supported in academic literature. The AEC also acknowledges the AEMC's improvements in relation to preferred implementation timing, FTR firming and transitional access.

However, as the National Electricity Market ("**NEM**") has operated for over two decades with a regional pricing construct of which its participants are entirely familiar, the move needs to be carefully assessed as to whether the benefits likely to emerge in a NEM context clearly exceed the unavoidable cost of disruption during a decade of already tremendous change.

The AEC's key comments to P2025 include:

- concerns regarding the type of, and scale, of the benefits claimed by NERA;
- that the cost analysis appears to have been hurried and under-estimated;
- that the timing of any implementation should be well clear of other P2025 reforms;
- that the FTR hub concept should be re-considered; and
- that the transitional access arrangements, whilst welcome, should be extended.

Discussion

Quantification of Benefits
Quantifying the theoretical future benefits of a more granular pricing structure will always be extremely challenging. The results are entirely dependent on the modeller's assumptions of the behaviours of numerous actors, the modeller's assumptions about how the generation fleet and transmission grid will evolve and the mechanics of the model itself.

Such a major and uncertain market reform should not hinge on the numeric results of one modelling exercise. Instead the AEC recommends the decision be ultimately determined through qualitative judgement informed by a combination of:

- theoretical construct;
- international experience;
- stakeholder feedback;
- detailed implementation costing; and
- several independent quantitative modelling exercises.

Such modelling exercises should be carried out not so much to produce a numerical result, but instead to explore and articulate how the theoretical construct of the reform will affect the industry. Successful reform modelling exercises are so well articulated and convincing that stakeholders' views are shifted and the recommendation becomes uncontroversial. That does not appear to have yet occurred with the NERA modelling.

The tremendous uncertainty in these quantification exercises is underlined by the variances of different attempts to assess it. During 2013-2015 the then proposed Optional Firm Access ("**OFA**") reform was quantified. OFA was a broadly similar reform, although somewhat more ambitious as a result of its intended changes to transmission planning.

For OFA, improved bidding incentives were assessed by ROAM in 2013[1], and improved generation siting incentives by Ernst and Young[2] in 2015. The Present Value of the summated benefits of that reform in its most ambitious scenarios were modelled at an order of magnitude lower than NERA, and for the less ambitious scenarios, including the "base case", two orders of magnitude lower.

When in March 2020 NERA extrapolated from the observed outcomes of the international experience of implementing LMP, NERA themselves estimated benefits of about an order of magnitude lower than this more recent modelling exercise[3].

The outlying nature of the NERA September 2020 results suggests it would be entirely prudent for the AEMC to seek a second opinion on this most important matter.

NERA - Classification of Benefits

As it pertains to accumulating benefits, the correct interpretation of the National Electricity Objective ("**NEO**") was detailed in the second reading speech to its introduction:

> "If the National Electricity Market is efficient in an economic sense the long term economic interests of consumers in respect of price, quality, reliability, safety and security of electricity services will be maximised."[4]

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[1] https://www.aemc.gov.au/sites/default/files/content/271255f4-4323-4931-934d-50566be6be5b/ROAM-Consulting-Modelling-Transmission-Frameworks-Review.PDF
[2] https://www.aemc.gov.au/sites/default/files/content/a854548f-c86f-4d5c-848d-ce1311f8177f/EY-Modelling-the-impact-of-OFA-in-the-NEM.PDF
[3] https://www.aemc.gov.au/sites/default/files/documents/nera_benchmarking_consultant_report_-_aemc_transmission_access_reform_-_march_update.pdf
[4] Hansard, South Australian House of Assembly, 7 February 2005

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With respect to NERA's work, this interpretation of economic efficiency means that only net market benefits – here called "social benefit" - is allowable against the NEO. Wealth transfers should be ignored. This is correct, because if we apply an assumption of a workably competitive market, then the economic cost of production, and only that cost, will reach consumers over the long-term.

Frequently reform modelling incorrectly presents a case for change based "consumer benefits": changes in consumer price. However these benefits usually contain wealth transfers between suppliers and consumers that, given an assumption of a competitive market, would be competed away over time with or without the reform.

NERA have instead applied a novel approach of describing consumer benefits as the *sum of both* net market benefits *and* wealth transfers to consumers. For the former to ultimately reach consumers NERA is assuming a workably competitive market as per classical economics, consistent with the NEO. But the latter could only benefit consumers in the long-term by assuming an uncompetitive market. Hence the addition is not logical.

NERA – Calculation of Benefits

As stated above, confidently projecting over decades the changes in investment, dispatch and prices that result from a more granular settlement structure is enormously challenging. It is clear that NERA have undertaken a very substantial exercise, inventing modelling approaches to postulate the different investment responses to regional and nodal signals. The result is highly dependent on these postulations, and quite possibly, other postulations with different results may have been similarly defensible.

Unfortunately, the AEC does not have the expertise to fairly interrogate the NERA model to form a view on the validity of these postulations. Several members with more expertise have related that, despite the information provided in sections 2 and 3 of the NERA report, and the public forum, they have been unable to confidently explain why the approach produced such a large divergence in investment levels between the reform and base-case.

Comparing figures 3.1 and 3.7, it would appear that NERA predicts the reform defers the construction of some 20 Gigawatts of large-scale solar plant, and this presumably delivers the bulk of the social benefit. The AEC theoretically agrees that a regional price could lead to higher generation investment than a regional price due to generation locating in congested areas, and therefore a lesser quantity of generation being available to customers, so the market will signal the need to build more.

It is always worth testing these theories against observed practice. It is true there has been some evidence of renewable energy developments building in already congested locations in the NEM. It appears however that developers under-anticipated the level of volume congestion due to a lack of information and experience and are now regretting such investments. We can have some confidence that the volume congestion signal itself is likely to have a greater effect in future and it is not clear if the model was able to incorporate this learning cycle.

Furthermore, having invested in congested locations, the transmission planning arrangement is able to release stranded generation in time, such as it is doing presently in North-west Victoria. Thus the generators' capacity will eventually become unconstrained and will not therefore require additional generation to meet demand. This narrative should result in the base case's inefficiency manifesting in greater transmission capital rather than generator capital. Indeed this was the finding of Ernst & Young in 2015.

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HARD Software Cost Estimates

The HARD Software cost report[5] begins:

> "The AEMC contracted HARD Software….to provide a quick assessment of the impact to the market operator's and market participants' systems…."

Consistent with this introduction, the assessment appears to be a desktop theoretical exercise drawn from the authors' understanding of the nature of the reforms and their assumptions of what type of systems the parties are likely to employ and what likely costs would be involved in their replacements. In this fashion, the consultant considered a single instance of each category of participant and extrapolated them up.

The Market Operator costs appear to have been developed without involvement of the Australian Energy Market Operator ("**AEMO**").

This quick assessment should be contrasted against that used for the equivalent exercise by Market Reform in 2015 for the OFA reform[6]. Market Reform directly surveyed 21 participants and received 15 responses covering 85% of generation capacity. Admittedly surveying affected parties naturally introduces error, as the reform may be poorly understood, or the responses could be biased; however, Market Reform understood this risk and, by considering the spread of responses, developed some confidence in these findings.

Market Reform also developed its own cost model, and used this to compare to the survey outcomes. Their cost model results were lower than the survey responses, but not excessively so.

Before comparing the outcomes of this and the OFA reform costings, we should consider the nature of the reforms impact on existing business operations:

- From an economic standpoint, OFA introduced a kind of LMP and FTR, however its unique design was intentionally structured to minimise systems change. Settlement adjustments flowed from the existing constraint constructs. In contrast, this new reform proposes conventional LMP which obliges abandoning the hub and spoke constraint model.
- OFA retained customer pricing from the existing Regional Reference Price ("**RRP**") determined at the existing Regional Reference Node which meant its impact on contracts and retailing was effectively nil.
- OFA impacts on the Market Operator were particularly small with no changes to dispatch and only minor settlement adjustments.

Faced with this less challenging systems change requirement, Market Reform assessed the cost impact of OFA on generators alone in the ranges of $67m-$162m (survey) and $50m-$120m (cost model). In contrast, HARD software has estimated only $34m as a total for all of generators, retailers, networks and large loads from the LMP/FTR reform.

HARD Software has correctly recognised that, unlike OFA, the introduction of Volume-Weighted Average Pricing ("**VWAP**") and Dynamic Loss Factors will have major impacts and costs on Market Operator dispatch systems. It has estimated total Market Operator costs at $71m – much more than OFA.

HARD Software's estimated total Market Participant and Market Operator system costs nevertheless seem low compared to other major recent reforms in the industry, the most significant being the

[5] https://www.aemc.gov.au/sites/default/files/2020-09/IT%20costs%20of%20implementing%20NEM%20locational%20_ng%20-%20Hard%20Software%20-%20Information%20Technology%20costs%20of%20nodal%20pricing%20-%202020_09_07.PDF
[6] https://www.aemc.gov.au/sites/default/files/content/a3f8d13e-b49b-4c4a-9f08-9331883f8393/Market-Reform-Transaction-costs-of-OFA-for-generators-in-the-NEM.pdf

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introduction of 5 minute/Global Settlement ("**5ms/GS**") in 2021. Whilst that is not a directly comparable reform, its scale can provide insight into the scale of costs resulting from a major re-engineering of industry-wide software.

The market operator costs of 5ms/GS are assessed at some $121m[7]. The AEC undertook a survey of its own membership in late 2019, after members had fully scoped their own changes and engaged software engineers. From this the AEC estimated a generator/retailer total cost of between $200m-$300m.

HARD Software has estimated costs for Distribution Network Service Providers ("**DNSP**"s) without explaining how these costs come about. At the same time it has attributed no costs for Transmission Network Service Providers ("**TNSP**"s). Yet the proposed reform:

- Includes major changes to the Short-term Performance Incentive Scheme ("**STPIS**") which impacts TNSP revenue and which is intended to be monitored closely by them.
- Will, through the receipt of FTR auction revenues replacing Settlement Residue Auction revenues, affect the calculation of Transmission Use of Service ("**TUoS**") charges and allowable revenues calculated by TNSPs.

The AEC considers that given the scale of the costs of implementing this reform, it deserves a thorough assessment of the cost of systems changes. This would require a careful systems audit involving direct survey of affected parties, including market participants, AEMO and networks.

Disruption Costs

The HARD Software analysis has discussed disruption costs with respect to contractual positions that extend through the implementation period. These are defined as effectively an administrative and legal process.

The AEC agrees that HARD software has correctly identified such costs exists, but that there is a larger cost associated with the disruption that does not seem to have been captured – that of general investor uncertainty. Such a large change in the market's basis – even if ultimately beneficial – will unavoidably entail a period of uncertainty as investors develop familiarity with its structure. For example, it will take some years for an understanding of typical FTR auction prices to develop. In the meantime, investors will need to speculate, and investors will incorporate an uncertainty allowance in their cost of capital.

Determining such an allowance requires judgement informed by necessarily qualitative discussions with investors. This will never be empirically definitive, but there are examples of it being employed[8].

This allowance could either be included in NERA's benefits analysis (as a reduction of the benefits) or in HARD Software's analysis as an explicit cost. However at this time it does not appear to have been captured within either exercise.

Implementation Timing

The current model has proposed a four-year implementation period following the making of the rule. The AEC acknowledges this increased lead-time as a major improvement from the initial proposals that the AEC criticised. The AEC concurs with the proposal to progressively release FTR auction volume during the period.

[7] See page 27 of https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/electricity-market-participant-fee-structure-review/final-aemo-electricity-fee-structure-consultation-paper_aug-2020.pdf?la=en
[8] See for example table 3.1 of http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/Report%20on%20the%20National%20Energy%20Guarantee.pdf

The AEC's biggest concern in relation to timing will be co-incidence with any recommendations arising from the P2025 review. It is quite probable that significant reforms associated with the Essential System Services and Reliability Assurance Mechanisms Market Design Initiatives will be implemented in the mid 2020's. The AEC considers that these reforms are the more urgent, and implementation timing should provide clear space for these to develop and bed down prior to the start date of LMP/FTR.

It is also noted that the benefits arising in the NERA modelling become most material post 2030 (table 3.2). Thus, a longer implementation period, in order to reduce the transition costs, should only marginally impact the value of the reform.

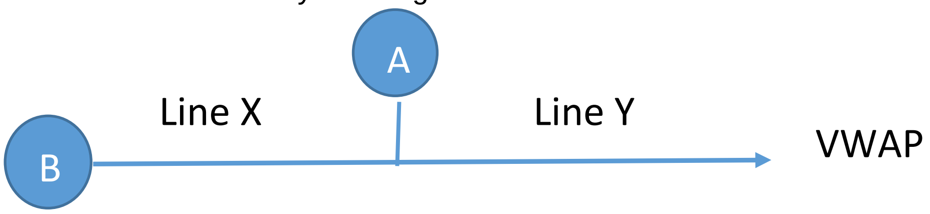
FTR Incidence

The paper has significantly changed the earlier design by proposing that FTRs are made available not at every connection point, but at a limited number of pre-defined "hubs". The paper recognises that this has the disadvantage of potentially re-introducing some basis risk between connection points and these hubs, but has been promoted in response to a desire:

- to make the reform simpler; and
- to increase liquidity and competition by having multiple parties interested in the FTRs at each node.

The AEC agrees that this adjustment does have the downside of introducing basis risk, but is doubtful of its claimed advantages.

There may be a misunderstanding of how the simultaneous feasibility mechanism within the FTR auction operates. The mechanism is able to translate access from any connection point to any other to the extent that the network physically permits it. For example, with the full nodal approach, if one Latrobe Valley 500kV generator bids for an FTR instrument at its connection point, it will be competing with all other Latrobe Valley 500kV generators. Consider:



The "hub" approach would see both generators only able to access FTRs from point A, leaving a basis risk for generator B associated with Line X's capacity.

However, the simultaneous feasibility auction incorporates a full network model and is able to contemplate the capacities of both lines X and Y. The nodal approach would see both generators, even though they are bidding for their respective connection points, competing for access to the capacity to Line Y. However, if generator B is successful, its FTR would also cover potential congestion on Line X.

If, subsequently, generator B chooses to sell its FTRs back into the auction, the simultaneous feasibility assessment would identify that access to Line Y is now available, and generator A could buy at least as many MW as generator B had released.

Thus the full nodal approach can achieve the same liquidity and competition than the hub approach: the limitation being only the physical capacity of the network.

Contrary to the intent, the hub approach seems to make the reform more complex, as most generators will be unable to buy an FTR at their connection point and will have to consider the physical congestion risks between themselves and their nearest hub. In the more common situation of loop flows, this can be very complex.

A nodal model will theoretically permit the purchase of hundreds of instruments. The gross number however does not create any complexity of itself – the auction process is automated.

Instrument and auction design

Should a LMP be implemented, the AEC broadly agrees with the FTR structure as described, being:
- One-way instruments conceptually similar to the existing Settlement Residue Auction (“**SRA**”) instruments.
- Available from nodes to any VWAP, and between VWAPs.
- An auction reserve price of zero.
- Having different instruments for different time periods.
- Progressively releasing via quarterly tranches to ten years ahead.
- Permitting selling-back of FTRs into the auction.

The design however requires a centrally determined time structure that will not suit all bidders. The AEMC is encouraged to further consider the possibilities created by using the SRA’s “linked-bids” logic. This could enable implementation of a highly granular FTR auction supporting bidders’ flexibility in structuring their own instruments. *In extremis* the FTRs could be broken into 5 minute segments across the entire auction horizon, and bidders would simply nominate, in their linked bids, the exact structure and tenor of the instrument that best suited them. The optimisation logic could still release all the network capacity according to the bids that valued the capacity most highly.

Instrument Firming

The AEC acknowledges developments in this area which are consistent with its previously argued positions. In particular it supports the NEM-wide settlement residue pooling approach and the withholding of one-year’s auction proceeds to support firmness. As AEC argued previously, the ability to draw down on these proceeds ahead of customers will paradoxically benefit customers because:
- The instruments will have a stronger insurance value, increasing their realised price at auction in comparison to a non-firm instrument.
- By reducing transmission risk, improving generators’ confidence to contract more of their plant.

It is acknowledged this will create some volatility for customers in relation transmission charge offsets. However as that revenue stream was dependent upon auction results it was therefore volatile before the drawdown capability.

Having made the decision above, the AEC believes it is no longer necessary to apply any artificial safety margin to the capacity released through the FTR auction for the protection from outages. Again, customers are better served by releasing the maximum possible quantity in order to produce the most auction proceeds that can then be drawn upon in the unfortunate event of network outages. The auction should instead target a full system normal grid capacity, noting this will be naturally conservative – for example by applying (system normal) hot weather ratings.

Transitional Access

The AEC welcomes the AEMC’s recognition of the need for transitional access in order to:
- Ease the systemic shock created by such a major reform.
- Recognise that generators have invested in good faith in the current open access regime that has never required payment for deep transmission access.

In the status quo regime, access volume is not guaranteed but variations have for the most part been very gradual occurring over many years. Hence, granted transitional access should not decay faster than the rate of change typically observed in current regime.

The AEC supports the proposed sculpting of starting with 100% grandfathering and declining at a linear rate. Considering all the issues under discussion, the AEC contends that the decline should happen over *ten years* rather than the proposed five.

The Interim Report leans toward a forward-looking modelling approach to the incidence of transitional access. Conceptually this sounds reasonable, however it is difficult to visualise how well it achieves its intended outcomes without seeing some its results. It is recommended that the AEMC engage expertise to produce an indicative calculation of the method based on the existing fleet.

The AEC supports allocating transitional access to those projects meeting AEMO's criteria for a "committed project" at the time of making the rule.

Any questions about this submission should be addressed to the writer, by e-mail to Ben.Skinner@energycouncil.com.au or by telephone on (03) 9205 3116.

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