19 October 2020

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Submitted by email to aemc@aemc.gov.au

Project number: EPR0073

Transmission access reform: Updated technical specifications and cost-benefit analysis

Snowy Hydro Limited welcomes the opportunity to comment on matters raised in the Consultation paper from the Australian Energy Market Commission (the Commission) on Transmission access reform: Updated technical specifications and cost-benefit analysis.

Snowy Hydro commissioned Baringa Partners (Baringa) to provide a qualitative-based critique of the NERA report to support our public submission to the Energy Security Board's post-2025 consultation paper and our position on the Coordination of generation and transmission investment implementation – access and charging. Please find the report attached.

The critique of the NERA report challenges both NERA's modelling methodology and results, and the "real-world" (i.e. non-modelling) implications of the AEMC's proposed transmission access reforms as discussed in NERA's report.

Snowy Hydro appreciates the opportunity to respond to the Commision on the Transmission access reform: Updated technical specifications and cost-benefit analysis and any questions about this submission should be addressed to panos.priftakis@snowyhydro.com.au.

Yours sincerely,

Panos Priftakis
Head of Wholesale Regulation
Snowy Hydro

An independent assessment of the NERA report on the AEMC's proposed transmission access reforms

CLIENT: Snowy Hydro Limited

DATE: 19/10/2020

Version History

Version	Date	Description	Prepared by	Approved by
0_1	15/10/2020	Draft report	Alan Rai Scott Sandles	Alan Rai
1_0	19/10/2020	Final report	Alan Rai Scott Sandles	Peter Sherry

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Executive Summary

The AEMC's proposed transmission access reform model consists of adopting locational marginal pricing (LMP) in the wholesale market where spot prices could differ by transmission node. These LMPs would be paid by most generators, whereas most load would be settled at a new region-wide price based on a volume weighted average of individual LMPs. A new form of hedging instrument, known as a financial transmission rights (FTR), would be introduced to enable market participants to hedge between locational prices across a small number of pre-defined nodes. This new hedging instrument would be in place of the current settlement residue auction (SRA) units. NERA Economic Consulting (NERA) was commissioned by the AEMC to conduct a cost-benefit analysis of the AEMC's proposed reforms.

Baringa Partners (Baringa) has been commissioned by Snowy Hydro to provide a qualitative-based critique of the NERA report to support Snowy Hydro's public submission to both the AEMC's COGATI review as well as the Energy Security Board's post-2025 consultation paper.[1]

Our critique of the NERA report challenges both NERA's modelling methodology and results, and the "real-world" (i.e. non-modelling) implications of the AEMC's proposed transmission access reforms as discussed in NERA's report. Due to the short timeframe for this engagement, to support its critique Baringa has not sought to undertake market modelling, and has not sought to undertake quantitative analysis beyond assessing the analysis in the NERA report. We consider that market modelling (especially modelling of intra-regional constraints and losses) would be a useful complement to this critique.

NERA define the AEMC's proposed transmission access reforms as the 'Reform' scenario. NERA's estimated benefits for consumers are calculated as the difference between total system costs, competition impacts and wealth transfers (from generators to consumers) between the Reform scenario and a counter-factual status-quo ('No-Reform') scenario.

We consider NERA has underplayed the role of locational signals to generators that exist under the current access regime, which therefore overstates the benefits of Reform. In particular:

- NERA's modelling of No-Reform does not account for the nodal-specific signals currently provided by marginal loss factors (MLFs) in the NEM. This overstates the difference in the extent of nodal price separation between Reform and No-Reform scenarios,
- NERA's No-Reform modelling also does not account for the nodal-specific signals provided for congestion (or curtailment) under the current access regime. Based on Baringa's first-hand experience, debt and equity investors in generation projects are acutely aware of the impact of MLFs and curtailment on revenues and profits. Baringa is aware of several projects whose final investment decision has been or is being delayed due to lenders' concerns about existing and projected future levels of local curtailment and losses. This is especially the case for utility-scale solar – the very technology that NERA argue require the locational signals provided by Reform, and
- NERA estimate that No-Reform would lead to an additional 20GW of solar generation investment that could be avoided with better locational price signals under Reform, but this

[1] Energy Security Board, *Post 2025 Market Design Consultation Paper*, September 2020. Available at: https://esb-post2025-market-design.aemc.gov.au/32572/1599383248-p2025-market-design-consultation-paper-final.pdf

is overstated given the strong locational signals provided under the current regime (from points 1 and 2 above). Further, NERA gives no weight to the role that AEMO's Integrated System Plan (ISP) has in guiding locational investment decisions for solar generation under the current regime, which contrasts with its acknowledgement that new wind generation would be unlikely to occur outside of the Renewable Energy Zones (REZs) established through the ISP. Baringa's experience working with solar developers reveals that the ISP is now critically important in guiding the long-term locational decisions of these developers, as is the case for wind developers.

In summary, we consider that the No-Reform scenario is poorly defined and not reflective of the real-world counterfactual in the Australian NEM. The relevance and value of all the subsequent analysis comparing the two scenarios (Reform vs No-Reform) is thus significantly undermined.

We also have concerns with how NERA has applied the Reform Scenario. Firstly, NERA assume 100% of the increase in system costs from Reform to No-Reform are passed through to consumers. This means consumers bear the full cost of the additional 20 GW of solar capacity installed under No-Reform, rather than generators wearing some of this cost. This assumption is contrary to NERA's modelling, which shows spot prices are *lower* under No-Reform. This implies generators, not consumers, bear the additional system costs of the extra 20 GW capacity installed under No-Reform. Similarly, NERA assumes that 100% of the decreased operational costs from eliminating 'race-to-the-floor' bidding would be passed through to consumers, notwithstanding that this bidding behaviour can lead to lower spot prices.

Secondly, NERA assumes that FTRs will be firm and consequently some of their findings are pre-determined: risk management and contract market liquidity can only be enhanced, not diminished, from the introduction of FTRs (as FTRs are assumed to be firm). We consider it likely that FTRs may suffer from a lack of firmness, for two related reasons:

- They are unlikely to capture all of the relevant constraints – the types of network constraints increasingly driving curtailment, especially of renewables, are not thermal ratings-based but instead system security-based constraints. The increasing incidence of these atypical constraints means it is highly likely FTRs would not be revenue adequate.
- To the extent that FTRs are non-firm for whatever reason, the most effective measure to enhance FTR revenue adequacy would be allowing for any shortfalls in settlement residues to be funded by a third party. However, this remains outside the design of the AEMC's transmission access reforms.

If FTRs are not firm and this leads to a decline in contract market liquidity, this implies more conservative contracting practices by market participants, with adverse outcomes for retailers and ultimately consumers.

We also provide the following criticisms of NERA's modelling of the benefits of Reform:

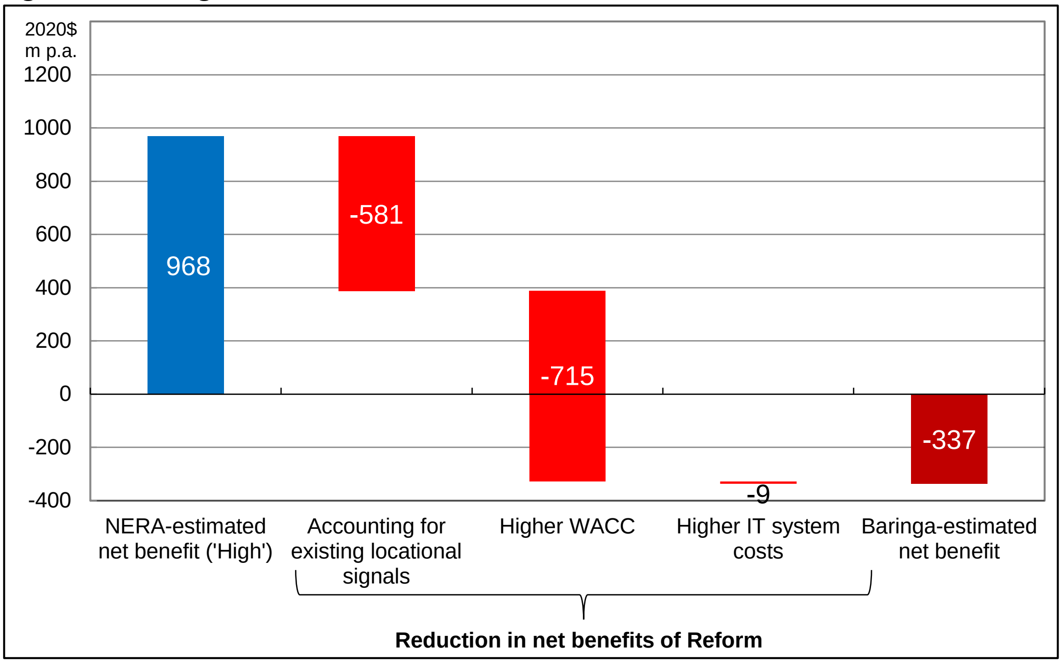
- The introduction of nodal pricing is considered costless – despite being titled a "cost-benefit analysis", NERA consider only the potential benefits of Reform. Ignoring costs, or assuming no costs will arise from Reform, is at odds with the vast majority of the sector's views on Reform.

▸ NERA projects baseload wholesale spot prices to be c.$30/MWh until 2030. These prices are significantly below price forecasts from other credible forecasters (e.g. Baringa projects SRMC-based prices in the $50-65/MWh range for the rest of the 2020s).

▸ NERA also adopt different input assumptions for the discount rate and WACC without explanation, and justification for both is lacking, including a lack of explanation whether these estimates are nominal or real. NERA's WACC assumption of 5.9% p.a. is well below publicly-available estimates of existing WACCs for generators in the NEM. Furthermore, in a recent survey of investors undertaken by the AEMC, participants considered their WACCs would increase by 150 basis points p.a. if nodal pricing was introduced. From our market due diligence work, we consider a pre-tax real WACC of around 8.5% p.a. would be an appropriate, yet conservative, discount rate under No-Reform (assuming a level of merchant exposure to power prices). And, given the evidence from the AEMC survey, a pre-tax real WACC of 9.9% p.a. would be an appropriate discount rate under Reform.

Taking into account a change in discount rate and our other critiques of NERA's modelling, our high level estimate of the net benefit of Reform over the 2026-2040 period is **minus $337 million p.a.** This is in stark contrast to the estimated net benefits of Reform in the NERA report, of $1200 million p.a. A significant portion of this difference is the result of accounting for MLFs in NERA's nodal subsidy calculations, which Baringa estimates would reduce NERA's nodal subsidy by around 65 per cent with a proportionally similar drop in the magnitude of these benefits.

Figure 1 Baringa cost-benefit estimate of Reform



Source: Baringa Partners LLP

Lastly, but no less important, the complexity of the proposed reforms means there is a high chance of smaller, non-integrated generators and retailers being competitively disadvantaged relative to vertically- and horizontally-integrated rivals. Concerns about insufficient FTR firmness and liquidity are likely to create further incentives to integrate horizontally and vertically – that is, to hedge inter-nodal risks internally – rather than externally by trading FTRs. This has implications for the extent and effectiveness of competition in both generation and retailing, and ultimately implications for consumer prices and affordability under the Reform case.

We consider further cost-benefit analysis on the impact of the AEMC's transmission access reform is warranted and necessary. Such cost-benefit analysis should include:

- A proper specification of the counterfactual scenario – including the role that MLFs, curtailment risk and the ISP play in sending locational signals to generation under the current access regime
- A more realistic methodology for how changes in system costs are ultimately likely to impact consumers – including how increases or decreases in system costs are likely to be shared between generators and consumers
- A proper accounting for risk – including through the adoption of a more realistic discount rate and taking into account that the proposed FTRs would not be fully firm
- Consideration of the implementation costs of reform
- Fully reflecting the specification of the AEMC's proposed transmission access reform framework in the modelling assumptions – including the design of FTRs, transitional arrangements and elements of the framework which are still being considered by the AEMC (for example, whether any pricing mitigation measures are adopted to limit the risk of inefficiently high LMPs)

1 Introduction

Baringa Partners has been commissioned by Snowy Hydro to provide a qualitative-based critique of a report published by NERA in September 2020 (the NERA report)[2] in support of the AEMC's COGATI review.[3] Baringa's critique is to support Snowy Hydro's public submission to the AEMC's COGATI review as well as the Energy Security Board's post-2025 consultation paper.[4]

The AEMC's COGATI review consists of the following four elements:

1. Moving away from the existing pricing of wholesale spot electricity based on the price at the regional reference node (RRN), to locational marginal pricing, where wholesale spot prices are allowed to differ by transmission node identifier.
2. Locational marginal prices (LMPs) are to be paid to scheduled and semi-scheduled generators, and paid by scheduled loads. In contrast, non-scheduled generators and non-scheduled loads will face a region-wide price, namely a volume-weighted average of individual LMPs (VWAPs). Non-scheduled loads could choose to become scheduled load and face LMPs.
3. Hedging instruments, commonly known as 'financial transmission rights' (FTRs), that can hedge the difference in prices between a relatively small number of pre-defined nodes based on the prevalence of congestion on the transmission network.
4. Consequential changes to AEMO and market participants' dispatch and settlement systems, to enable LMPs or VWAPs to be paid (received) by load (generators).

This report provides Baringa's qualitative-based critique of the NERA report, including the:

- estimates of benefits of implementing the AEMC's COGATI reforms
- consideration of implementation costs associated with the COGATI reforms
- assumptions and statements with respect to the real world implications of implementing COGATI (including real world considerations not considered by NERA):
  - impacts on contract market liquidity, including issues associated with integrating FTRs with financial hedge contracts
  - grandfathering of FTRs
  - the potential impact on the cost of financing new generation investment, based on evidence from investor surveys done by the AEMC and others
  - the impact of loads paying different prices to that of generators, and the impact of different generator types receiving different prices, and

[2] NERA Economic Consulting, *Cost Benefit Analysis of Access Reform: Modelling Report*, Prepared for the Australian Energy Market Commission, 07 September 2020. Available at: https://www.aemc.gov.au/sites/default/files/2020-09/NERA%20report%20Cost%20Benefit%20of%20Access%20Reform%202020_09_07.pdf

[3] AEMC webpage, *Coordination of generation and transmission investment implementation – access and charging*, https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and

[4] Energy Security Board, *Post 2025 Market Design Consultation Paper*, September 2020. Available at: https://esb-post2025-market-design.aemc.gov.au/32572/1599383248-p2025-market-design-consultation-paper-final.pdf

- consideration on how a lack of transparency on impending generation connections under the current access regime impacts the locational decisions and outcomes of generators, which are unlikely to be addressed through the COGATI reforms

That is, Baringa's critique of the NERA report challenges both NERA's modelling methodology and results, and the "real-world" (i.e. non-modelling) implications of the AEMC's proposed transmission access reforms as discussed in NERA's report.

As the term "qualitative review" suggests, Baringa has not sought to undertake market modelling (due to the short timeframe available), and has not sought to undertake quantitative analysis beyond the critique of the analysis in the NERA report. We consider market modelling (especially modelling of intra-regional constraints) would be a useful complement to this critique.

2 A critique of NERA's modelling: benefits of Reform

2.1 Summary of NERA's results

NERA's analysis assumes the AEMC implements transmission access reforms ("Reform") in the fiscal year from July 2025 to June 2026, and the benefits of Reform are estimated over the fifteen-year period from July 2025 to July 2040. NERA use the market modelling software program PLEXOS to estimate system costs under Reform and then under no-access reform ("No-Reform").

2.1.1 NERA's approach to calculate overall consumer benefits

Consumer benefits are defined as the sum of social benefits and generator-to-consumer wealth transfers, with social benefits defined as the reduction in system costs between No-Reform and Reform. That is, consumer benefits are equal to the sum of:

- the reduction in system costs in Reform vs. No-Reform, which is claimed to result from:
  - new-entrant generators locating, under Reform, in areas with less congestion[5] and lower losses, than in No-Reform, meaning less capacity is required to deliver the same energy to end-consumers
  - generators being dispatched on the basis of their short-run marginal cost (SRMC) under Reform, which means higher-SRMC generators are dispatched by a lesser amount compared to No-Reform. This can save fuel and other short-run marginal costs
- wealth transfers from generators to consumers as a result of generators, under Reform, losing their ability to automatically access intra-regional settlement residues (IRSRs) for free ("congestion rent", as dubbed by NERA). Under Reform, generators would need to pay to be entitled to these residues – these payments are transferred to consumers, thereby representing the wealth transfer

We have concerns with how NERA has applied the Reform Scenario. Firstly, NERA assume 100 per cent of the increase in system costs from Reform to No-Reform are passed through to consumers. This means consumers bear the full cost of the additional 20GW of solar capacity installed under No-Reform, rather than generators wearing some of this cost. This assumption is contrary to NERA's modelling, which shows spot prices are *lower* under No-Reform. This implies generators, not consumers, bear the additional system costs of the extra 20GW capacity installed under No-Reform. Similarly, NERA assume 100 per cent of the decreased operational costs from eliminating race-to-the-floor bidding would be passed through to consumers, notwithstanding that this bidding behaviour can lead to lower spot prices.

[5] In this document, 'curtailment' and 'congestion' are used interchangeably.

2.1.2 NERA's results by benefit category

NERA estimate benefits attributable to locational marginal prices (LMPs) that solely reflect the congestion benefits of Reform, and also estimates benefits attributable to LMPs that reflect both congestion and dynamic losses. Their results are summarised in Table 1 (reproduced from Table 1 of NERA's report).

Table 1 NERA's estimated social and consumer benefits of access reform

Category	Source of consumer benefit	Benefits in year 2026 (2026 $m)		NPV of Benefits (7% p.a. discount rate, 2020$m)					
				2026-2035		2036-2040		2026-2040	
		Low	High	Low	High	Low	High	Low	High
1	Capital and fuel cost savings from more efficient locational decisions	66		454		1,285		1,739	
2	Improved dispatch efficiency from eliminating Race to the Floor bidding	141	181	700	898	95	122	795	1,020
3	Introduction of dynamic losses	102		510		151		661	
4	Competition benefit	0	9	0	140	0	68	0	208
5	**Total social benefit** (= 1 + 2 + 3 + 4)	**309**	**358**	**1,664**	**2,002**	**1,531**	**1,626**	**3,195**	**3,628**
6	*Total social benefit excluding dynamic losses*	*207*	*256*	*1,153*	*1,492*	*1,380*	*1,475*	*2,533*	*2,967*
7	Wealth transfer from generators to consumers	105		1,176		1,785		2,961	
8	Competition-related wealth transfer	0	200	0	1,119	0	536	0	1,655
9	**Total consumer benefit** (= 5 + 7 + 8)	**414**	**663**	**2,840**	**4,297**	**3,316**	**3,948**	**6,156**	**8,245**
10	*Total consumer benefit excluding dynamic losses (= 6 + 7+ 8)*	*312*	*561*	*2,329*	*3,787*	*3,165*	*3,796*	*5,494*	*7,583*

Source: Table 1 from NERA report

The following points are worth noting with respect to NERA's estimated benefits:

- estimated overall consumer benefits (including benefits attributable to adopting dynamic losses) under Reform range from $6.2 billion to $8.2 billion over the 2026-2040 period in net present value (NPV) terms. This is equivalent to $676 million to $905 million per annum on a constant-annuity basis (based on NERA's 7% discount rate), or 6-9 per cent of estimated annual pool revenues[6]

- social benefits comprise around one-half of overall consumer benefits, across the selected time periods and across both 'Low' and 'High' estimates of the various benefits of Reform
- prior to 2036, around one-half of the estimated social benefits (i.e. around one-quarter of overall consumer benefits) arise from improved dispatch efficiency. From 2036, and reflecting the increasing penetration of variable renewable energy (VRE) generation – which reduces system-wide SRMC and also reduces the inter-generator spread in SRMCs – dispatch benefits fall to 6-8 per cent of social benefits, and barely 2-3 per cent of overall consumer benefits
- conversely and symmetrically, the contribution to social benefits of avoided capital and fuel costs from more efficiently located new-entrant capacity increases markedly, from around one-quarter prior to 2036 to around four-fifths from 2036. Over the 2036-2040 period, this one benefit category represents around two-fifths of overall consumer benefits from Reform
- the vast majority of consumer benefits from introducing LMPs relates to pricing congestion; the incremental benefit of also pricing dynamic losses into LMPs is relatively small, with total consumer benefits reduced by 10 per cent over the 2026-2040 period if the current marginal loss factor (MLF) regime is retained instead of adopting dynamic loss factors, and
- as with the benefits of congestion, most of the benefits associated with adopting dynamic losses under Reform occur prior to 2036, as the benefits of adopting dynamic losses relate to more efficient dispatch. As noted above, the extent of dispatch-related benefits is positively related to the size of system SRMC.

Section 2.5 provides a more in-depth discussion, and critique, of each benefit category. We make here the following several points of critique in relation to Table 1:

1. NERA's modelling of No-Reform does not account for the nodal-specific signals currently provided by MLFs. This therefore understates the existing nodal price separation (between LMPs and the regional reference price, RRP), and overstates the extent of nodal price separation between Reform and No-Reform. In turn, this overstates the social and consumer benefits from moving to LMPs, as follows:
    a. Benefits from lower capital and fuel costs are overstated, since generators under No-Reform are incentivised to locate in areas with high MLFs. It is worth noting there is also likely to be a related benefit in terms of reduced congestion, since losses and congestion are positively correlated (albeit not perfectly) given they have the same underlying issue: a lack of network capacity at times of peak generation.
    b. Dispatch benefits are also overstated, since under the current regime generators are dispatched on the basis of their bids *adjusted for their MLF*. Assuming SRMC-based bidding, as the NERA report does, two generators with the same pre-MLF SRMC but different MLFs will be dispatched in a manner that minimises losses under the MLF

[6] Annual pool revenue is estimated by multiplying projected annual operational consumption under the Central scenario in AEMO's *2019 Input and Assumptions workbook v1 5 Jul 20* Excel workbook, with projected volume-weighted average wholesale prices from Figure 3.3 of the NERA report.

regime (see Table 2). It is again worth noting there is also likely to be a related benefit in terms of reduced congestion, since losses and congestion are positively correlated.

c. The wealth transfer from generators to consumers are overstated in three ways. First, under the existing market design, generators get free access to the congestion component of IRSRs, but not to the bulk of the loss component: the loss component of IRSRs are returned to consumers via reductions in network prices, since load MLFs are typically greater than generator MLFs. As such, generators would need to pay to get access to only the congestion component of IRSRs, resulting in lower wealth transfers.

Second, the AEMC's September 2020 COGATI paper[7] notes sales of FTRs would be used to top-up available funds for FTR payouts, to boost FTR firmness, rather than be returned to consumers. And third, there is a presumption generators are making excess return/profits under No-Reform, with these profits 'competed away' under Reform, resulting in generator-to-consumer wealth transfers. Yet, NERA do not disclose their estimates of the level of generator profits under No-Reform and Reform. Moreover, profits under No-Reform might not be excessive were a more appropriate WACC used.

For all these reasons, the estimated generator-to-consumer wealth transfers are likely to be highly overstated.

Table 2 Dispatch with and without accounting for MLFs (ignoring actual losses)

Generator	Bid (MW)	Demand (MW)	SRMC ($/MWh)	MLF	MLF-adjusted SRMC ($/MWh)	Dispatched volumes (MW)	
						Ignoring MLFs	Accounting for MLFs*
A	100	100	10	1.0	10.0	50	100
B	100		10	0.9	11.1	50	0

*as occurs under the existing market design (i.e. No-Reform)

2. NERA's modelling presumes generators do not respond to congestion under the existing market design; that is, NERA's No-Reform modelling does not account for the nodal-specific signals currently provided *for congestion*. Based on Baringa's first-hand experience, debt and equity investors in generation projects are acutely aware of the impact of MLFs and congestion on revenues and profits. This is true for both prospective generators' business case assessments, and for existing generators with upcoming debt refinancing.

   Baringa is aware of several projects whose final investment decision has been or is being delayed due to lenders' concerns about existing and project future levels of curtailment. This is especially the case for utility-scale solar – the very plant NERA argue require the locational signals provided by Reform.

   As noted in Section 2.6, congestion is currently projected over the life of a generation project, and the projected curtailment volumes, along with projected MLFs, are used to size the debt

[7] Previously, the AEMC proposed for these proceeds to be returned to consumers via reductions in network prices. For more details, see AEMC, *Transmission access reform: Updated technical specifications and cost-benefit analysis*, 7 September 2020

portion of the project. Any curtailment (and losses) above or below these projections are borne by the equity investors.

Hence, and in contrast to NERA's presumption, generators *are* aware of congestion, and *do* respond to congestion signals under the existing market design. Therefore, from a modelling and a policy perspective, the question is not whether generators respond to congestion; the question is whether converting this signal into a wholesale price differential price (i.e. the LMP, and the differential between the LMP and the RRP) is likely to result in better locational decisions than the existing volume and price-based, signals for congestion. Similarly, AEMO's bi-annual Integrated System Plan (ISP) provides locational signals for prospective new-entrant generators, based on a co-optimised (least-cost) projection of generation and transmission investment both intra- and inter-regionally.

a. By failing to account for the ways in which congestion is currently incorporated into new-entrant decision making, NERA's benefits of Reform are grossly overestimated.

b. This overestimation would apply to all congestion-related benefit categories in Table 1, especially avoided capital and fuel costs (category #1) and generator-to-consumer wealth transfers (category #7). Together, these represent around 80-90 per cent (i.e. $3.07 billion of the total $3.3 to $3.9 billion) of consumer benefits over the 2036-2040 period.

3. The introduction of nodal pricing is considered costless; despite being titled a "cost-benefit analysis", NERA consider only the potential benefits – and as noted above the benefits seem overstated. Ignoring costs, or worse assuming no costs will arise from Reform, is at odds with the vast majority of the sector's views on Reform. Indeed, the AEMC's interim report acknowledges that NERA's analysis is focused on benefits only and excludes implementation costs. Separately, the AEMC commissioned Hard Software to estimate IT implementation costs. The AEMC describes Hard Software's analysis as "preliminary" cost estimates, and the AEMC acknowledges that more engagement with industry is necessary to obtain detailed estimates of the direct implementation costs of Reform.[8] We agree that more focus and consideration of implementation costs is vital. As noted in various and multiple AEMC stakeholder forums, the industry remains deeply concerned about the costs and complexity of adopting Reform:

- costs of IT and other system changes of adopting Reform, as well as the legal costs from reopening long-dated hedging contracts to reflect the move away from RRPs to LMPs, and
- increased risks due to a potential reduction in contract market liquidity and imperfect hedging of LMP volatility with FTRs. Combined with the previous point, this is likely to increase the weighted average cost of capital (WACC) for both prospective and existing generators, and deter new investment. We note a recent AEMC-led survey of generation investors which showed a 150 basis point increase in the cost of capital under Reform.

We discuss the issue of costs further in Section 3.

In addition, as we discuss in section 2.3, little explanation or justification for NERA's discount rate is provided. Given some of the benefit categories (e.g. capital and fuel cost savings from LMP) are long-dated and largely confined to the 2036-2040 period, the choice of discount rate has a highly material

[8] AEMC, *Transmission access reform: Updated technical specifications and cost-benefit analysis*, 7 September 2020, pp.iii-iv.

impact on the estimated benefits of Reform. We consider NERA's discount rate is around half of what it should be. Using a more realistic discount rate, along with more realistic estimates of the benefits of Reform, our high level calculations suggest the benefits of Reform to be around **80 per cent below** the estimates determined by NERA. Of this 80 per cent:

- around one-third (25 percentage points, ppts) comes from using a more realistic discount rate, and
- the remaining two-thirds (55 ppts) comes from accounting for the locational signals that exist under No-Reform.

This said, it is worth stressing that our estimates of the extent to which NERA's benefits of Reform are overstated have been calculated without the benefit of further market modelling. Market modelling would provide a more rigorous assessment of the extent to which NERA's benefits are inflated.

Further, in relation to transitional arrangements, under the AEMC's proposed framework, FTRs would initially be fully grandfathered to generators, with the amount of FTRs auctioned gradually increasing over the first five years of implementation. Only after five years would all FTRs be auctioned. This means that on day one of the reform, consumers would lose all of the SRA auction proceeds they currently receive (through TUOS offsets) but only gradually gain the proceeds from FTR auctions over time. It does not appear to us that NERA have reflected this aspect of the AEMC's proposed framework within their modelling of consumer benefits moving from No-Reform to Reform.

2.2 NERA's wholesale price outcomes

A final point to note relates to NERA's wholesale price outcomes. NERA's modelling presumes SRMC-based bidding behaviour to project wholesale spot prices from 2026 to 2040. We make the following comments in relation to NERA's wholesale price projections:

- NERA project wholesale spot prices to be c.$30/MWh until 2030. These prices are significantly below price forecasts from other credible forecasters (e.g. Baringa projects SRMC-based prices in the $50-65/MWh range for the rest of the 2020s). NERA's prices therefore do not seem plausible to Baringa.
- NERA's price outcomes seem even less plausible considering there appear to be no account of COVID-related impacts on demand or commodity prices, or indeed any other sources of downside risks to prices. These low prices are also not an outcome of assumed low demand, fuel prices or technology costs, as NERA use AEMO's Draft ISP 2020 and ESOO 2019 for its input assumptions. Baringa uses largely the same input assumptions as NERA, yet arrives at projected spot prices during the 2020s more than double those of NERA.
- From 2032, NERA's prices steadily rise to ~$90/MWh by 2040 (under No-Reform or around ~$100/MWh under Reform), which is above other consultants' price forecasts, including those of Baringa. Using SRMC-based bidding behaviour, Baringa's wholesale spot price projections are in the vicinity of $80/MWh for 2040.

While NERA's cost-benefit analysis is based on the change (i.e. the 'delta') in wholesale prices between No-Reform and Reform, rather than the level of prices, the wide divergence of NERA's price projections with those from other credible forecasters including our own does raise questions about the credibility of NERA's estimated benefits of Reform.

2.3 Impact on consumers is not based on spot market price outcomes

The approach to estimate the consumer benefits of Reform adopted by NERA is to the sum their estimated social benefits and wealth transfers (from generation to consumers).[9] Social benefits are calculated as the net reduction in total system costs, and in the case of improved competition, the additional consumer surplus resulting from increased consumption/generation of electricity.

All reductions in total system costs are assumed to ultimately pass through to consumers under NERA's method. The reverse is also true. NERA assume all increases in total system costs are ultimately paid for by consumers. While that may appear to be a reasonable assumption, it produces the following counterintuitive outcome from NERA's modelling – spot prices under No-Reform are forecast to be lower than under Reform however consumers do not benefit from these lower spot prices.

NERA's forecasts of spot market prices out to 2040 under the Reform and No-Reform scenarios are contained in Figures 3.3 and 3.11, respectively, of the NERA report. NERA forecast broadly comparable (average) spot market price outcomes under both scenarios throughout the 2020's and the early 2030's. Where the forecasts substantially differ is in the 2036-2040 period:

- under the Reform scenario the VWAP which would be paid by non-scheduled load (and RRP which has been calculated for comparison purposes) climbs to around $100/MWh, with the GWAP climbing to over $80/MWh
- whereas under the No-Reform, the RRP which would be paid by load (and received by generation) does not climb higher than ~$85-90/MWh

Under the No-Reform scenario, NERA estimate there would be 20GW of additional generation, mostly solar, relative to the Reform scenario. It would appear that this extra generation pushes down spot market prices under the No-Reform scenario. Rather than any of that additional total system cost being shared between generation and consumers, NERA assume that generators would somehow find a way to fully recover the system costs of that additional 20GW of capacity, despite NERA modelling that additional capacity instead leading to lower spot market prices.

2.4 Discount rate is demonstrably too low

NERA use a 7% p.a. rate to discount future values back to present values (i.e. based on 2020-year prices). As NERA note (see note to Table 3.2 in the NERA report), this discount rate is based on a WACC of 5.9% p.a. As an aside, we note it is odd for the discount rate to not be equal to the WACC, since the WACC *is* the discount rate in an NPV calculation.

Furthermore, and more importantly, the WACC is assumed to be the same in both Reform and No-Reform. There is no discussion of whether this WACC is pre-or post-tax; we assume it is real as it is the basis for the discount rate, and all present values are expressed in constant, 2020-year prices. There is also no discussion by NERA of the source for either the assumed WACC or the assumed discount rate.

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[9] With an adjustment to net off the estimated producer surplus element of the social benefits on the basis that the producer surplus is retained by generators.

Because NERA is discounting estimated benefits out to 2040 back to present value, the choice of discount rate has a highly material impact on NERA's estimated benefits. Given this materiality, the methodology and quantification of the discount rate used by NERA deserves appropriate justification, which is lacking in NERA's report.

To demonstrate the materiality of the discount rate choice to NERA's estimated benefits, Baringa recalculated NERA's estimates for the two benefit categories associated with the impact of reforming locational signals on investment generation and storage (capital and fuel cost savings; and wealth transfer). In the sensitivity analysis below only the discount rate is changed from NERA's analysis. The impact of just a 1% increase or decrease in NERA's 7% discount rate on these benefit categories results in a range of benefits ~$630m lower to ~$750m higher than NERA's estimated benefits. The higher the discount rate the lower the estimated benefits of reform. This is relevant as Baringa considers NERA's chosen discounted rate is demonstrably too low.

Table 3 The sensitivity of NERA's estimated benefits to changes in the discount rate

	NPV of Benefits (2020$m) 2026-2040		
Discount rate	**Cost difference**	**Wealth transfer**	**Revenue difference**
5%	$647	$980	$1,627
6%	$295	$451	$746
7%	$0	$0	$0
8%	-$249	-$385	-$633
9%	-$458	-$714	-$1,172
10%	-$636	-$996	-$1,631
11%	-$786	-$1,238	-$2,024
12%	-$913	-$1,447	-$2,361

Source: NERA report (p.36), Baringa analysis

Baringa notes a generator WACC of 5.9% is lower than other estimates of generator WACCs, even on a post-tax basis. We make the following two observations:

1. A WACC of 5.9% p.a. even under No-Reform is well below publicly-available estimates of existing WACCs for generators in the NEM. Rai and Nelson (2020)[10] conducted a survey of investors in the generation sector between April and June 2020, and found WACCs to range between 8% and 13% p.a. (on a real, pre-tax, basis), depending on the extent to which generators were diversified horizontally and/or vertically.
    a. For example, WACCs for diversified generators were in the order of 8-10% p.a., compared to 10-13% p.a. for undiversified participants
2. A WACC of 5.9% p.a. under Reform is even further below estimates of the likely WACCs faced by generators in the NEM if the nodal pricing reforms were to eventuate. Survey participants in the Rai and Nelson study, which collectively have invested in or operate around one-quarter

[10] Rai, A., and Nelson, T., 2020, Financing costs and barriers to entry in Australia's electricity market, *Journal of Financial Economic Policy*, forthcoming. Available at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3692295

of installed utility-scale generation capacity in the NEM, considered their WACCs would increase by 150-200 basis points p.a. if nodal pricing is introduced.

a. Applying a 150 basis point uplift to a conservative assumed WACC of 11% p.a., suggests a generator WACC of 12.5% p.a., more than double the WACC NERA used

b. The increase in WACC would increase system costs under Reform, and in turn reduce the benefits of Reform vis-à-vis No-Reform. WACC impacts is an important issue neglected by NERA, which we discuss in detail in section 3.1.

Given the preceding discussion, we consider a pre-tax real WACC of around 8.5% p.a. would be an appropriate, yet conservative, discount rate under No-Reform. And, as discussed in section 3, a pre-tax real WACC of 9.9% p.a. would be an appropriate discount rate under Reform.

Assuming the future value of NERA's estimated benefits remain unchanged – a simplifying, yet highly unrealistic assumption given the increase in system costs arising under a higher WACC – applying a 9.9% p.a. discount rate to the future value of NERA's estimated consumer benefit would result in the NERA-estimated benefits over the 2026-2035 period being 12 per cent lower, and **10 per cent lower** over the entire 2026-2040 period.

2.5 Estimated benefits by benefit category

2.5.1 Capital and fuel cost savings

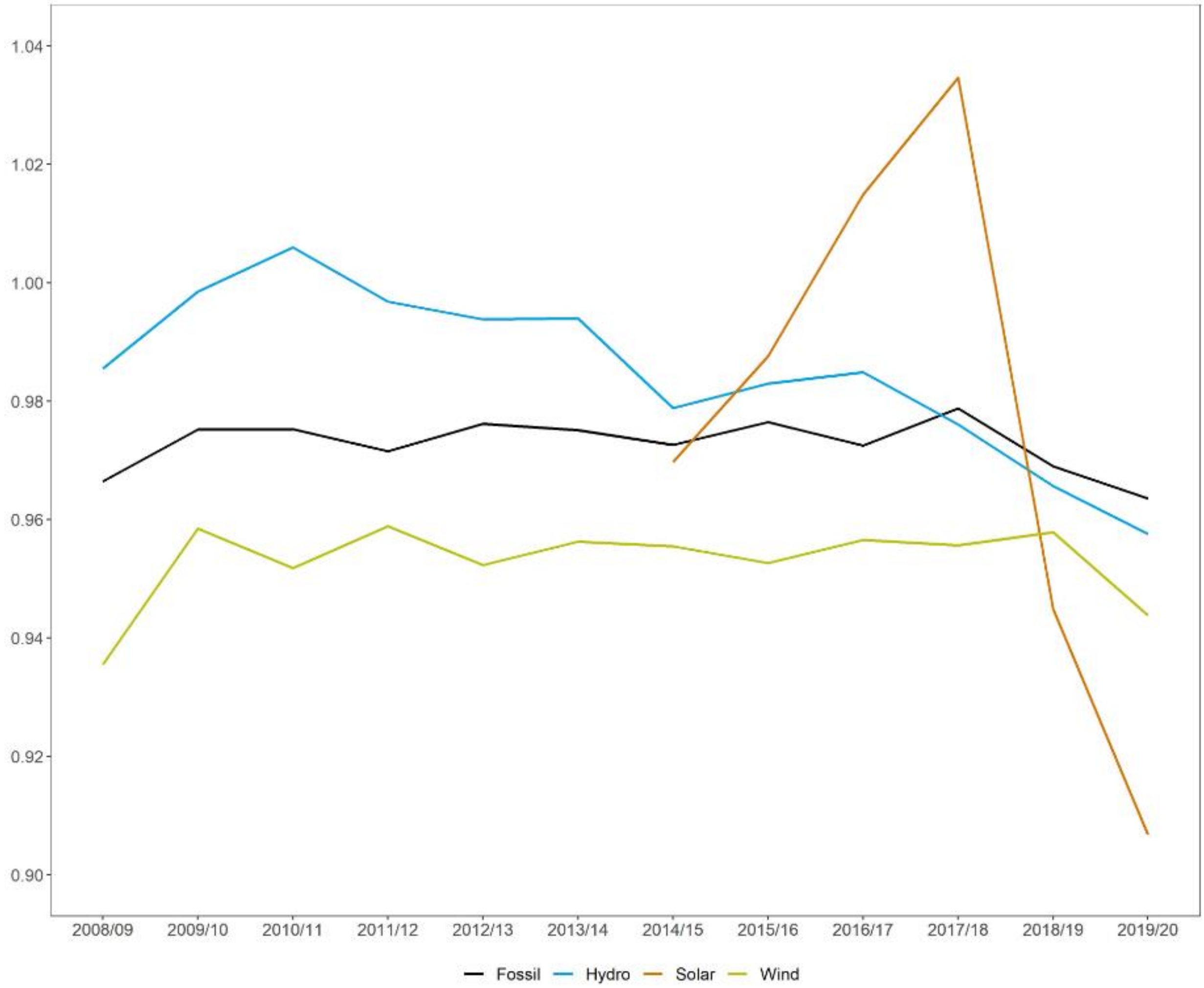
As noted in Section 2.1, the apparent presumption behind the NERA modelling is that generators are currently not incentivised to locate in areas with relatively less congestion and losses. In the NERA modelling, generators enter in response to the reduction in their capital costs from the "nodal subsidy". The nodal subsidy reflects the allocation of IRSRs that generators receive for free under No-Reform. As noted in Appendix A.1, this "nodal subsidy" has three components:

1. The congestion component of the IRSRs – the increase to generator revenues under No-Reform/RRN-based pricing due to congestion not being priced into LMPs
2. The loss component of the IRSRs – the increase to generator revenues under RRN-based pricing due to dynamic losses not being priced into LMPs; instead, the LMP-RRP price separation that *does* occur under RRN-based pricing reflects MLFs. However, as noted in Appendix A, the losses-related allocation of residues to generators are *transitory* in nature.
3. A volume dilution component reflecting the increase in dispatch inefficiency (i.e. increased disorderly bidding) under No-Reform, as more generators move into an area, in turn increasing congestion and thereby resorting to disorderly bidding. This would decrease the nodal subsidy.

The third component links in with our point, made in Section 2.1 and reinforced below in Section 2.6, that there are congestion signals currently in place in the NEM, and generators do respond to these signals as congestion has a direct, adverse impact on generators' revenues and profits.

However, MLFs and existing, volume-based, congestion signals dilution effects seem to be both ignored in NERA's calculations of the "nodal subsidy", leading to this subsidy being significantly overstated.[11] Solar and wind MLFs were well below 1.0 for FY2020 (Figure 2).

Figure 2 Historical MLFs in the NEM, by fuel type*



* Equally-weighted average of individual-generator MLFs, for each generator in the NEM, by fuel type.
Source: Figure 2.2 from AEMC, Transmission loss factors, Consultation paper, 6 June 2019

NERA estimate the size of the "nodal subsidy" to increase over time, from \$3-4/kW in the mid-2020s to nearly \$20/kW by the end of the period, especially for wind and solar PV (see Figure 3, sourced from Figure 3.6 of the NERA report).[12]

Accounting for MLFs in NERA's nodal subsidy calculations, based on a generation-weighted average MLF of FY2020 MLFs in Figure 2, Baringa's estimate is NERA's resulting nodal subsidy would be around

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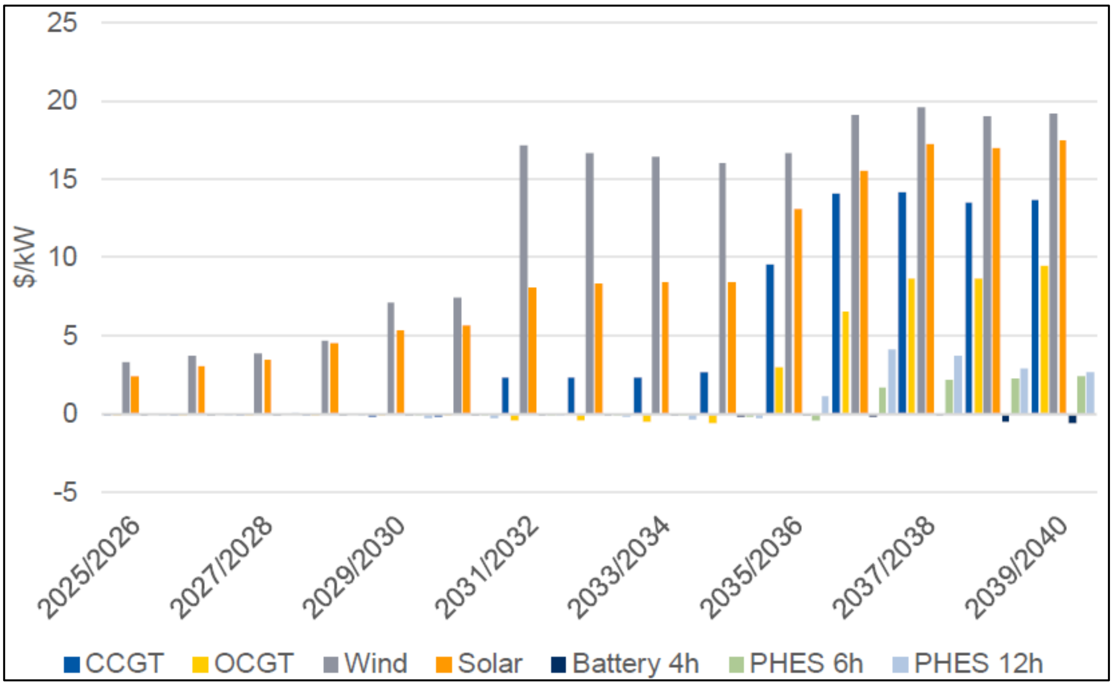
[11] Using the formulation in Appendix A.1, NERA's nodal subsidy equals $\left(P^{j,v}_{RRN,t} - P^{j}_{i,t}\right)\cdot Q^{j}_{h,RRP,t}\cdot DLF^{j}_{h,i,t} + P^{j,v}_{RRN}\cdot Q^{j}_{h,RRP,t}\cdot\left(1 - DLF^{j}_{h,t}\right)$, when it should equal: $\left(P^{j,v}_{RRN,t} - P^{j}_{i,t}\right)\cdot Q^{j}_{h,RRP,t}\cdot DLF^{j}_{h,i,t} + P^{j,v}_{RRN}\cdot Q^{j}_{h,RRP,t}\cdot\left(MLF^{j}_{h,i,T} - DLF^{j}_{h,t}\right) + P^{j}_{i,t}\left(Q^{j}_{h,RRP,t} - Q^{j}_{h,i,t}\right)\cdot DLF^{j}_{h,i,t}$.

[12] Note the discrepancy between "\$/kW" label in Figure 3, and reference to "\$/MWh" in the NERA report (see p.28).

65 per cent lower than shown in Figure 3. Given the direct link between the nodal subsidy and the benefits of avoided capital costs in Table 1, accounting for MLFs is likely to result in a proportionally similar drop (i.e. 65 per cent) in the magnitude of these benefits.

Furthermore, we consider our estimates of NERA's inflation of benefits to be conservative, given that MLFs for wind and solar PV are likely to decline, as per NERA's analysis which shows load factors for wind and solar PV falling by 20-25 per cent over the FY2026 – FY2040 period (see Figure 3.10 of the NERA report). That said, it is worth stressing that our estimates of the extent to which NERA's benefits of Reform are overstated have been calculated without market modelling. Market modelling would provide a more rigorous assessment of the extent to which NERA's benefits are inflated.

Figure 3 NERA's estimates of locational subsidies under No-Reform, by technology type



Source: Figure 3.6 from NERA report

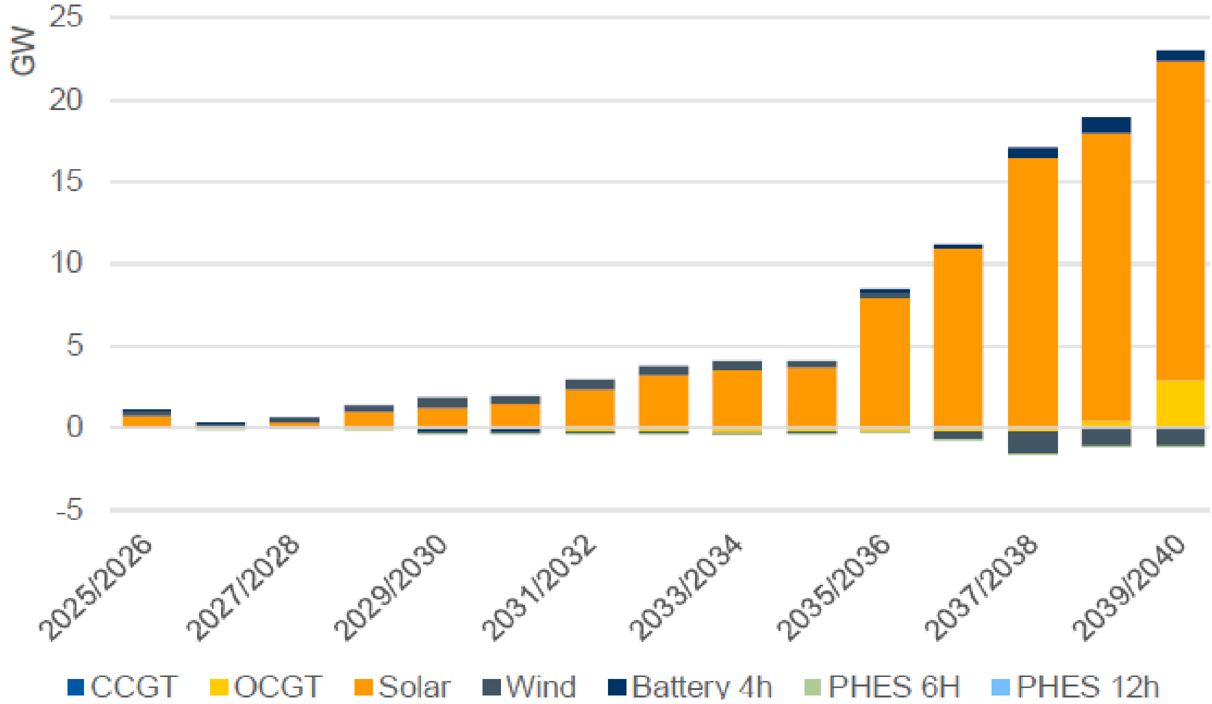
NERA's avoided capital and fuel costs under Reform would be even more inflated were congestion-based signals under No-Reform are taken into account. As discussed in Section 2.6, based on Baringa's experience banking multiple projects in the NEM, congestion is projected over the life of a project, and the projected curtailment volumes, along with projected MLFs, then determine the project's expected net present value (NPV) and, ultimately, the project's business case.

Therefore, understanding how generators are financed in the NEM, and the considerations undertaken to determine their 'financeability', is essential to understanding the means by which losses and congestion currently provide locational signals to prospective generators in the NEM. Establishing an appropriate counterfactual for the No-Reform scenario is important to be able to estimate the benefits of Reform against.

From a modelling perspective, it seems NERA have not sought to undertake either projected curtailment or projected MLF modelling, to determine the level of curtailment and losses for each project under No-Reform. Taking account of these projections would reduce the volume of new-entrant capacity under No-Reform and in turn reduce the extent of the overbuild under No-Reform vis-à-vis Reform.

It is noteworthy that despite NERA estimating that wind generators are the dominant recipient of locational subsidies under the No-Reform scenario, NERA's estimated benefits from Reform predominantly relate to less investment in solar generation. Under the No-Reform scenario, NERA estimate there would be an additional 20 GW of generation capacity by 2040, which is almost exclusively additional solar generation, as can be seen in the figure below (sourced from Figure 3.8 of the NERA report).

Figure 4 NERA's estimates of additional generation under No-Reform, by technology type



NERA explain this outcome as wind, whilst receiving the highest subsidies on average, does not receive enough subsidies in commercially viable nodes and is therefore displaced by the larger investment in solar generation capacity.

We consider a factor that may be contributing to this outcome for solar concerns the locational restrictions by generation type which are input assumptions into NERA's modelling. These assumptions are set out in the table below. For new wind, gas, coal and pumped hydro generation, NERA adopt a series of assumptions intended to provide a plausibly filter over the practical limitations of where new generation could locate taking into account terrain and whether the node is located in a metropolitan area. For wind, NERA also takes into account the locational investment signal provided by the ISP and assume that new wind generation would only occur within REZs because it would not be realistic or profitable for new wind generation to build outside REZs.

On the other hand, there appears to be only one restriction on new solar which is it cannot be built at a node with existing hydro generation. For example, if high LMPs in a metropolitan area (due to high demand at that node exceeding supply) suggested it would be financially advantageous to build a new solar farm in the middle of a metropolitan region, NERA's modelling does not appear to restrict this implausible outcome. Further, and most importantly, the locational informational signal that the ISP provides for new solar generation has not been taken into account, unlike for wind.

NERA give no weight to the role that AEMO's Integrated System Plan (ISP) has in guiding locational investment decisions for solar generation under the current regime. Yet Baringa's experience working with solar developers reveals the ISP is important in guiding the locational decisions of these developers as is the case for wind developers.

Table 4 NERA's location restriction assumptions for new generation, by technology type

	REZ locations	Metropolitan locations	Mountainous locations
Solar	No restrictions. New solar generation located within and outside REZs	No restrictions. New solar generation located within and outside metropolitan areas	No new solar at locations with existing hydro generation
Wind	New wind generation only within REZs	New generation constrained to within REZs so excludes metropolitan areas	New wind generation only located in mountainous region if within REZs and excluding areas with existing hydro generation
CCGT & OCGT	No new thermal generation in REZs	New thermal generation constrained to existing nodes with thermal generation outside metropolitan regions	New thermal generation constrained to existing nodes with thermal generation
Coal	No new coal in the NEM	No new coal in the NEM	No new coal in the NEM
Battery	No restrictions	No restrictions	No restrictions
PHES	Constrained to existing areas with hydro generation	Constrained to existing areas with hydro generation so excludes metropolitan locations.	Constrained to existing areas with hydro generation

Source: NERA report

2.5.2 Improved dispatch efficiency

Based on the NERA report, it appears to Baringa that the same premise that results in inflated "nodal subsidies" also results in inflated dispatch inefficiencies – namely, generators are assumed to not be incentivised to locate in less-congested and less-'lossy' areas under No-Reform. In NERA's modelling, this presumed lack of locational incentive results in generators increasingly being sited behind network constraints, resulting in increased instances of disorderly bidding.

In addition to the above comments about the locational incentives (for both congestion and losses) faced by generators under the existing market design – comments borne out by Baringa's lived experience advising generation developers and their debt and equity investors – we make the following additional comments:

- The premise of NERA's analysis is that coal and hydro generation have the strongest incentive for race-to-the-floor bidding, therefore disorderly bidding is a significant problem now given the current generation mix, though the problem will decrease over time as more variable renewable (low-SRMC) capacity is added to the system. However, NERA's analysis is based solely on modelled future behaviour, rather demonstrating the materiality of disorderly bidding using current and past actual generator behaviour and market outcomes. Disorderly bidding requires congestion among generators with diverse SRMC – which exists currently. Yet there is no discussion or analysis of historical bidding behaviour by NERA or the AEMC.
- Related to the first point, NERA cites a study by Matthew Katzen and Gordon Leslie[13] on the extent of historical 'overcompensation' (defined as instances of LMPs being below RRPs) in the NEM, as evidence of the magnitude of disorderly bidding. Yet, Katzen and Leslie's findings speak more to NERA's "nodal subsidy", not "disorderly bidding": Katzen and Leslie show wind and solar PV as deriving the greatest benefits under existing RRP-based pricing, rather than higher-SRMC plant.
- The benefits from removing disorderly bidding drop sharply as the penetration of low-SRMC generators rises, with only $95 million of modelled benefits over the 2036-2040 period (see Table 1). This is equivalent to $23 million p.a. of benefits (using NERA's 7% discount rate), barely 0.2 per cent of estimated annual pool revenues.[14] Over the entire 2026-2040 period, NERA's estimated dispatch efficiency benefits are $87-112 million p.a., less than 1 per cent of estimated annual pool revenues.

Baringa has sought to identify a metric based on commonly observable market outcomes that can be used to test the materiality of disorderly bidding over time to assess the extent to which the proposed reforms are seeking to address "yesterday's problem", rather than addressing some of the current and emerging challenges in the NEM. Measuring the changes in negative settlement residues over time is a possible metric.

In the AER's opinion, counter-price flows on an interconnector is commonly caused by disorderly bidding by generators close to an interconnector.[15] Counter-price flows mean that electricity is flowing

[13] Katzen, M. and Leslie, G., 2019, Siting and operating incentives in electrical networks: a study of mispricing in Australia's zonal market, https://ssrn.com/abstract=3501336

[14] Annual pool revenue is estimated by multiplying projected annual operational consumption under the Central scenario in AEMO's *2019 Input and Assumptions workbook v1 5 Jul 20* Excel workbook, with projected volume-weighted average wholesale prices from Figure 3.3 of the NERA report.

[15] AER, Special report – The impact of congestion on bidding and inter-regional trade in the NEM, December 2012, pp.6-7. As the AER explains, AEMO is required under the rules to use reasonable endeavours to manage the accumulation of negative inter-regional settlement residues when the accumulation reaches $100 000. This

from high price regions to low price regions, and consequently AEMO collects less revenue from load (in low price regions) than it pays out to generators (in high price regions), resulting in negative settlement residue. The costs of funding negative settlement residues are imposed on the TNSP in the importing region, and ultimately, passed on to consumers.

Back in 2012, the AER published a Special Report on the impact of congestion on bidding and inter-regional trade in the NEM. Between the three-year period of December 2009 and December 2012, the AER estimated that there were almost $34m of negative settlement residue that occurred and this figure relates only to counter-price flows between NSW and Victoria. The figure for the entire NEM would have been larger.

In contrast, over the last three years, the amount of negative settlement residue across the entire NEM is less than half that amount at ~$18m. And this comparison is in nominal dollars. Adjusting for the time value of money, the relative comparison of recent negative settlement residues to this historical period when there was AER concern over disorderly bidding would be even more stark.

Accordingly, this analysis suggests that, using negative settlement residues as an indicator of the magnitude of any disorderly bidding, that this has reduced significantly over time.

Even under NERA's modelling, the benefits of eliminating the presumed disorderly bidding is transitory in nature, and largely dissipate as more low-SRMC variable renewable capacity is built. Further, NERA's modelling of the benefits from eliminating disorderly bidding does not take into account the increased transmission and interconnector capacity likely to be made in accordance with the ISP. Therefore, even under the No-Reform counterfactual scenario, this increased transmission capacity would likely further reduce congestion and reduce the opportunities for disorderly bidding.

Table 5 Negative settlement residue ($m)

		NSWQLD	QLDNSW	SAVIC	VICSA	NSWVIC	VICNSW	Total
2017	**Q3**	$0.00	$0.00	-$0.24	$0.00	-$0.02	-$0.14	-$0.40
	Q4	$0.00	-$0.01	-$0.29	$0.00	-$0.04	-$0.02	-$0.36
2018	**Q1**	-$0.01	-$0.01	-$0.09	-$0.01	-$0.03	-$0.08	-$0.22
	Q2	$0.00	-$0.02	-$0.80	$0.00	-$0.21	-$0.05	-$1.08
	Q3	$0.00	-$0.02	-$1.56	-$0.03	-$0.03	-$0.06	-$1.69
	Q4	-$0.03	-$0.54	-$0.09	$0.00	-$0.02	-$0.25	-$0.93
2019	**Q1**	-$0.03	-$0.01	-$0.26	-$0.03	-$0.57	-$1.69	-$2.59
	Q2	-$0.01	-$0.58	-$0.11	$0.00	-$0.02	-$0.58	-$1.30
	Q3	-$0.07	-$2.08	-$0.15	-$0.09	-$0.02	-$0.74	-$3.16
	Q4	-$0.01	-$0.10	-$0.35	-$0.12	-$0.01	-$2.31	-$2.90
2020	**Q1**	-$0.01	-$0.06	-$0.74	-$0.10	-$1.69	-$0.63	-$3.23
	Q2	$0.00	-$0.29	-$0.07	-$0.02	-$0.01	-$0.04	-$0.43
Total		-$0.17	-$3.72	-$4.75	-$0.42	-$2.66	-$6.58	-$18.30

Source: AEMO quarterly settlement residue auction reports

is achieved by invoking constraints on interconnectors to limit or 'clamp' exports from the high priced exporting region into adjoining region(s). At times this is ineffective (with counter-price flows continuing to occur) as power system security (the management of network elements and generator technical parameters such as ramp rates) takes precedence over the management of counter-price flows.

2.5.3 Introduction of dynamic losses

NERA estimate the introduction of dynamic losses would result in $660m of consumer benefits over the 2026-2040 period, a 12 per cent share of overall consumer benefits. These benefits arise from dispatch or operational efficiencies, namely:

- less generation from plants with dynamic loss factors (DLFs) lower than their MLFs,[16] and
- more generation from plants with DLFs higher than their MLFs.

However, NERA's estimated benefits of introducing dynamic losses are overstated for the following reasons:

- The potential benefits from introducing dynamic loss factors apply year-by-year, since MLFs are a volume-weighted average of DLFs (as discussed in Appendix A). That is, to the extent that a generator's DLF over year *t* differs systematically from its MLF for year *t*, this discrepancy is removed in year *t+1*, since MLFs are re-calculated using actual losses from year *t*.
- NERA focus on the potential improvements in generator *operational* decision making, and overlooks the implications of DLFs for *investment* decision making. As discussed in Appendix C, MLFs are a key determinant of a projects' debt-carrying capacities, which in turn impacts the financeability and viability of projects. And as discussed in Appendix B, more volatile MLFs increase a project's revenue volatility and in turn increase its WACC – a standard outcome from corporate finance.

  Since MLFs are a volume-weighted average of DLFs, MLFs are, by definition, less volatile than DLFs. Therefore, a generator's revenue volatility would be higher under DLFs than MLFs. This, in turn, means WACCs would be higher under Reform vs. No-Reform. By overlooking the implications of DLFs for financing generation projects, NERA's analysis ignores the potential impact of a more volatile DLF regime on generator WACCs. This oversight is especially glaring given the AEMC's September 2020 technical report noted the AEMC's preference that FTRs *not* hedge dynamic losses.[17] This means the issues with respect to revenue volatility and associated financeability issues under a DLF regime remain a live issue, since FTRs would not hedge for dynamic losses.
- Finally, as NERA notes (see p112 of their report), their benefits likely overstate the dispatch inefficiency under No-Reform, since these benefits include price and volume distortions, whilst in practice AEMO mitigates most of the volume distortion by forecasting demand gross of losses.

2.5.4 Wealth transfers (including competition-related transfers)

Two other benefit categories in the NERA report relate to competition-related "wealth transfers", and generator-to-consumer wealth transfers. These transfers are defined as reductions in electricity prices that do not occur due to a change in the underlying volume of electricity generated/consumed or from

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[16] For the avoidance of doubt, DLFs here are different to the more common usage of that acronym which is for distribution loss factors.

[17] https://www.aemc.gov.au/sites/default/files/2020-09/Interim%20report%20-%20transmission%20access%20reform%20-%20Updated%20technical%20specifications%20and%20cost-benefit%20analysis%202020_09_07.PDF. See Section 3.8.5

a reduction in the costs of electricity production – in short, these "wealth transfers" relate to the reduction in generator profits/returns between No-Reform and Reform, due to:

- Greater and more effective competition in the generation and retailing sectors under Reform compared to No-Reform ("competition-related wealth transfers"). These wealth transfers are, effectively, from incumbent generators to new-entrants, and then to consumers. They are estimated by NERA to be up to $1.6 billion over the 2026-2040 period, though NERA acknowledge these benefits could also be as low as zero (see Table 1).

  This enhanced competitiveness seems to be a direct and automatic consequence of NERA's assumptions that FTRs are firm – which improves contract market liquidity, reduces transaction costs and risks, and in turn reduces barriers to entry under Reform. However, as we discuss in sections 3.1 and 4.1, it is far from certain that FTRs would be firm; indeed, we have concerns, as expressed below, that the proposed measures to provide FTR firmness are insufficient. Indeed, if FTRs are not firm and this leads to a decline in contract market liquidity, in turn, this could increase barriers to entry and reduce competition. Liquidity may become fractured and competition reduced as a consequence of contract volumes gravitating towards each generator's LMP, as they seek to diversify their exposure between the LMP and RRP.

- Wealth transfers from incumbent generators to consumers, which occur not from benefits of competition, but rather from requiring generators to pay for the settlement residues, by purchasing FTRs, they currently receive for free under regional/zonal pricing. These purchase costs are then passed through to consumers via lower network prices. These wealth transfers are estimated by NERA as being significantly larger than the competition-related wealth transfers, with NERA-estimated benefits of almost $3 billion over the 2026-2040 period (see Table 1).

These two sets of wealth transfers, which comprise more than half of the overall consumer benefits under NERA's 'High' scenario, make the following critical assumptions:

- Reform reduces barriers to entry into the generation sector relative to No-Reform, such that the increased competitive tension under Reform limits generators' ability to pass through FTR purchase costs to consumers
- Incumbent generators earn excess returns under No-Reform, with these profits then eroded under Reform via new-entry of generators and via needing to purchase FTRs. Furthermore, under Reform, generators earn, at worst, zero excess returns.

The requirement for excess returns under No-Reform, and lower (but not negative) excess returns under Reform, are both important, as together they prevent generators from exiting following the increase in their costs from the introduction of Reform. If excess returns were to become negative under Reform (i.e. expected returns are less than the cost of capital), then subsequent generator exits would increase the costs to consumers, and lower the consumer benefits, from implementing Reform.

Thus, the magnitude of these wealth transfers stems from a view held by NERA that competition would be enhanced and made more effective under Reform vs. No-Reform, and that generators exercise significant market power – and in turn earn significant profits – under No-Reform, which will be lessened under Reform.

Baringa challenges both of these assertions and assumptions with the following points:

- The bulk of stakeholders view the AEMC's proposed reforms as highly complex and likely to increase barriers to entry into generation and retailing. This is evidenced by an AEMC survey showing generation sector investors considered Reform would increase their cost of capital by 150 basis points (an increase of 15%). Concerns about FTR firmness is a key aspect of these views.
- The complexity of the proposed reforms means there is a high chance of smaller, non-integrated generators and retailers being competitively disadvantaged relative to vertically- and horizontally-integrated rivals. Concerns about a lack of FTR firmness and liquidity are likely to create further incentives to integrate horizontally and vertically; that is, to hedge inter-nodal risks internally, rather than externally by trading FTRs. These incentives to integrate already exist under No-Reform, given the ongoing decline in contract market liquidity over the past few years, and the incompleteness of existing contract markets.
- There is no reporting or analysis by NERA of the level of generator profits under each of No-Reform and Reform, to aid in determining the level of any economic profit existing under either scenario. This is an important omission, given the criticality of NERA's assumption that generators' profits are eroded under Reform, yet generators do not exit following its implementation. We make the following three related points:
    1. The bulk of assessments on the effectiveness of competition in generation and retail markets – including assessments done by the AEMC – conclude retail and generation markets to be workably competitive[18], such that there are limited (or no) excess returns being earned, at least on a sustained/non-transitory and structural basis. This in turn means any excess returns under No-Reform would be, at best, transitory and therefore unlikely to serve as the basis for any generator-to-consumer "wealth transfers"
    2. A higher, more realistic, WACC under No-Reform would reduce the size of any excess returns under No-Reform, and in turn reduce generator-to-consumer wealth transfers.
    3. An increase in WACC under Reform would raise barriers to new-entrants, and possibly encourage exits from incumbents who are unable or unwilling to refinance their debt at the higher cost of debt capital. This in turn would detract from competition in the generation sector – reducing generator-to-consumer wealth transfers – and also increase system costs under Reform, both of which would reduce the benefits associated with Reform.

All of this means the increased costs associated with Reform are highly likely to be passed through to consumers, as there is likely to be limited excess returns to erode without impacting generator entry and exit decisions. Therefore, the AEMC's proposed reforms are likely to worsen the effectiveness of competition in the generation and retailing sectors, and the "wealth transfers" purported by NERA to arise under Reform, are highly likely to not materialise to the extent estimated by NERA.

[18] For the retailing sector, see the annual AEMC *Retail energy competition* reports; for the generation sector, see the AER's biannual *Wholesale electricity market performance* reports. The AEMC's latest (2020) report is available at https://www.aemc.gov.au/market-reviews-advice/2020-retail-energy-competition-review. The AER's latest (2018) report is available at https://www.aer.gov.au/wholesale-markets/performance-reporting/aer-wholesale-electricity-market-performance-report-2018

2.6 Congestion signals currently exist and generators do respond to them

Baringa has undertaken market modelling for over 50 projects in the NEM as an input into determining projects' business cases and investment decisions. This experience is instructive for understanding both:

- the signals for congestion in place under the current market design (i.e. 'No-Reform'), and
- how prospective new-entrant generators respond to these signals, with responses ranging from not proceeding (and potentially then considering other locations in the NEM) through to proceeding but with a lower level of debt capital to finance the project.

This section outlines the considerations involved in a new-entrant generator's investment decisions, and how congestion feeds into these considerations and, ultimately, a project's business case. While the proceeding discussion is focused on prospective new-entrant generators, these considerations are of course also relevant for existing generators (who consider actual revenues and actual costs).

2.6.1 Considerations involved in a generator's investment decision

Prospective new-entrant generators base their investment decisions on the expected NPV of their project (and the sensitivity of the project's NPV to changes in key assumptions such as future demand, commodity prices and competitors' technology costs). The NPV is a function of a generation project's:

1. Expected revenues
2. Expected costs
3. WACC

The location of a prospective generator plays a key role in influencing all three of these variables. As discussed in more detail in Appendix B, expected revenues are based on three factors:

1. Generation profiles – this determines the timing and volume of output. In combination with projected future wholesale electricity prices, this determines the generator's projected spot market revenues, for every trading interval over the life of the project. This calculation is done prior to taking account of any losses or congestion at that location/site. All else equal, locations that yield superior generation profiles (i.e. higher capacity factors) are preferred.
2. MLF projections – MLFs have a direct, one-to-one, impact on generators' expected revenues. All else equal, locations with lower losses (i.e. higher MLFs) are preferred
3. Curtailment projections – locations with less projected curtailment are preferred

These three considerations are 'co-optimised' to find the most desirable location in the grid for a prospective project. This co-optimisation is especially relevant for VRE projects, due to the historical development of the transmission network in the NEM, areas with superior resource availability (i.e. better generation profiles) are typically those with low MLFs and/or high projected curtailment (i.e. areas with insufficient network capacity). Given this network topology, for VRE generators the 'co-optimisation' involves trading off sites that can yield higher generation capacity factors yet lower network hosting capacities.

Generators will stop moving into a particular location once the expected revenues decline. Assuming no change in generation profiles, the reason for this expected revenue decline and cease of additional new-entrant capacity entering a particular location would therefore be due to point 2 and/or 3.

In terms of the AEMC's proposed nodal pricing reforms, and in NERA's Reform scenario, LMPs would be the price-equivalent of points 2 and 3. However, in both No-Reform and Reform, location remains very relevant to generators' investment decisions.

2.6.2 The impact of expected congestion on a project's business case

Based on Baringa's experience, congestion is projected over the life of a project, and the projected curtailment volumes, along with projected MLFs, then determine the project's:

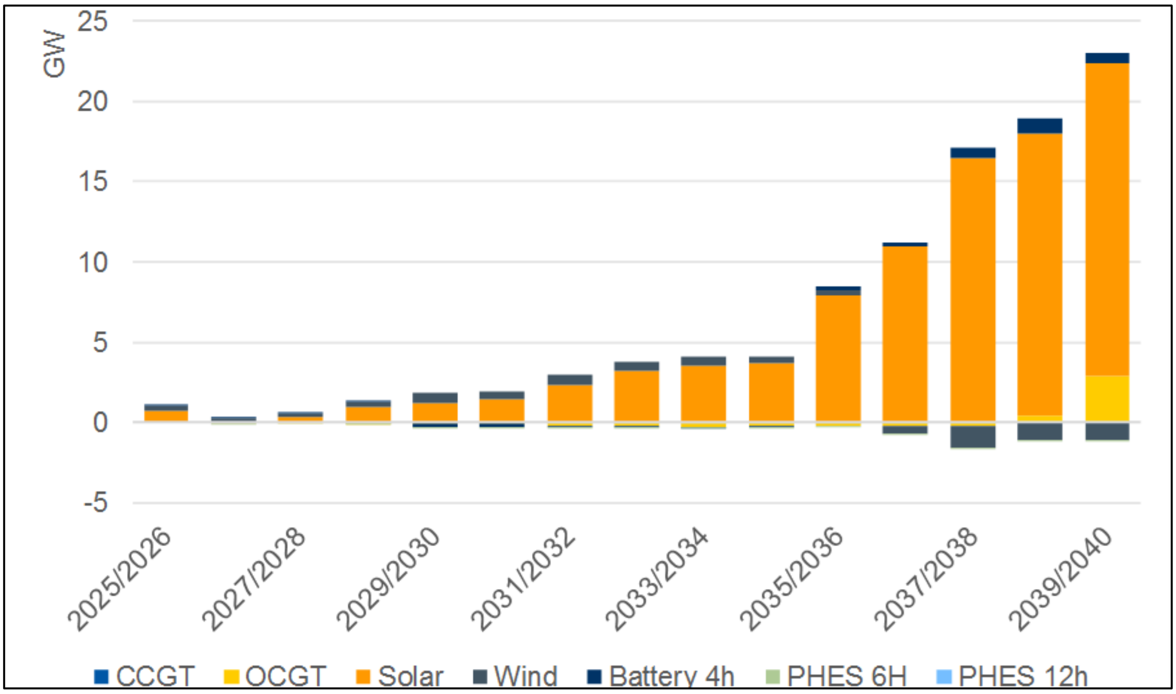
- Expected generation-weighted average (GWA) spot price expected over the next thirty years – For all generator types, the typical assumption is they will be curtailed at their SRMC, which for renewables is assumed to be $0/MWh because of their zero fuel cost and because forward large-scale generation certificate (LGC) prices are projected to fall to zero post-2025. As discussed in Appendix C, Baringa does detailed and rigorous constrained-equation modelling to ascertain the level of projected congestion, using the very same constraints NERA note it has factored into its market modelling (i.e. thermal ratings-based constraints allowing for credible contingencies).
- Expected dispatched output – This is directly reduced by the level of projected curtailment and by the extent to which the project's MLFs are less than 1.0 in value. This then determines the project's expected cashflows (i.e. the numerator in an NPV calculation).
- WACC (i.e. the denominator in the NPV calculation), with the level of projected curtailment inversely related to the project's financial leverage – That is, the debt portion of the total invested financial capital in the project is sized proportional to the level of expected output 'lost' due to MLFs and congestion. A lower level of debt means a higher proportion of more expensive equity capital is needed to fund the project, resulting in a higher overall WACC for the project.

Projected curtailment/congestion therefore has a direct impact on a project's business case, which is why there is so much attention on current and projected levels of curtailment. This is especially the case for VRE plant, for whom congestion has a direct effect on actual and expected revenues, since:

- VRE generators are price-takers as they cannot control their 'fuel' consumption, and so find it difficult to withhold generation at times of high congestion, and generate more at times of lower congestion (i.e. engage in a form of economic withholding of capacity).
- As the NERA modelling shows, the benefits of Reform relate principally to reduced entry of solar PV (see Figure 5). The paradox of this is that, based on Baringa's experience, these are the very generators who are *most* concerned about congestion under No-Reform given solar's 'correlation penalty' is higher than for other plant, and who spend the most time understanding how different sites can result in different levels of congestion. That is, those generators whose NERA's modelling presumes are oblivious to congestion under No-Reform, and thus require congestion-related (price-based) signals under Reform, are in reality the very generators most responsive to congestion under the existing market design.

- Congestion, like MLF risk, is not currently hedged away via PPAs/financial contracts; that is, this component of VRE generators' volume risks remain with the project, and are borne by equity investors first, and then debt holders. Given this risk allocation, generators remain concerned about, and sensitive to, potential future congestion (and losses).

Figure 5 The amount of excess capacity built under No-Reform vs Reform



Source: Figure 1 from NERA report

2.6.3 Does higher actual congestion in the NEM imply generators need a sharper signal?

MLF volatility and unexpected declines in MLFs, along with unexpected increases in congestion, are symptomatic of lack of transparency and co-ordinated generator entry – these are the core issues that would also befall FTR prices and LMPs if not dealt with i.e. nodal pricing is neither a necessary nor a sufficient condition for solving for the "core issues".

Forecasting LMPs is no harder or easier than forecasting MLFs and curtailment. NERA's modelling appears to presume that LMPs can be forecast more easily than MLFs or curtailment, however, NERA has not sought to establish this presumption. This informational benefit for locational price signals is a key driver of the *Capital and fuel cost savings from more efficient locational decisions* benefit category in NERA's modelling. However, as explained, NERA's modelling gives insufficient weight to the informational signals on locational that drive real-world generation investment decisions under the current access regime.

3 A critique of NERA's modelling: costs of Reform

The costs associated with the introduction of nodal pricing is considered by NERA to be immaterial. Indeed, despite being titled a "cost-benefit analysis", NERA consider only the potential benefits of Reform – and as noted in section 2 the benefits seem overstated. Considering costs to be immaterial, or worse assuming no costs will arise from Reform, is at odds with the vast majority of the sector's views on Reform – and indeed the evidence in the Hard Software report which was released by the *AEMC on the same day as* the NERA report.

As noted in various AEMC stakeholder forums, including its technical working groups and submissions to the COGATI review, the industry remains deeply concerned about the costs and complexity of adopting Reform. These costs include:

- costs of IT and other system changes of adopting Reform
- legal costs associated with reopening long-dated hedging contracts to reflect the move away from RRPs to LMPs, and
- increased risks due to a potential reduction in contract market liquidity and imperfect hedging of LMP volatility with FTRs (i.e. FTR non-firmness).

Combined with the previous point, this is likely to increase the WACC for both prospective and existing generators, and deter new investment.

Furthermore, these costs are likely to be borne by renewables generators – existing, new-entrants, and prospective – given these generators are located in weaker areas of the grid than incumbent thermal generators. This in turn is likely to impact the extent and effectiveness of competition in the generation sector, and in turn the impact on consumer prices.

The rest of this section discusses the various costs associated with Reform, drawing on third-party estimates of these costs.

3.1 Costs of financing generation investment

Baringa is aware that participants at the AEMC's February 2020 investor forum expressed a view that the AEMC's nodal pricing reforms would increase their cost of capital by, on average, **150 basis points p.a**. A slightly higher increase (200 basis points p.a.) has been reported in a recent survey of investors in the NEM's generation sector, which corresponds to a 15-20% increase in the WACC.[19]

A higher WACC reflects the following two, non-mutually exclusive, concerns about various design elements of the proposed transmission access reform:

1. Lack of FTR firmness, with a resulting net increase in spot price volatility and revenue volatility, with a higher WACC needed to compensate for the additional risks faced by generators.

[19] See Rai, A., and Nelson, T., 2020, *Financing costs and barriers to entry in Australia's national electricity market*, available at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3692295

2. Generators' loss of automatic and free access to the congestion component of IRSRs. A higher WACC reflects a higher spot price required over a project's lifecycle to compensate generators for the costs to generators for accessing IRSRs under nodal pricing –these costs being the price of the FTRs.

Each of these concerns are discussed in more detail below.

3.1.1 Lack of FTR firmness

In the absence of FTRs, nodal pricing will result in increased price and in turn revenue volatility for generators, as their settlement price will incorporate two time-varying components:

1. dynamic loss factors: essentially, MLFs that vary across every settlement interval. With the introduction of five-minute settlement from 01 October 2021, loss factors would vary every five minutes, and
2. congestion between the RRN and the generator's node.

As shown in Appendix A.1, nodal prices would be more volatile than regional reference prices. In turn, this would increase generators' revenue volatility, especially if the amounts dispatched under nodal pricing were no different than the amounts dispatched under zonal pricing.

FTRs can serve to fully hedge the differential between the nodal price/LMP and the zonal price/RRP, with the effectiveness of this hedge fundamentally linked to the firmness of the FTRs:

- the firmer the FTRs, the more that nodal price volatility can be reduced down towards the price volatility under regional reference-based pricing
- while the AEMC has proposed various measures to enhance FTR firmness, it has not committed to measures that would otherwise ensure FTR firmness. This issue is discussed further in section 4; the key thing to note here is that FTRs are unlikely to be as firm as required to fully hedge the LMP-RRP price differential. This is especially the case for price differentials induced by dynamic losses, given the AEMC's preference for FTRs to *not* hedge dynamic losses.

In turn, as noted by Rai and Nelson (2020), concerns about a lack of requisite FTR firmness drives investors' expectations of higher WACCs under nodal pricing, given the increase in revenue volatility under nodal pricing vis-à-vis revenue volatility under regional pricing.

Moreover, concerns about the lack of FTR firmness would reduce the debt-carrying capacity of projects, increasing the proportion of more expensive (and non-tax deductible) equity capital in a project, which would also increase the overall WACC for a project.

3.1.2 Loss of automatic and free share of settlement residues

As shown in Appendix A.1, under nodal pricing generators would lose their free and automatic share to the pool of settlement residues they currently obtain under zonal/RRN-based pricing. Under nodal pricing, generators would be required to pay to obtain a share of these residues via purchase of FTRs.

As discussed in section 2.5, the NERA report's calculation of benefits due to competition and generator-to-consumer "wealth transfers" assumes generators do not seek to recover these costs from consumers, due to a combination of:

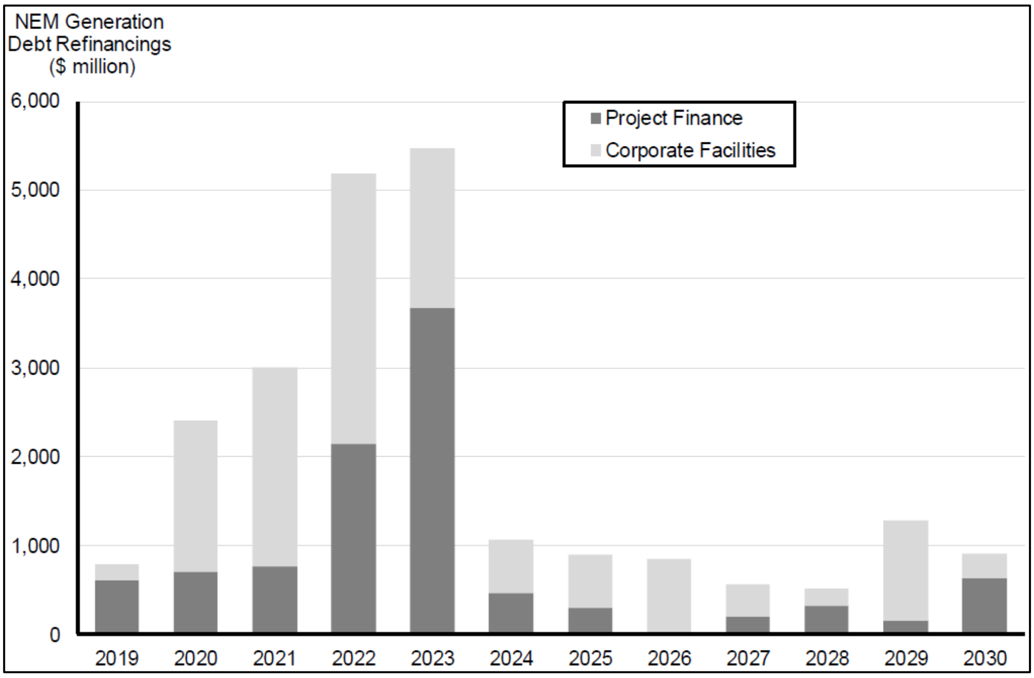
- Reform reducing barriers to entry into the generation sector relative to No-Reform, such that the increased competitive tension limits generators' ability to pass through FTR purchase costs to consumers, and
- incumbent generators earning economic profits under No-Reform, with these profits then eroded under Reform via new-entry of generators and via needing to purchase FTRs. Furthermore, under Reform, generators earn, at worst, zero excess returns, so as to avoid generator exits under Reform.

Existing generators could seek to recover payment for these FTRs from consumers by increasing their bids into the energy market, while prospective generators could seek to recover these payments by factoring in a higher break-even electricity price prior to market entry. A higher WACC is one means by which the cost can be factored into a higher break-even price.

3.1.3 Impacts on both new-entrant and existing generators

Investors in the AEMC survey considered a higher WACC would be incurred by both prospective and existing generators, the latter due to the debt refinancing needs of existing generators, with around $18 billion of debt facilities issued by wind and solar PV generators – both project debt ($8.4bn) and corporate debt ($9.6bn) facilities – needing to be refinanced between 2020 and 2025 (Figure 6).

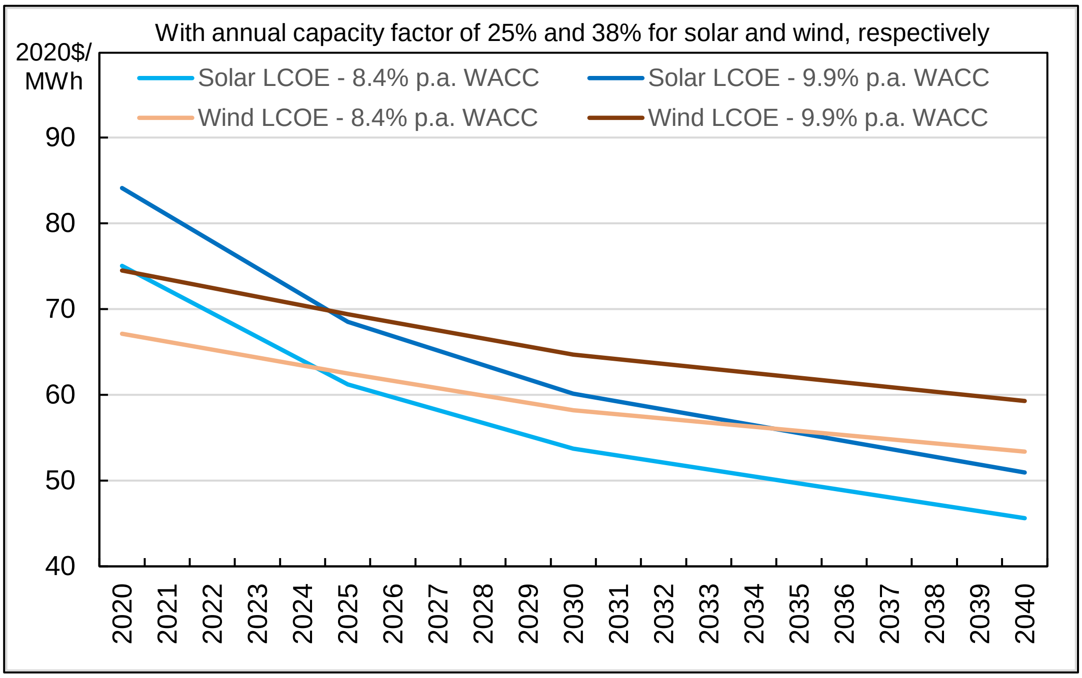
Figure 6 Expected refinancing of VRE project debt, 2019-2030



Source: Figure 17 from Simshauser, P. and Gilmore, J., 2020, *Is the NEM broken? Policy discontinuity and the 2017-2020 investment megacycle*, available at: https://www.eprg.group.cam.ac.uk/wp-content/uploads/2020/05/2014-Text_UPD.pdf

We note this estimate of the system cost of a higher WACC under Reform is an approximate and high level calculation, as we have not sought to re-optimise the capacity mix under a higher WACC.

Figure 7 Impact of higher WACC on Onshore Wind and Solar PV LCOEs



Source: Baringa Partners LLP

3.2 Other implementation costs

There are four broad costs ignored by NERA's cost-benefit analysis:

1. IT system costs
2. legal costs associated with reopening and rewriting hedging contracts
3. costs of increased credit support associated with increased price volatility, and
4. financial market-related transaction costs.
5. economic costs resulting from a decline in contract market liquidity (discussed in section 4.2)

Exclusion of IT system costs is especially striking considering a report by *Hard software* was published on the same day the NERA report was published – and, like NERA, Hard Software was commissioned by the AEMC.

While the scope of Baringa's current engagement does not extend to estimation of these four cost categories, we consider this work is critical to an appropriate and rigorous assessment of the costs and benefits of the AEMC's proposed transmission access reforms.

3.2.1 Systems-related implementation costs

The consultancy *Hard software* was commissioned by the AEMC to provide a "quick assessment" of the impact on AEMO's and market participants' IT systems from implementing Reform, providing a view of the likely system's costs, taking into account potential savings and offsets against future required expenditure for AEMO and market participants.[20] Over a 20-year period, *Hard software* estimated system implementation costs would range between $62 million and $105 million, or $5 million – $8.5 million pa. (see Table 6).

Table 6 IT system costs for each of three different LMP implementation options

Impacted entity	Present value of system costs based on a 5% p.a. real discount rate (Real 2020$)		
	Option 1	Option 2	Option 3
AEMO	34,000,000	46,000,000	71,000,000
Market participant	28,000,000	34,000,000	34,000,000
Total NPV over 20 years	**62,000,000**	**80,000,000**	**105,000,000**
Total p.a.*	**$4,975,040**	**$6,419,407**	**$8,425,472**

* Equivalent annual cashflow at 5% p.a. discount rate
Source: Baringa analysis of Table 2 in *Hard software* report

Baringa is of the view that these IT system estimates are understated, but it is beyond the scope of this report for a detailed critique of *Hard software*'s analysis. In any event, it is not clear why NERA excluded the cost estimates in Table 6 when they are easily obtainable, though admittedly incorporating these costs into NERA's analysis would not have materially impacted their results.

3.2.2 Legal costs

The AEMC's September 2020 report proposes that scheduled loads pay LMPs, but non-scheduled loads, which constitute the vast bulk of loads in the NEM, would continue to pay one price – but instead of the RRP, this price would be a volume-weighted average of individual LMPs: the volume-weighted average LMP (VWAP).

The move to VWAPs would require those hedging contracts currently existing with an expiry date after the start of the proposed transmission access reforms (mid-to-late 2020s) to be reopened, so that references to RRPs can be replaced with LMPs on the generator side, and VWAP on the off-taker side. Such contracts include PPAs written to the end of the LRET (December 2030). There is no discussion in the NERA report of "contract reopening costs", and therefore these costs are not taken into account in its cost-benefit analysis.

Furthermore, the AEMC's technical report quotes legal costs of between $5,000 and $20,000 per PPA, which suggests legal costs relating to reopening PPAs totalling $1.4m to $5.4m (based on an estimated 273 PPAs being in existence)[21]. There are two issues with this:

1. There is no justification provided by the AEMC of the size of these contract reopening costs. In Baringa's experience dealing with contracts, a legal cost of $20,000 per contract is

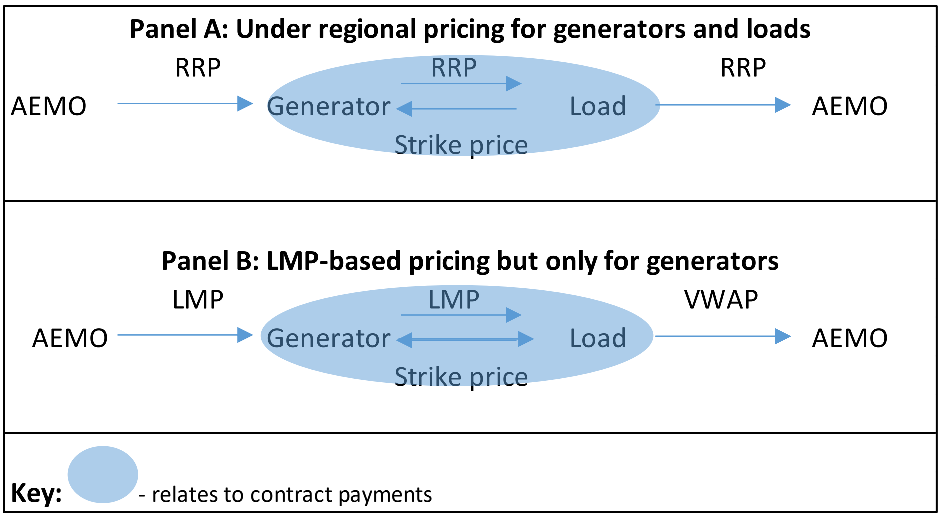
[20] HARD software, *A preliminary indication of the information technology costs of Locational Marginal Pricing*, 07 September 2020, https://www.aemc.gov.au/sites/default/files/2020-09/IT%20costs%20of%20implementing%20NEM%20locational%20_ng%20-%20Hard%20Software%20-%20Information%20Technology%20costs%20of%20nodal%20pricing%20-%202020_09_07.PDF
[21] See Section 4.3.3 of AEMC, *Transmission access reform: Updated technical specifications and cost-benefit analysis*, 7 September 2020

unrealistically low (and $5,000 even more unrealistic). Costs in the order of $50,000 per contract would be more realistic, but higher costs are possible depending on the complexity of the contract.

2. The AEMC notes there are other reforms being considered by the ESB that may also require contract re-openings to occur, and therefore the incremental contract reopening costs from transmission access reforms may be lower than the values indicated in point 1. This, in Baringa's view, is a curious argument to make considering much of the ESB's post-2025 work, of which the AEMC's proposed transmission access reforms are a part of, are in a much earlier stage of development than the AEMC's proposed reforms appear to be.

Moreover, for bilateral hedging contracts between a scheduled or semi-scheduled generator and a non-scheduled load[22], which constitute a nontrivial share of the contract market, the (floating) price paid by the load within the hedge contract would not be the same as the price the load needs to pay AEMO (Figure 8).

Figure 8 Schematic of payment flows in a bilateral hedging contract under nodal pricing



Source: Baringa Partners LLP

Both panels in Figure 8 show the payments currently made in the spot market between AEMO and the generator, and between AEMO and the load. In addition, Panel A shows the payments made between generators and loads within a RRP-linked hedging contract (shaded oval); Panel B shows the same bilateral payments but for a LMP-linked hedging contract.

Panel B shows that an LMP-linked hedging contract creates basis (settlement) risk for the load – the spot payments it makes to AEMO are based on its VWAP, whereas the payments it receives from the generator under the hedging contract is the LMP. This creates basis risk as LMPs and VWAPs may not, and are often unlikely to be, perfectly correlated. For example, changes in VWAPs can be driven by changes in the volume weighting of loads, independent of changes in underlying LMPs.

There would be a cost to the load to hedge this basis risk – and this basis risk is *not* due to RRP-LMP differentials. Hence, FTRs cannot be used to hedge this basis risk. Alternatively, the hedging contract

[22] Under the AEMC's proposed design, scheduled and semi-scheduled generators, and scheduled loads, will face LMPs, while non-scheduled generators and non-scheduled loads will face VWAPs.

may stipulate that the generator pay the retailer the VWAP – but then the generator would face a basis risk as what it pays under the contract would not be offset by what it receives from AEMO in the spot market.

3.2.3 Costs of increased credit support

The introduction of nodal pricing is highly likely to result in increased price volatility for all market participants, with higher margin requirements due to key risks faced, as follows:

1. Market participants that will face LMPs (i.e. scheduled and semi-scheduled generators, and scheduled loads). These participants will face spot prices that are more volatile than RRPs, and since FTR firmness is not certain – indeed, FTRs will *not* be firm with respect to dynamic losses and even for congestion will only be available for a relatively small number of pre-defined nodes, as per the AEMC's latest design proposal – this increased price volatility is highly likely to result in increased prudential support to cover spot market exposures. Increased credit support to cover contract market exposures are also likely, given hedging contracts would now need to link to more volatile LMPs.
2. Market participants that face VWAPs (i.e. all non-scheduled loads and non-scheduled generators) will need to provide additional collateral when entering hedging contracts, to cover LMP-VWAP basis risk.

As with the prior cost categories, the NERA report does not consider the potential for Reform to impose increased credit support costs on *all* market participants, including loads. The AEMC's September 2020 report also ignores this important cost category.

3.2.4 Higher transaction costs in financial markets

A fourth cost category relates to the increase in transaction costs that may arise were contract market liquidity to decline following the implementation of Reform. As we discuss in section 4.2, we consider contract market liquidity may decline if the existing design elements of the proposed reforms are implemented, since these design elements do not provide for sufficient FTR firmness – and FTR firmness is key to determining whether contract market liquidity is enhanced or diminished with the implementation of nodal pricing and FTRs. The NERA report ignores the potential for transaction costs to increase under Reform; indeed, this potential is presumed away by NERA's presumption that FTRs are firm. We further discuss this issue in section 4.

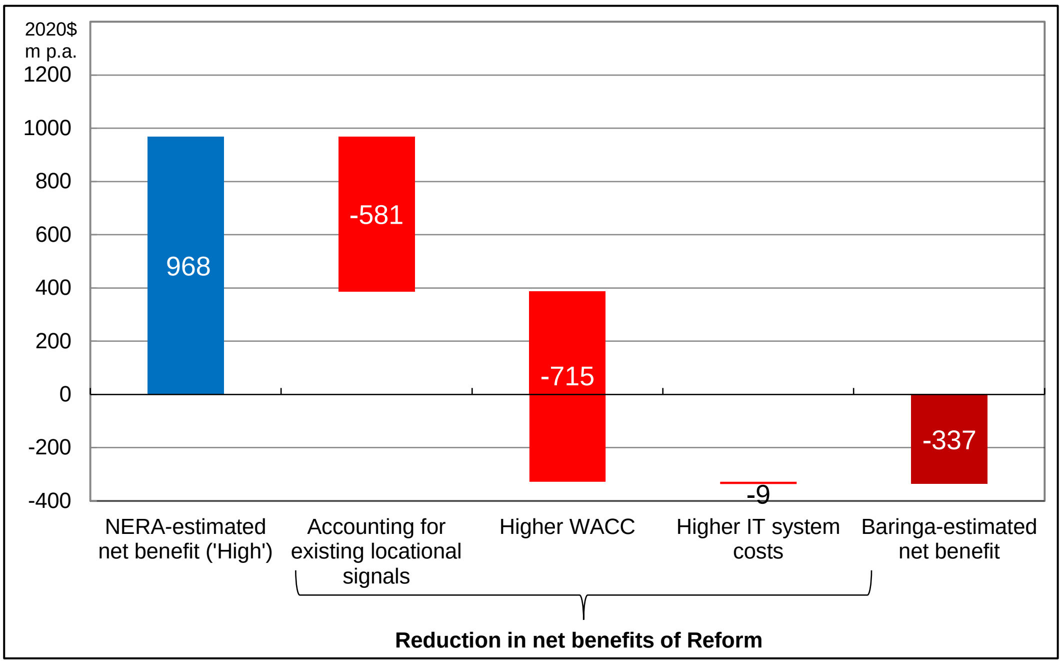
3.3 Estimating the impact on net benefits of Reform

Based on the preceding discussion, and in stark contrast to the estimated net benefits of Reform in the NERA report, we estimate the net benefit of Reform over the 2026-2040 period to be **minus $337 million p.a.** (see Figure 9). This estimate is obtained as follows:

- We annuitise the lump-sum benefits over the 2026-2040 period reported in Table 1, at a discount rate in of 9.9% p.a., based on the real, pre-tax WACC under Reform. To maximise the chance of getting positive net benefits, we use the NERA-estimated benefits under *High* in Table 1. This yields an updated NERA-estimated benefit of $968 million p.a.

- We then reduce the size of these benefits by 60 per cent, consistent with our estimate of the extent to which NERA's estimated benefits of Reform are inflated by not accounting for locational signals under No-Reform (see section 2.5). This reduces the net benefits to $479 million p.a.
- We then apply the estimated costs of a 150 basis point increase in the WACC under Reform, which reduces net benefits by a further $715 million p.a.
- And, finally, we apply the equivalent annual IT system cost of $9 million p.a. (rounded up from $8.4 million) under Option 3 in the *Hard software* report (see Table 6).

Figure 9 Net benefits of Reform over the 2026-2040 period, based on 'High' benefits



Source: Baringa Partners LLP.

This calculation shows Reform is likely to result in a net cost to consumers, with the bulk of this driven by the increase in generator WACC. And these negative net consumer benefits would be prior to any consideration of other potential costs associated with Reform, such as the costs of increased credit support, legal costs, and higher transaction costs associated with diminished contract market liquidity.

4 Additional real-world considerations

As noted in *Introduction* (section 1), Baringa's critique of the NERA report challenges both NERA's modelling methodology and results, and the "real-world" (i.e. non-modelling) implications of the AEMC's proposed transmission access reforms as discussed in NERA's report. One important real-world implication of the proposed reforms was discussed in section 3: the potential costs of implementation. This section discusses FTR firmness, impact on the management of market risk, and how the problem of a lack of transparency under the current regime is not addressed by the proposed reforms.

4.1 FTR firmness

As noted in Section 3, the financial firmness of FTRs has a critical role to play in reducing the cost – to generators and to consumers – of implementing any move to nodal pricing. The firmer an FTR, the greater its ability to hedge price separation between nodes. This ability is fundamentally related to the predictability of actual power flows. In turn, this requires an understanding, and an ability to predict, the nature, timing and extent of system constraints that bind over the life of an FTR. This section discusses these issues.

Furthermore, NERA note that in their analysis of liquidity and risk "we have assumed that FTRs are firm" (see p63 of their report). This assumption is a critical one, as it validates the assumption of no increase in WACC between No-Reform and Reform. NERA base this assumption on some highly stylised analysis which does not take into the full set of relevant constraints. As discussed in section 3, one of the key costs associated with implementing Reform is the potential increased cost of financing generation investment.

4.1.1 Capturing the full set of relevant constraints

For FTRs to be financially firm, the projected power flows into and out of each transmission node, which are a necessary input into the design of each FTR, are realised in practice; that is, projected flows equal actual flows. For this to occur, the timing, duration and extent of network constraints need to be known and incorporated ahead of time, into the FTR design and formulation. This is a well-known requirement for FTRs to be an effective and efficient risk management tool.[23]

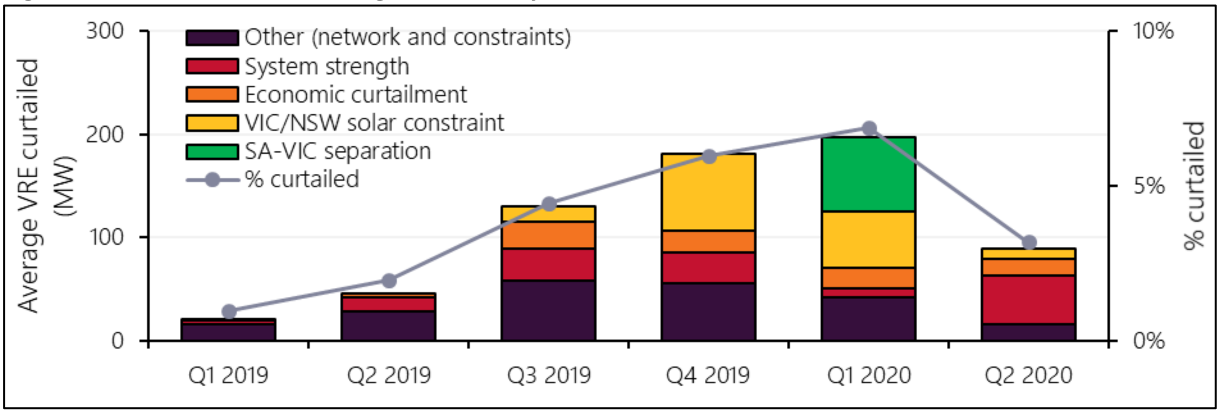
However, the types of network constraints increasingly driving curtailment, especially of renewables, are *not* thermal ratings-based. Instead, the network constraints of most concern to VRE generators are the system security-based constraints that have emerged in (North) Queensland, (North-West) Victoria, parts of (west) NSW, and South Australia. For example, 65 per cent of VRE output curtailed during Q2 2020 was due to system security-based constraints (Figure 10).[24] Thermal ratings-based constraints ("Other" in Figure 10) comprised just 17 per cent of VRE output curtailed in Q2 2020.

[23] For example, see AEMC, *COGATI TWG #6 - Congestion FTR Funding and Procurement working paper*, June 2020. Mathematically, using equation (3) from Appendix A.1, FTRs would not be firm if its formulation did not include all of the constraint equations which featured generator h's coefficient i.e. the FTRs did not span the full set $\{H_{l,i}\}_{l\in L}$

[24] This is the sum of system strength-based constraints (53 per cent) and curtailment of five utility-scale solar in Victoria and NSW (12 per cent) due to concerns about post-contingency voltage instability in those areas.

The types of system security-based constraints noted above have occurred unexpectedly, and with unknown timing and duration. For example, as illustrated in Figure 10, four utility-scale solar plants in Victoria's West Murray region, and one solar plant in NSW, had their potential output suddenly halved in September 2019, with the constraints not lifted until April 2020.

Figure 10 Curtailment of VRE generators by reason for curtailment



Source: Figure 39 from AEMO, *Quarterly Energy Dynamics – Q2 2020*, July 2020

By their very nature, these constraints are hard to predict, especially in relation to a multi-year FTR. This inability to predict the timing, duration and severity of these types of network constraints means FTRs designed prior to 2019, to hedge for the period through to April 2020, would not have been able to fully hedge the five impacted solar plants' LMP-RRP basis risks.

That is, these solar plants' LMPs would have been driven much lower as these system security-based constraints were invoked, without any or much offsetting FTR compensation, *unless* the FTR payouts were able to cover any and every reason for LMP-RRP price separation.

4.1.2 Design of FTRs and revenue adequacy

For FTRs to hedge LMP-RRP separation – which arises due to any type of binding export constraint at the generator's node – the FTRs have to be "revenue adequate". "Revenue adequacy" refers to the extent to which FTR promised payouts can actually be paid in practice out of the pool of settlement residues, and hence refers to the ability of FTRs to hedge price basis risk. Revenue adequacy is satisfied when the actual constraints invoked are those expected at the time of FTR formulation. This is identical to the requirement for FTR firmness noted above; that is, revenue adequacy and FTR firmness are equivalent.

However, as noted above, the increasing incidence of atypical, non-thermal ratings-based, constraints mean it is increasingly likely FTRs would not be revenue adequate. To ensure revenue adequacy in the context of an increasing incidence of atypical constraints, any shortfalls in settlement residues (i.e. negative residues) need to be funded, by definition, outside of the residue pool. In overseas nodal markets, this outside funding is often provided by the transmission network service provider (TNSP).

The enhancements to FTR firmness proposed by the AEMC in its September 2020 interim report were as follows:

- use of proceeds from FTR auctions, in addition to settlement residues, to back FTRs

- allowing non-physical participants to participate in FTR auctioning – this greater participation is argued by the AEMC to decrease “FTR competition issues”, increase FTR firmness, and also improve FTR secondary market liquidity
- settling (non-scheduled) loads on the basis of volume-weighted average prices (VWAPs) rather than regional reference prices, and
- allowing FTRs to not hedge losses, which is argued by the AEMC to be firmness-enhancing.

In Baringa’s view, these measures would provide limited additional firmness compared to an explicit commitment to fund any shortfall between the level of promised FTR payouts and settlement residues. Baringa considers that, fundamentally, the best way to enhance FTR firmness would be for FTRs to be guaranteed to be “revenue adequate”. However, Baringa understands the AEMC remains opposed to third-party funding of residue shortfalls, in turn implying a lack of firmness in the FTRs.

A credible and explicit commitment to fund any shortfalls in FTR promised payouts would have the beneficial impact of increasing generators’ willingness to pay for FTRs (i.e. increase FTR prices and auction proceeds) and in turn, somewhat paradoxically, *decrease* the chance of having to actually make good on these payment shortfalls, as increased FTR prices can increase the amount of funds available for FTR payouts. At the very least, a cost-benefit analysis of nodal pricing and FTRs should consider the costs and benefits of providing such an explicit commitment, though unfortunately this was not done in NERA’s report. Indeed, none of the pros and cons of varying degrees of FTR firmness were considered by NERA, given their assumption that FTRs are firm.

4.1.3 Inter-regional settlement residues

Financial transmission rights do currently exist, inter-regionally, in the NEM: settlement residue auction (SRA) units. In contrast to the proposed design of (intra-regional) FTRs, negative inter-regional settlement residues can and do occur, with TNSPs the designated party to fund any negative residues. Negative inter-regional settlement residues have helped with SRA firmness, and the same can be expected if negative IRSRs were to occur under FTRs. It is not clear to Baringa why the AEMC would design intra-regional FTRs that precluded negative IRSRs, given the precedent for negative residues already exists, along with the funder of choice.

If the approach used for SRAs were to be applied to FTRs, then negative intra-regional settlement residues would be allowed, but the size of any negative residues could be limited via AEMO ‘clamping’, akin to AEMO’s current approach for SRAs and inter-regional residues. Such ‘clamping’ would serve to strike a balance between maximising FTR firmness and limiting exposure of TNSPs (and by extension customers) to very large negative settlement residues. Again, many of the nuances associated with FTR design and firmness are assumed away by NERA’s assumption that FTRs are firm.

4.2 Impact on the management of market risk

The discussion of FTR firmness in section 4.1 is important for understanding the extent to which generators can better manage their price and volume risks under Reform. In turn, the extent to which risk management can be improved, or diminished, under Reform is intimately linked with FTR firmness. As discussed in section 3.1, investors in the generation sector have told the AEMC they consider Reform is likely to result in a higher WACC; that is, they consider their ability to manage risk is likely to be undermined with the introduction of nodal pricing and FTRs, with a higher WACC required to compensate them for the price and volume risks market participants are forced to face following the implementation of Reform.

A key consequence of sufficient FTR firmness would be improved liquidity in the contract market – or at least not a deterioration in liquidity – following the introduction of nodal pricing and FTRs. In turn, contract market liquidity has a key role to play in determining the cost-effectiveness of managing risks externally vis-à-vis managing risk internally via horizontal and/or vertical integration. This in turn would have implications for the viability of standalone (non-integrated) generators and standalone retailers, and by extension implications for the effectiveness and workability of competition in both generation and retailing sectors.

NERA's assumption of firm FTRs means the findings from the analysis in Section 7 of their report is pre-determined: risk management and contract market liquidity *can only* be enhanced, not diminished, from the introduction of FTRs. That is, NERA's quantitative analysis cannot be used to critically evaluate the extent to which FTRs enhance or detract from contract market liquidity – and by extension, enhance or detract from market participants' ability to manage price and volume risk – since NERA have already assumed the answer to be 'enhanced'.

Below, we provide a critical evaluation of some of the real-world considerations involved in understanding the link between FTR firmness, contract market liquidity, and risk management ability.

4.2.1 Impact on liquidity in hedging contracts

'Hedging contracts' refer to both existing RRP-linked contracts – such as ASX-listed and OTC-traded swaps and caps – as well as FTRs under Reform. If FTRs are not sufficiently firm, then contract market liquidity is likely to decline following implementation of Reform, and incentives to integrate horizontally and/or vertically may increase, which may further exacerbate the decline in contract market liquidity.

If FTRs are not firm and this leads to a decline in contract market liquidity, this implies more conservative contracting practices by market participants, with adverse outcomes for retailers and ultimately consumers - it could become more difficult for retailers to obtain a hedging contract, or retailers must pay a premium for a hedging contract in the presence of this basis risk. Ease of contracting and a liquid secondary market was one of the reasons why policymakers adopted a regional price structure for the NEM. Accordingly, the consideration of a move towards nodal prices under a model where FTRs are not fully firm requires a clear understanding and consideration of the impacts on contract market liquidity and the outcomes that could follow from this.

Conversely, the firmer that FTRs are made to be:

- the greater the potential liquidity in the FTR market itself (i.e. in the market for "LMP-linked contracts"), and by extension
- the less likely a chance that liquidity in the RRP-linked contracts market diminishes following the introduction of nodal pricing and FTRs.

For liquidity in RRP-linked and LMP-linked hedging contracts to be promoted under nodal pricing, FTRs need to meet the following requirements:

- financial firmness: to be as financially firm as possible, the chance of FTR revenue inadequacy needs, in Baringa's view, to be reduced to zero. As noted in section 4.1, we believe this is best met when negative residues are permissible, which would provide the strongest signal of firmness relative to the measures proposed in the AEMC's September 2020 report

- FTRs need to integrate with the design of RRP-linked hedging contracts: an FTR can create volume-based basis risk when the volumes settled under an FTR differ from:
  - the volume settled in the spot market, for generators and loads with a net exposure to the spot market, and/or
  - volumes settled under hedging contracts, for market participants that are fully hedged.

We note the AEMC has proposed both fixed-volume FTRs and time-of-use FTRs. However, both types of FTRs can create residual volume risk for VRE plant and other variable-volume plant – such as OCGTs, hydro, and battery storage technologies – unless the volumes settled under an FTR can offset the volumes settled under contract or settled in the spot market. Baringa understands investors' and other stakeholders' concerns about a lack of integration between FTRs and RRP-linked hedging contracts is a prime reason for why they consider their ability to manage risk may diminish under Reform, and in turn a prime reason for why they consider their WACC would increase under Reform.

4.3 Lack of transparency under current regime is not addressed by proposed reforms

Under the current open access regime, a key dilemma that negatively impacts on the efficient locational choice for a new generator is the lack of transparency over what may be planned by other potential new generation at the same location.

Consider a situation with two potential new generators wanting to connect at the same location in the network. Generator A is investigating building and connecting new generation at the location because that location currently has a reasonable level of spare capacity and, absent other new generation connecting in the same area, might continue to face low levels of network congestion after Generator A connects. Generator A enters into negotiations with AEMO and the local TNSP with respect to the connection process.

Unbeknown to Generator A, Generator B is also investigating connecting a similar type and capacity of generation at a similar location and has also commenced negotiations with AEMO and the local TNSP over the connection process.

The local TNSP is not permitted to divulge to Generator A that Generator B is also seeking to connect to a similar location, or vice versa, even if the TNSP considered that both generators connecting in that area would exceed the available spare capacity and likely lead to network congestion and higher loss factors. Further, until a connection agreement is signed, we understand AEMO does not take into account the new potential generation into its forecasts and modelling (e.g. MLF calculations). If Generator A was aware of the intentions of Generator B, it might choose to connect at a different location where it would face less congestion.

While well intentioned, the confidentiality restrictions result in a lack of transparency for new generation under the current regime that can lead to less optimal co-ordination of generation and transmission investment. This lack of transparency around when multiple generators are seeking to connect at a similar point in the grid, even where this outcome is not optimal, would not be resolved through nodal pricing (or by the recent rule change on improving information on new generation projects).

Appendix A RRPs, LMPs, FTRs and IRSRs

A.1 Mathematical formulation

Under regional reference node-based pricing, every generator is paid the RRP regardless of the price at the generator's node (or 'nodal price'). Let $P^j_{RRN,t}$ denote the RRP and $P^j_{i,t}$denote the nodal price, pre-losses, for a five-minute dispatch interval t within a given 30-minute trading interval v, for a generator h located at node i in region j. Let $Q^j_{h,RRP,t}$ denote the output of generator h dispatched under RRN-based pricing, and $Q^j_{h,i,t}$ denote the volume dispatched of that generator under nodal pricing. Then the revenue (Rev) of generator h within that five-minute dispatch interval t is given by equation (1):

$$\begin{aligned} Rev^{j,t}_{h,i} &= P^{j,v}_{RRN,t} \cdot Q^j_{h,RRP,t} \cdot MLF^j_{h,T} \\ &= \left(P^j_{i,t} \cdot Q^j_{h,i,t} \cdot DLF^j_{h,i,t}\right) + \left(P^{j,v}_{RRN,t} - P^j_{i,t}\right) \cdot Q^j_{h,RRP,t} \cdot DLF^j_{h,i,t} \\ &+ \boldsymbol{P^{j,v}_{RRN} \cdot Q^j_{h,RRP,t} \cdot \left(MLF^j_{h,i,T} - DLF^j_{h,t}\right) + P^j_{i,t}\left(Q^j_{h,RRP,t} - Q^j_{h,i,t}\right) \cdot DLF^j_{h,i,t}} \end{aligned} \tag{1}$$

MLFs are a static representation of electrical losses associated with the transport of energy from generators to loads. In particular, a generator's MLF is the generation-weighted average of its DLF over a financial year; that is, for financial year T:

$$MLF^j_{h,i,T} = \left[\frac{1}{\sum_{t=1}^{17{,}520} Q^j_{h,i,t}} \sum_{t=1}^{17{,}520} Q^j_{h,i,t} \cdot DLF^j_{h,i,t}\right] \tag{2}$$

The first line in equation (1) is the revenue under existing pricing arrangements for settlement purposes in the NEM: regional prices based on marginal loss factors (MLFs). The second and third lines disaggregate this into revenue attributable to (for each and every five-minute dispatch interval t):

- the nodal price with congestion and dynamic losses included: $(P^j_{i,t} \cdot Q^j_{h,i,t} \cdot DLF^j_{h,i,t})$. Reflecting its dynamic nature, the dynamic loss factor ($DLF^j_{h,i,t}$) varies every five minutes, just like $P^j_{i,t}$ and $Q^j_{h,i,t}$
- the congestion-induced IRSRs allocated to generator h, for a given dynamic loss factor: $(P^{j,v}_{RRN,t} - P^j_{i,t}) \cdot Q^j_{h,i,t} \cdot DLF^j_{h,i,t}$
- the losses-induced IRSRs allocated to the generator under regional pricing vis-à-vis nodal pricing: $P^{j,v}_{RRN} \cdot Q^j_{h,i,t} \cdot (MLF^j_{h,i,T} - DLF^j_{h,t})$, and
- dispatch inefficiency ("disorderly bidding") under RRN-based pricing: $P^j_{i,t}(Q^j_{h,RRP,t} - Q^j_{h,i,t}) \cdot DLF^j_{h,i,t}$

These four components can then be mapped to various components of the consumer benefits in the NERA report:

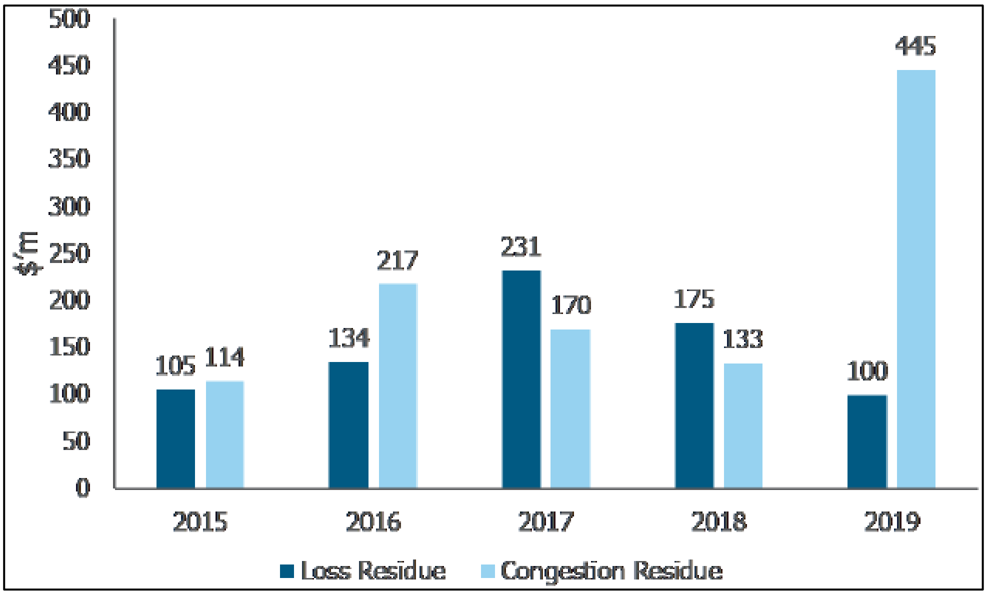
- the "nodal subsidy" in the NERA report, which is a key driver of the capital and fuel cost savings under Reform, as well as the benefits from introducing dynamic losses, is linked to the second and third components
- the benefits of improved dispatch efficiency under Reform is (inversely) linked to the fourth component

Nodal pricing would decrease generators' revenues as generators would no longer receive IRSRs for free. This would be especially so for those generators located in areas with high export congestion and/or high losses:

- the second term in equation (1) would be eliminated by allowing for congestion-induced price differentials between the local price and the RRP. For generators in export-congested areas, their LMP would be less than the RRP, and
- the third term in equation (1) would be eliminated by incorporating DLFs, rather than volume-weighted averages of DLFs (i.e. MLFs). For generators in areas where their DLFs are lower than their MLFs, the local price would be less than the RRP. However, in contrast to congestion, losses-related allocation of residues to generators would be *transitory* (i.e. intra-year) as MLFs are updated annually.

Both features of losses-related IRSRs – namely, the transitory nature of the allocation to generators and the sharing of losses-related IRSRs between generators and consumers due to an annually-revised MLF – are shown in Figure 11. The AEMC estimates the losses component of IRSRs has declined over time, from 48 per cent in FY2015 to 18 per cent in FY2019.

Figure 11 Aggregate IRSRs across the NEM, split into losses and congestion



Source: Figure 3.4 from AEMC, *Transmission access reform: Updated technical specifications and cost-benefit analysis*, 7 September 2020 (link to document)

This reduction in revenues will be greater if generator h's output is reduced with the removal of disorderly bidding i.e. if $Q^{j}_{h,RRP,t} > Q^{j}_{h,i,t}$, which would occur if generator h had a relatively high SRMC. Conversely, some of the reduction in generator h's revenues may be offset if they benefit from the removal of disorderly bidding i.e. if $Q^j_{h,RRP,t} < Q^j_{h,i,t}$, if generator h had a low SRMC. In the absence of modelling and quantitative analysis to determine the impact on the revenues of low-SRMC generators from a move to nodal pricing, it is difficult to determine the overall net effect, though it is likely to be negative.

In order to get a share of the settlement residues under nodal pricing, generators would need to purchase financial transmission rights (FTRs). FTRs serve to hedge the LMP-RRP basis risk: the risk of changes in the LMP-RRP price differential. FTRs are financially backed by the size of the residues. By holding FTRs, some of the forgone IRSR revenue to generators upon moving from regional-based pricing to nodal pricing can be recovered via FTR payouts when congestion and/or losses arise. However, FTRs would cost generators money and therefore, on balance, generators would be worse off.

NERA assumes the proceeds of generators' purchases of FTRs are transferred to consumers in the form of lower network prices – this is the "wealth transfers" in their study. NERA does not allow for generators to seek to recover the FTR purchase costs from consumers via higher-priced bids; that is, generators' profits are allowed to decrease with the adoption of nodal prices and FTRs.

A.1.1 The link between LMPs and RRPs

The link between the nodal price and the RRP is as per equation (3):

$$P^j_{i,t} = P^{j,v}_{RRN,t} - \sum_l \lambda_l \cdot H_{l,h} \qquad \textbf{(3)}$$

where $P^j_{i,t}$ and $P^j_{RRN,t}$ are as per equation (1), λ_l is the "shadow price" for each congested line l (i.e. the Lagrangian multiplier for each constraint equation), and $H_{l,i}$ is the collection of all of the coefficients related to generator h's output in each and every relevant constraint equation.

Taking the variance of both sides (and ignoring the correlation between $P^{j,v}_{RRN,t}$ and the λ_l's[25]) gives:

$$var(P^j_{i,t}) = var(P^{j,v}_{RRN,t}) + var(\textstyle\sum_l \lambda_l \cdot H_{l,h}) = var(P^{j,v}_{RRN,t}) + \sum_l H^2_{l,h} \cdot var(\lambda_l) \qquad (4)$$

That is, $var(P^j_{i,t}) > var(P^{j,v}_{RRN,t})$.

A.1.2 Five-minute settlement

Currently the RRP used for settlement purposes is the equal-weighted average of the six dispatch interval RRPs within that trading interval (with the trading interval starting either on the hour or half-past the hour), for each region j. That is, $P^{j,v}_{RRN} = \frac{1}{6}\sum^6_{t=1} P^j_{RRN,t}$, for a given trading interval v.

From 1 October 2021, the settlement RRP in the NEM will be set at the five-minute RRP; i.e. $P^{j,v}_{RRN} = P^j_{RRN,t}$ and equation (1) would need to be modified accordingly. Similarly, equation (2) would calculate MLFs based on dynamic losses calculated over each five-minute interval.

[25] This is done for simplicity; in practice, as the pairwise correlations between $P^{j,v}_{RRN,t}$ and the λ_l's are not perfect, we still obtain the same result: $var(P^j_{i,t}) > var(P^{j,v}_{RRN,t})$

A.2 FTRs and revenue adequacy

Volume-based basis risk under regional pricing – that is, the risk of being constrained-on or constrained-off – is converted into price-based basis risk under nodal pricing. This price risk can be perfectly hedged (at a cost to generators) with FTRs provided the FTRs are of sufficient firmness and of sufficient duration.[26]

The NERA report notes the AEMC has proposed one-way FTRs (i.e. FTR options). FTR options give FTR holders the option to avoid making payments when the FTR's value is negative (i.e. when IRSRs are negative, or when the LMP is less than the RRP).[27] With one-way FTRs, the generator's revenues will be determined as per the following modification of equation (1):

$$Rev_{h,i,t}^{j} = P_{i,t}^{j} \cdot DLF_{h,i,t}^{j} \cdot Q_{h,i,t}^{j} + max\left(0, P_{RRN}^{j,v} \cdot MLF_{h,i,T}^{j} - P_{i,t}^{j} \cdot DLF_{h,i,t}^{j}\right) \cdot FTR_{h,i}^{j} \quad (5)$$

$max(0,\cdot)$ reflects the payout on the FTR option, $FTR_{h,i}^{j}$ is the volume of FTRs held by generator h, and all other terms are as per equation (1).

The one-sided nature of an FTR option is designed to make generator h no worse off under nodal pricing, and to also be more valuable to generators than two-way FTRs.

However, these two conditions only apply if there is no cap on FTR payouts. If, instead, FTR payouts are capped by the sum of the pool of settlement residues and the price paid for the FTRs – as per the AEMC's latest design of the FTRs under nodal pricing[28] – then the FTRs are no longer firm, since if negative residues were to arise the FTRs would need to be scaled down until the residues were no longer negative. Non-firmness and FTR downscaling are, in turn, likely to arise when the nature of the constraints that result in intra-regional price separation are outside of the set of constraints used to model power flows and in turn, to value the FTRs.

FTR downscaling would undermine FTR firmness, and consequently revenue volatility may be no lower under nodal pricing vis-a-vis regional pricing.

This and other aspects of FTR firmness are further discussed in section 4.

[26] Rai, A., and Nelson, T., 2020, Financing costs and barriers to entry in Australia's electricity market, *Journal of Financial Economic Policy*, forthcoming. Available at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3692295

[27] In contrast, under two-way FTRs (i.e. FTR obligations), FTR holders are obliged to pay when the FTR's value is negative, as well as have the right to be paid when the FTR's value is positive.

[28] The AEMC is now proposing for revenues from the sale of FTRs to be added to settlement residues to increase the funds available for FTR payouts, and in turn improve the firmness of FTRs. Previously, the AEMC proposed for these proceeds to be returned to consumers via reductions in network prices. For more details, see AEMC, *Transmission access reform: Updated technical specifications and cost-benefit analysis*, 7 September 2020, available at: https://www.aemc.gov.au/sites/default/files/2020-09/Interim%20report%20-%20transmission%20access%20reform%20-%20Updated%20technical%20specifications%20and%20cost-benefit%20analysis%202020_09_07.PDF

Appendix B How congestion and losses impact VRE generators' revenues

This section discusses the impact of changes in MLFs and curtailment levels on VRE generators' spot market and contracted revenues, the latter based on a generator selling a generation-following hedge contract such as a PPA. As discussed in Section 2.6, congestion and MLFs are risks that remain with generators and are not hedged away via financial contracts (e.g. PPAs), unlike spot price risk. Given this risk allocation, generators remain concerned about, and sensitive to, potential future congestion (and losses), regardless of the extent of the generator's net spot market exposure. This is especially the case for VRE generators – the very generators assumed by NERA to require locational signals.

MLFs have a direct impact on generators' spot market and PPA revenues: higher MLFs result in higher revenues, all else equal. Similarly, higher curtailment results in lower PPA revenues, and also results in lower spot revenues when curtailment occurs at spot prices above zero.[29]

Two stylised examples are provided below, of the impact of changes in MLFs and curtailment on generator revenues, respectively, assuming a generator that has entered into a long-dated PPA. While stylised, the example does illustrate the arguments, made in the main body of this report, that:

- generators are acutely aware of how losses and congestion can impact their revenues under the existing market design (i.e. under 'No-Reform')
- generators are therefore incentivised to locate in areas with low losses and low congestion
- therefore, NERA's assumptions that generators are effectively oblivious to congestion, and so need a price signal (i.e. a nodal price under Reform) to tell them where to locate and where not to, overlooks the existing signals of congestion (and losses) under No-Reform, and
- consequently, NERA's estimates of the benefits of Reform are highly overstated.

B.1 Stylised example: impact of changes in MLFs

Consider a hypothetical 200MW wind farm in the NEM, that commenced operation in July 2017, with the following physical and financial attributes:

- annual generation of 780,000 MWh (i.e. annual capacity factor of 44½ per cent)
- short-run marginal cost (for operations and maintenance) of $15/MWh[30]
- entered a PPA that expires in 2030 for its entire capacity, at a $65/MWh strike price, consistent with strike prices for wind PPAs in 2017.[31] By contracting all of its capacity

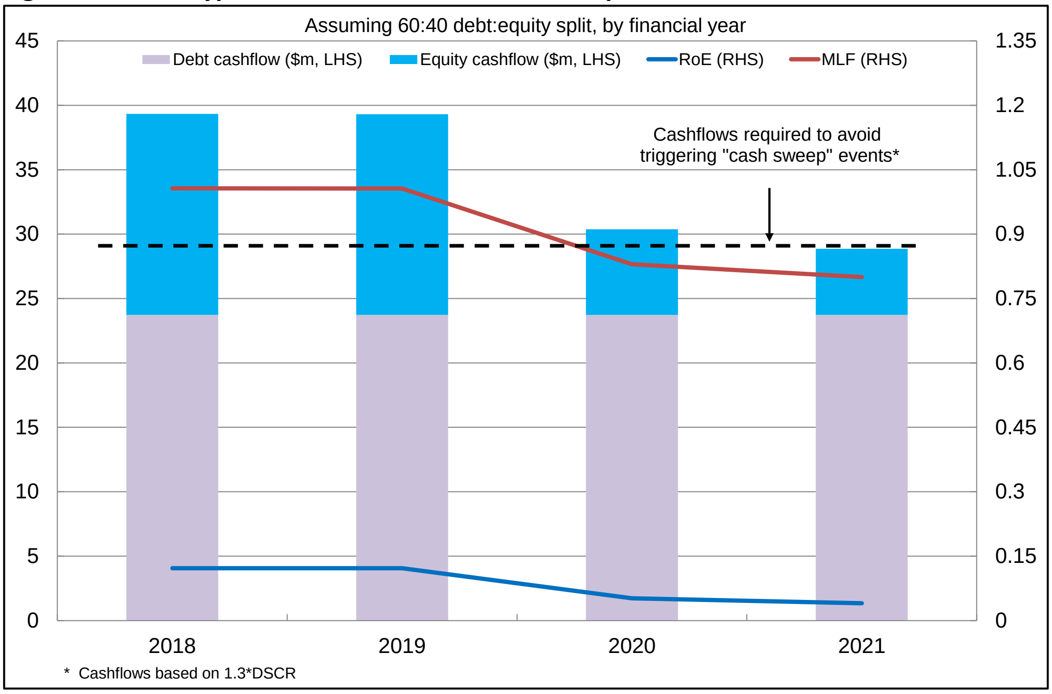
[29] In contrast, if curtailment occurs when spot prices are negative, then curtailment has a positive impact on a generator's spot market revenues, and no impact on spot revenues if curtailment occurs when spot prices are zero.
[30] This is a conservative assumption as the SRMC of VRE is likely to be closer to $0/MWh.
[31] For more details, see PricewaterhouseCoopers, 2017, *Optimising energy procurement via corporate PPAs*, available at: https://www.pwc.com.au/publications/pdf/optimising-energy-corporate-ppas-nov17.pdf

forward under a PPA, this generator's wholesale revenues are now solely determined by the strike price and volume generated; that is, the generator has no spot market exposure

- a gearing (i.e. debt-to-assets) ratio of 60 percent
- cost of debt based on the yield on bonds issued by 5-year BBB-rated non-financial corporates (4.3 per cent p.a. as at end-December 2016)
- MLF values of 1.0065 in FY2018, 1.0062 in FY2019, 0.8298 in FY2020 and 0.80 in FY2021. The values for FY2018-FY2020 are based on published MLFs for Silverton Wind farm in NSW.[32]

Based on the above assumptions, this hypothetical wind farm would be in equity lockup in FY2020 meaning that, under its agreements with lenders, it would not be allowed to pay any returns to equity holders until its debt commitments are fully serviced.[33] By FY2021, the potential return on equity would be 4%, down from around 12% in FY2018 (Figure 12).

Figure 12 The hypothetical wind farm's financial performance



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[32] See AEMO, *Regions and Marginal Loss Factors: FY 2019-20*, July 2020. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Loss_Factors_and_Regional_Boundaries/2019/Marginal-Loss-Factors-for-the-2019-20-Financial-year.pdf

[33] Equity lockup occurs when the debt service coverage ratio (DSCR) for the project falls below a pre-specified value (this value ranges across projects, but is typically in the order of 1.3-1.4). The project then goes into "lockup", meaning any cashflows in excess of operating costs are applied to debt facilities until the DSCR is restored to the pre-specified threshold value. Equity lockup is a mechanism designed to protect debt holders' financial interests and maintain project solvency.

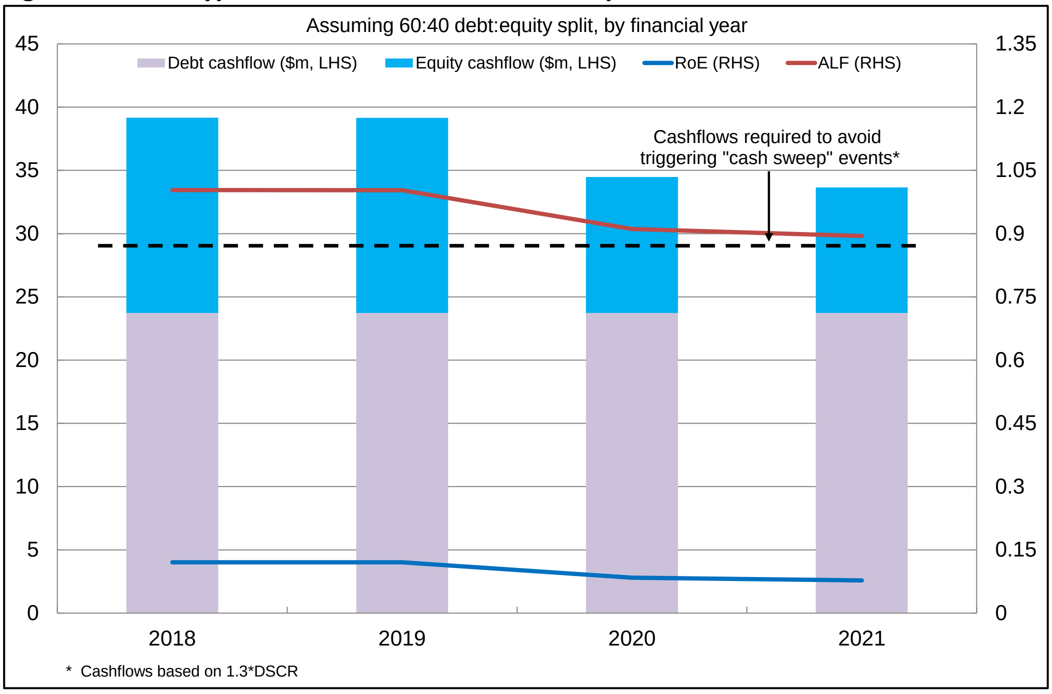
Source: Baringa Partners LLP

This example illustrates how falls in MLFs (i.e. increase in losses) can adversely impact a generator's revenues. MLF risk is borne first by equity holders, reflecting their first-loss-taking position in the capital structure, and then debt holders.

To see how MLF risk impacts the level and volatility of a project's revenues, and therefore its WACC, consider again the above example, where the only difference from the prior assumptions is that the MLF of the wind farm is set equal to the square root of the prior MLFs. This would be akin to using an average loss factor (ALF), a rule change request which the AEMC determined not to make, in February 2020.[34]

While cash flows decrease between FY2018 and FY2021, as per Figure 12, the generator defers equity lockup by one year (from FY2020 to FY2021). Revenue volatility is also lower, illustrated by the lower volatility in equity returns: the minimum realised equity returns are 7% (in 2021), compared to a minimum 4% under less stable MLFs (Figure 13).

Figure 13 The hypothetical wind farm's financial performance – more stable MLFs



Source: Baringa Partners LLP

In summary, the stylised example illustrates the following two findings:

[34] For more details, see AEMC, Transmission loss factors, Rule determination, 27 February 2020. Available at: https://www.aemc.gov.au/sites/default/files/2020-02/Final%20rule%20determination%20Transmission%20loss%20factors.pdf

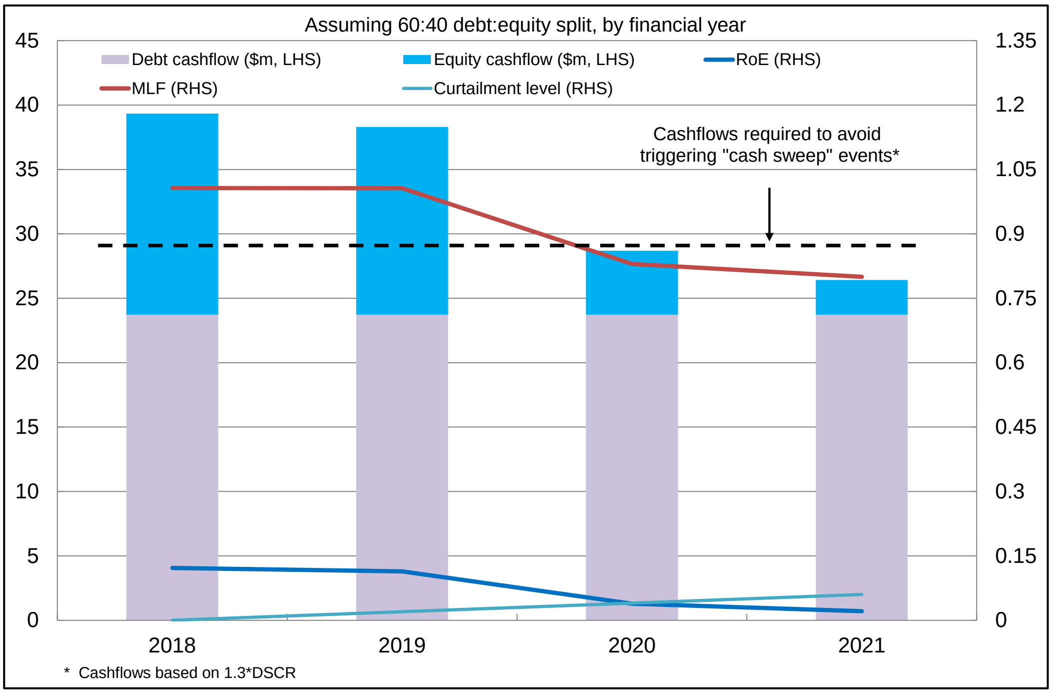
1. More stable MLFs would reduce the volatility of generator revenues, and in turn reduce generators' cost of capital. The positive relationship between revenue volatility and cost of capital is a well-known result in the corporate finance literature since the late 1950s.[35]
2. MLFs provide a clear locational signal – areas with higher and more stable MLFs are preferred to locations with lower and less stable MLFs, all else equal.

B.2 Stylised example: impact of changes in congestion

Continuing the stylised example developed in Appendix B.1, we now allow for a proportion of the wind farm's output to be curtailed: 0% in FY2018, 2% in FY2019, 4% in FY2020, and 6% in FY2021. All other assumed values, including MLFs, are the same as per Figure 12.

Congestion exacerbates the drop in the generator's revenues from the decline in MLFs, with revenues for FY2021 4% lower than corresponding revenues in Figure 12 (Figure 14). Like MLF risk, curtailment risk is borne first by equity holders: equity-investor returns fall to 2% in FY2021, around one-half of corresponding equity returns if there were no congestion. That is, the effect of congestion on equity investors is magnified by the project's degree of financial leverage.

Figure 14 The hypothetical wind farm's financial performance – impact of congestion



Source: Baringa Partners LLP

In summary, this stylised example illustrates two broad findings:

[35] See Modigliani, F., and Miller, M.H., 1958, *The cost of capital, corporation finance and the theory of investment*, American Economic Review, Vol. 48, pp. 261–297. Available at https://doi.org/10.1257/aer.103.4.i

1. Curtailment impacts generator revenues, with adverse impacts for those generators who contract forward their capacity. Moreover, the extent of adverse impacts increases as generators contract forward increasing proportions of their capacity.
2. Curtailment provides a clear locational signal – areas with lower congestion are preferred, especially for generators who have contracted forward their capacity via generation-following hedges such as PPAs.

Appendix C Baringa's transaction advisory services

Baringa's transaction advisory and due diligence services have supported over 50 buy- and sell-side processes for equity and debt financing of generation projects in the NEM.[36] There are three key projections that inform these processes:

1. Generation-weighted average (GWA) price projections
2. MLF projections
3. Curtailment projections

Together, these three projections inform spot market revenues expected by generators over the life of the project, with projected dispatched volumes adjusted for projected MLF and curtailment values.[37] This section briefly describes Baringa's MLF and curtailment models.

C.1 Baringa's MLF model

Baringa's MLF model mirrors closely AEMO's MLF modelling methodology as follows:

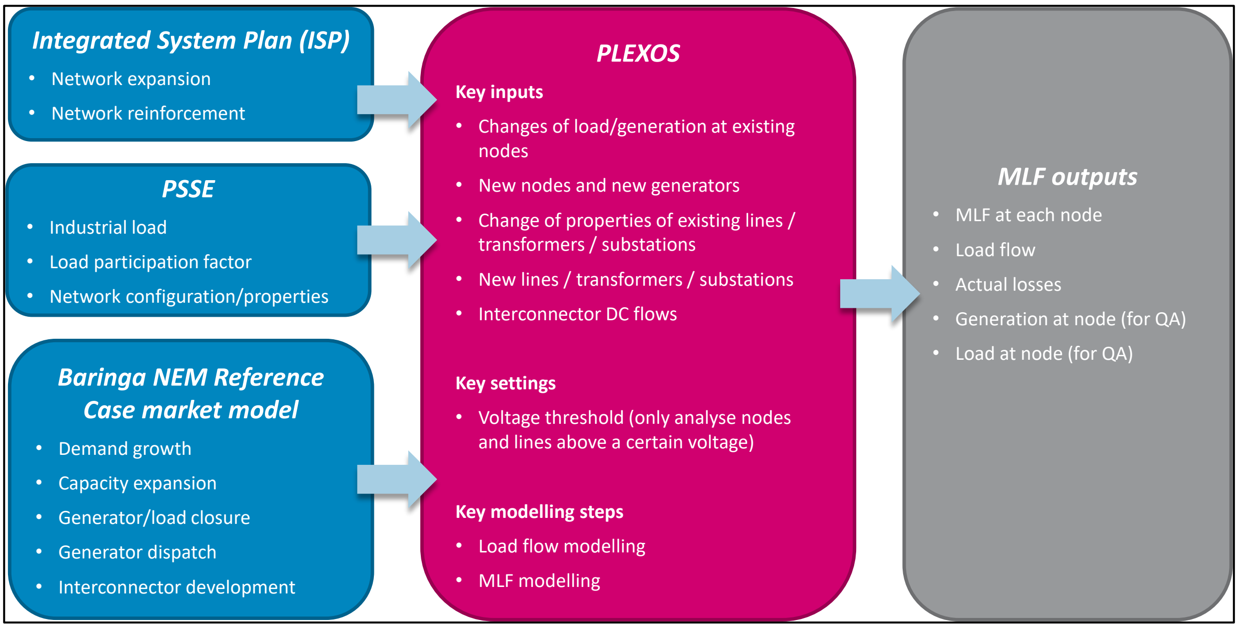
- Baringa obtains power flow and network configuration data from AEMO, and then performs a thorough mapping exercise to establish the relationships between generators, loads, lines, transformers, substations and other types of equipment in the power system critical for the modelling of MLFs
- Using this information, Baringa has built a power flow model in PLEXOS. To check the robustness of this model, Baringa carries out thorough backcast exercises to match closely the modelled MLF values with the MLF values published by AEMO
- Our MLF projection model interacts closely with Baringa's *NEM Reference Case* market model, taking key inputs such as generator expansion, demand growth, plant closure, interconnector development and EV deployment from Baringa's *NEM Reference Case*
- Baringa's views on the timing and magnitude of network augmentations and reinforcements are based on AEMO's ISP

Figure 15 illustrates the inputs, process (i.e. modelling mechanics), and outputs of Baringa's MLF model, including the Interaction between the MLF model and AEMO's ISP and PSSE datasets, and also with Baringa's *NEM Reference Case* market model.

[36] For more details, see https://www.baringa.com/en/industries/energy-utilities-resources/energy-markets/

[37] In addition, equity and debt investors are often interested in our FCAS price projections and FCAS causer pays projections, which also inform a project's business case and influence final investment decisions.

Figure 15 Baringa's MLF model: interaction with AEMO's ISP and Baringa's *NEM Reference Case*



Source: Baringa Partners LLP

C.2 Baringa's curtailment model

Baringa's curtailment model builds on the power flow model developed for the MLF projections.

In addition to representation of generators and load at each node and the main equipment items on the transmission network, the constraint model incorporates heat rate, start cost and variable operating & maintenance costs on all generators, as well as thermal ratings on key transmission equipment under normal and emergency conditions.

Generator dispatch is then economically optimised subject to thermal limits on transmission equipment, and also considers N-1 contingencies on select items on the transmission network.

Our analysis focuses on two forms of curtailment:

1. *Technical curtailment* that arises from binding network thermal constraints, both "system normal" and N-1 contingency thermal constraints.[38]
    a. Thermal constraints which are linked to the thermal limits of network components such as lines and transformer
    b. N-1 contingencies are thermal ratings-based constraints that require power flows on lines to not exceed their thermal ratings when a credible contingency occurs
2. *Market curtailment*, which arises when generators self-curtail due to a regional oversupply of zero marginal cost generation such as wind and solar. Prices are typically zero or low during market curtailment events.

[38] N-1 contingency-based thermal constraints are those that require power flows on lines to not exceed their thermal ratings when a credible contingency occurs.

In relation to market curtailment, Baringa's curtailment model uses a tie-breaking rule: When several generators are bidding at the same price at the RRN and the total available energy is greater than the load to meet, AEMO follows a tie-breaking rule which allocates the generation on a pro-rated basis in accordance with Cl. 3.8.16 of the NER

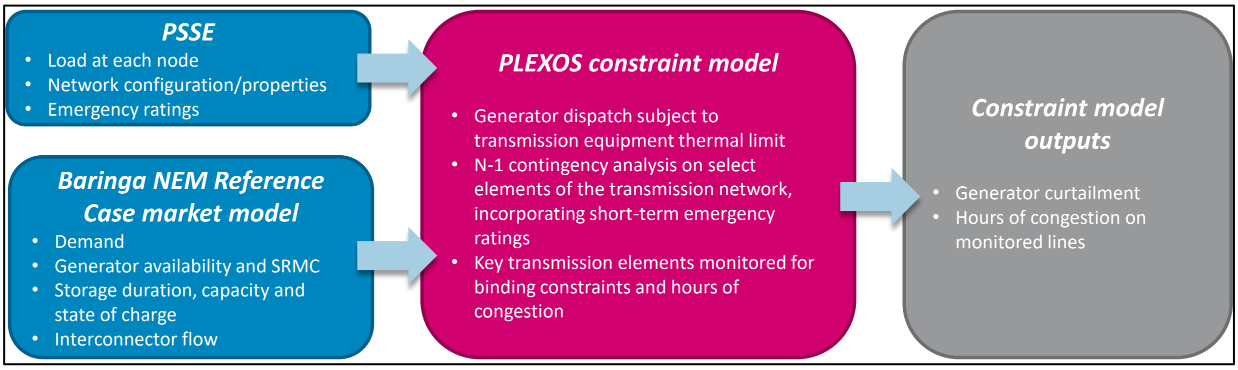
AEMO's NEMDE operates under the principle of security-constrained economic dispatch, which means in the context of curtailment that:

Baringa's MLF model mirrors closely AEMO's MLF modelling methodology as follows:

- technical curtailment would be applied first to generators, to ensure the grid operates in a safe way, and
- to the extent there is still oversupply of renewables at a regional level following technical curtailment, market curtailment will be applied using the tie-breaking rule

Figure 16 illustrates the inputs, process and outputs of Baringa's curtailment model.

Figure 16 Baringa's curtailment model: inputs, process, and outputs



Source: Baringa Partners LLP

C.2.1 Connection with NERA's curtailment modelling

NERA notes (see footnote 16, p13 of the NERA report) that their constrained-equation modelling is based on N-1 thermal ratings-based constraints. Using this model, NERA determines the system costs under Reform and then No-Reform, and in turn calculate the benefits of Reform. Hence, the modelling approach used by NERA to determine the benefits of Reform is **the very same approach** used by generation sector investors to project curtailment under the existing market design (i.e. No-Reform).

This therefore illustrates the two broad points made in section 2.6:

1. congestion signals currently exist in the NEM, generators are aware of these signals, and
2. generators do respond to congestion signals; indeed, generators use the very same tools and modelling approach that NERA uses to determine the benefits of providing price-based congestion signals.

In short, NERA's estimates of the benefits of Reform are overstated, as NERA's modelling and approach fails to fully take into account the existing locational signals in the NEM, and how generators respond to these signals.

Glossary

Abbreviation	Explanation
$, AUD	Australian Dollars (assumed to be real 2020 terms unless otherwise stated)
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ALF	Average Loss Factor
ASX	Australian Securities Exchange
COGATI	*Co-ordination of generation and transmission investment* (AEMC review)
CCGT	Combined Cycle Gas Turbine
CfD	Contract for Difference
DD	Due Diligence
DLF	Dynamic Loss Factor
DSCR	Debt Service Coverage Ratio
ESB	Energy Security Board
ESOO	Electricity Statement of Opportunities
FCAS	Frequency Control Ancillary Services
FTR	Financial Transmission Right
FY	Financial Year (specified as year to 30 June)
GJ	Gigajoule
GW	Gigawatt
GWA	Generation Weighted Average
IRSR	Intra-Region Settlement Residue
ISP	Integrated System Plan
IT	Information Technology
kW	Kilowatt
LCOE	Levelised Cost Of Electricity
LGC	Large-scale generation certificate
LMP	Locational Marginal Price

Abbreviation	Explanation
LRET	Large-Scale Renewable Energy Target
MLF	Marginal Loss Factor
MWh	Megawatt Hour
MW	Megawatt
NEM	National Electricity Market
NER	National Electricity Rules
NSW	New South Wales
PPA	Power Purchasing Agreement
PV	Photovoltaics
ppts	Percentage Points
OTC	Over The Counter
QLD	Queensland
RRN	Regional Reference Node
RRP	Regional Reference Price
SA	South Australia
SRMC	Short-Run Marginal Cost
TAS	Tasmania
TWh	Terawatt Hour
USD	US Dollars
VIC	Victoria
VWAP	Volume Weighted Average locational marginal Price
VRE	Variable Renewable Energy
WACC	Weighted Average Cost of Capital