TRANSMISSION ACCESS REFORM

Response to AEMC Interim Report: Updated Technical Specifications and Cost-Benefit Analysis

October 2020

Transmission Access Reform

Stanwell appreciates the opportunity to provide feedback on the Australian Energy Market Commission's (AEMC) interim report on transmission access reform, detailing updated technical specifications and cost-benefit analysis.

This submission contains the views of Stanwell Corporation Limited (Stanwell) in relation to the current iteration of the proposed transmission access reform provided in the consultation documents and should not be construed as being indicative or representative of Queensland Government policy.

Overview

Stanwell does not support the continued development or implementation of transmission access reform at this time. The significant changes between iterations of the proposed reform indicates the AEMC is not converging on a robust final design for consultation and implementation.

Over the iterations of the proposed access reform, the AEMC has put forward a range of issues the proposed reform purports to address, including transmission network congestion, decreasing marginal loss factors, generator revenue uncertainty, lack of locational price signals and adverse operational incentives for generators and storage such as disorderly bidding. In its current state, the reform represents a costly, complex and disproportionate approach to achieving incremental gains in dispatch efficiency.

Stanwell contends there are a number of no-regrets changes that could be implemented that would capture the bulk of the benefits of improved locational signals without the sizeable costs associated with transmission access reform implementation.

Current iteration of transmission access reform

The proposed reform continues to lack a clear purpose and demonstrable marginal benefits. The problems transmission access reform purports to address are not expected to improve under the current iteration:

- Investor certainty and cost of capital will not be improved by 3 month Financial Transmission Rights (FTRs) available up to 10 years in advance;
- FTRs do not protect established generators from the inefficient locational decisions of new entrants;
- Race-to-the-floor bidding will not be eliminated;
- Dynamic loss factors will continue to reflect the physics of generation located on congested parts of the network far from major load centres;
- Generator revenue certainty is expected to worsen, as even generators holding FTRs are potentially exposed to price risk and volume risk; and
- Contract market liquidity is expected to decrease, reducing retail competition and increasing retail prices for consumers.

Stanwell has significant concerns with the analysis of estimated implementation costs and modelled benefits. HARD software's estimated IT implementation costs appear to vastly understate implementation costs of both the Australian Energy Market Operator (AEMO) and market participants. Stanwell suggests it would have been preferable for the AEMC to compare HARD software's estimates with IT implementation costs of contemporary significant market reforms (e.g. Five Minute Settlement) and undertake a comprehensive survey of market participants before publishing estimates that understate implementation costs to the point of being misleading.

Stanwell has identified several issues with the modelling of potential benefits that may result in the analysis overstating the potential benefits of the proposed reform, including:

- **Assumptions:** The modelling incorrectly assumes incentives for race-to-the-floor bidding will be eliminated and efficient dispatch is achieved when plant is bid into the market at incurred costs (i.e. short-run marginal cost) rather than economic cost (i.e. long-run marginal cost).
- **New technologies:** Batteries and pumped storage hydro have not been included in the solve (rather calculated external to the model) and new entrant pumped hydro is geographically constrained to areas of existing hydro.
- **Locational decisions:** Under the no-reform case, neither the Integrated System Plan (ISP) and Renewable Energy Zones (REZs) nor the available locational signals steer investment away from congested parts of the network.
- **Analysis:** Downplays instances where the results indicate the reform will deliver low or negligible benefits (e.g. includes more than $1.8 billion in benefits stemming from competition that may not materialise) and factors that could result in the modelled benefits exceeding the benefits that could be realised in practice (e.g. includes more than $1.7 billion in benefits from not investing in congested parts of the network while conceding investors would probably not invest in congested parts of the network anyway).

While transmission access reform is not warranted in relation to energy alone, it may be warranted if the ESB redesigns the NEM for co-optimised markets and those other markets benefit from granular locational signals. Further investigation into Locational Marginal Prices (LMPs) at that time in order to determine the expected marginal net benefits of their introduction would be justified. However, there would still be significant challenges that would need to be addressed, such as how AEMO would co-optimise the procurement of regional services (e.g. FCAS, inertia, operating reserves) against local services (e.g. energy, system strength).

Interaction with other Market Design Initiatives

Interactions between the current iteration of transmission access reform and the other Energy Security Board's (ESB) Market Design Initiatives (MDIs) cannot be determined as the other MDIs are still in their options phase. This is discussed further in Stanwell's ESB submission.

Stanwell questions the alignment between the market redesign task set for the ESB and the process and progress of the project to date. As detailed in the ESB's scope and forward work plan:

> *"The COAG Energy Council has tasked the Energy Security Board with developing advice on a long-term, fit-for-purpose market framework to support reliability that could apply from the mid-2020s. By the end of 2020, the ESB needs to recommend any changes to the existing market design or recommend an alternative market design to enable the provision of the full range of services to customers necessary to deliver a secure, reliable and lower emissions electricity system at least-cost. Any changes to the existing design or recommendation to adopt a new market design would need to satisfy the National Electricity Objective."*[1]

The lack of firm recommendations and detail about options within the other MDIs and the tight deadline for design options to be released for consultation mean the ESB will not be able to deliver a long-term, fit-for-purpose market framework that demonstrably satisfies the National Electricity Objective. While options are still being developed, participants are unable to determine the expected net benefits of each option individually or the outcomes of interactions between the potential combinations of various options under each MDI.

Stanwell is concerned that advancing access reform while other MDIs are still in the option phase means the range of reforms cannot be assessed as a complete package. The implementation of the proposed transmission access reform could preclude other options from being implemented, potentially resulting in a less efficient market design or the need for further disruptive changes to address these inefficiencies.

No-regrets actions

There are a number of locational signals for investors currently, but these are blunt (e.g. current congestion) and some are not visible until deep into the investment decision process (e.g. "do no harm" provisions) or even after final investment decision (e.g. annual adjustments to Marginal Loss Factors). While greater attention is now being paid to the location of new investment on the network, additional ex-ante investment signals are needed to better guide investment location decisions to minimise the impacts on congestion and inefficient investment decisions. Transmission access reform is one of number of options to improve locational signals.

Over the course of recent reviews of transmission access, the AEMC does not appear to have considered potential alternative options to address the perceived issues with current access arrangements or deliver the claimed benefits of improved locational signals under the proposed access arrangements.

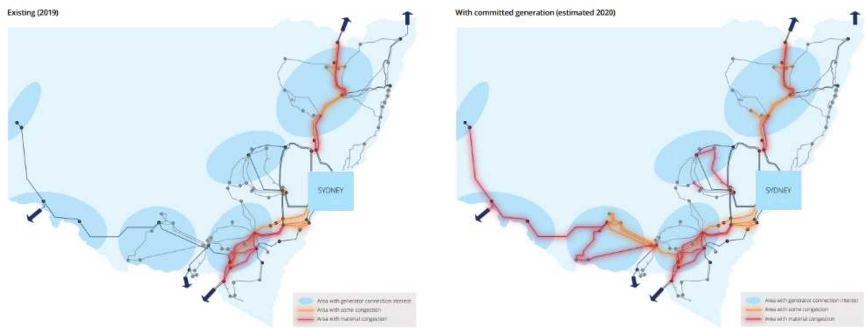
Stanwell suggests the majority of the benefits of better locational signals to inform investment decisions can be achieved without the cost and increased complexity of the proposed significant changes to the market

[1] ESB, Post 2025 Market Design – Scope and Forward Work Plan, p 1

design. To this end, there are several no-regrets actions can be implemented - the majority at little to no incremental cost - to improve locational signals ahead of investment decisions, including:

- Publishing all locational information currently produced by NEMDE to provide an immediate signal to potential projects.
- Redeveloping the National Electricity Market Dispatch Engine (likely to be required for the implementation of the South Australia-New South Wales interconnector) to incorporate locational load, reduce model-induced inefficiency and increase locational signals for publication.
- Proactive publishing of indicative ‘do no harm’ requirements across the network to ensure new entrants are aware of and are required to mitigate the impact of their entry on established generators and the network more broadly.
- Producing network congestion maps to show potential participants the areas of the transmission network where there is currently sufficient network capacity for additional generation capacity to be added. Transgrid has previously produced maps showing expected congestion at times of high demand if committed projects proceed (refer Figure 1).

Figure 1: Congestion at times of high electricity demand



Source: Transgrid, Transmission Annual Planning Report 2019, p 7

Conclusion

Stanwell does not support the continued development or implementation of transmission access reform at this time.

The proposed reform is an overly complex solution to an loosely and at-best generally defined problem. It has not been demonstrated that transmission access reform is needed or the proposed reform is the best way of delivering the purported benefits. The AEMC has focussed on producing numerous iterations of transmission access reform, both in the current review and previous reviews, rather than identifying and assessing other potential ways to address the identified concerns with the current access arrangements or deliver the purported benefits of the proposed transmission access reform.

Stanwell also has significant concerns with the analysis of estimated implementation costs and modelled benefits. HARD software’s estimated IT implementation costs appear to vastly understate implementation costs of both the Australian Energy Market Operator (AEMO) and market participants, and both NERA’s modelling and analysis of the results overstate the potential benefits of the reform.

Stanwell maintains the bulk of the benefits of locational signals can be achieved without the increased complexity and cost of the proposed changes to the market design. There are several no-regrets actions can be implemented to improve locational signals ahead of investment decisions (e.g. redevelopment of the dispatch engine, producing network congestion maps, indicative "do no harm" requirements across the network) to dissuade generators from building in congested parts of the network.

Stanwell welcomes the opportunity to further discuss this submission. Please contact Evan Jones on (07) 3228 4536 or via email at evan.jones@stanwell.com.

Appendix A: Feedback on changes to reform design

Feedback on the current iteration of the proposed transmission access reform provided in this appendix should not be construed as support for continuing to progress this MDI.

Locational Marginal Pricing

Volume-weighted average price

Setting the regional price as the volume-weighted average price (VWAP) for non-scheduled load ensures "revenue adequacy" when the physical capacity of the network in a dispatch interval is equal to or greater than the volume of FTRs sold. While the resulting increase in FTR firmness will provide some benefit to FTR holders, there are several issues and market impacts of this design choice.

First, as the Interim Report notes, forecasting VWAP is materially harder than forecasting a Regional Reference Price (RRP), as:

> *"In order to forecast the VWAP, market participants would need to estimate the LMP and its weighting at every location with a non-scheduled participant."*[2]

Forecast VWAP is a key input into spot and contract trading strategies and decisions. Given VWAP is weighted by load at every location with a non-scheduled participant, generators would require load by connection point to forecast VWAP. Some consumers, particularly large consumers, have previously resisted this information being publicly available, as evidenced by the number of AEMO's connection point forecasts that are restricted.

The introduction of VWAP could also split the contract market between those denominated in VWAP and those denominated in LMP (as different segments of the market are incentivised to trade on different bases), reducing both liquidity in regional price contracts and overall contract market liquidity.

There could also be a sizeable impact on retailing activity. If there was significant price separation between LMPs and VWAP, retailers would need to consider where a customer is located when pricing the retail deal. For those customers located away from an FTR node, a risk premium would need to be attached to reflect the uncertainty about potential price separation. These issues would be compounded for large users with a large geographical spread of connection points.

Second, Stanwell does not share the AEMC's optimism that increasing the firmness of FTRs through the adoption of VWAP will result in a lower cost of capital for generators. As Stanwell noted when 3 year FTRs were proposed in a previous iteration of the transmission access reform:

> *"The proposed 3 year tenure of FTRs does not provide a sufficient level of certainty for new projects that would be expected to result in a lower cost of capital. FTRs represent a fixed cost for generators (as they do not vary with changes in electricity generation), so are likely to be treated as a noncurrent liability or lease. This would likely increase the amount of equity required for a project, increasing the weighted average cost of capital or the revenue requirement to achieve minimum debt service coverage ratios.*
>
> *FTRs may even increase the cost of capital for new projects, as financiers penalise potential projects on both unsecured volume (i.e. any shortfall between FTRs and expected*

[2] AEMC, Transmission Access Reform: Updated Technical Specifications and Cost-Benefit Analysis, Interim Report, p 5

capacity) and the variable firmness of the FTRs they have purchased."[3]

Stanwell has raised other issues with LMPs previously, namely:

> *"Generators/market participants who are unhedged and do not hold FTRs would receive revenue based solely on their local marginal price which may or may not be aligned with the regional price. The local price is both more difficult to forecast and more susceptible to being impacted by individual investment and operational decisions of a competitor than the regional price."*[4]

This issue is best illustrated with an example: Participant A builds a solar farm in an area with good irradiance, spare network capacity and no announced competing projects. Local price will typically match the regional price because of limited occurrences of congestion. Participant B then announces and builds a solar farm neighbouring Participant A's project, constraining the local network. The local price frequently diverges from the regional price during times of congestion. Even if Participant A holds FTRs they will only be for a short period beyond Participant B's project commissioning date, after which both projects are equally exposed to the locational price. FTRs to hedge the price difference may not be available in a volume and at a price which allows Participant A's investment to remain whole. LMP and FTRs have not protected Participant A's efficient locational decision from Participant B's inefficient locational decision – which is the proposed intent of the reform.

Stanwell has also previously highlighted the potential impact of LMPs on the "missing money" problem:

> *The reliance on local pricing may also exacerbate the "missing money" problem which is only overcome if generators are able to rely on periods where a higher cost competitor sets the price in order to recover their fixed costs. Denying generators access to some of these periods of higher prices will mean they need to raise their own offer prices in order to recover fixed costs, potentially impacting on dispatch efficiency.*[5]*"*

Reflect dynamic marginal losses

The introduction of dynamic marginal losses would require a change in bidding rules, as generators would not know their loss factor when submitting day-ahead bids. As discussed in Stanwell's submission to the discussion papers in November 2019:

> *"The introduction of dynamic loss factors will mean generators are no longer able to ensure their day-ahead bids are within the Market Price Cap (MPC) and Market Floor Price (MFP) (i.e. not a corrupt bid). Typically a discussion of dynamic loss factors includes consideration of allowing bids to be priced "at the node" in order to avoid this issue, however it is unclear whether this approach would remain relevant under the VWAP proposal."*[6]

The Interim Report does not detail how issues such as bid conformance and late rebidding will be addressed in the recommended design. Further discussion is warranted, including quantification of the potential impacts of these issues, the range of potential solutions and the costs of each to ensure the recommended solution provides a net benefit to consumers.

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[3] Stanwell, Response to AEMC Coordination of Generation and Transmission Infrastructure discussion papers, November 2019, p 8

[4] Stanwell, Response to AEMC Coordination of Generation and Transmission Infrastructure discussion papers, November 2019, p 9

[5] Stanwell, Response to AEMC Coordination of Generation and Transmission Infrastructure discussion papers, November 2019, p 9

[6] Stanwell, Response to AEMC Coordination of Generation and Transmission Infrastructure discussion papers, November 2019, p 12

Stanwell has previously proposed the introduction of ex-ante loss factors (set for at least one trading day) as a potential way of ensuring bid conformance. Dynamic loss factors or ex-ante loss factors published close to real time could increase the volume of late rebidding as participants adjust their bids as new information about their expected or actual losses is received.

The AEMC should also consider whether the potential benefits of dynamic loss factors can only be realised under the proposed transmission access reform. The potential for dynamic loss factors to address some or all of the AEMC's concerns with the current market design without incurring the considerable costs of implementing LMPs needs to be determined.

Ex-ante pricing mitigation

Stanwell does not support the introduction of ex-ante pricing mitigation of LMPs. The NEM already has a market price cap, market floor price and cumulative price threshold to constrain wholesale prices. Additional wholesale price constraints are not required.

The introduction of LMPs is meant to provide a clear locational signal to market participants and potential participants. Any attempts to limit LMPs would defeat that goal. Instances where an LMP persistently exceeds the region's VWAP would provide a robust signal to potential investors that additional generation capacity may be required in that region.

Financial Transmission Rights

Competition measures

Stanwell would be keen to gain a deeper understanding of the AEMC's rationale for allowing non-physical participants to purchase FTRs in the primary auctions. The AEMC states:

> *"The previous design proposal to exclude non-physical participants from the FTR auction would exacerbate competition issues as restricting participation would potentially lead to decreased competition in the FTR market. Consequently, and for the other reasons discussed in section 3.4, non-physical participants should be allowed to participate in the FTR auction in order to increase competition and decrease the ability of participants to "hoard" FTRs. Participants supported this change at the technical working group."*[7]

Allowing non-physical participants to purchase FTRs could deprive generators from acquiring the risk management instruments required under the proposed transmission access reforms. For financial participants to win FTR auctions means they are placing a higher value on FTRs than physical participants, increasing the price of FTRs. The benefits to consumers of increased TUOS offset stemming from higher auction revenues would be eroded by higher FTR costs being factored into the prices FTR holders are willing to sell electricity at.

The AEMC also addresses concerns about non-physical participants "hoarding" FTRs:

[7] AEMC, Transmission Access Reform: Updated Technical Specifications and Cost-Benefit Analysis, Interim Report, p 16

> *"…even were hoarding to occur, this does not directly impact the physical dispatch of the system, since FTRs are financial rights – therefore, the energy market would still dispatch based on a least cost optimisation, although generators would potentially not be able to get access to congestion management tools that they otherwise would have been able to purchase."*[8]

The claim that FTRs do not directly impact the physical dispatch of the system is a misdirection as the impact is indirect but tightly bound. Over the short-term (i.e. dispatch timeframe), generators that do not hold FTRs may withdraw their plant from the system (altering the resources available for dispatch) or increase their bid prices (altering the resources dispatched). Over the longer-term (i.e. investment timeframe), access to FTRs will influence the type and location of new generation capacity. If a lack of FTRs did not impact physical dispatch as is claimed, their introduction seems pointless as they would not contribute to efficient dispatch or investment location decisions.

Further, the point that hoarding could result in generators not being able to access FTRs is not an afterthought but rather a critical issue for established and potential generators. Without access to FTRs, generators would face unhedgable, inefficient price risk instead of volume risk.

The AEMC goes on to claim:

> *"…we note that non-physical players are unable to gain an advantage in the energy market because they do not participate in this market, and so hoarding would expose themselves to financial loss in the FTR market."*[9]

The key issue isn't the potential advantage non-physical participants can gain in the energy market, but rather that non-physical participants can potentially gain advantage in the financial market. If non-physical participants could not gain advantage in the financial market through FTRs (e.g. by creating bespoke products from standard contracts), they would have no incentive to purchase them. While this trading could increase liquidity and create FTR products that are not available from the primary FTR auctions, the primary focus must remain on generators being able to procure the limited supply of FTRs.

The AEMC also appears to overstate the support for allowing non-physical participants in the FTR auctions among Technical Working Group participants. The minutes of Technical Working Group meeting #9, held on 9 July 2020, show that:

> *"**Some** [emphasis added] participants were supportive of having financial players participate in the FTR auction, stating that competition laws would act as an effective deterrent to uncompetitive behaviour in the market"*[10]

Stanwell is also concerned that the proposed limit on the volume of FTRs physical participants can purchase also appears to have been removed. Stanwell supported limiting the volume participants can purchase on a line to the generation capacity they have utilising the line. This would be an effective way of addressing hoarding issues and increase the ability of those participants that need FTRs for risk management purposes to acquire FTRs.

Finally, with respect to the following statement:

> *"A lack of competition in the FTR market could also preclude market participants from being able to purchase the FTRs*

[8] AEMC, Transmission Access Reform: Updated Technical Specifications and Cost-Benefit Analysis, Interim Report, p 16
[9] AEMC, Transmission Access Reform: Updated Technical Specifications and Cost-Benefit Analysis, Interim Report, p 21

[10] AEMC, Grid access reform (COGATI) review – technical working group #9 minutes, 9 July 2020, p 5

they might otherwise have acquired if the market was more competitive, with this in turn limiting their ability to manage risks associated with congestion and so potentially increasing their cost of capital."[11]

Stanwell would be keen to understand the mechanism foreseen by the AEMC through which limiting the pool of FTR purchasers to those with a specific interest could preclude those market participants from purchasing FTRs.

FTR tenure and availability

Stanwell appreciates the intent of making FTRs available up to 10 years in advance is to drive greater investment certainty. However, Stanwell suggests that the limited volume available 10 years in advance and the 3 month tenure would limit the impact of this design choice on investment certainty.

Stanwell also questions how a short tenor FTR could be valued that far in advance, particularly given the value of an FTR would be expected to change with any subsequent network augmentations.

As noted at a Technical Working Group meeting:

The AEMC noted that feedback from generators/investors was consistently that FTRs of 3- 4 years [tenure] are not long enough. This does not provide generators / investors with sufficient certainty over their investments."[12]

Stanwell maintains longer tenure FTRs are critical to support greater certainty for both established generators and new investment.

No reserve price for FTRs

If the proposed auctions were to proceed, Stanwell would support FTR auctions not having a reserve price. Differing views of AEMO and market participants of future market conditions could result in the reserve being set above the expected value to generators, resulting in participants not purchasing FTRs.

Limited number of nodes

Stanwell appreciates that the intent of reducing the number of nodes is to decrease complexity and increase liquidity, but this comes at the cost of generators not located at pre-defined nodes not being able to buy FTRs from their connection point i.e. exposes them to new basis risk that cannot be hedged.

Further information on the number of nodes, the location of nodes and the expected price differentiations between nodes and generator connection points across the network will be required before participants are able to determine the potential impact on their physical and contract market operations.

Service Target Performance Incentive Scheme

Stanwell is concerned about the source and size of the incentives for TNSPs to manage the physical capacity of the network. Under the current iteration, adjusting the market impact component of the current STPIS to better align with the proposed reforms:

"would provide TNSPs with a small financial reward as an incentive to manage the physical capacity of the system. Symmetrically, TNSPs would also be penalised a small

[11] AEMC, Transmission Access Reform: Updated Technical Specifications and Cost-Benefit Analysis, Interim Report, p 16
[12] AEMC, COGATI 2019 review – technical working group #4 minutes, 15 November 2019, p 4

amount for poor performance. Penalties and rewards under the scheme flow to and from TUOS charges."[13]

The AEMC continued that it is:

"expected that the 'strength' (i.e. the revenue at risk) of the incentive scheme would be the same which would avoid significantly altering TNSPs' risk profile."[14]

It is not clear how TSNPs' incentives to manage the physical capacity of the system would change under an altered incentive scheme that offers small incentives and penalties and the same revenue at risk as the previous incentive scheme.

In its previous submission, Stanwell detailed how such an incentive scheme could encourage TNSPs to provide fewer FTRs to participants, namely:

"Under FTRs, generators pay NSPs to provide access to the network. NSPs also face the Service Target Performance Incentive Scheme (STPIS), which incentivises NSPs to manage the physical capacity of the network with relatively small financial rewards and penalties. The Commission acknowledges the balance that will have to be struck between providing sufficient FTRs for participant risk management purposes and ensuring reasonable firmness of FTRs sold. Stanwell is concerned that NSPs will tend towards limiting the volume of FTRs made available relative to the capacity of the network (either under normal operating conditions or when the network is constrained). The costs of under-provision are borne by all generators (and by extension, consumers);

- *those who are unable to purchase FTRs are exposed to the LMP when additional FTRs could have been made available; and*
- *those who are do purchase FTRs do so at a price higher than the market clearing price had a higher volume of FTRs been available."*[15]

[13] AEMC, Transmission Access Reform: Updated Technical Specifications and Cost-Benefit Analysis, Interim Report, p 27
[14] AEMC, Transmission Access Reform: Updated Technical Specifications and Cost-Benefit Analysis, Interim Report, p 27
[15] Stanwell, Response to AEMC Coordination of Generation and Transmission Infrastructure discussion papers, November 2019, p 6

Transitional arrangements

Implementation period

In the absence of key details of the final iteration of the proposed reform, Stanwell is unable to comment on the appropriateness and potential impacts of the four-year implementation period. The implementation period for Five Minute Settlement (5MS) was three years and seven months; this timeframe is proving a challenge for participants in attaining minimum compliance before 5MS commences.

Stanwell acknowledges the four-year implementation period would go some way to reducing the impact of the proposed transmission access reform on contracting, but there will still be issues with long-term PPAs and long-term retail agreements.

Transitional FTRs

The proposed sculpted profile of transitional FTRs for established generators (and financially committed at the date the final rule is made) is too short and the reduction in transitional FTRs too rapid to materially mitigate the impacts on these significant market reforms on established generators. As detailed in a previous submission:

> *"The volume and length of FTRs provided to existing generators under grandfathering provisions is critical in delivering the proposed benefits of the reform. Short duration or low volumes of grandfathered access would leave incumbent generators exposed to the impacts of congestion and increased losses caused by new entrants while also exposing them to the increased risk of a different market design than the one they invested in.*
>
> *…*
>
> *If the intent is to avoid the negative impacts of increased losses and congestions being observed in response to new entrants locating in relatively weak or heavily utilised areas of the grid, grandfathering should be on a "first-commissioned, first-served" basis and provide long term certainty commensurate with the expected life of these long-lived assets. The concept that it needs to be scaled quickly to reflect the current risk undermines the proposed benefits."*[16]

Stanwell appreciates the AEMC is mindful about potentially stalling investment in generation capacity but is concerned that granting financially committed projects transitional FTRs could potentially provide a perverse incentive to potential participants, causing a rush of marginal projects in sub-optimal locations ahead of transmission access reform commencing. This would exacerbate the problems caused by sub-optimal locational decisions this reform is attempting to address.

Turning to established generation, based on expected closure years of coal-fired power stations and commencement date of transmission access reform, only Callide B and Vales Point stations and some Yallourn units would be fully covered by the proposed five year transitional arrangements. The remaining coal-fired power stations would have between two and 21 years of operation not covered by the transitional arrangements, meaning the mitigation of financial impacts of the proposed reform offered by transitional FTRs will be fleeting and minimal. There could be significant financial impacts on these younger coal-fired power stations.

[16] Stanwell, Response to AEMC Coordination of Generation and Transmission Infrastructure discussion papers, November 2019, p 9

Table 1: Coal-fired power station expected closure dates and years of operation after assumed 2025 start to transmission access reform

Station	Capacity (MW)	Expected closure year	Years of operation after COGATI start
Callide B	700	2028	3
Vales Point	1,200	2029	4
Yallourn	1,450	2029-2032	4-7
Eraring	2,880	2032	7
Gladstone	1,680	2035	10
Bayswater	2,640	2035	10
Tarong	1,400	2036-2037	11-12
Tarong North	440	2037	12
Kogan Creek	744	2042	17
Mt Piper	1,320	2042	17
Stanwell	1,445	2043-2046	18-21
Loy Yang B	1,040	2047	22
Loy Yang A	2,000	2048	23

Note: Callide C has not yet submitted an expected closure date.
Source: AEMO, Generating unit expected closure year – July 2020

Stanwell suggests longer transitional arrangements for a percentage of nameplate capacity would allow a more orderly transition for established generators. Further details of Stanwell's preferred transitional FTR allocation methodology is detailed in the following section.

Transitional FTR allocation

Not enough detail on the proposed transitional FTR allocation methodologies has been provided for participants to provide material feedback.

Stanwell has previously provided a recommended transitional FTR allocation methodology:

> *"In order to balance the benefits of grandfathering with the desire to ensure rights are available for auction, Stanwell considers a process of graduated allocation could occur, for example:*
>
> - *No more than 80 per cent of existing transmission capacity to be allocated under grandfathering arrangements; and*
> - *No more than 80 per cent of nameplate capacity is grandfathered to any plant:*
>   - *Incumbents are allocated 50 per cent of nameplate capacity in order of commissioning date followed by up to three 10 per cent increments;*
>   - *If a generator cannot be allocated access to one of these levels the process continues for other plant*
> - *Grandfathered access remains valid until the earlier of the nominated closure year or 25 years.*
>   - *Alternatively the first tranche (up to 50 per cent) could be longer than subsequent tranches."*[17]

Stanwell notes that since this recommendation was made almost all scheduled and semi-scheduled generators have provided AEMO with a nominated closure year.

[17] Stanwell, Response to AEMC Coordination of Generation and Transmission Infrastructure discussion papers, November 2019, p 9

Appendix B: Feedback on cost-benefit analysis

Feedback on the estimated costs and benefits of the current iteration of the proposed transmission access reform provided in this appendix should not be construed as support for continuing to progress this MDI.

Information Technology implementation costs

The AEMC should have checked HARD software's estimates of AEMO and market participant IT implementation costs against other contemporary data before publishing it. One potential yardstick would be the 5MS and Global Settlement (GS) implementation cost information AEMO and participants recently provided to the AEMC and ESB. Stanwell believes the HARD software report understates the implementation costs to the point of being misleading. The Interim Report acknowledges:

> *"that these figures are on the lower side of what a more detailed assessment of the cost of implementation is likely to reveal. We will be working with stakeholders and AEMO over the coming months to provide more precise figures now that more details of the reform are proposed."*[18]

Stanwell suggests it would have been preferable to refrain from publishing estimates until this detailed assessment, including a comprehensive survey of vendors, AEMO and participants, had been undertaken.

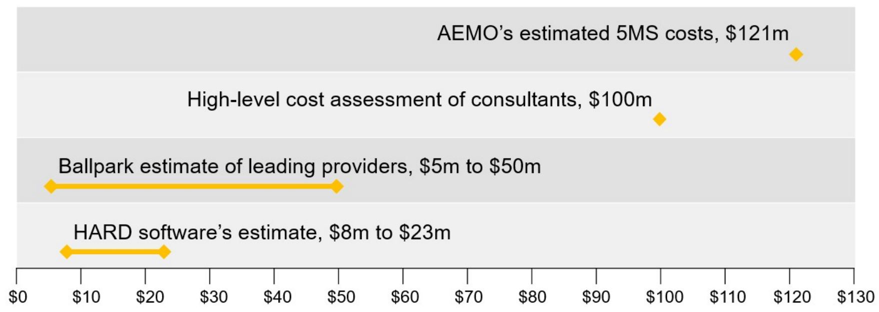
The comparison of HARD software's estimated LMP/FTR implementation cost with AEMO's and participants' 5MS/GS implementation costs is illuminating. Stanwell notes the upgrades required for 5MS/GS were largely concerned with increasing the frequency of an existing activity (i.e. replacing 30-minute settlement with 5-minute settlement), whereas the implementation of LMPs and FTRs is a fundamental change to the market design. Stanwell would expect costs to be largely commensurate with the complexity of the reform and the number of systems affected, but the HARD software report indicates the opposite.

Market Management Systems

HARD software's estimate of AEMO's LMP/FTR implementation costs of $8 million to $23 million is at the lower end of the range of indicative costs detailed in the Interim Report: from $5 million to $50 million (ballpark figures from providers of market management systems) to around $100 million (high-level cost assessments of various consultants).[19]

HARD software's estimate is also considerably below AEMO's expected expenditure of $121 million for 5MS/GS implementation, as illustrated in Figure 2. This indicates AEMO's estimated LMP/FTR implementation costs will be between five and 15 times less than AEMO's 5MS/GS implementation costs.

Figure 2: Estimates of AEMO's LMP/FTR implementation costs versus AEMO's 5MS/GS implementation costs ($ million)



[18] AEMC, Transmission Access Reform: Updated Technical Specifications and Cost-Benefit Analysis, Interim Report, pp 52-53

[19] AEMC, Transmission Access Reform: Updated Technical Specifications and Cost-Benefit Analysis, Interim Report, p 48

Initial analysis of the Net Present Value (NPV) of AEMO's expenditure on 5MS/GS implementation based on the cashflow of $121 million indicates an NPV of $112 million. This is markedly higher than HARD software's NPV range of LMP/FTR implementation of between $34 million to $71 million.

Stanwell suggests closer examination of the impact of the complexity of the reform on the market operator's IT implementation costs, particularly in light of AEMO's 5MS/GS expenditure, is warranted.

Participant costs

HARD software's estimated LMP/FTR implementation costs by type of participant and market area are detailed in Table 2. The total cost to all participants is estimated at between $31.5 million and $37.8 million.

Table 2: HARD Software estimated average participant system enhancement costs ($ million)

	Spot market	Wholesale	Retail customers	Market data	Risk management	Total
Small generator	$0.010	$0.020	$0.000	$0.020	$0.020	$0.070
Small generation aggregator	$0.010	$0.020	$0.050	$0.020	$0.020	$0.120
Distributed network service provider	$0.010	$0.025	$0.000	$0.050	$0.100	$0.185
Large generator with portfolio	$0.100	$0.250	$0.000	$0.100	$0.250	$0.700
Large gentailer	$0.200	$0.250	$0.250	$0.250	$0.500	$1,450
Small retailer	$0.000	$0.025	$0.050	$0.020	$0.010	$0.105
Large load participant	$0.010	$0.025	$0.000	$0.020	$0.010	$0.065
Large retailer	$0.050	$0.250	$0.250	$0.050	$0.250	$0.850

Stanwell is concerned that these estimated implementation costs are significantly below the actual costs of implementing the proposed reform. These low estimated costs rely at least in part on the assumption that:

> *"[F]or most commercial systems or in-house developments, the changes required for the participant spot market functions would be relatively minor and may even be at no additional*

cost to the participant as part of their commercial support arrangements."[20]

Stanwell does not consider the changes required for LMP/FTR implementation to be relatively minor. Stanwell would be keen to learn of any commercial agreements under which IT system upgrades stemming from such a significant market design change would be included at no cost.

HARD software contrasts LMP-related upgrades with those required for the implementation of 5MS/GS:

> *"Recent experience with the participant submissions associated with the implementation of five minute settlement in the NEM would suggest that many of the very high IT costs in those submissions may have included significant costs associated with the upgrading or replacement of legacy IT systems rather than for the reform itself."*[21]

Stanwell rejects the assertion that the high costs associated with 5MS/GS were for purposes other than the reform itself. Stanwell's 5MS/GS implementation project scope was to deliver compliance with no increase in operational risk. It did not include "upgrading or replacing legacy systems" unless those replacements were specifically triggered by 5MS. Stanwell's compliance-only implementation costs (details of which Stanwell has previously provided to the AEMC) are considerably higher than HARD software's estimated LMP/FTR implementation costs.

As part of the consultation into AEMO's proposed rule change to delay 5MS implementation, Deloitte was engaged by the AEMC to provide advice on participants' costs and capability relating to the proposed delay to the start date of 5MS and GS rule changes.

In order to determine the relative size of the costs of the delay, Deloitte estimated the likely range of IT costs for participants prior to the pandemic. Table 3 details Deloitte's estimated range of costs associated with meeting 5MS/GS obligations for generators, networks and retailers. These estimates are based on both publicly available recent information on program costs and Deloitte's experience in IT implementation projects (including current 5MS and GS programs).[22]

Table 3: Range of costs to meet the 5MS and GS timeframe prior to the COVID-19 pandemic ($ million)

	Small		Medium		Large	
	Low	High	Low	High	Low	High
Generator	-	-	$5.0	$20.0	$20.0	$25.0
Network	-	-	$5.0	$20.0	$20.0	$30.0
Retailer*	$0.1	$1.0	$15.0	$25.0	$25.0	$40.0

* Retailer includes vertically-integrated retailers

Assigning the cost ranges in the above table to the 60 participants listed in Appendix B of the Deloitte report and aggregating the results indicates the total 5MS/GS implementation costs for participants is between $388 million to $823 million. This is between 12 and 21 times higher than HARD software's estimate of participants' LMP/FTR implementation costs.

Underestimating IT implementation costs in the cost-benefit analysis will overstate the net benefits of the proposed reform. Stanwell looks forward to engaging with the AEMC to ensure accurate IT implementation costs are used in this analysis.

[20] HARD software, A preliminary indication of the Information Technology Costs of Locational Marginal Pricing, p 55
[21] HARD software, A preliminary indication of the Information Technology Costs of Locational Marginal Pricing, p 52

[22] Deloitte, Delayed implementation of the five minute settlement and global settlement rules, p 9

Quantitative impact assessment

Modelling assumptions and methodology

Stanwell's review of the modelling and assumptions has raised the following high-level issues with the methodology:

- Batteries or pumped storage hydro have not been included in the solve. These asset classes are aggregated to the single Regional Reference Node and calculated external to the model. This has unknown implications for the efficacy of the solve. Stanwell would expect the growth in these assets (along with electric vehicle impacts) to significantly affect NEM operations across the timeframes of this modelling.

- The same nodal model to solve both current state (no reform) and proposed state (reform) market structures. The efficacy of this solve depends heavily on power flows though the model structure; if the model introduces complexity that does not exist in the current NEM, then this is a potentially prejudiced study. Apart from being referenced up-front, it is not apparent in any detail how the current state (no reform) is processed externally to the Plexos model. Stanwell believes these two states would be better compared using separate models tailored to each market structure that incorporated common base assumptions.

- Numerous assumptions have been made based on 'marginal cost of generation'. As this cost information is confidential to participants it is an unknown to modellers and assumptions need to be made (presumably linked to published AEMO assumptions). In Stanwell's experience, these AEMO values can contain significant deviations from actuals. As an illustrative example, AEMO datasets indicate that the sub-critical Callide B units are less efficient than the co-located super-critical Callide C units.

- Crucial assumptions around disaggregation of regional loads by factors supplied by AEMC are not adequately explained or quantified. These nodal loads are fundamental to the solve of a nodal model.

- Renewable Energy Zone (REZ) traces are used rather than actual Variable Renewable Energy (VRE) proxies. In Stanwell's experience, these REZ traces can significantly overstate VRE capacity factors.

- New entrant pumped hydro is geographically constrained to areas of existing hydro. It is not clear why this assumption is made; it seems unnecessarily constraining.

- The capacity expansion model is not run against the 1,000+ nodes in its full iteration, rather it is run against 25 'zones' across the NEM. Secondary modelling is then used to expand the zones to nodes. At this stage the capacity expansion has already been completed – this makes their model more of a zonal solution rather than a nodal solution.

Further discussion of the findings and conclusions of NERA's report are covered in the following section.

Capital and fuel cost savings

NERA's capital and fuel costs savings analysis finds that:

> *"Generators are also better utilised as a result of the reforms. Renewable plants have higher capacity factors under transmission access reform than under a scenario in which existing transmission access arrangements are maintained,*

> *because generators are located making better use of the transmission infrastructure available, avoiding congestion."*[23]

Stanwell agrees that greater coordination of generation and transmission investment could result in increased efficiency, but the proposed reform is not the only way these benefits could be achieved. Assigning the entirety of this benefit to the proposed access reform would minimise the effectiveness of the ISP and REZs in corralling new investment into uncongested parts of the network, as well as assume that generators will continue to locate in areas of the network where they will be frequently constrained off.

Dispatch efficiency

With respect to the dispatch efficiencies realised through the removal of race-to-the-floor bidding, NERA finds "total system costs increase by $140 to $180 million per year, the vast majority of which results from coal plant bidding at the market floor", but then goes on to acknowledge:

> *"our analysis may not reflect the frequency with which market participants race to the floor in practice and the balance of risk lies towards overstatement of the benefit, at least in the sample year. Insight from previous studies of the NEM, for instance, suggests that renewable plant might have a higher incentive to bid at the floor than what is shown in our model."*[24]

Stanwell notes NERA's estimate of the cost of race-to-the-floor bidding is significantly higher than previous estimates of the impact of race-to-the-floor bidding. The Coordination of Generation and Transmission Investment (COGATI) directions paper from June 2019 noted the historical cost of race-to-the-floor bidding was relatively low:

> *As part of the transmission frameworks review in 2013, the AEMC engaged ROAM Consulting to analyse the magnitude of disorderly bidding in the NEM. ROAM Consulting estimated that over the period June 2008 to June 2011, electricity dispatch costs were $21 million higher than they could have been due to race to the floor bidding behaviours."*[25]

ROAM Consulting's modelling indicated race-to-the-floor bidding costs would decrease in the future:

> *"ROAM Consulting's forward-looking modelling estimated that removing race to the floor bidding could save $8.8 million (in net present value terms) over the 18 years to 2030, with annual savings increasing to $3-6 million in the last five years of the period."*[26]

Regardless of the purported cost of race-to-the-floor bidding, Stanwell does not believe the proposed transmission access reforms will remove incentives for race-to-the-floor bidding, as discussed in its previous submission:

> *"Much of the recent investment in generation assets has occurred where a long term offtake agreement was able to be committed to as part of the final investment decision. These agreements reduce the risk to the investor and their financiers by reducing or removing their exposure to unpredictable pool price outcomes.*
>
> *A common offtake arrangement is a whole-of-meter swap whereby the investor is incentivised to maximise generation in order to receive maximum revenue. Early versions of these*

[23] AEMC, Transmission Access Reform: Updated Technical Specifications and Cost-Benefit Analysis, Interim Report, p 42
[24] NERA, Cost Benefit Analysis of Access Reform: Modelling Report, p iv
[25] AEMC, Coordination of Generation and Transmission Investment – Access reform directions paper, p 17
[26] AEMC, Coordination of Generation and Transmission Investment – Access reform directions paper, p 40

agreements incentivised volume maximisation in all market conditions while contemporary agreements are reported to include some exceptions such as during periods of negative wholesale price.

Where such a clause is included to protect the buyer it is likely to remain referenced to the regional price rather than the generators local price. Accordingly, where the regional price is positive the generator may remain incentivised to maximise dispatch volume regardless of the local price in order to receive revenue.

If multiple such plants are behind a constraint is it [sic] likely that their bids will reflect the incentives rather than their short run cost as assumed in the Commissions examples."[27]

Further, the assumption regarding "increased efficiency of dispatch" is flawed in that it assumes any available generation capacity offered at prices above marginal cost is under-utilised. This approach does not adequately account for the range of factors that informs generators' bidding strategies, such as the physical characteristics of each plant (e.g. minimum load, start-up costs, physical constraints) or fuel supply (e.g. availability, cost, conservation).

A "marginal cost" approach to generation dispatch is inefficient, as detailed by Professor George Yarrow in his analysis of efficient bidding in an energy-only wholesale electricity market:

"Short-run efficiency can be achieved in energy-market designs provided that it is recognised that pricing should reflect economic costs, not incurred costs. Economic costs encompass scarcity rents as well as such things as expenditures on fuel used to generate electricity.

…

What would be problematic is if misguided regulatory policy required that bids reflected within-period, marginal, incurred costs or set an unduly low upper bound to prices."[28]

The respective impacts on dispatch efficiency of complimentary market design changes must also be considered, to avoid implementing rule changes based on the total benefits instead of the marginal benefits of additional reforms. 5MS implementation is currently in progress ahead of full commencement on 1 October 2021. The claimed benefit of this reform is that it will:

"…provide a better price signal for investment in fast response technologies, such as batteries, new gas peaking generation, and demand response. The alignment of the operational dispatch and financial settlement periods are expected to lead to more efficient bidding, operational decisions, and investment."[29]

Given both 5MS and LMP aim to improve the efficiency of dispatch and investment, the AEMC must demonstrate the marginal benefits of LMP for dispatch efficiency and investment above those delivered by 5MS.

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[27] Stanwell, Response to AEMC Coordination of Generation and Transmission Infrastructure discussion papers, November 2019, p 11

[28] Yarrow & Decker, Bidding in energy-only wholesale electricity markets, Final report, November 2014, pp 4-5

[29] AEMO, Five Minute Settlement: Program Information and Fact Sheet

Wealth transfers

When discussing the estimated wealth transfers, the AEMC notes:

> *"In a world without transmission access reform, this [LMP deviating from RRP] increases substantially following the retirement of significant coal capacity post 2035, and the need to build new capacity in already constrained parts of the network."*[30]

It is not explained in the Interim Report why there is a need to build new capacity in already constrained parts of the network, either with or in the absence of transmission access reform. Stanwell contends that between the effectiveness of the ISP and REZs in guiding investment decisions and increased investor awareness of the importance of locating in uncongested parts of the network ('do no harm' provisions, capacity constrained off for security reasons (particularly in Victoria and North Queensland), reductions in Marginal Loss Factors), investment in sub-optimal parts of the network would not continue to occur unabated.

Contract market liquidity

The potential impact on contract market liquidity does not appear to be acknowledged. Despite the analysis showing a decline in the incentive to hedge by generators who do not hold FTRs, NERA found that:

> *"no material impact on contract market liquidity is expected over the long term."*[31]

This conclusion runs counter to the feedback participants have given the AEMC over the course of this project. As discussed at the Technical Working Group, there are a number of reasons why contract market liquidity is expected to decline, including:

- *"the quantity of FTRs sold may be less than the actual network capacity on the day. The project team noted that it would consider this point further.*
- *the increased basis risks for participants, may result in the market being more complex and so impacting liquidity.*
- *while the firmness of the FTRs has increased, because they are not fully firm, this may not increase the amount of contracts sold into the market."*[32]

Stanwell also detailed the conditions required for contract market liquidity to increase in its previous submission, noting:

> *"Generators typically consider a number of inputs such as planned and unplanned outage risk, fuel constraints, desirability of spot exposure compared to the current contract price, losses and congestion when determining a maximum hedge volume to offer. While FTRs may reduce the impact of congestion (and potentially losses) they do not address these other factors.*
>
> *However a lack of FTRs held by a generator may decrease their willingness to sell hedge contracts which are settled against a price they are not receiving for their generation. As such the volume of contracts offered is only likely to increase if:*

[30] AEMC, Transmission Access Reform: Updated Technical Specifications and Cost-Benefit Analysis, Interim Report, p 45
[31] AEMC, Transmission Access Reform: Updated Technical Specifications and Cost-Benefit Analysis, Interim Report, p 46

[32] AEMC, Grid access reform (COGATI) review – technical working group #9 minutes, 9 July 2020, p 4

- *congestion risk was the factor limiting existing hedging; and*
- *the generator could secure sufficient FTRs; and*
- *the FTRs were considered highly firm; and*
- *the contract price was high enough to offer a return on investment including the cost of the FTRs.*

For any generators where these four conditions are not met, the risk is skewed to a reduction in hedge volume being offered."[33]

NERA's analysis of contract market liquidity under the proposed reform rests on the assumption that:

"if the unhedgeable, inefficient volume risk that the reform eliminates is greater than the basis risk faced by generators after ownership of FTRs then contract market liquidity will likely improve as a result of the reform."[34]

Stanwell contend there are a couple of assumptions behind this statement that require closer examination. First, the proposed reform does not eliminate volume risk. Volume risk is only eliminated for FTR holders when the network capacity is equal to or exceeds the volume of FTRs sold on the relevant transmission assets. While the firmness of FTRs has been increased in the current iteration, they are not 100 per cent firm; physical constraints on transmission lines mean FTR holders can still be exposed to volume risk as well as price risk. Those not holding sufficient or any FTRs will face volume and price risk on their generation above their volume of FTRs.

Second, risks are not commensurate. The shift from volume risk to price risk is a significant change for generators. The analysis does not appear to consider which risk generators are best placed to manage. Stanwell contends that generators have demonstrated they can effectively manage volume risk, and questions whether they will be as successful managing price risk when prices at nodes and connection points can significantly diverge.

Locational signals

Stanwell agrees that there are benefits that can be realised through improving locational signals for established generators, new investment and consumers.

The paucity of ex-ante locational signals has seen sizeable investment in large-scale VRE in weak areas of the network, far from major load centres, with negative externalities for established generators in or affected by those areas of the network. Recent changes in marginal loss factors and constraints for power system security imposed on VRE generators in Victoria and more recently North Queensland are crude but effective ex-post locational signals for future investment.

Stanwell disputes that the modelled benefits of improved locational decisions by new investment can only be achieved through the proposed transmission access reform. Additional ex-post locational signals would achieve the bulk of the long-term benefits from transmission access reform (i.e. more efficient investment in new generation and storage assets).

Conclusions

NERA's analysis tends to downplay instances where their modelling indicates reform will deliver low or negligible benefits and factors that could result in modelled benefits exceeding benefits that could be realised.

[33] Stanwell, Response to AEMC Coordination of Generation and Transmission Infrastructure discussion papers, November 2019, p 12
[34] NERA, Cost Benefit Analysis of Access Reform: Modelling Report, p 72

Table 4: Estimated social and consumer benefits of access reform

	Benefit in 2026 ($2026M)	NPV 2026-2035 ($2020M)	NPV 2036-2040 ($2020M)	NPV 2026-2040 ($2020M)
Capital and fuel cost savings	66	454	1,285	1,738
Dispatch efficiency	141 - 181	700 - 898	95 - 122	795 - 1,020
Dynamic losses	102	510	151	661
Competition benefit	0 - 9	0 - 140	0 - 68	0 - 209
Total social benefit	**308 - 358**	**1,663 - 2,002**	**1,531 - 1,626**	**3,194 - 3,629**
Wealth transfer	105	1,176	1785	2961
Competition-related wealth transfer	0 - 200	0 - 1,119	0 - 536	0 – 1,655
Total consumer benefit	**414 - 662**	**2,839 - 4,297**	**3,316 - 3,948**	**6,155 - 8,245**

On the former:

- The modelled benefit of competition is between $0 and $209 million (NPV) as NERA "cannot rule out there being no material impacts on competition" of transmission reform.[35]
- Similarly, a benefit of between $0 and $1,655 million (NPV) of consumer benefit stemming from a wealth transfer to consumers would only be realised "**if** [emphasis added] a competition benefit arises".[36]

The $1,864 million (NPV) of benefits that might not be realised account for between 22 per cent to 30 per cent of the total consumer benefits of the proposed reform. In the event there are no competition benefits, the modelled benefits of the reform would decrease to $4,291 million to $6,381 million (NPV).

On the latter:

- A benefit of $795 million to $1,020 million (NPV) is attributed to improved dispatch efficiency from eliminating race-to-the-floor bidding, while acknowledging the analysis "may not reflect the frequency with which market participants race-to-the-floor in practice" and ignores portfolio effects.[37]
- A benefit of $1,738 million (NPV) of avoided costs stemming from the locational signals of the proposed reform resulting in 20 GW less generation capacity being built in inefficient areas of the network, but noting that plant in inefficient locations of the network would be more frequently constrained so the "assumed subsidy may be overstated and more overstated as time progresses".[38]

Collectively, these indicate that the quantitative benefits of the proposed reform may be overstated in the modelling.

[35] NERA, Cost Benefit Analysis of Access Reform: Modelling Report, p vii

[36] NERA, Cost Benefit Analysis of Access Reform: Modelling Report, p viii

[37] NERA, Cost Benefit Analysis of Access Reform: Modelling Report, p iiii

[38] NERA, Cost Benefit Analysis of Access Reform: Modelling Report, p 38