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Cost Benefit Analysis of Access Reform: Modelling Report

Prepared for the Australian Energy Market Commission

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Executive Summary

The current market design in the NEM prices electricity to generators and loads at the Regional Reference Price (RRP) for each participating state, adjusted for a static estimate of Marginal Loss Factors (MLFs) and does not compensate generators who are not dispatched due to network constraints. In October 2019, the AEMC proposed a model of Access Reform which would provide sharper locational signals to market participants by introducing Locational Marginal Pricing for scheduled and semi-scheduled generators and scheduled loads (LMP), Financial Transmission Rights (FTRs) and dynamically-calculated losses.

The AEMC asked NERA Economic Consulting to provide a Cost Benefit Analysis to accompany its proposed reforms including:

- Reviewing international evidence on the implementation of analogous reforms and drawing top-down conclusions for the likely costs and benefits of reform for the NEM; and
- Quantifying the likely benefits of reform for the NEM using a bottom-up electricity market model.

The AEMC published our review of international evidence in March 2020.[1] We concluded that international experience suggested that the social benefit of Access Reform could fall within the range of $382 million to $877 million per year.[2] In our report, we noted that the benefits experienced in the NEM could differ from those experienced internationally. The benefits of Access Reform ("Reform") in the NEM may differ due to the scope of the reform, the supply and demand characteristics and network constraints in the NEM and because current transmission access arrangements in the NEM do not offer generators the firm access to the grid, as is common internationally prior to the implementation of LMP and FTRs. This report builds on our earlier work using a granular bottom-up model to estimate the potential benefits of access reform.

We use PLEXOS to Model the Benefits of Access Reform

Our analysis assumes that the AEMC implements Reform in the fiscal year from July 2025 to June 2026 and we estimate the benefits of Reform over the fifteen-year period from July 2025 to July 2040. We model the potential benefits of Reform using PLEXOS, a software package commonly in use in Australia and internationally for modelling electricity market outcomes. We use PLEXOS to estimate market outcomes under the Status Quo arrangements and given Reform. We estimate the benefits for society as the difference in system costs between No-Reform and Reform. We estimate the benefits of consumers based on the difference in wholesale (and ultimately retail) prices paid.

Throughout, we base our data and assumptions on the Electricity Statement of Opportunities (ESOO) and Integrated System Plan (ISP) assumptions book published by AEMO in December 2019. The ESOO/ISP database does not include a nodal representation of the NEM. We have developed a nodal representation of the NEM with over 1,000 nodes in

1 NERA, *Costs and Benefits of Access Reform*, Prepared for the Australian Energy Market Commission, 9 March 2020.

2 NERA, *Costs and Benefits of Access Reform*, Prepared for the Australian Energy Market Commission, 9 March 2020, Table 3.

PLEXOS, a cost-minimising market-modelling and system planning software package. This platform forms the basis of our market modelling of the NEM. We use the same nodal model structure for both our Status Quo and Access Reform cases to ensure that the differences in system costs or consumer prices we calculate do not reflect changes in the underlying assumptions regarding the physical characteristics of the network. Our modelling approach takes account of the reactance and resistance of the transmission lines in the system as well as thermal limits to reflect the operating constraints in the NEM.

PLEXOS relies on a cost-minimising algorithm. Accordingly, given the same nodal representation of the network, PLEXOS's logic would deliver the same efficient investment and dispatch in both the Reform and No-Reform cases. We model the inefficiency of No-Reform by running our models multiple times and completing offline calculations in order to mimic the market signals sent under current access arrangements. We describe our approach to estimating each of the major potential benefits of access reform below and in more detail in the chapters of this report.

Impact of Reforming Locational Signals on Investment in Generation and Storage

Current transmission access arrangements do not reflect the locational value of the energy being produced in real time. Generators located at nodes where the LMP is higher than the RRP will receive a locational penalty every time they generate (unless they bid unavailable and AEMO subsequently dispatches them). Generators located at nodes where the LMP is lower than the RRP will receive a locational subsidy every time they generate.

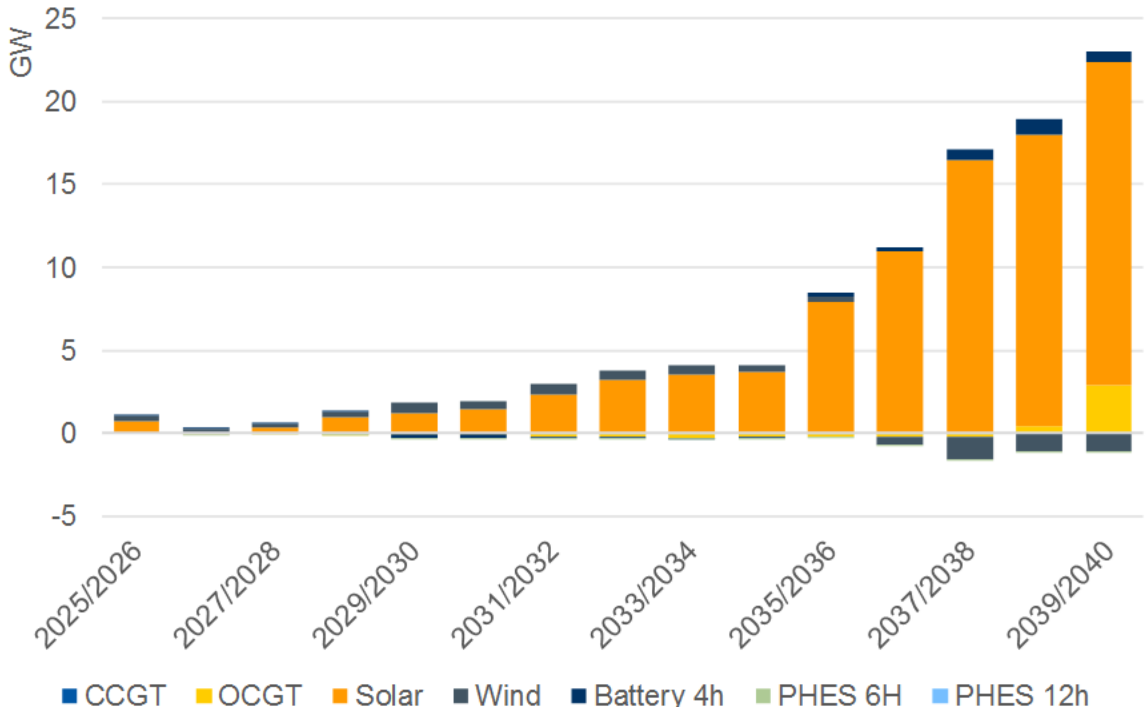
Our modelling approach assesses how the inefficiency of the current locational signals causes generation to be deployed in higher-cost locations on the grid over time. We estimate the subsidy (or penalty) that generators and storage effectively earn (or lose) from receiving the RRP under No-Reform relative to the economically-efficient signal generation would receive under Reform. We estimate how that subsidy or penalty drives the inefficient locational signals of future investment and higher-cost dispatch. Finally, we compare the total system costs and price outcomes that result from the case under No-Reform with the theoretically-efficient equilibrium that would occur under Reform.

Our modelling suggests that the primary impact of the current inefficient locational signals in the NEM is to promote investment in additional – and potentially inefficiently-located – capacity. Figure 1 shows the difference between the capacity mix in the No-Reform and the Reform cases. As can be seen from the Figure, our modelling suggests that the inefficiency of the locational signals under the current NEM design result in over 20 GW of additional capacity being constructed in the NEM by 2040, most of which is solar plant and occurs after the retirement of most of the coal plant in the system from 2035.

The additional capacity comes at a cost to society and consumers. In Net Present Value terms, social costs are higher by $454 million by 2035 and $1,738 million by 2040.[3] Consumers pay $1,629 million more by 2035 and $4,699 by 2040 in Net Present Value terms in our modelling.

[3] Here and throughout, by 'social costs' we mean the total costs in the system under the Reform and No-Reform state, that is, variable costs of generation and storages plus annuitised build costs and other fixed costs.

Figure 1: The No-reform Scenario Results in More Capacity Built (No-Reform *minus* Reform in GW)



Source: NERA Analysis of PLEXOS results

Impact of Reform on Transmission Investment

Our modelling results set out the impact of investment in generation and storage in the NEM and holds the transmission network constant across our Reform and No-Reform scenarios. Transmission investment may mitigate the impact of investment in generation and storage in inefficient locations on the grid by reducing the constraints between the sources of power and the load they serve. Transmission investment to relieve constraints could also increase the costs of No-Reform relative to Reform by encouraging investments in locations that would cause constraints to arise (following relief or in expectation of further relief).

We ran a simplified analysis on our PLEXOS results to check whether transmission investment would be likely to reduce the benefits of Reform. We made material simplifying assumptions in that analysis, including linearising the benefits of transmission investment, assuming a constant cost of transmission expansion of $2,000/km, analysing reinforcements to the existing grid only and not censoring the results for actionable projects of minimum efficient scale. Our simplifications contain a mix of assumptions which would tend to promote transmission investment and assumptions which would tend to inhibit it.

Our analysis suggests that the benefits of transmission investment may be higher under Reform than No-Reform. Although investment in capacity is higher and less efficiently-located in No-Reform, the excess generation and the similarity of marginal costs between neighbouring nodes in No-Reform results in lower congestion rent by the end of the period. Our results therefore indicate that the additional costs of No-Reform may be unlikely to be mitigated by Transmission investment.

Increased Efficiency of Dispatch from Eliminating Distorted Bidding

Generators in the NEM receive Regional Reference Prices adjusted for MLFs for their generation. When a node is export-constrained (i.e. the LMP is below the loss-adjusted RRP), AEMO constrains generators off without compensation if their offer price is above the shadow LMP at the node. These arrangements create an incentive for generators to bid artificially-low in order to secure dispatch whenever their marginal costs of generation are above the LMP but below the loss-adjusted RRP (so called "race to the floor" bidding). When a node is import-constrained (i.e. the LMP at the node is above the loss-adjusted RRP), generators may have an incentive to bid unavailable: If required to meet load, AEMO will direct unavailable generators to generate and pay them the 90th percentile of the spot price for generation.

We estimated the change in system costs by modelling the incentive of generators to race to the floor for the year from July 2025 to June 2026. We first identify the generators who are not fully dispatched but whose price if they generated would be above their marginal costs. We then re-ran PLEXOS with those generators and co-located generators with marginal costs below their price received submitting artificially-low bids at the market floor price. We find that total system costs increase by $140 to $180 million per year, the vast majority of which results from coal plant bidding at the market floor. Over the sample period to 2040, the volume of coal generation on the system decreases by more than three quarters. We therefore estimate the social benefits over time by indexing the increase in system costs in the sample year with the coal generation on the system over time. We estimate total benefits in Net Present Value terms of $795 million to $1,020 million.

Our analysis may not reflect the frequency with which market participants race to the floor in practice and the balance of risks lies towards overstatement of the benefit, at least in the sample year. Insight from previous studies of the NEM, for instance, suggests that renewable plant might have a higher incentive to bid at the floor than what is shown in our model. Our approach assumes that market participants bid to the floor whenever the individual generator would have an incentive to do so. In practice, market participants have imperfect information and may not bid to the floor for fear of having to generate at a loss. Moreover, our modelling is at generator-level and ignores portfolio effects which may prevent generators with market power in constrained areas from artificially decreasing their bids. Finally, the constraints in our model are exclusively thermal, therefore only a subset of the constraints generators face in real life, which might create further incentive to bid disorderly.

On the other hand, indexing to the volume of coal generation on the system over time is arguably conservative and may understate benefits. Other technologies with variable costs may bid to the floor more frequently as the capacity mix in the NEM evolves and LMPs become more volatile in the NEM over time. Our lower-bound is deliberately conservative in that it prevents any displacement of renewables by coal plant.

Introducing Dynamic Losses

Static MLFs used in the NEM do not reflect the dynamic losses incurred by the system. As a result, AEMO may give priority in dispatch towards plant with higher losses, measured in real time, but a lower static MLF.

We estimate the impact of Dynamic Losses on system costs in a three-step process.

- First, we estimate dispatch in a lossless system for a sample year from July 2025 to June 2026. Each plant's marginal cost of generation adjusted by its MLF determines its position in the merit order.
- Second, we calculate the system costs of that same dispatch in a system with dynamically-calculated losses and adjust for any additional curtailment or dump energy.
- Third, we calculate the system costs in a system with dynamic losses determining the cost-minimising dispatch.

Our estimate of the social benefits of introducing dynamic losses is the difference between the system costs in the second and third steps above. We estimate total benefits of $102 million in the sample year and $661 in NPV terms.

Our approach to quantifying the benefits of introducing dynamic losses is likely to be an overstatement, at least insofar as it is an estimate of the increased efficiency of short-run dispatch. Our method captures differences between the second and third steps in both the volume of electricity that needs to be procured to cover losses (the "volume effect") and the effective relative prices of generators' bids (the "price effect"). In practice, we understand that AEMO forecasts gross demand including losses and its demand forecasting method adjusts for the volume that it will be necessary to procure dynamically in real time based on that locational forecast. In other words, AEMO at least partially mitigates the volume effect contained within our estimate.

Our method does not address the impact of introducing dynamic loss factors for investment in the system. Introduction of dynamic losses would reward plant based on the losses the system would experience in real time. Accordingly, one would expect a positive impact on the efficiency of investment because it would introduce a more granular price signal which would reflect system costs and needs. Our estimate understates the benefits of Reform insofar as it does not include any benefits for the improved efficiency of investment. However, we note that that static loss factors are updated annually and therefore the distorted signal only exists *within* years.

Impact on Liquidity and Risk

Under No-Reform generators face the risk that they will be constrained off without compensation. Generators who have sold hedging contracts forward at the RRP are exposed to the risk that at times of high prices they will be unable to generate and are financially exposed to the difference between the spot and strike prices of their hedging contracts. The introduction of LMP with one-way FTRs allows generators to hedge downside constraint risk. The AEMC's proposal for Reform includes both Time of Use FTRs for particular hours of the day, aimed at generators who generate only in particular hours, and continuous FTRs for the whole day, aimed at baseload generators.

Some market participants have previously expressed concern that the introduction of LMP with FTRs would reduce liquidity in the NEM. Their arguments include that LMP exposes market participants to additional price risk and not all generators may be able to secure FTRs for all of their capacity.

We conducted a deliberately conservative analysis which examined the risks faced by generators after the introduction of LMP with FTRs. We examined the risks faced by individual generators (rather than across portfolios) and the impact of one-way, continuous

FTRs only (i.e. we don't analyse Time of Use FTRs which would better match the expected profile of generation for non-baseload plant). We found minimal change in the exposure of generators who had hedged power in advance to market-price and volume risk as a result of Reform. Whether measured by mean dispersion of cash-flows or by number of periods with negative cash-flows, baseload generators' risk exposure fell on average following Reform and incentives to hedge typically remained stable or increased. As a result, we conclude that there is no evidence that liquidity of hedging products is likely to fall following the implementation of Access Reform.

Impact on Competition

Introducing FTRs in place of the settlement residue auction (SRA)_units should theoretically offer improved inter regional price risk management. If an inability to hedge locational price risk is currently hindering interregional competition, this swapping SRA units for FTRs may result in improved competition in generation and retail markets. For this to be the case, a number of conditions must hold:

- FTRs provide a material improvement in locational price hedging compared to SRA units and the alternative methods of mitigating locational price risk (e.g. co-locating generation and retail) stymy competition;
- But-for locational price risk, there are no material barriers to entry/expansion in the markets in question and markets are not expected to be in a situation of excess supply; and
- There must be an existing competition problem in the markets in question, such that an improvement in could competition could actually occur;

Regarding these three points:

- FTRs should theoretically provide a superior hedge against locational price risk, but the evidence available to us that generators consider SRAs to be ineffective is essentially anecdotal. However, it does appear to be true that the vertically integrated generators co-locate their generation and retail. At the same time however, most recent entry in generation has been by non-vertically integrated players which may suggest that a lack of an effective inter-regional hedge may not be an important factor for generator competition.
- The ACCC has found that there are not material barriers to entry and expansion and evidence suggests there is a large need for new generation capacity in the future; and
- The ACCC and AER already have existing concerns about competition in both the retail and generation markets.

We therefore think it is plausible that the introduction of FTRs in the place of SRA units will result in an improvement in retail and generator competition. On the other hand, introducing FTRs simply swaps one *inter* regional hedging product for another and at the same time the reforms change the way *intra* regional risk is managed. Given we have not been able to verify the incremental improvement in risk management from swapping SRAs for FTRs, it is difficult to draw conclusions about the materiality of the improvement in risk management. Similarly, most new generation investment appears to be coming from non-integrated players, which might suggest locational risk is not hindering competition, at least in generation. We therefore calculate a range for the potential competition benefit with a moderate impact on competition (a price and variable cost decrease of 0.5% in retail and generation markets) as the upper bound and zero as a lower bound, given that we cannot rule out there being no material impacts on competition. This gives a range in NPV terms for the social benefit of $0 – $209m. Improved competition could also result in wealth transfers if existing volumes of electricity if consumers pay lower prices for their existing consumption of electricity. We estimate total transfers in NPV terms of $0 – $1,687.2m.[4,5]

Summary of Results and Comparison with International Benchmarks

To summarise our results, we calculate three broad metrics:

- **Social benefit:** The improvement in economic efficiency, which is quantified as the net reduction in system costs, and in the case of improved competition, additional surplus[6] due to increased consumption/generation of electricity;
- **Wealth transfer:** reductions in prices can occur that do not result in any change in the underlying volume of electricity generated/consumed or the costs of producing that volume of electricity. These price reductions redistribute wealth between generators and consumers, making consumers better off without any corresponding improvement in economic efficiency. Economists therefore refer to these effects as "wealth transfers"; and
- **Consumer benefit:** this is calculated as the sum of the social benefit and the wealth transfer, on the assumption that changes in system costs ultimately accrue to consumers;[7]

As summarised in Table 1 below, we estimate that the Reform, including the introduction of dynamic losses in the NEM-DE, could yield social benefits of over $3 billion in NPV terms, discounted to 2020. More than half of that benefit occurs in the first ten years of the reforms. In the earlier part of the period, most benefits accrue from improved efficiency of dispatch (items 2 and 3 in the Table). However, as investment needs ramp up towards the end of the period, the benefits from improved investment signals exceed the short-term benefits from dispatch as new plant locates in more efficient locations.

Benefits to consumers are larger than social benefits. Under No-Reform, generators receive the congestion rent in the system because they receive the RRP, albeit adjusted for MLFs. Under Access Reform, consumers will pay generators only the locational value of the energy they produce. As a result, our analysis suggests that consumers receive a wealth transfer

4 Note that this figure sums together transfers as a result of improved generator and retailer competition. In the generation market, transfers due to lower prices are between generators and retailers. These are therefore only a consumer benefit if they are passed through to end consumers. This figure therefore represents an upper bound on the transfer.

5 Note that this figure differs from that presented in Table 1 below. This is because the figure in Table for the transfer takes the total transfer and nets off the producer surplus gain, which is not a consumer benefit and therefore should be stripped out when calculating the consumer benefit.

6 Where "consumer surplus" is the difference between a consumer's willingness to pay for electricity and the price they pay for the additional volumes of electricity consumed. "Producer surplus" is the difference between the price generators receive and the cost of producing the additional output (in effect, the margin on additional sales).

7 Note that we net off the producer surplus change component of the social benefit when we calculate the consumer benefit, on the basis that this is a pure producer benefit.

from generators of approximately a further $3 billion over the modelling horizon in NPV terms, most of which falls in the final five years of the modelling horizon to 2040. If a competition benefit arises, this could add up to approximately $1.6b to consumer benefit in NPV terms.

The Table assumes that all reductions in system costs ultimately accrue to consumers. Accordingly, we have added the social cost reductions from introducing dynamic losses and eliminating the race to the floor to the price reduction in our long-term expansion modelling set out in Chapter 3.

Our bottom-up modelling is broadly consistent with the top-down analysis we prepared for the AEMC in March 2020.[8] Our estimates of social benefits of reform lie within the range of social benefits we estimated based on international benchmarks (of $2,318 million to $5,323 million stated in equal terms). Our estimates of consumer benefits overlap with, but are at the higher end of the range considered in our previous report (of $1,811 million to $8,217 million), albeit above our preferred estimate for the *annual* benefits of Reform.

Table 1: Estimated Social and Consumer Benefits of Access Reform

		Annual benefits 2026 (2026 $m)		NPV of Benefits (discounted at 7 per cent per year, 2020$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		1,738	
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	209
5	**Total social benefit**	**308**	**358**	**1,663**	**2,002**	**1,531**	**1,626**	**3,194**	**3,629**
6	*Social benefit (w/o 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 from generators/retailers to consumers*	*0*	*200*	*0*	*1,119*	*0*	*536*	*0*	*1,655*
9	**Total consumer benefit**	**414**	**662**	**2,839**	**4,297**	**3,316**	**3,948**	**6,155**	**8,245**
10	*Consumer benefit (w/o dyn. losses)*	*312*	*561*	*2,329*	*3,787*	*3,165*	*3,796*	*5,494*	*7,583*

Source: NERA Analysis
** This figure is net of the producer surplus increase in (4), as this should not be counted when adding the social benefit and wealth transfer to give the consumer benefit.*

[8] NERA (2020), *Costs and Benefits of Access Reform – Prepared for the AEMC*, 9 March 2020.

1. Introduction and Overview

Under the current transmission access arrangements, the National Electricity Market (NEM) is divided into five states (Queensland, New South Wales, Victoria, South Australia and Tasmania). In each state, generators earn a Regional Reference Price (RRP) for their output, modified by a static Marginal Loss Factor (MLF). The Australian Energy Market Operator (AEMO) dispatches generation in the NEM and determines the MLF for each generator on an annual basis based on an estimate of the average marginal losses imposed by each generator's production. When system constraints arise, AEMO may constrain generators off without compensation, even when those generators bid prices that are below the RRP adjusted for the generator's MLF.

The Australian Energy Market Commission (AEMC) has found in its review that the current arrangements do not reflect the locational value of electricity of on the system.[9] Taken as package, they offer incentives to invest in generation in locations which may not be cost-minimising for society as a whole. The absence of compensation when constrained off creates incentives for distorting bidding and dispatch. The use of static marginal loss factors does not accurately signal the losses that the system incurs from dispatch in real time.

In October 2019, the AEMC proposed an alternative access model which would better signal the locational value of energy to generators and loads. The AEMC's proposed access model incorporates Locational Marginal Pricing (LMP), Financial Transmission Rights (FTRs) and dynamic losses in place of static MLFs. The AEMC asked NERA Economic Consulting to provide a Cost Benefit Analysis to accompany its proposed reforms. In particular, the AEMC asked NERA to:

- Review international evidence on the implementation of analogous reforms and draw top-down conclusions for the likely costs and benefits of reform for the NEM; and
- Quantify the likely benefits of reform for the NEM using a bottom-up electricity market model.

The AEMC published our review of international evidence in March 2020.[10] We concluded that international experience suggested that international experience suggested that the benefit of Access Reform could fall within the range of $382 million to $877 million per year.[11] We noted that evidence from international experience may not accurately reflect benefits in the NEM due to:

- differences in the precise reforms being implemented. International reforms often included multiple reforms at once which were not directly analogous to the package of reforms proposed for the NEM;
- institutional differences between the NEM and other jurisdictions. For instance, the jurisdictions we reviewed offered firm access with compensation for being constrained off prior to the introduction of LMP;

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9 AEMC (21 December 2018), Coordination of Generation and Transmission Investment

10 NERA, *Costs and Benefits of Access Reform*, Prepared for the Australian Energy Market Commission, 9 March 2020.

11 NERA, *Costs and Benefits of Access Reform*, Prepared for the Australian Energy Market Commission, 9 March 2020, Table 3.

- differences in the capacity mix and supply and demand conditions between the NEM and other jurisdictions. For instance, gas-fired CCGTs dominated the California electricity system at the introduction of LMP. The principle benefits of reform allegedly stemmed from reduced variable costs of operating gas plant. In the NEM, gas plant account for less than 20 per cent of total installed capacity.[12]
- The Cost Benefit Analyses we surveyed internationally frequently omitted potentially-important categories of benefits that may materialise in the NEM. For instance, most international Cost Benefit Analyses did not evaluate the dynamic benefits from sending better locational signals for investment. Our review of international evidence we relied on a single estimate from the state of New York for the benefits of better locational signals for investment, given this lack of alternative sources.

Given the differences between the NEM and international jurisdictions and the potential inadequacy of relying purely on international comparisons, the AEMC asked us to provide bottom-up analysis based on conditions in the NEM itself. This report sets out NERA's Analysis of the potential costs and benefits of Access Reform in the NEM based on that bottom-up modelling. It proceeds as follows:

- Chapter 2 provides an overview of our modelling approach
- Chapter 3 describes the benefits and impacts on consumers that would occur under Access Reform due to improved siting of generation and storage;
- Chapter 4 considers the impact of allowing for transmission reinforcement in our modelling and the directional impact that allowing for transmission expansion would have on our results;
- Chapter 5 sets out the benefits that would occur from Access Reform as a result of eliminating Race to the Floor bidding;
- Chapter 6 quantifies the potential benefits from replacing the current static MLFs with explicit dynamic losses in the NEM Dispatch Engine (NEM-DE);
- Chapter 7 analyses the impact of Access Reform (and FTRs in particular) on liquidity and risk for market participants;
- Chapter 8 assesses the impact of Access Reform on competition in generation and retail; and
- Chapter 9 summarises our results and compares them with international evidence on the impact of reform.

Our analysis of the impact of FTRs on liquidity and risk depends on the extent to which FTRs are firm. In addition to the Chapters above, we include an analysis of the impact of transmission outages on the settlement residues that back FTRs in Appendix A.

[12] In 2020/2021. Gas capacity then reduces to 9% of the total by 2040, according to our modelling.

2. Modelling Set-up and Assumptions

Our overarching approach to calculating the benefits of Reform was to estimate market outcomes in the Reform and No-Reform cases and estimate the differences in social costs and distributional effects. To our knowledge, no nodal model of the NEM existed with which we could conduct our analysis. As a result, we developed a nodal model for this assignment. In producing our results, we drew heavily on assumptions published by AEMO. This Chapter details our approach and assumptions and proceeds as follows:

- Section 2.1 describes our overall modelling set-up and approach;
- Section 2.2 describes our approach to defining the nodes on the network;
- Section 2.3 describes our approach to projecting demand by node;
- Section 2.4 explains our capacity assumptions; and
- Section 2.5 sets out our method for modelling generation expansion.

2.1. Model Set-up and Modelling Approach

Throughout our modelling exercise, we base our data and assumptions on the Electricity Statement of Opportunities (ESOO) and Integrated System Plan (ISP) assumptions book published by AEMO in December 2019.[13] We describe where we have departed from the Central scenario assumptions in that assumptions book in this Chapter.

The ESOO/ISP PLEXOS database does not include a nodal representation of the NEM. We have developed a nodal representation of the NEM in PLEXOS, a cost-minimising market-modelling and system planning software package, with expert input from AEMC staff on the nodal constraints and congestion in the NEM. This platform forms the basis of our market modelling of the NEM and, with data from AEMO's input and assumptions book, allows us to model operations in the NEM for any period of time between July 2019 and June 2040.

Our high-level approach is to model market outcomes by running our PLEXOS model under two scenarios:

- No-Reform, where the prices generators earn depend on the RRP and Marginal Loss Factors (MLFs); and
- Reform, where generators earn locational marginal prices.

Having obtained market outcomes for the above two scenarios, we evaluate the net benefits of access reform by calculating the change in system costs between the two scenarios and the distributional impacts by assessing the change in prices paid by consumers. In practice, we have only one, nodal, version of the PLEXOS model that we use for all of our modelling work. By having only one representation of the physical network, we can be sure that there

13 AEMO (17 October 2019), 2019 forecasting and planning scenarios, inputs, and assumptions. PDF URL: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2019/2019-to-2020-forecasting-and-planning-scenarios-inputs-and-assumptions-report.pdf?la=en

Excel database URL: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/2019-input-and-assumptions-workbook-v1-3-dec-19.xlsx?la=en are no differences in physical constraints between Reform and No-Reform which drive differences in system costs.

Because the basic set-up is nodal, PLEXOS's algorithm seeks to model outcomes including price-setting and optimal investment in the Reform world. Using a cost-minimising algorithm and nodal inputs, PLEXOS does not have the ability to model, for instance, suboptimal construction that might occur in No-Reform (although one can assume different settlement models for dispatch). Accordingly, we run the model multiple times to quantify some benefits and complete offline calculations based on our initial modelling results to estimate the market outcomes under No-Reform (we describe those runs and calculations in detail in Chapters 3 to 6 below). We also conduct multiple modelling runs in order to reduce run-times and solve the optimisation problems in steps to ensure that PLEXOS can find a feasible solution. In particular we conduct two high-level categories of runs:

- **Long-term runs:** PLEXOS is (indeed as similar tools would be) unable to model endogenous construction of new plant with hourly dispatch and typically relies on less granular sample hours to estimate new entrant. We run a PLEXOS Long-term plan with relatively low granularity, e.g. 24 blocks per month, to estimate new entry ("long-term runs").
- **Short-term runs:** PLEXOS is capable of running a granular, short-term dispatch, without endogenous construction, on a half-hourly, hourly or daily basis. PLEXOS is also able to run that short-term dispatch repeatedly over a long-term horizon. In short-term dispatch-mode, PLEXOS will also conduct medium-term runs over calendar years in order to dispatch storage (whose dispatch depends on future prices). For these runs, we take the investment pattern calculated with the Long-term plan as given.

2.2. Defining the Nodal Network

The ESOO/ISP database does not provide a nodal representation of the NEM. We developed a nodal PLEXOS model on the basis of the existing regional one and data provided by AEMO. The resulting nodal infrastructure is a representation of the NEM's "system normal" configuration, that is, the baseline state of the system in which transmission elements are in service and operating in their normal configuration.[14] There are 1,060 nodes in total – 1,058 in the first year plus two entering the system in later years to accommodate the Snowy 2.0 pumped hydro complex, as planned in the 2020 ISP.[15] Our PLEXOS nodes are a synthetic representation of real-life substations that connect lines and allow generators to input energy to the grid; in practice, a PLEXOS node can be the equivalent of multiple real-life connection points combined into a substation. For instance, the model may show three power plants belonging to the same complex (e.g. Bayswater plants 1, 2 3, and 4) to be connected to the same node, while in reality each plant has its own connection point.

Table 2.1 below summarises the number of nodes in every region and the corresponding Regional Reference Node.

14 AEMO (May 2020), Victorian Transfer Limit Advice – System Normal, p.27.

15 AEMO (31 July 2020), 2020 Integrated System Plan, para B2.1.

Table 2.1: Summary of Nodes per Region

	Number of Nodes	Reference Node	RRN Voltage (kV)
NSW	328	Sydney West	330
QLD	303	South Pine	275
SA	216	Torrens A Power Station	275
TAS	93	George Town	220
VIC	120	Thomastown	220

Source: AEMC/NERA PLEXOS model

The database includes a detailed transmission network linking the nodes. The transmission infrastructure has 1,897 lines. The lines are combined with a contingency representation, to reflect AEMO's network security practice of monitoring lines and diverting flows to other lines in case of faults.[16]

We have assumed that Priority 1 and 2 projects in AEMO's 2020 ISP go ahead plus the Marinus Link Line from 2036. Priority 1 and 2 projects are either listed as "committed" or "actionable" by AEMO. AEMO expects preparatory work for the Marinus Link project to begin by 2023, before the AEMC will have implemented Access Reform. Other Priority 3 projects are currently listed as not actionable and insufficient data exists in AEMO's ISP to identify clearly to which nodes the projects would connect.[17] The transmission infrastructure identified in the Draft 2020 ISP, as well as the current ISP, is meant to strengthen the network in Renewable Energy Zones (REZs). We have not explicitly modelled this, although some of the project included may include some REZ development – in particular, the Western Victorian Augmentation.

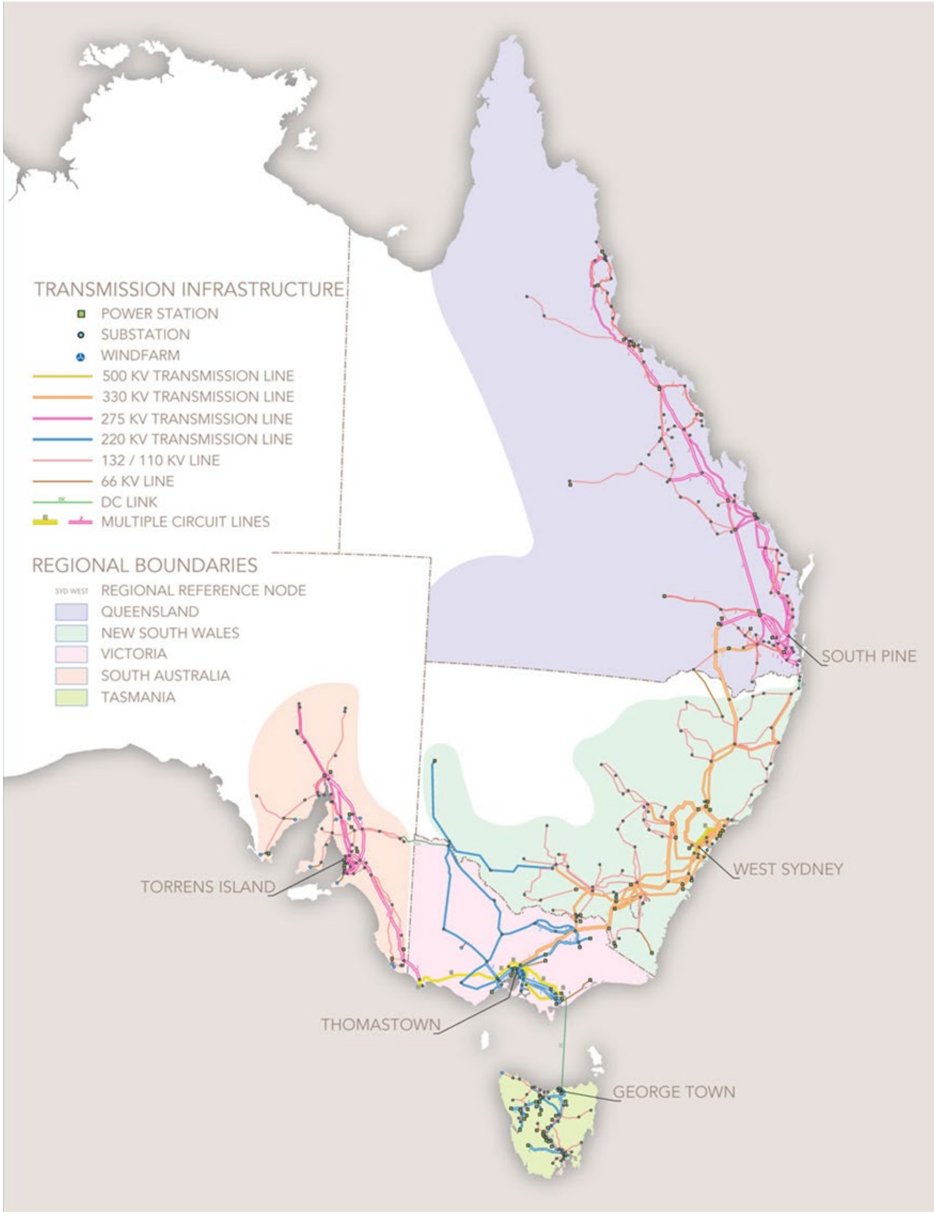
Throughout the modelling exercises, flows modelled in this database obey Kirchhoff's second law and the lines have physical properties (reactance and resistance) as well as a thermal representation.[18] Using these physical properties ensures that the power flows we model reflect as closely as possible the feasible dispatch in the NEM.

16 Specifically, we include an N-1 security envelope in our modelling.

17 AEMO (31 July 2020), 2020 Integrated System Plan, Executive Summary, Section E, pp.13-16.

18 Kirchhoff's second law states that the (directed) sum of potential differences across a closed loop in a circuit is zero. Source: Royal Academy of Engineering.

Figure 2.1: The National Electricity Market Transmission System



Source: AEMC

2.3. Projecting Demand

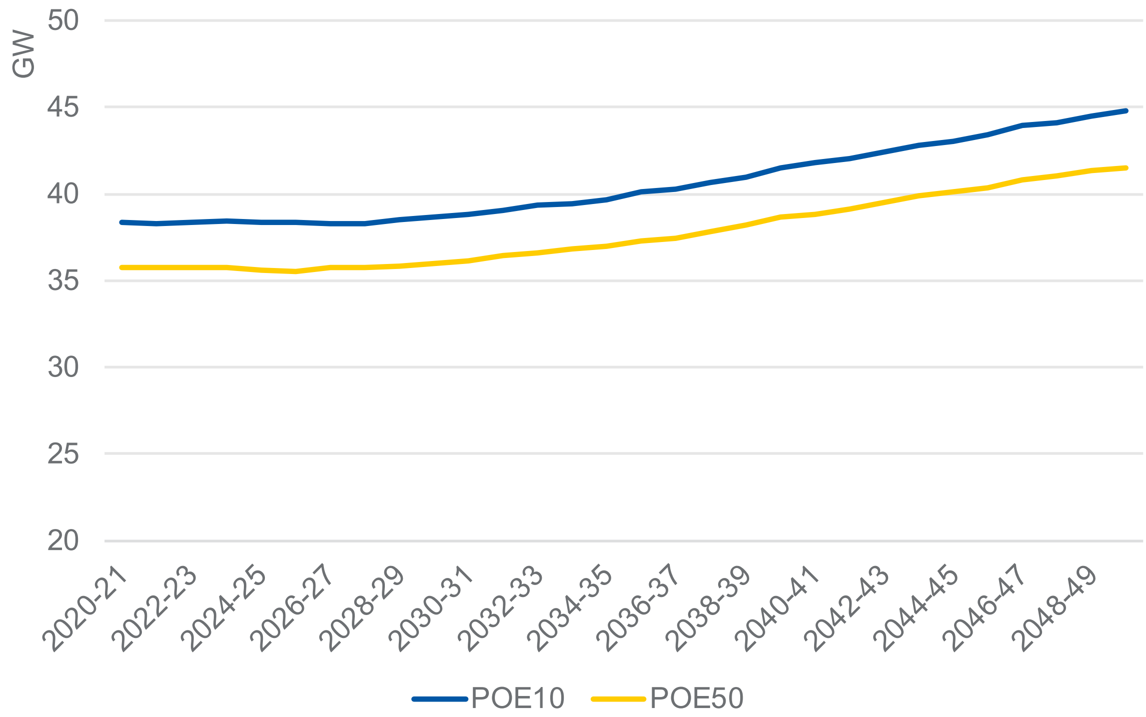
The ISP contains assumptions on regional demand only. We allocated load to nodes based on "load participation factors" provided by the AEMC, which was derived from data provided by AEMO.

- For long-term expansion, we model demand using the Probability of Exceedance 10 (POE-10, i.e. the demand forecast at the upper decile of the distribution) demand scenario from AEMO's ISP. We select the POE-10 scenario rather than the POE-50 because the POE-50 reflects the investment that would be necessary to meet *median* demand. In practice, however, because returns are asymmetrically distributed to the upside, one might anticipate that generators would invest to meet a higher peak.

- For short-term modelling runs, we use POE-50 demand forecasts. We understand from the AEMC's input that this dual approach is common practice in AEMO's modelling exercises.

Figure 2.2 shows the evolution of the two forecasts over the entire ISP horizon (2020 to 2050).

Figure 2.2: Summer Peak Demand, Central Scenario



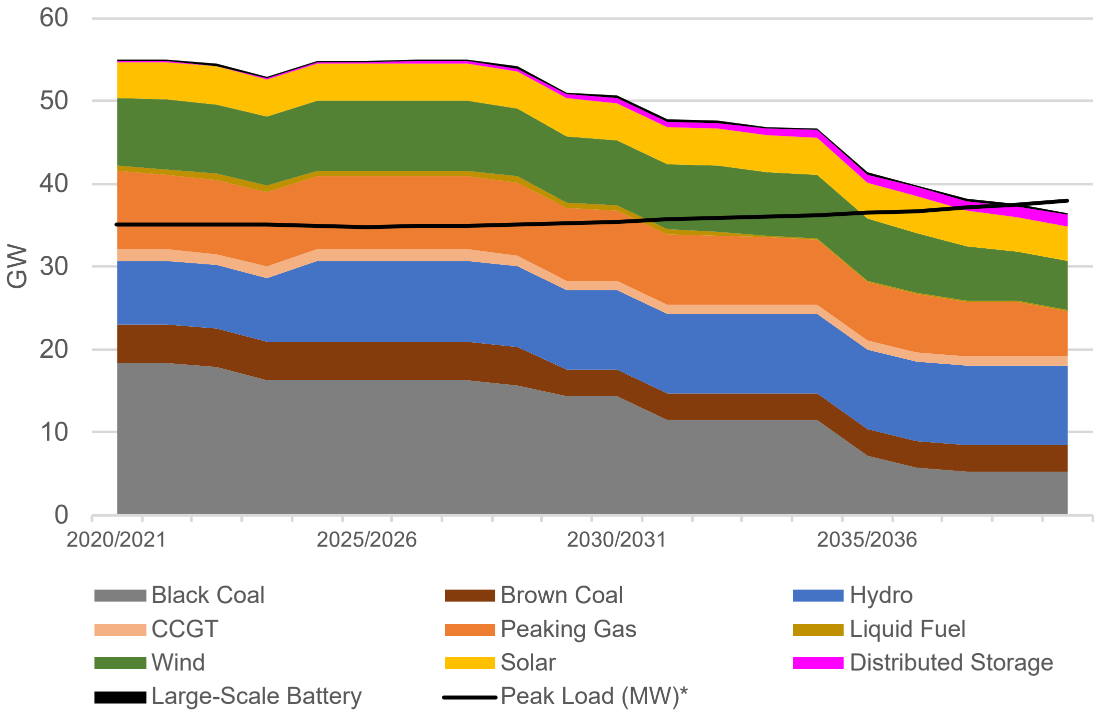
Source: AEMO (December 2019), ISP Input and Assumption Workbook.

2.4. Generation Capacity and its Properties

The ESOO/ISP regional models allocate all generation to the region's reference node. We matched generators to nodes through a process of iterating data requests with the AEMC and investigating the physical locations of the network connection points and generations. Our nodal database assigns generators to their nearby substation/set of buses.

We adopt ISP 2020 assumptions on the existing generation fleet; we also exogenously schedule "committed" projects – largely solar, wind and pumped hydro – expected to enter the network between 2020 and 2039. We retire capacity following expected retirement dates in the ISP input and assumptions material. As shown in Figure 2.3Figure 2.3 below, the majority of black coal capacity will retire by the end of the modelling horizon, as new "committed" renewables are scheduled to enter.

Figure 2.3: Existing Capacity Mix, 2020-2040



Source: AEMO (December 2019), ISP Input and Assumption Workbook. Peak Load POE50.

We use ISP 2020 assumptions on fuel prices in real 2020 $/GJ,[19] as shown in Figure 2.4, Figure 2.5, and Figure 2.5 below. As can be seen from the Figures, AEMO forecasts that gas prices will rise in real terms until the early 2030s before plateauing until the end of the modelling horizon. Coal prices remain broadly flat in Queensland and Victoria but rise by around $1/GJ by the mid-2030s in New South Wales.

We model forced outage rates with the 2019 ESOO "Outages All Average" scenario. AEMO calculates outage rates at station level and aggregates it by technology type. The "All Average" scenario represents the average outage rate for each technology type aggregated across historical years 2015/16, 2016/17, 2017/18 and 2018/19.[20]

We have modelled the dispatch of renewable plants using generation traces obtained from the ISP 2020 database. Traces are available half-hourly at plant level, for existing plant, or by Renewable Energy Zone (REZ) for candidate entrants; they show the plant's rated generation capacity in every period, normalised to a 1 MW unit, as shown in Figure 2.7Figure 2.7.

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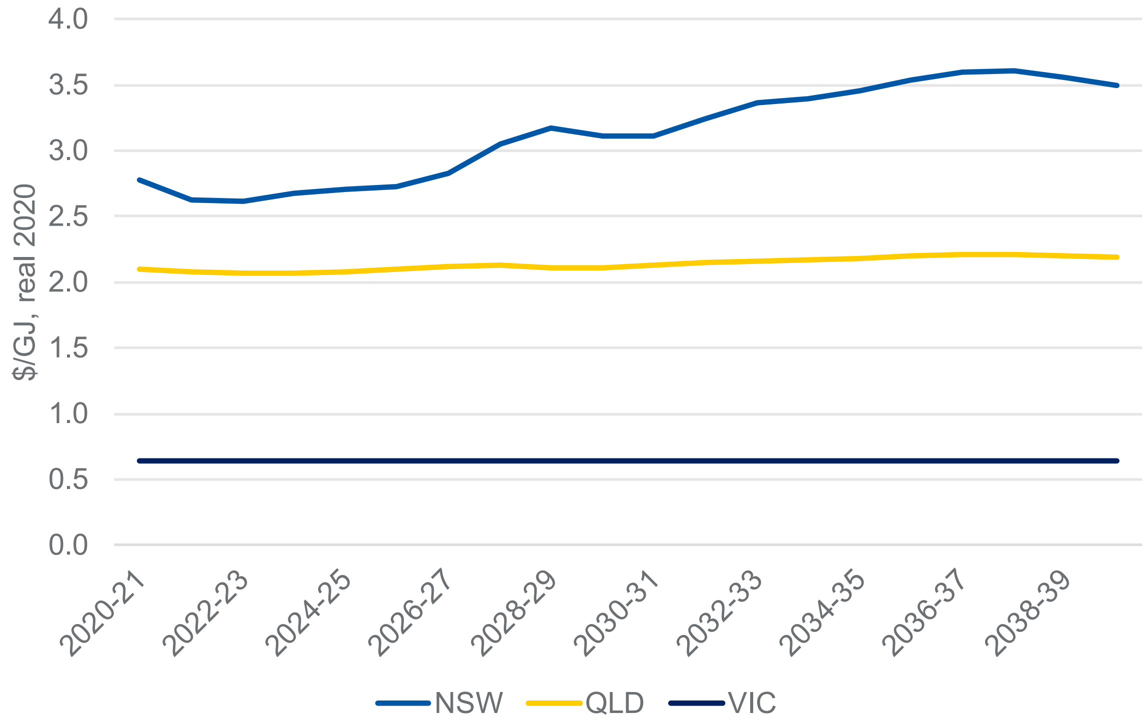
[19] AEMO's ISP modelling horizon starts in July 2019, i.e. the beginning of fiscal year 2019/2020. Throughout the report we use prices and costs for that base year. "Real 2020" should therefore be interpreted from 01 July 2019 to 30 June 2020. We do not index results to express prices and costs for calendar year 2020 as this period has not concluded at the time of writing. We maintain this convention for all our modelling results going forward.

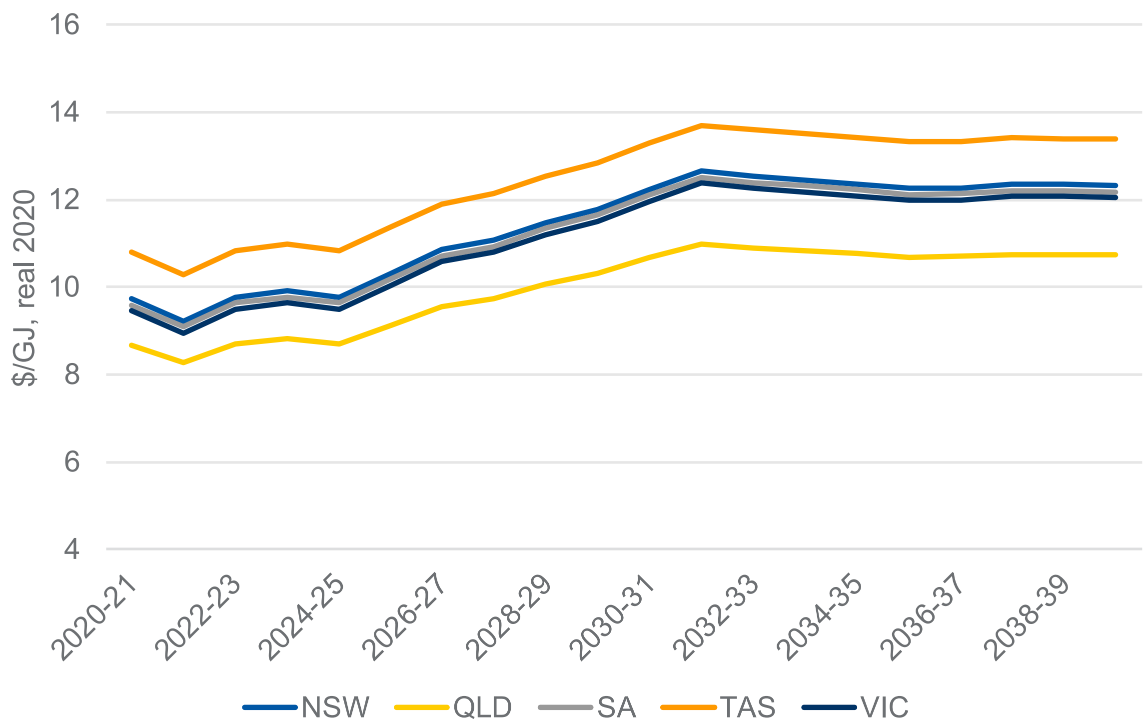
[20] AEMO (August 2019), 2019 ESOO Input Data Package and Model Instructions, pp. 4-5.

Figure 2.4: Average Coal Prices, Central Scenario



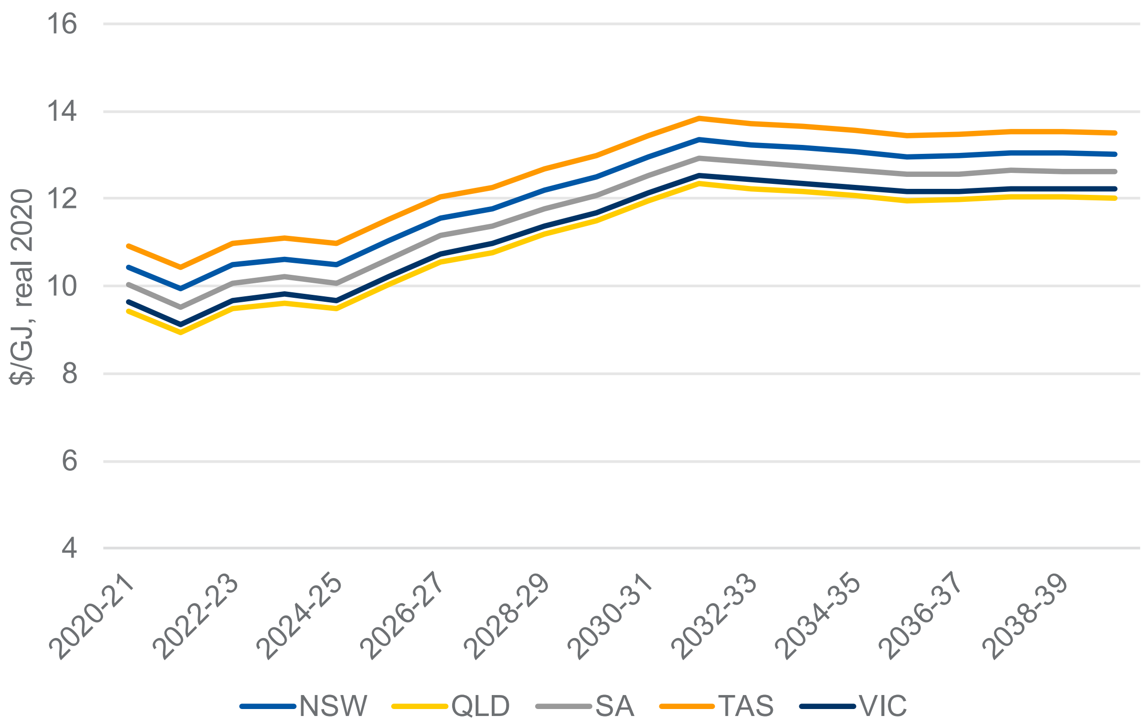
Source: AEMO (December 2019), ISP Input and Assumption Workbook

Figure 2.5: Average Gas Prices (CCGT), Central Scenario



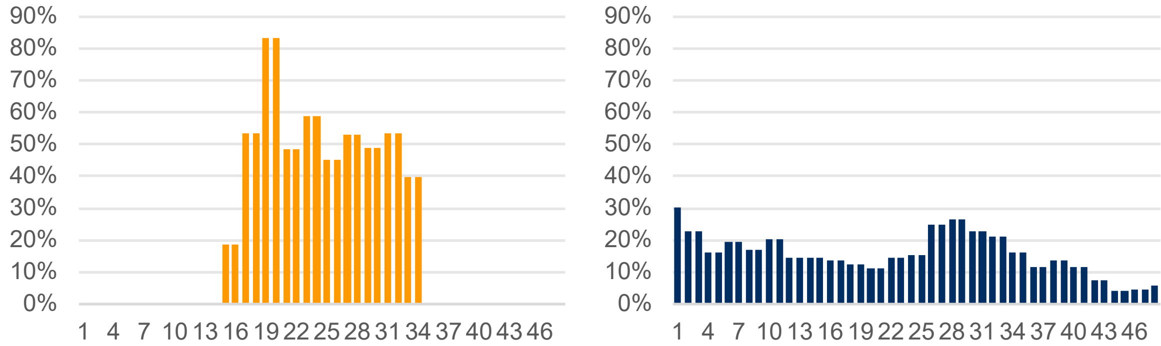
Source: AEMO (December 2019), ISP Input and Assumption Workbook

Figure 2.6: Average Gas Prices (OCGT & Steam), Central Scenario



Source: AEMO (December 2019), ISP Input and Assumption Workbook

Figure 2.7: Half-hourly Generation Trace on Sample Day for a Solar (Left) and Wind (Right) Generator



Source: AEMO (December 2019), ISP 2020 database. The charts show half-hourly rating (normalised to a 1MW plant) on 31 July 2020 for a solar and a wind plant in the North-West NSW Renewable Energy Zone (REZ). The choice of the day is entirely aleatory for this representation.

2.5. Modelling Generation Expansion

We have assumed that no new coal will be constructed in the NEM and therefore that generation investment benefits occur only for gas, wind and solar plant. Storage capacity expansion covers large scale batteries and pumped hydro storage (PHES).

Construction of both gas and renewables are endogenous. We constrain new construction of renewable plant to meet the following renewable targets:

- LRET: Nationwide generation target - applies in the model to wind, solar and hydro – requires 33,000 GWh of renewable generation in 2020;
- QRET: Queensland wind and solar - 50% of total capacity to come from renewables by 2030;
- VRET: Victoria wind and solar - 40% of generation to come from renewables by 2025 and 50% by 2030.

In the case of new renewable capacity, we do not have an individual generation trace for most nodes. We have used traces by REZ for the missing nodes, obtained through geographical mapping; where a node does not belong to a REZ, we use the solar trace belonging to the nearest REZ, which we calculate using GPS coordinates and GIS mapping software.

We adopt ISP assumptions on build costs of new technology. We use the CSIRO 4-degree estimate cost trajectory, consistent with the "Central" planning scenario. Due to the timeline of this project, the cost estimates available were part of the Draft ISP 2020 material. To account for stakeholder feedback provided to AEMO before the publication of the final plan, we reduce candidate battery build costs by 30 per cent compared to the published values, and raise build costs for 6-hour and 12-hour pumped hydro candidates by 40 per cent.

PLEXOS, in common with most market modelling software, is typically unable to solve for the deployment of batteries for complex models in reasonable run-times. Batteries result in increased run times because the opportunity cost of a battery depends on future electricity prices which necessitates repeated iteration between short, medium and long-term dispatch. Accordingly, we impose the growth in small-scale battery capacity (operated as a Virtual Power Plant and modelled as an aggregate unit at the reference node of each State) by State exogenously in the model. We follow the growth pattern set out in AEMO's ISP December 2019 Assumptions. We constrain PLEXOS to build 4-hour large-scale batteries; that is, batteries that take up to 4 hours to discharge (for instance, a 1 MW battery can generate 4 MWh with a full charge). We model the deployment of batteries assuming a fixed entry cost of zero, an annual (high) variable cost to account for levelised building/fixed costs and a charging cost of zero. We set the variable cost of generation equal to the annuitised capacity cost from the 2020 ISP divided by an assumed 365 cycles per year.[21] Consequently, the PLEXOS model treats storage as a peaking generator. The term "generator" will be used through the rest of this section to refer to both storage and generators.

We model entrant Pumped Hydro as batteries, with the same methodology described above, except we use 6 and 12 hour batteries and different cost profiles, also from the ISP assumptions to avoid modelling waterways, head and tail generators separately in PLEXOS.

We constrain the number of nodes at which construction of gas and renewable plant can take place. For thermal generators, we constrain new construction to nodes with existing generation outside of metropolitan areas that are not in a Renewable Energy Zone (REZ). In the case of new wind plant, we constrain construction to REZ nodes and do not allow

[21] We use technical properties (capacity, maximum power, economic and technical life, charge efficiency) and cost information by region (fixed O&M costs, build costs) from the 2020 ISP assumptions; we integrate missing information with the Aurecon report used as a source for the ISP. https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/aurecon-2019-cost-and-technical-parameters-review-draft-report.pdf?la=en

building outside of REZs. For solar and large-scale batteries, we build both within and outside REZs (including the nodes already selected for thermal build and nodes with existing renewable generators).[22] Construction of Pumped Hydro is constrained to areas with existing hydro generation.

22 We understand from discussions with the AEMC and AEMO that the REZs are established as optimal areas for renewable build, and therefore it is not realistic/profitable to expect investors to build wind plants outside of those boundaries. Solar, on the other hand, is more versatile, so we allow for build outside the REZ. We do not allow build of solar and wind at nodes with existing hydro, as they are often on mountainous terrain which is not suitable for build. We did not rely on topographic mapping for this exercise, so as a simplification we restrain build of new hydro at nodes with existing hydro, since this provides a signal of suitable terrain.

3. Impact of Reforming Locational Signals on Investment in Generation and Storage

Economic theory broadly states that competitive, decentralised markets lead to efficient outcomes that maximise social welfare. That efficient decentralised equilibrium requires, amongst other conditions, the absence of market power, the absence of externalities and that all goods and services are traded at prices.

Under the Status Quo, generators earn a single (loss-adjusted) electricity market price for each region of the NEM. When constraints bind, goods which are essentially different and have a different value to society (i.e. power at different locations on the grid) are in effect not traded separately and are constrained to have the same price. As a result, generators have incentives to invest in locations and dispatch plant where the true value to society may be low but the value to the generator is high or vice-versa.

In this chapter, we analyse the impact of introducing Locational Marginal Pricing (LMP) under the Access Reform on incentives to invest in plant in inefficient locations on the grid. LMP resolves the inefficient investment and dispatch signal by attributing a different locational price that reflects the value to society. LMP therefore results in the economically efficient outcome with lower costs of both investment and dispatch.

The chapter proceeds as follows:

- Section 3.1 describes the existing locational signals in the NEM and the benefits of reform;
- Section 3.2 sets out the modelling process we use to estimate the benefits of reform;
- Section 3.3 sets out the results of our modelling under our Reform scenario;
- Section 3.4 describes our approach to estimating the inefficiency of the signal under the Status Quo;
- Section 3.5 describes our results for the No-Reform scenario;
- Section 3.6 quantifies the resulting benefits for society and consumers; and
- Section 3.7 discusses the results.

3.1. Theoretical Benefits of Reforming Locational Signals

Current transmission access arrangements provide some incentives for generators to locate in areas of the network that are short of generation and electrically close to load. These incentives broadly comprise that:

- There are multiple geographic pricing regions, with regional reference prices varying between regions.
- Generators receive prices adjusted by static MLFs, which vary locationally across the system. Generators currently earn the Regional Reference Price adjusted by their Marginal Loss Factors and therefore earn lower prices at locations on the grid where losses tend to be high.

- Generators operating behind constraints face the risk that they will be unable to generate fully even when the RRP is above their marginal costs. When prevented from generating due to network constraints, generators in the NEM do not receive compensation and therefore face incentives to locate in areas of the network which are less frequently constrained.

However, these signals are inefficient because they do not reflect the locational value of the energy being produced in real time. Generators located at nodes where the LMP is higher than the RRP will receive a locational penalty every time they generate (unless they bid unavailable and AEMO subsequently directs them on). Generators located at nodes where the LMP is lower than the RRP will receive a locational subsidy every time they generate.

Our modelling approach assesses how the inefficiency of the current locational signals causes generation to be deployed in higher-cost locations on the grid over time. PLEXOS minimises total system costs rather than simulating the market-orientated logic that underpins new investment decisions. As a result, PLEXOS does not automatically allow the user to allocate deployment of new capacity to individual nodes based on the commercial signals offered by Regional Reference Prices under the No-Reform scenario.

We estimate the subsidy (or penalty) that generators and storage effectively earn/lose from receiving the RRP under No-Reform relative to the economically-efficient signal generation would receive under Reform. We estimate how that subsidy or penalty drives the inefficient locational signals of future investment and higher-cost dispatch. Finally, we compare the total system costs and price outcomes that result from this with the theoretically-efficient equilibrium that would occur under Reform.

3.2. Modelling Process

Our modelling process consists of the following seven steps:

1. **Simplify Model to Zonal Structure:** Define a zonal model of the NEM, which reflects the constraints between zones including thermal limits, reactance and resistance of the interconnecting lines. Our zonal model consists of 25 zones across the NEM (five in each of New South Wales, Queensland and South Australia, three for Victoria and seven for Tasmania) which represents the major and most frequently binding-constraints within the NEM. The nodal groupings were provided by the AEMC based on AEMO data.

2. **Identify Candidate Plant Expansions by Zone:** Run PLEXOS to model long-term expansion to 2040, including entry of new plant, to identify in which zones plant would be built to minimise system costs. It is not possible to run scenarios which model every hour in the year chronologically. Our modelling relies on 24 hours per month to identify capacity requirements. We conduct this interim step to reduce run-times and allow for increased granularity relative to starting directly with a nodal model.

3. **Allocate Zonal Capacity Construction to Nodes and Augment if Necessary:** Re-run PLEXOS in long-term expansion mode to allocate the capacity identified in step 2 above to nodes within each zone using our full nodal model. We enter the capacity constructed by zone as minimum build constraints within that zone. We then allow the model to allocate capacity optimally within the nodes in a zone.

4. **Identify Granular Prices and Market Outcomes in Reform Scenario:** Add trivially-small "probe" generators (of capacity 0.1 kW) of each technology type to each node where that technology may be built (see Section 2.5). Run PLEXOS in dispatch mode to 2040, without allowing long term expansion. Input capacity built in Step 1 exogenously for each year in order to define the capacity mix. Running PLEXOS in dispatch mode allows us to model each of the half-hours in each year and identify generator revenue for each year until 2040 under the Reform scenario based on LMP;

5. **Estimate Implicit Subsidies under No-Reform:** Re-run the PLEXOS model used in step 4 to 2040 but apply regional settlement, with all generator revenues defined by the relevant Regional Reference Price (RRP) rather than the LMP. Identify net revenues to the probe generators assuming regional settlement and deduct net revenues for those same generators from step 4 above. The difference between net revenues at a regionally-settled price and LMP is the subsidy for each technology at each node, taking account of the frequency with which each technology is constrained at each node. We divide the net revenue difference by the capacity of the probe generator to obtain a $/kW figure for each node-technology-year pairing. This difference in (net) revenues is the subsidy to generators at a given node, which may be positive or negative depending on whether regional reference prices are typically above or below the LMP;

6. **Re-run Long-Term Expansion with Subsidies:** To estimate the impact of the subsidies and penalties identified in step 5, we adjust the fixed costs of new entrant plant at each node by the subsidy in $/kW for each node-technology-year pairing. PLEXOS's cost-minimising algorithm will subsequently reflect these subsidies in its decisions over where to locate new entrant plant. We then repeat steps 1-3 to identify the optimal capacity mix and 4 to identify granular prices and outcomes under No-Reform.

7. **Calculate changes in System Costs and Consumer Benefits:** We add the subsidies estimated in step 5 back into the fixed costs of new entrant plant in the results of step 6 to obtain the total system costs (fuel costs, fixed and variable O&M and annuitised capital costs of generation) of No-reform. We then deduct the total system costs of the Reform scenario from step 4 to obtain the reduction in system costs resulting from Access Reform. We estimate consumer benefits by taking the difference in total compensation to generators between our results for No-Reform and Reform.

3.3. Results in the Reform Case

Figure 3.1 to Figure 3.4 below contain the high-level results for the Reform Scenario, i.e. the results of our modelling in step 4 above.

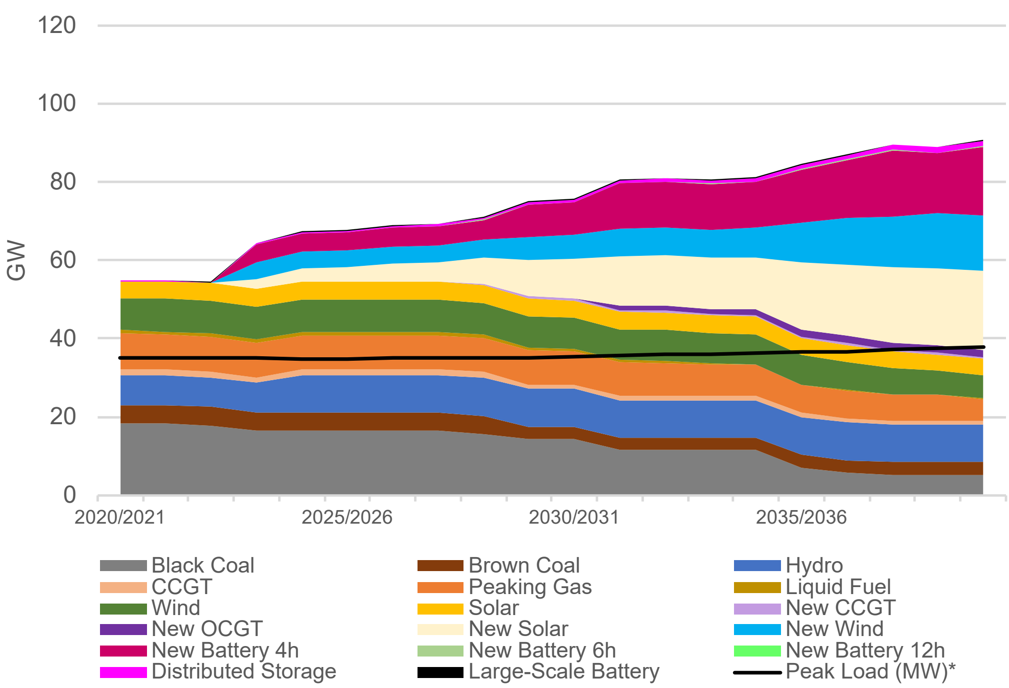
As can be seen from Figure 3.1, AEMO's P50 demand forecast suggests that demand will increase from around 35 GW in 2020 to 38 GW by 2040. Based on AEMO's projected retirements, coal capacity will decline from almost 20 GW in 2020 to only 5.2 GW by 2040. The falling installed capacity on the system is largely replaced by solar and wind plant, as well as batteries to support security of supply. The fall in load factors associated with increasing penetration of intermittent plant means that overall capacity in the NEM rises to over 90 GW by 2040 from 55 GW today.

Figure 3.2 shows the generation mix for the Reform scenario. As can be seen from the Figure, the fall in coal plant capacity is accompanied by a fall in coal-fired generation. Solar generation, on the other hand increases by six times over the modelling horizon from 11 TWh in 2020 to 62 in 2040 between "committed" projects and new candidates. By the end of the modelling period around seventy per cent of generation in the NEM comes from renewable sources and over half of that from renewables constructed after 2025. As can be seen from the Figure, the generation output and therefore load factor on batteries is relatively low in our modelling because we dispatch batteries assuming that the full costs of battery operation must be recovered on a variable basis from a fixed number of lifetime cycles. Instead, our modelling under the Reform scenarios dispatches gas peaking plant in preference to batteries in most periods.

As coal plant retires, prices rise to meet rising demand and incentivise the construction of new plant. The weighted-average RRP in the NEM rises from around $40/MWh in 2020 to nearly $100/MWh by 2040 (see Figure 3.3). Average prices in the market rise despite falling marginal costs of the average plant on the system due to increased intermittency. As a result and as shown in Figure 3.4, nodal prices become more dispersed over time. Prices become more volatile, and more volatile prices result in an increasing role for peaking plant, demand side response and price arbitrage by batteries.

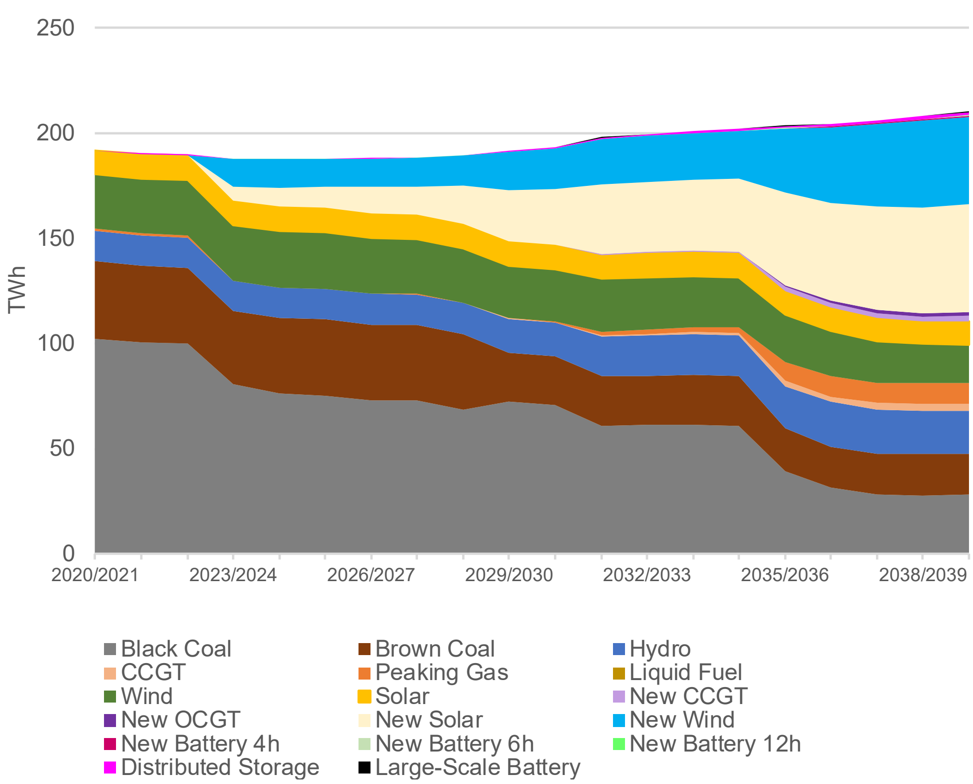
The Volume Weighted Average Price (VWAP) is close to but slightly higher than our weighted-average RRP even though the RRP is at a relatively high-priced node: the distribution of nodal prices is asymmetric and the small number of nodes with higher prices than the RRN in any given half-hour have prices which typically exceed the RRP by more than nodes with lower prices undershoot it (at least once weighted for relative volumes of load). Under the Reform scenario, consumers capture the value of congestion rent in the system: although non-scheduled loads face VWAP at the margin, AEMO will collect the difference between VWAP and Generation Weighted Average Prices (GWAP) as settlement residue, which ultimately consumers will receive through lower network charges. GWAP is lower than both VWAP and RRP in all periods and the difference rises to nearly $16/MWh by 2040, which translates to a large settlement residue.

Figure 3.1: Capacity Mix for Reform Scenario 2020-2040 (GW)



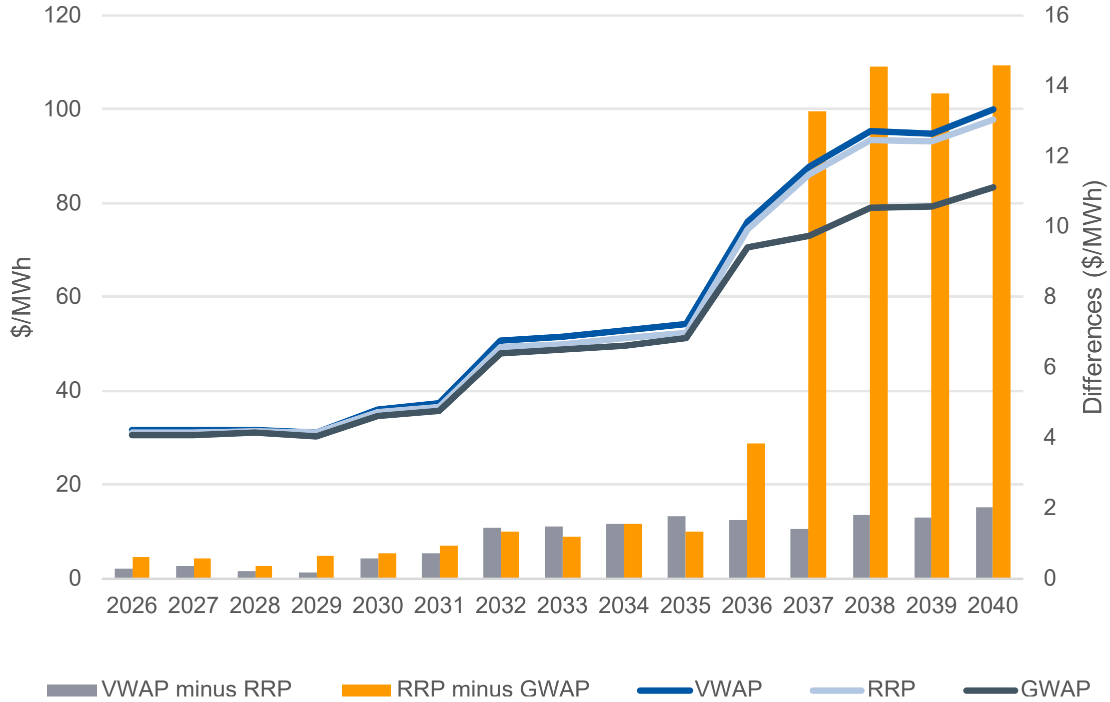
Source: NERA Analysis

Figure 3.2: Generation Mix for Reform Scenario 2020-2040 (TWh)



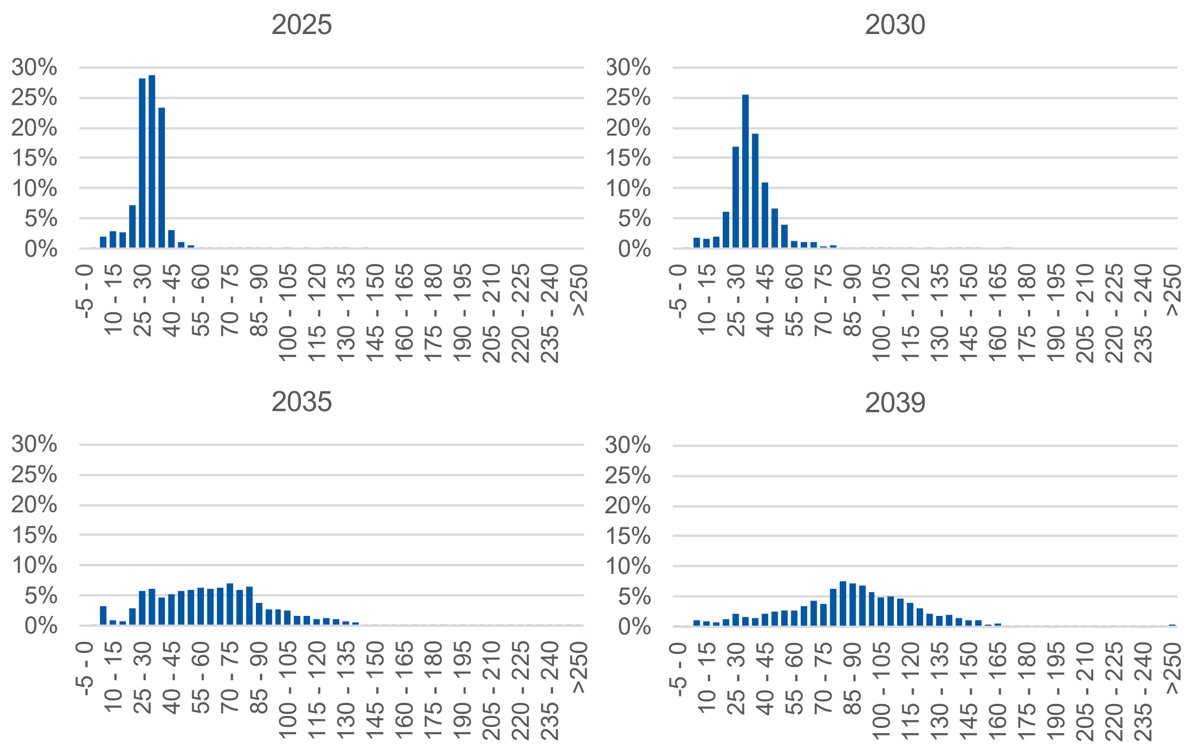
Source NERA Analysis

Figure 3.3: Prices in the Reform Scenario to 2020 (Real 2020, $/MWh)



Source: NERA Analysis

Figure 3.4: Distribution of Daily Prices in Sample Years (2020 $/MWh) - Reform Case



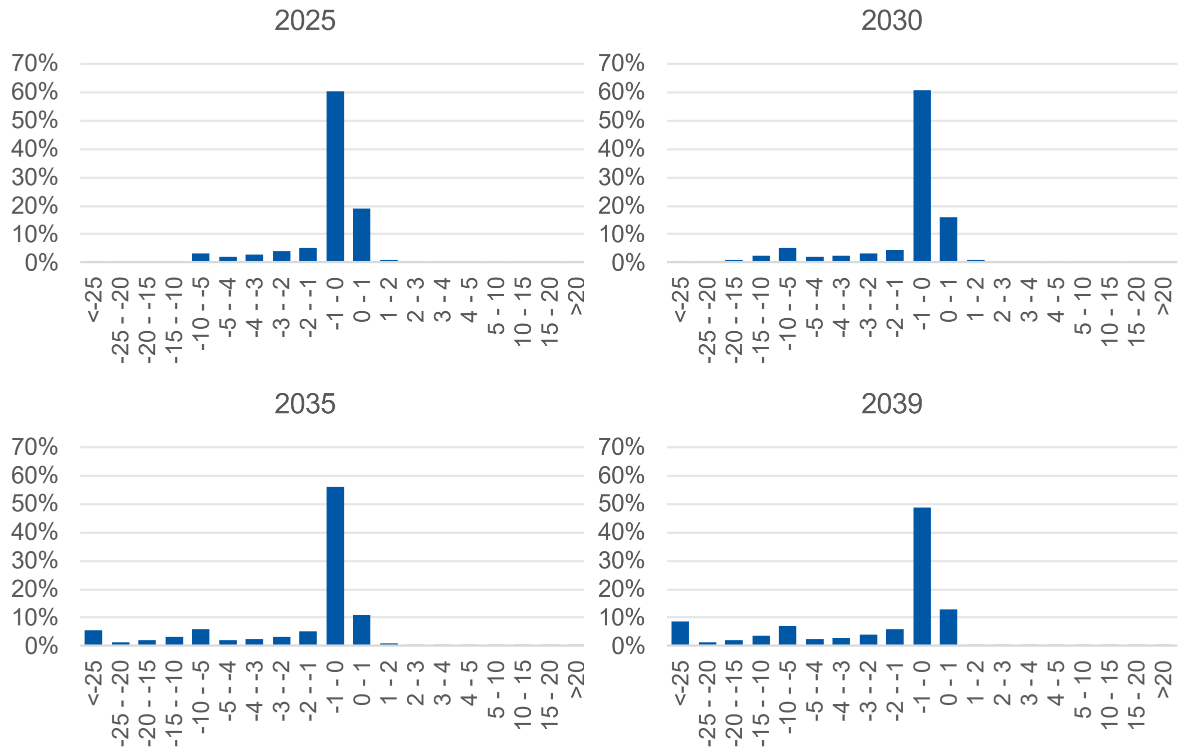
Source: NERA Analysis. Prices in $/MWh, real 2020.

3.4. Inefficiency of the Signal for Investment

As explained in section 3.1 above, economic theory suggests that adopting a single price sends an inefficient signal for investment and dispatch. The extent of the inefficiency depends on the differences between the LMPs under Reform (which reflect the marginal benefit to society of electricity in any given location) and the Regional Reference Prices under No-Reform. Figure 3.5 shows the distribution of LMPs relative to the relevant RRP for each half-hour in 2025, 2030, 2035 and 2040. As can be seen from the Figure, the most common price difference between the RRP and LMP is for LMPs to be lower by $0-1/MWh. Some nodes, however, in some half-hours experience much larger departures from the relevant RRP, which increases with the dispersion of prices over time. For instance, Figure 3.5 shows that while in 2025 there is relatively little price dispersion, by 2039 around 12 per cent of daily prices are higher or lower than the RRP by more than $15/MWh. In the previous years shown in the Figure, the proportion of daily prices lower than the RRP by more than $15/MWh is 0.6 per cent, 2%, and 9%, respectively.

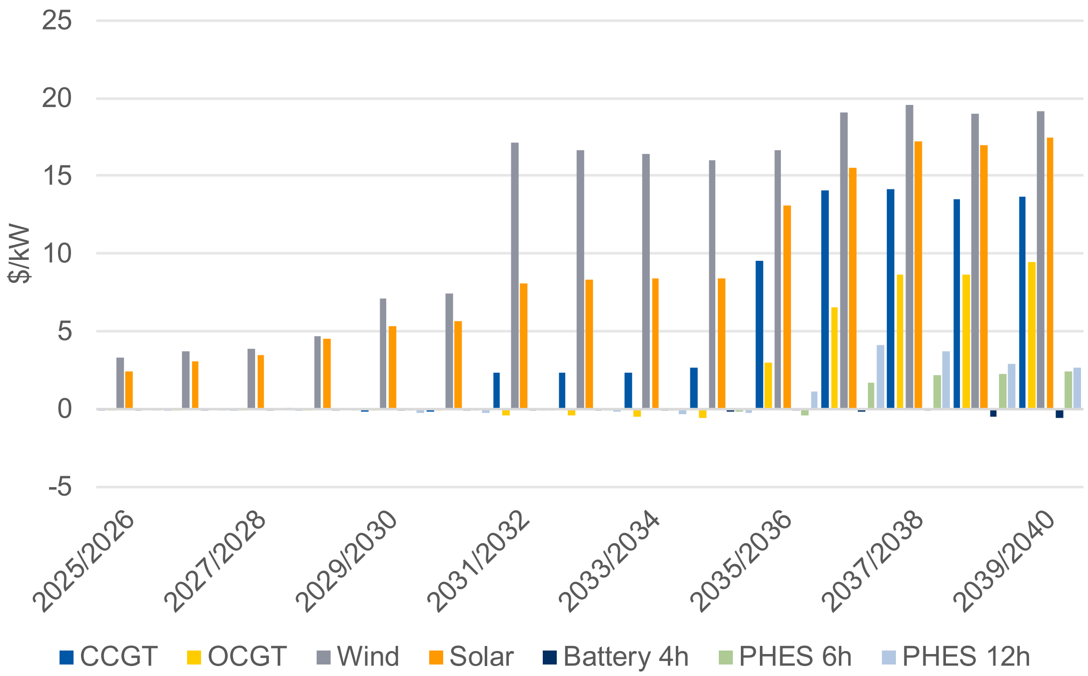
Generators earn an implicit subsidy under the Status Quo by receiving the RRP rather than the LMP in every half-hour interval. To quantify this difference by location on the network, we calculated the difference in the price received for a probe generator of each technology type assuming settlement at LMP and settlement at RRP by year. Figure 3.6 presents the average subsidy by technology and year for the NEM. As can be seen from the Figure, the nodal subsidies rise over time from $3-4/MWh in the 2020s to nearly $20/MWh by the end of the period for some technologies. In the earlier part of the period the entry subsidies are (nearly) exclusively felt by wind and solar, at least on average. These technologies are systematically overcompensated by receiving RRP in part due to their co-location and correlated intermittent output. In the latter part of the modelling period, from 2030 onwards, dispatchable capacity also benefits from inefficient locational subsidies under the Status Quo.

Figure 3.5: Daily Deviation from Regional Reference Price (2020 $/MWh) – Reform Case



Source: NERA Analysis of PLEXOS results. Notes: The figure shows the impact of price differences excluding MLFs. In other words, the differences between prices shown above are due to constraints only.

Figure 3.6: Locational Subsidies Increase Significantly from 2031, in Particular for Wind and Solar Build



Source: NERA calculation

3.5. Results in No Reform

For our No-Reform case, we model the impact of implicit subsidies under the Status Quo on the pattern of investment and subsequent dispatch. Specifically, we re-run PLEXOS after reducing the fixed costs of entrant plant to reflect the entry subsidies offered by market arrangements under the Status Quo. Each generation technology receives a separate subsidy in the form of reduced fixed costs for each node depending on the difference between revenues under Reform (i.e. LMP) and No-Reform (i.e. RRP).[23]

Figure 3.7 to Figure 3.12 present the results of our analysis. The outcomes under No-Reform are similar to those under Reform in that both show investment in solar and batteries over the modelling horizon. However, investment under No-Reform is materially larger than under Reform, comprising an additional 20 GW of investment by 2040. Most of that additional investment occurs from 2035 onwards sparked by the retirement of over 4 GW of coal capacity and the tightening supply and demand balance on the system.

Figure 3.8, shows the breakdown of the additional investment by technology. As can be seen from the Figure, the vast majority of the additional investment in the no-reform case is solar plant. Wind plant, whilst receiving the highest subsidies on average, does not receive enough subsidies in commercially-viable nodes and is displaced by the larger investment in solar plant under no-reform. Given the higher solar capacity on the system, total generation from solar is also higher in No-reform.

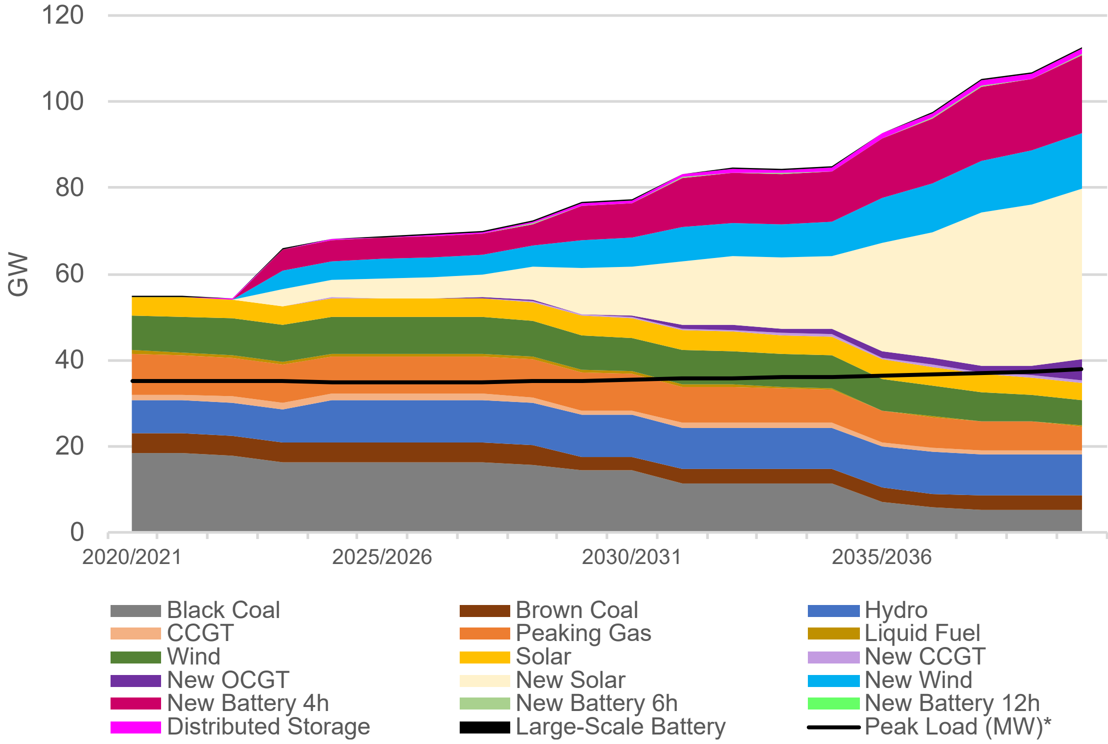
The additional capacity on the system towards the end of the modelling period and relative to Reform results in existing plant running at lower load-factors. By 2040, under No-Reform, load factors for Wind and solar plant drop by 4 to 9 per cent (see Figure 3.10). Load factors for all plant types including existing renewable plant are lower towards the end of the period under No Reform than Reform.

Price trends are similar in the No-Reform case to the Reform case – both rise from around $40/MWh in 2020 and more than double over the period (see Figure 3.11). Under No-Reform, RRP, VWAP and GWAP have different interpretations to Reform: Because all generators are paid based on RRP under No-Reform, all three measures are different weighted-averages of state-level RRPs.

Although both price trends follow a similar upward path, the average price paid to generators for their output (GWAP) is higher under No-Reform than Reform by $1-2/MWh before 2032 and rising to $12/MWh in 2038 (see Figure 3.12). That prices paid to generators are higher under No-Reform is intuitive: Under No-Reform, generators earn the congestion rent (typically positive) on their output between their LMP and the RRP. As a result, consumers ultimately pay more on average for generation output under No-Reform.

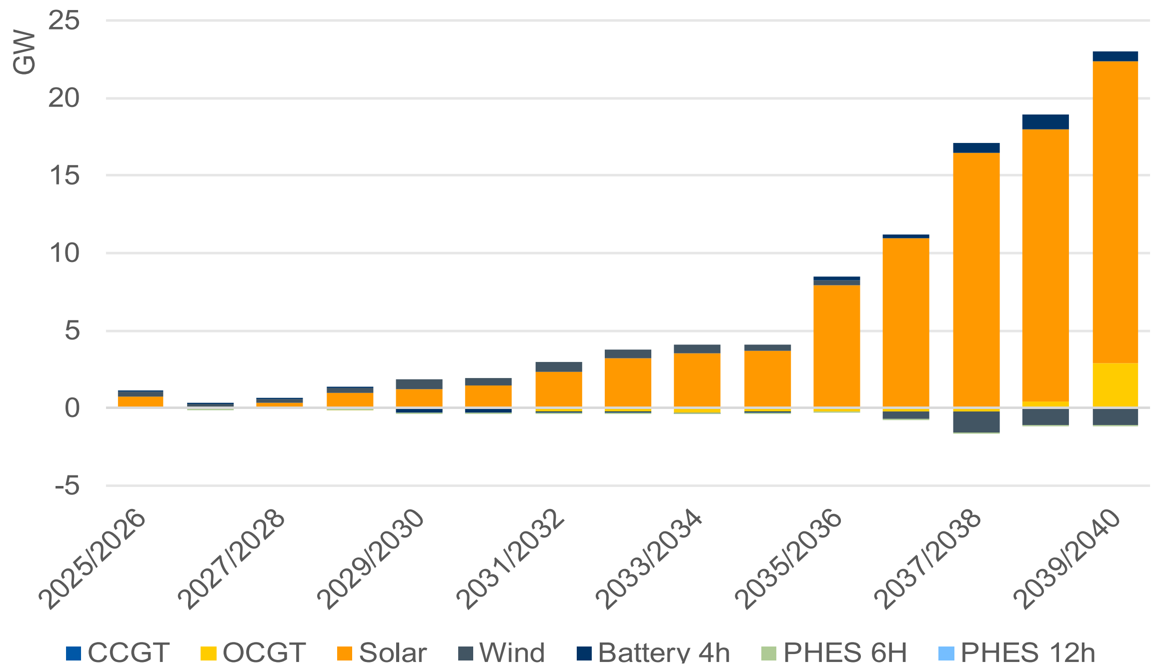
[23] We cap locational subsidies below the annuitised fixed costs of the best new entrant plant to ensure that our method cannot encourage entry from plant that do not generate. Our cap never binds before 2032 and never binds for more than a handful of candidate-node pairings (a single digit percentage of total candidate-node pairs). This cap is arguably conservative, because, in principle at least, the annual subsidy provided by RRP could exceed the annuitised fixed costs in any given year in the current market structure.

Figure 3.7: Modelled Capacity Mix in the No-Reform Case



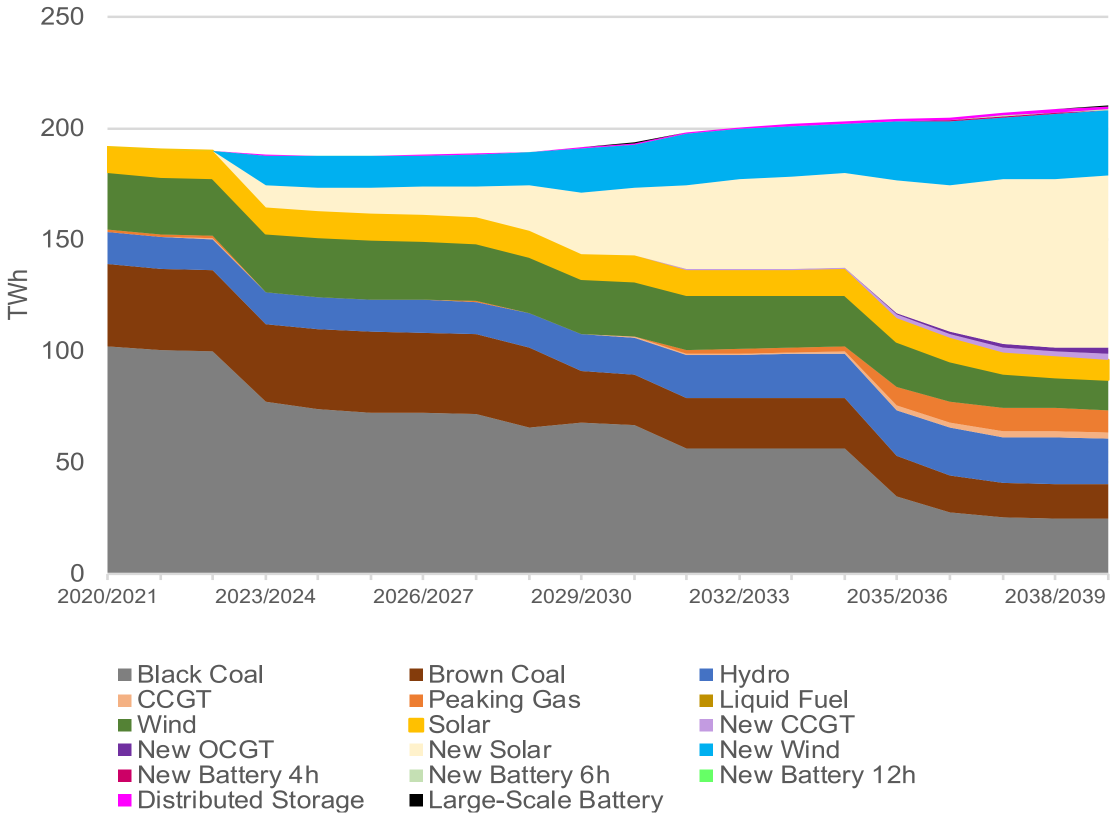
Source: NERA Analysis of PLEXOS results

Figure 3.8: The No-Reform Scenario Results in Higher Capacity Built: No Reform minus Reform Differences, GW



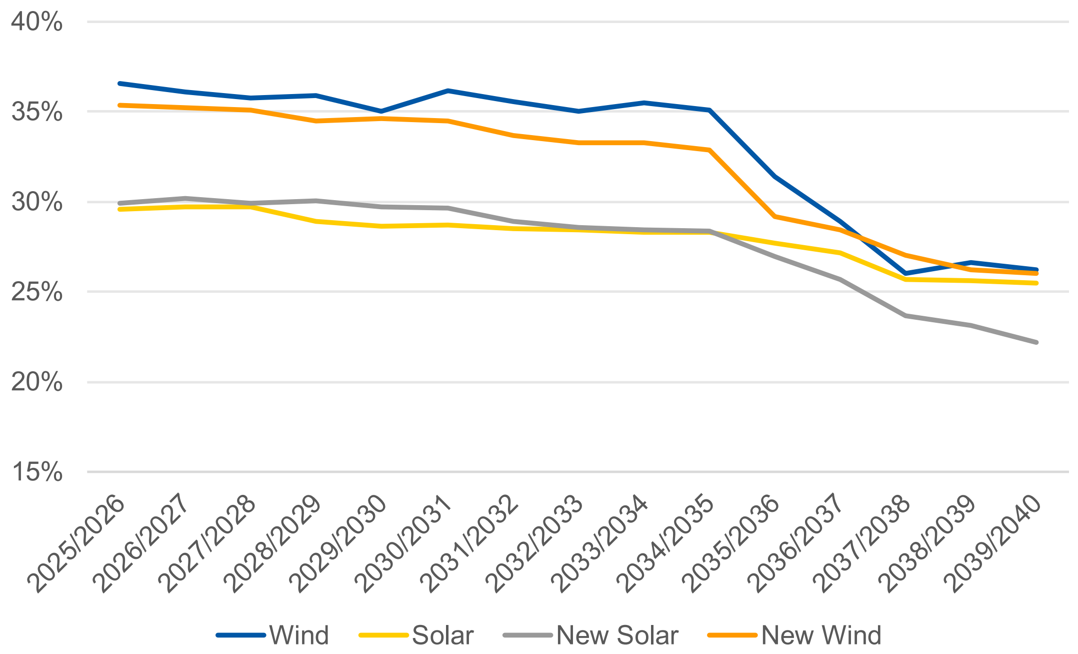
Source: NERA Analysis of PLEXOS results

Figure 3.9: Generation Mix for the No-Reform Case (TWh)



Source: NERA Analysis of PLEXOS results

Figure 3.10: Load Factors for Renewable Capacity Decrease in the Final Years



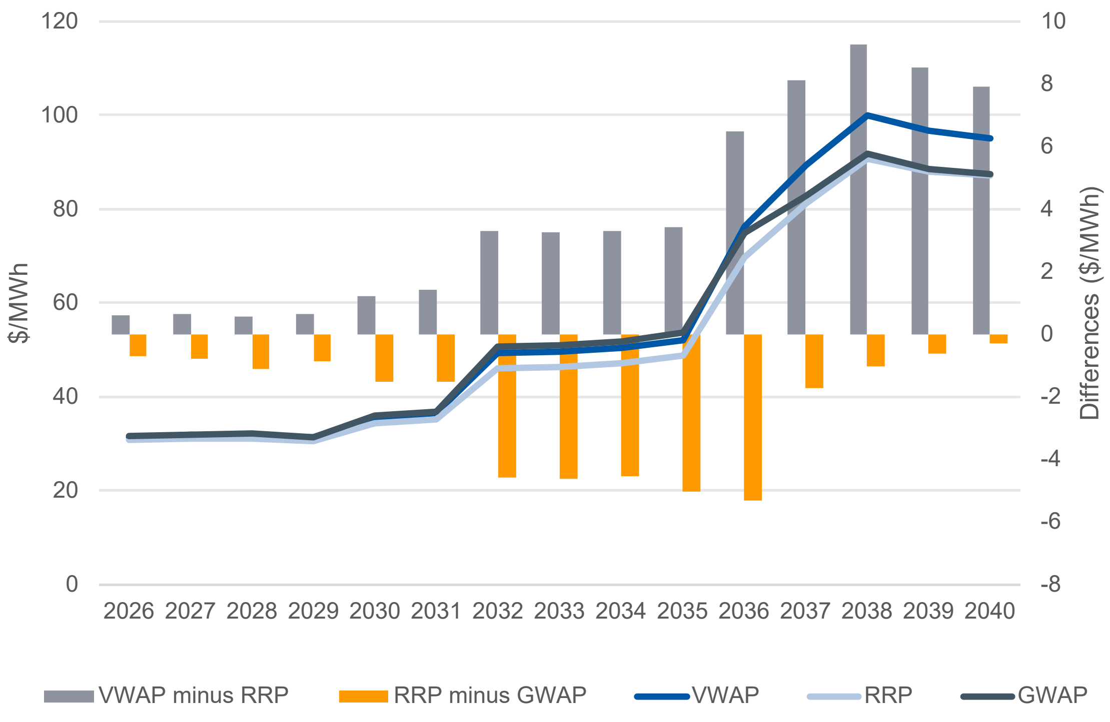
Source: NERA Analysis of PLEXOS results

Table 3.1: Relative Change in Loss Factors (Percentage Points, No Reform v. Reform Case)

	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40
Black Coal	-5%	-5%	-5%	-7%	-7%	-7%	-7%	-7%
Brown Coal	-2%	-2%	-2%	-7%	-9%	-13%	-13%	-14%
CCGT	0%	-1%	-1%	-5%	-4%	-5%	-7%	-8%
Peaking G.	0%	0%	0%	-2%	0%	2%	0%	0%
New CCGT	-1%	-1%	-1%	-5%	-4%	-4%	-8%	-11%
New OCGT	0%	0%	0%	0%	1%	2%	0%	-4%
Wind	-1%	-1%	-1%	-3%	-5%	-8%	-8%	-9%
Solar	-1%	-1%	-1%	-2%	-2%	-4%	-4%	-4%
New Solar	-1%	-1%	-1%	-2%	-4%	-6%	-6%	-7%
New Wind	-2%	-2%	-2%	-5%	-6%	-7%	-8%	-8%

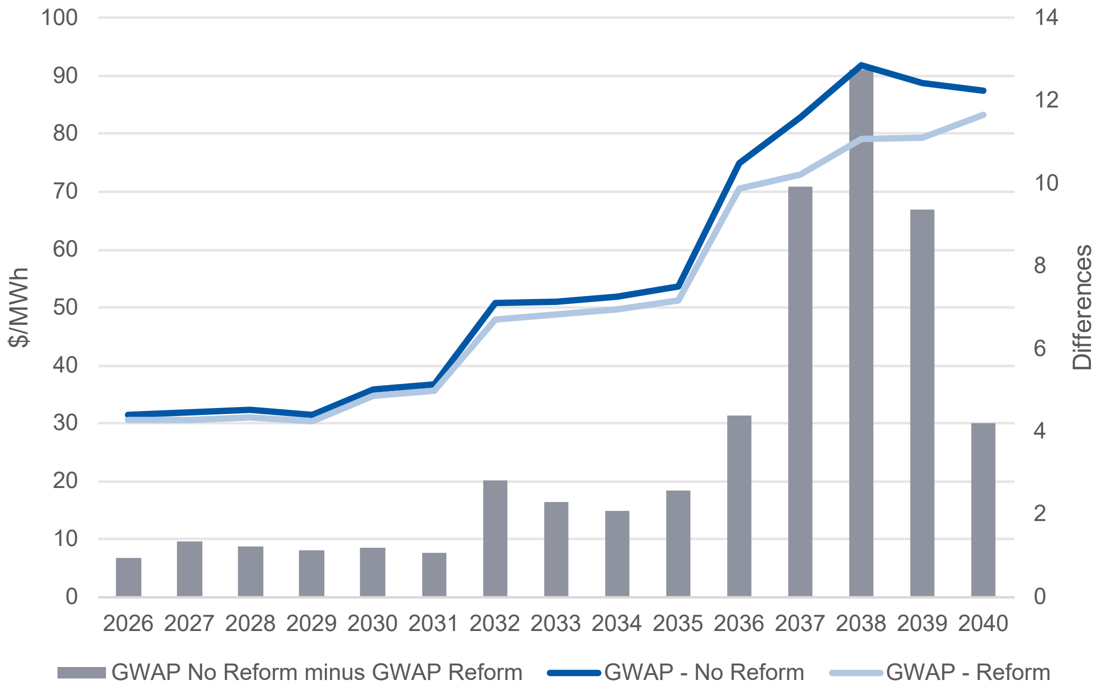
Source: NERA Analysis of PLEXOS results

Figure 3.11: Price Trends in the No-Reform Case



Source: NERA Analysis of PLEXOS results

Figure 3.12: GWAP Differentials between No-Reform and Reform Case



Source: NERA Analysis of PLEXOS results

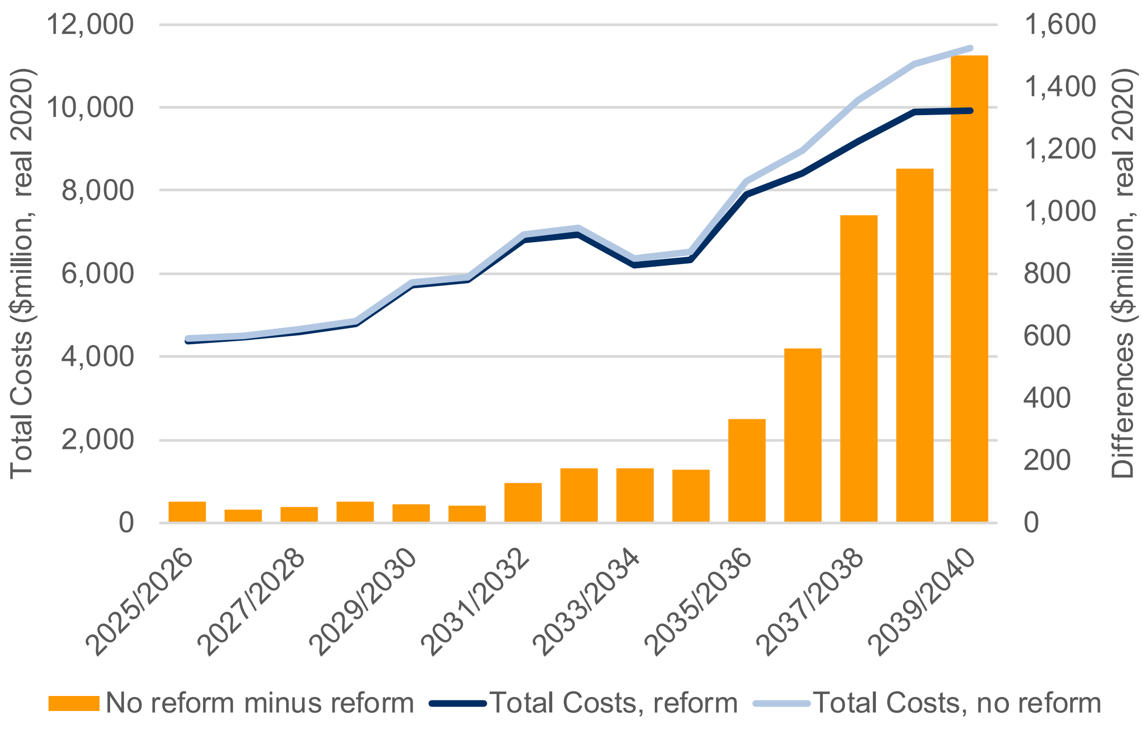
3.6. Benefits to Society and Consumers

The modelling results presented in this chapter show the social benefits and market impacts from the more efficient pattern of investment that occurs under Reform relative to No-reform. Under the No-reform scenario, the electricity market invests in an additional 20 GW of capacity by the end of the modelling period, for which costs consumers must ultimately reimburse generators – we note that construction in the Reform scenario already meets POE10 demand. Figure 3.13 below sets out the total system costs, defined as fuel costs, non-fuel fixed and variable costs of generation, and annuitised capital costs, under Reform and No-Reform for the modelling period from 2025/6 to 2039/40, expressed in real 2020 $ million. As can be seen from the Figure, the additional system costs under No Reform are always positive over the period. Costs are typically between $40 million and $70 million in the first five years of the modelling period to 2030/31. By 2031/32, as generation investment picks up under both Reform and No-Reform and coal retirements gather pace, the increase in system costs begins to rise. By the end of the period, following the retirement of Bayswater, the need for additional investment causes total system costs under No Reform to exceed those under Reform by over $1.5 billion annually. The additional costs under No-Reform comprise the additional dispatch costs from less-well located plant, less the reduction in variable costs from increased renewable capacity on the system, plus the annuitised capital costs of the cumulative additional investment. By the end of the period, the additional costs of No-Reform includes the annuitised capital costs of over 20 GW of additional investment, which will be fully accounted for in future years.

Our modelling suggests that costs to consumers also rise over the period and exceed the increase in total system costs. Under No Reform, consumers pay generators the value of the congestion rent at the generator's node. With investment in more intermittent plant in suboptimal locations on the grid over time and the widening dispersion of LMPs over time, the value of that congestion rent rises. Accordingly, the gap between the total paid to generators in Reform as opposed to No-Reform widens over the period. Our modelling suggests that excess generation compensation is around $200 million annually in the 2020s and peaks in 2038 at over $3bn annually in real 2020 terms (see Figure 3.14, below). In NPV terms, our results are broadly equivalent to the international case studies reviewed in our previous report (see Chapter 9). However, we must note that, unlike our modelling exercise, these studies do not clearly adjust for efficiency of investment decisions over time, so the comparison can only be qualitative.

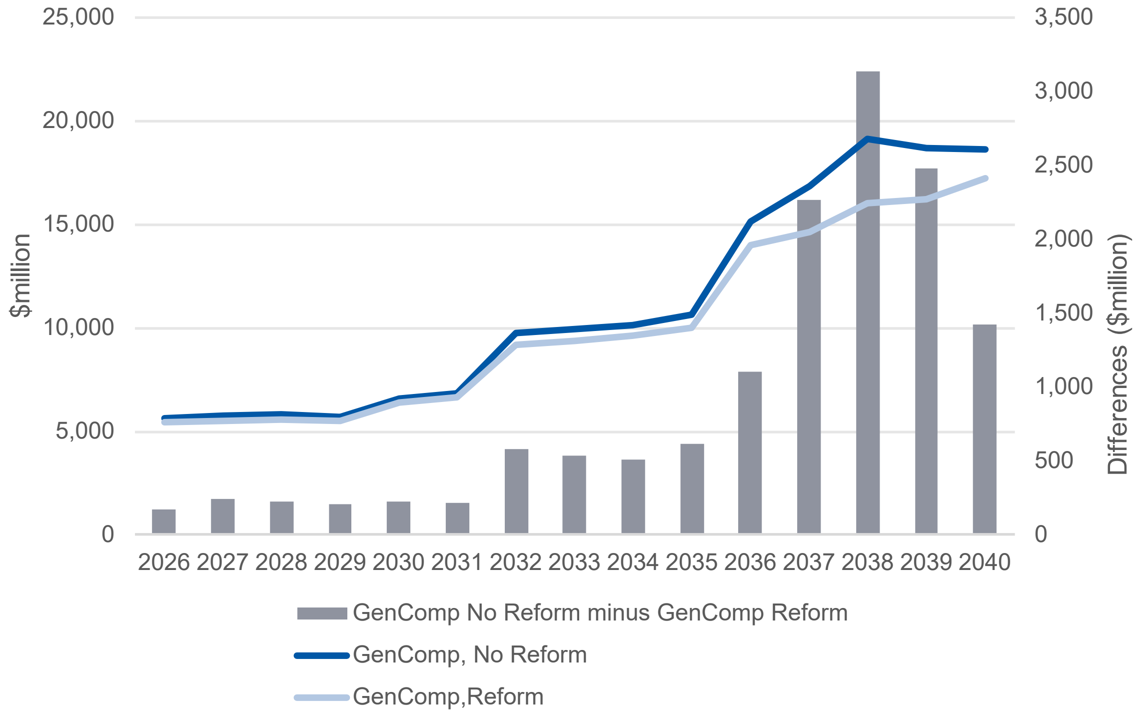
Table 3.2 and Figure 3.15 present our modelling results by year and Net Present Values of benefits, discounted at 7 per cent per annum, all expressed in real $2020 terms. The Table shows that the total benefits to consumers in the first ten years of reform (2026-2035) accounts for around $1.6 billion or 40 per cent of the total. Over $450 million or 28 per cent of the total benefit to consumers arises from a reduction in system costs with the remainder resulting from a wealth-transfer from generators (expressed as revenue difference minus cost difference). The benefits are larger in the final five years of the modelling period than the first ten, even discounted in net present value terms, due to the spike in investment that occurs in the latter part of the period.

Figure 3.13: Total Cost Differences Between No-Reform and Reform Case Increase at the End of the Horizon



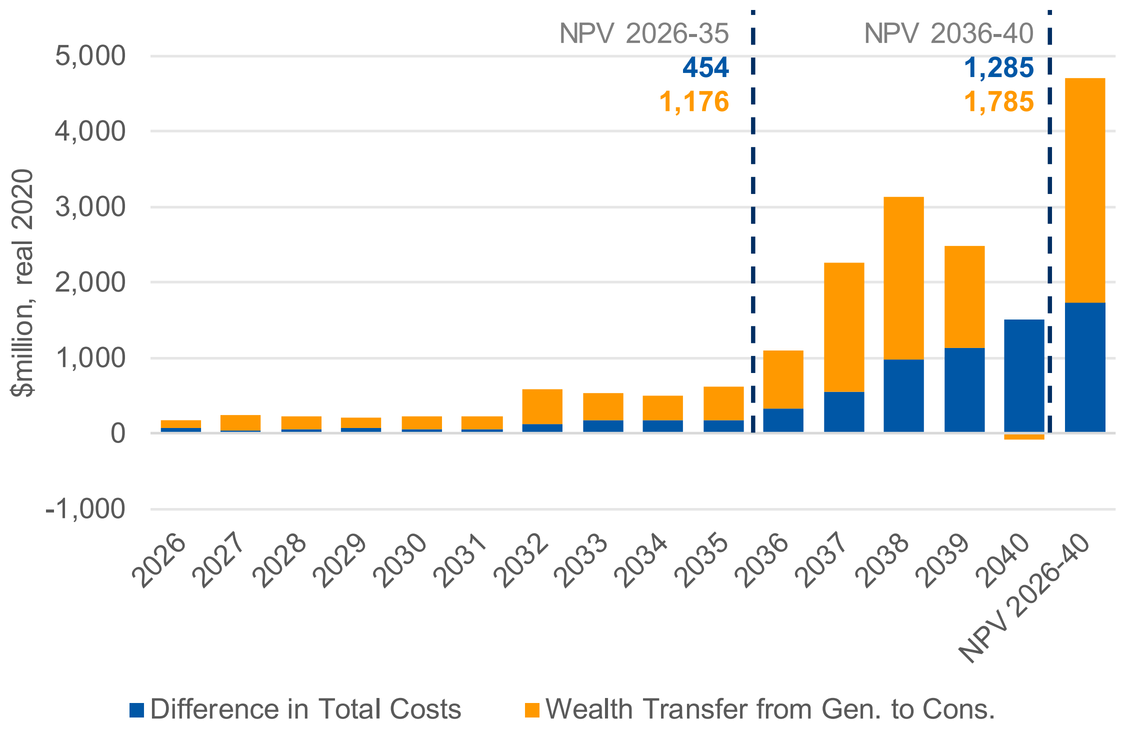
Source: NERA Analysis of PLEXOS results

Figure 3.14: Differences In Generator Compensation Peak In 2037/38



Source: NERA Analysis of PLEXOS results

Figure 3.15: Around One-Third of the Benefit to Consumers Results from a Reduction in Total System Costs



Source: NERA Analysis of PLEXOS results. Note: the wealth transfer is calculated as the total difference in revenues (No Reform minus Reform) minus the total difference in costs

Table 3.2: The Total Benefit to Consumers by Year (2026-2040 in 2020 $ million)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	NPV 2026-35	2036	2037	2038	2039	2040	NPV 2036-40	NPV 2026-40
Cost Difference	66	41	52	70	59	56	128	174	176	171	**454**	334	560	986	1,139	1,502	**1,285**	**1,738**
Wealth Transfer	105	201	170	143	170	163	453	361	329	446	**1,176**	766	1,705	2,150	1,341	- 81	**1,785**	**2,961**
Revenue Difference	171	242	222	212	229	218	581	535	506	617	**1,629**	1,100	2,264	3,136	2,480	1,421	**3,070**	**4,699**

Source: NERA Analysis of PLEXOS results. Data in 2020 $million, actualised to fiscal year 2020/2021, discounted at 7 per cent. Note: in this and future modelling exercises, we discount values at the same rate of 7 per cent for both the reform and no-reform case. This is done to maintain an all-else-equal approach and ensure consistency with the assumed WACC of 5.9 per cent for all cases.

3.7. Qualitative Discussion of Results

As would be the case with any modelling exercise to assess the benefits of Access Reform, our results are a representation of the theoretical improvement in efficiency that settlement at LMP offers. Interpreting our results necessitates clarity over the assumptions that may influence them. In this section we set out some of the key assumptions and qualifications that should inform the use of our results.

First, our model assumes competitive cost-based bidding and ignores distortions to dispatch arising from the Status Quo. These distortions are examined in full in Chapter 5.

The benefits we have modelled occur from two sources. First, we have lower capital costs of investment in the Reform scenario because the model builds fewer plant (in the efficient locations) to meet system demand. Second, we obtain a more efficient pattern of dispatch resulting from better-located plant dynamically over time. However, these modelling results do not include any benefits due to the inefficiencies that may occur in a static setting that are eliminated by a move to settlement at LMP. Because PLEXOS has a cost-minimising objective function, it will dispatch the lowest-cost plant from a system perspective even assuming settlement at LMP and will not account for the impact of distorted bids. We address potential efficiency gains from removing distorted bids in Chapter 5, below.

Second, the demand forecasts we use define the extent of congestion and the likely benefits of reform.

Throughout our modelling runs we have used AEMO's P10 forecast of demand for Long-Term expansion and the P50 forecast for dispatching plant and calculating prices. We understand this is standard practice in AEMO's modelling exercises, including the ISP models.[24] Investors make investment decisions based on expected returns, not returns in the median (or even expected) demand forecast. Electricity and the rewards from investing in new capacity are asymmetrically-distributed and positively-skewed. We used the P10 demand forecast as a benchmark for a higher-than-median outturn demand and as a proxy of the scenario on which investors would make investment decisions. If the P10 is below the demand level consistent with expected *returns* to investment, we will understate investment and social benefits of reform. If the P10 is above the demand level consistent with expected *returns* to investment, we will overstate investment and social benefits of reform.

For our dispatch runs with granular chronology, however, we have relied on AEMO's P50 demand forecast. The benefits of reform stem from congestion on the grid. Congestion, like prices, is likely to be positively-skewed. Therefore our assumption of the median (or even expected) demand forecast is likely to understate median (or even expected) congestion and understate the dispatch-related benefits of reform.

Third, we estimate the annual subsidy driving inefficient investment in a one-shot process based on the reform scenario.

The inefficiency of construction in our modelling relies on our estimate of the effective subsidy to generation under No-Reform. We calculate that subsidy as the additional net revenue that a small probe generator would earn per kilowatt from generation at that node.

[24] Source: AEMO ISP DLT PLEXOS database.

We calculate this subsidy on an annual basis based on the capacity that is on the system in the Reform scenario. As new capacity is constructed in inefficient locations on the grid, we would expect generators in those locations to be more frequently constrained and the volume of electricity over which the subsidy payment is felt would fall. In other words, our assumed subsidy may be overstated and more overstated as time progresses and capacity in the No-Reform case differs more from the Reform case.

On the other hand, as new capacity is constructed in inefficient locations on the grid, the LMP at the node is also likely to fall. In those circumstances, the subsidy in our modelling is understated and the more understated as time progresses and capacity in the No-Reform case differs more from the Reform case.

Fourth, we have used annuitised capital costs reported by PLEXOS to estimate total system costs.

One interpretation of the analysis presented in this chapter could be that the benefits of reform are skewed towards the latter part of the 2030s when Bayswater and other coal stations have largely retired. Indeed, such an interpretation would have some merit because the additional investment that occurs in the latter part of the 2030s increases system costs materially. However, the reported benefits we show in our analysis reflects the annuitised capital costs in PLEXOS, as opposed to the entire overnight cost. In other words, it is unsurprising that the benefits rise over time: part of the benefits of reduced capital costs from Reform for investments in the early part of the period continues to be reported in the form of a reduced annuity to cover capital costs later in the period.

4. Impact of Reform on Transmission Investment

Our results in Chapter 3 hold the transmission network as given in both the Reform and No-Reform scenarios. On the one hand, the improved efficiency of transmission investment could comprise a material benefit of Access Reform by providing clearer signals for investment. On the other hand, at least in principle, transmission capacity could substitute for inefficient locational incentives under the Status Quo by connecting inefficiently-located generation to load. Transmission investment could thereby mitigate the impact of inefficient locational decisions on society and consumers. In this Chapter, we review our modelling results from Chapter 3 and examine whether the potential for transmission investment materially increases or reduces the benefits of reform. Our analysis suggests that transmission investment may increase the benefits of reform but is necessarily simplified. In the interests of conservatism, we do not attribute additional benefits to Access Reform from improved transmission investment.

The Chapter proceeds as follows:

- Section 4.1 sets out the theoretical benefits of reform;
- Section 4.2 describes our modelling process;
- Section 4.3 presents our results;
- Section 0 provides a qualitative discussion of our results and our conclusions.

4.1. Theoretical Benefits of Reform

A more efficiently-utilised transmission system is one of the potential benefits of introducing Access Reform. Transmission planning could improve following the introduction of Access Reform for at least three reasons:

- LMP provides better signals about the locational need for new capacity, which improves the ability of AEMO to recommend reinforcement of the network and TNSPs' ability to identify and agree on the need for reinforcement with the regulator; and
- Locational prices disincentivise construction of generation in locations where further reinforcement would be necessary to accommodate their generation. As a result, generators have a greater incentive to construct units taking the available capacity on the network into account. Under the Status Quo, AEMO and TNSPs plan the network given the locational decisions of generators that have been constructed without the full benefit of these price signals.
- ISP planning models the optimal expansion path for the NEM. Therefore, even given perfect foresight of costs and demand, the ISP would not capture the market incentives of generators under No-Reform. The Access Reform is intended to improve locational signals in the NEM, thus helping the ISP optimal path come to fruition.

These factors are challenging to model quantitatively because it reflects the political economy of investment in network businesses and modelling imperfect information (for which purpose PLEXOS is ill-suited).

In principle, PLEXOS can model the development of transmission systems over the long term, either by allowing the model to build specific links at pre-defined costs or allowing the model to build a wide range of links at generic costs. In practice, using PLEXOS to identify optimal transmission investment would likely be challenging because:

- Transmission investment costs are lumpy and the costs vary widely between different installations. Optimising using PLEXOS is likely to lead to a spurious pattern of investment and false precision;
- Even a constrained optimisation of transmission investment would be computationally extremely heavy, slow down run times and likely require compromises elsewhere in the model; and
- Identifying the constrained set of transmission investments that could take place is not trivial. AEMO proposed existing ISP projects may not represent the comprehensive set of potential investments.

In any case, using PLEXOS to define what transmission infrastructure gets built would not itself be an accurate representation of current or future practice in the NEM. PLEXOS's algorithm would optimise the trade-off between generation and transmission investment over the modelling horizon. In practice, the AEMO makes recommendations for transmission expansion in the NEM through the ISP process, which recommends reinforcement of the grid taking the existing capacity on the system as given. Therefore, in principle at least, AEMO's future recommendations are influenced by generators' investment decisions rather than coordinated and co-optimised with generation over the entire modelling horizon.

Not assessing the benefits of improved transmission investment could overstate the benefits of Access Reform in relation to the benefits of better-sited generation investment. Transmission investment may ameliorate the costs of generators investing in inefficient locations on the grid. Accordingly, a heavily constrained network, without investment in transmission capacity may tend to suggest that the costs in the Status Quo of generation in the wrong locations were larger than would in practice be the case. Transmission investment may therefore be a partial – albeit expensive – substitute for Access Reform in that it ameliorates the results of sending inefficient signals to generators.

Instead of modelling transmission investment endogenously, we developed an offline calculation of the optimal pattern of and benefits of incremental transmission investment. Using our PLEXOS results and an assumed cost of transmission investment, we estimate the costs and benefits of increasing transmission investment at each node at which transmission expansion is feasible.

Figure 4.1 illustrates the principle for a quantity of power (Q) and price differentials (P) for a node facing a rising cost of exports and with falling willingness to pay for imports as quantity increases. Prices P^d_0 and P^s_0 represent the LMPs either side of a transmission constraint of size Q^T_0 and result in a price differential of Y''. Expanding the transmission capacity by Z to Q^T_1 would yield gross benefits (i.e. benefits without considering the cost of expansion) equal to the blue-shaded trapezium and reduce the price gap to P^d_1 *minus* P^s_1 (i.e. Y'). Expanding transmission by z'' to $Q^T_{2'}$ i.e. eliminating the price differential would yield gross benefits equal to the blue-shaded trapezium *plus* the orange triangle.

We use simple geometry to identify the benefits of transmission expansion. Our method consists of the following steps:

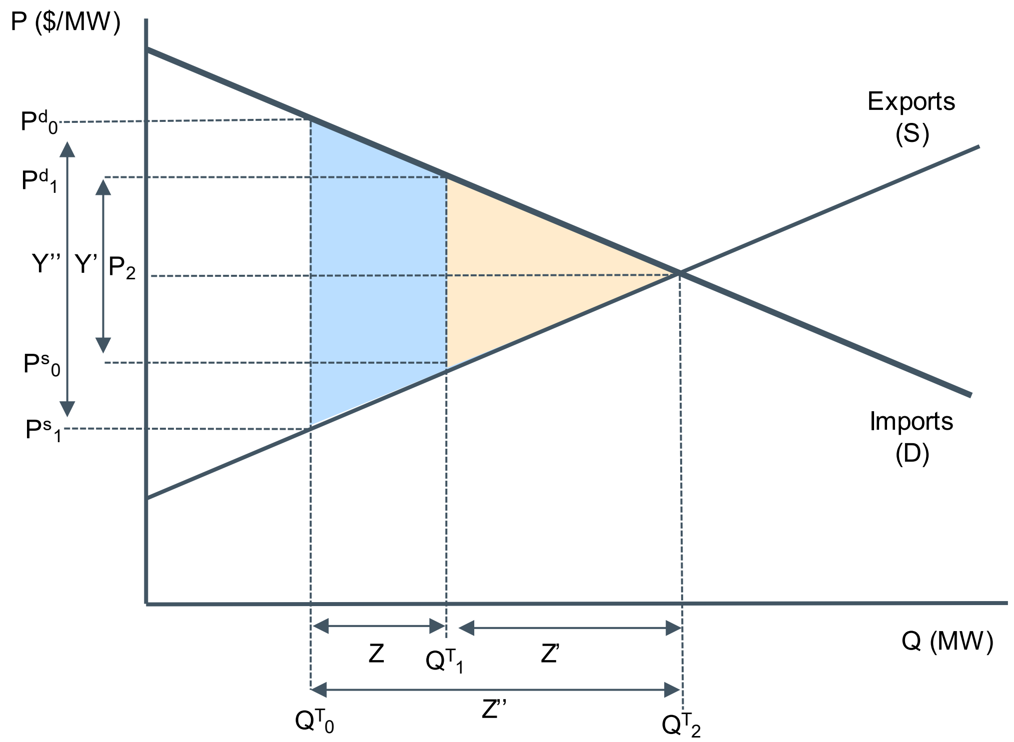
- We estimate current price differentials in the NEM (Y``) from our PLEXOS modelling;
- We estimate the additional flow were the constraint to be fully relaxed (Z``) and assume that both supply (exports) and demand (imports) are linear. From those additional flows and the knowledge that in a fully unconstrained network LMPs are equal, we are able to calculate the gross benefits that would result (i.e. the blue triangle in the diagram);
- The optimal level of transmission expansion (Z) occurs when the marginal price differential is exactly equal to the marginal transmission cost. Therefore, for a fixed assumed cost of transmission expansion (Y`), it is trivial to estimate the (gross) benefits of a transmission expansion, shown on the diagram as the blue-shaded trapezium. The costs of transmission expansion are given by the quantity of additional investment (i.e. Z multiplied by Y').

Having estimated the (gross) benefits and costs of transmission expansion, we then need to combine them with those for the other categories of Access Reform. We will combine costs and benefits of transmission expansion with our other estimates as follows:

- The impact of transmission expansion includes costs of congestion that may be obviated by transmission investment. We therefore *deduct* the change in gross benefits of relieving congestion from the total benefits we estimate from the location of generators and storage under Access Reform.
- The costs of transmission investments form part of total system costs. We will therefore *add* the change in costs of transmission investment to the total benefits, if any, we estimate from the location of generators and storage.
- The gross benefits, if any, of transmission expansion will (weakly) exceed the costs of transmission investment in our offline optimal expansion plan (i.e. the net benefits of transmission expansion will be positive in both Reform and No-Reform). Our estimated total benefits of Access Reform will therefore be lower if the net benefits of transmission investment in No-Reform are larger.

We will perform this calculation only once for all years in the sample. In principle, once the network has been reinforced for generators who have located in inefficient locations under the Status Quo, more inefficient generation could elect to locate at those nodes. Our method may therefore understate the additional costs of transmission investment in the No-Reform case and understate the benefits of Access Reform.

Figure 4.1: Illustration of the Costs and Benefits of Transmission Expansion



Source: NERA Analysis

4.2. Modelling Process

Our modelling process consists of the following steps:

1. **Identify Capacity Mix:** Run PLEXOS in long-term expansion mode to obtain a pattern of new build thermal and renewable generators and batteries in Access Reform and Status Quo (i.e. steps 1-6 described in section 3.2 above);
2. **Identify Prices Given Constraints:** Run PLEXOS in short-term/dispatch mode until 2040 in both Access Reform and Status Quo; this step is equivalent to steps 4 and 6 in section 3.2 above, except that we use P10 demand forecasts instead of P50 to reflect the higher security standard likely to be prevalent in transmission investment than would be reflected in use of a P50 forecast.
3. **Identify additional prices and volumes in an unconstrained world:** Adjust transmission capacities to assume no thermal limits on transmission capacity within each state. Kirchoff Laws and the underlying physics of the system remain. Run PLEXOS in short term/dispatch mode until 2040 in both Access Reform and Status Quo.
4. **Estimate Gross Benefits of Transmission Investment:** Calculate the total addressable benefit from transmission investment (the blue trapezium and the orange triangle) shown in Figure 4.1) for each power transmission line:
   A. The average spread between the hourly prices at the connected nodes; multiplied by
   B. The difference in volume transported in the unconstrained world and the assumed network; and

C. Divided by 2 (because ½ base x height = formula for area of a triangle).

5. **Estimate Line Costs:** Calculate the length of each existing line using GPS data. We assume a cost of transmission reinforcement of $2000/km, a discount rate of 7 per cent in real terms and an asset life of 40 years for transmission investment. The annuitised cost of transmission is therefore approximately $150/km. We multiply this figure by the length of each line to give the cost of reinforcement between two nodes. We excluded the Marinus and Basslink upgrades from our analysis because they are subsea cables and would require a higher rate of expenditure per km.

6. **Identify Optimal Reinforcement, Benefits and Costs:** Assuming that $Q^T{}_1$ is the optimal transmission investment in Figure 4.1, to calculate the benefits associated with the investment trapezium, we subtract the smaller (unlabelled) triangle from the larger triangle shown in blue, on average over the course of a year in order to determine whether transmission investment is optimal in that year.

   A. We know the area of the blue triangle, the dispersion of prices (Y''), the additional volume transported in the run with no thermal limits on the existing network (Z'') from step 3.

   B. The area of the orange triangle (the unfulfilled transmission investment) has an area equal to:[25]

   ½ x base x height = ½ y' x z'

   $$y' = cost\ of\ transmission\ investment\ over\ line$$

   $$z' = \frac{y''}{z''} z' (by\ law\ of\ similar\ triangles$$

   Transmission lines are long-lived investments. For simplicity we estimate and quantify the optimal reinforcement, benefits and costs based on the average optimal reinforcement in periods in which the investment signal is positive.

7. **Calculate Net Impact of Transmission on Benefits of Reform:** Calculate the (net) transmission costs of Access Reform and Status Quo by:

   A. Adding costs of transmission investment (Y' multiplied by [QT1 - QT0])

   B. Deducting the benefits of the transmission investment (which are weakly greater than costs) from both.

4.3. Results

Our PLEXOS Modelling Results suggest that congestion rents (i.e. price differences between connected nodes multiplied by line flows) are similar in No-Reform to Reform in the earlier

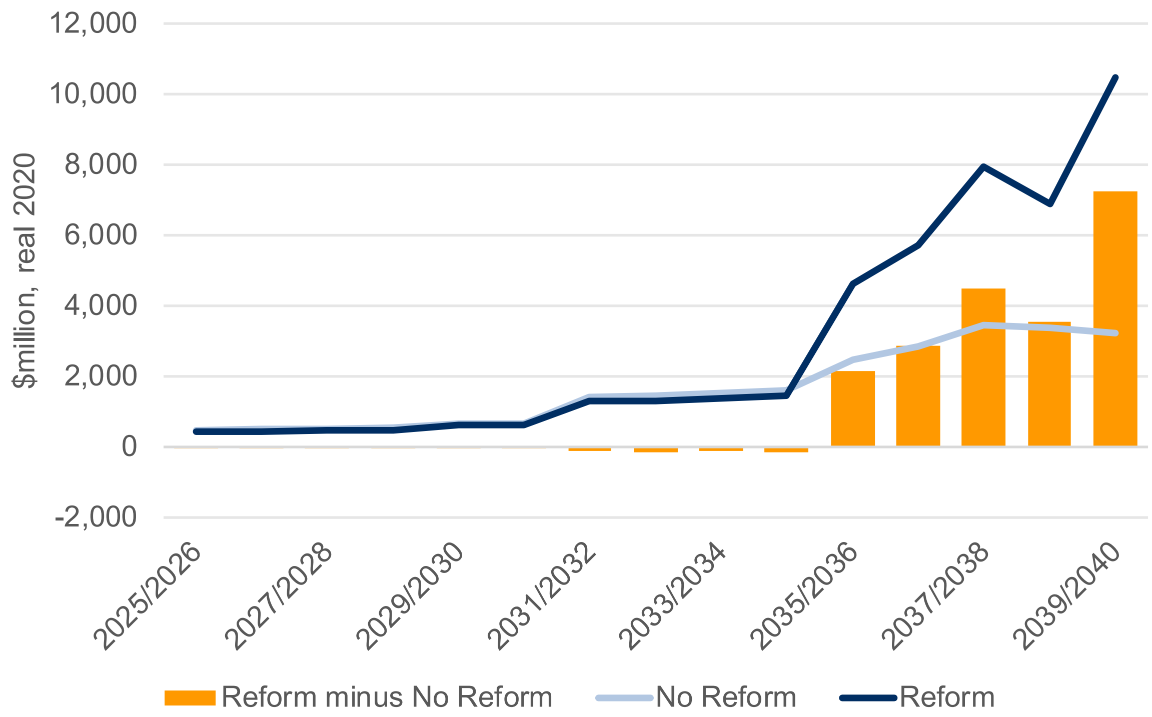
[25] In practice, we continue to have price differences from our PLEXOS runs without thermal limits due to the other physical properties of the lines constraining flows. We have retained the algebra here for simplicity. In practice, we apply analogous algebra for similar trapezia, where the unconstrained run includes a price difference. Our initial investigations suggested that very little transmission investment would be commissioned if we assessed transmission investment using maximum hourly flows. Accordingly, we conduct our analysis using average annual flows to set the upper limit of capacity and that capacity expansions would be fully utilised. This has the impact of increasing the number of lines where capacity is built, decreasing the reinforcement for lines where our analysis suggested that capacity would be built using maximum flows and increasing the net benefits of expansion.

part of the period. The congestion rents under No-Reform exceed those under Reform by between $28 million and $172 million per year, accounting for a $370 million difference between 2025/6 and 2034/5 in NPV terms (discounted at 7 per cent in real dollars of 2020).

From the closure of the Bayswater units in 2035/6, congestion rents in both Reform and No-Reform increase markedly. However, congestion rents (measured as the difference between LMPs at neighbouring nodes) rise much more quickly in Reform than No-Reform.

The principal reason that congestion rents are lower in No-Reform is the excess capacity on the system. Consumers pay generators billions of dollars more over the modelling horizon in the No-Reform world. As a result of that additional investment signal, the system has much more capacity. The differences in LMPs between neighbouring nodes are typically lower than under Reform because the marginal, price-setting technologies are frequently the same.

Figure 4.2: Congestion Rent Increases at the End of the Horizon in the Reform World



Source: NERA calculation on PLEXOS results

The key question for assessing the benefits of transmission is not the extent of congestion rent in the system but the extent to which transmission investment could address that congestion cost-effectively. Table 4.1 below shows the volume of capacity investment (in MW) indicated as being cost-effective in our analysis in the reform and no-reform case in each year, relative to baseline transmission capacity. Table 4.2 and Table 4.3 show the net benefits of this transmission investment in no-reform and reform case on an annual and NPV basis respectively.

As can be seen from the Tables, despite the heavy congestion in the No-Reform scenario, the average expansion for upgraded lines over the period as a whole is larger in the Reform case, even over the full period. Accordingly, net benefits of the upgrades are larger in the reform case by around $140 million over the entire period, in net present value terms to 2020.

This analysis suggests that our estimate of social benefits of Access Reform from better-located generation and storage may understate the total social benefits of Reform: If we were to expand the transmission grid in both the Reform and No-Reform, the social costs would fall by more in Reform. However, the discrepancy is negligible compared to the size of benefits estimated in Chapter 3.

We note that our analysis is necessarily high-level and the results presented are not recommendations for specific system upgrades. The key question we are seeking to address is whether transmission expansion materially affects the results we present in other chapters in this report and principally in Chapter 3, above.

Table 4.1: Total Optimal Investment Capacity (MW) – Reform Case, No-Reform and Differences

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
No Reform	2,357	2,394	2,460	2,421	2,751	2,816	2,122	2,103	2,106	2,069	3,016	2,508	2,693	2,604	2,700
Reform	1,648	1,965	2,040	2,088	1,937	2,009	1,196	1,164	1,305	1,297	2,422	2,179	2,593	2,405	2,898
No Ref. Minus Ref.	**709**	**429**	**419**	**333**	**814**	**807**	**926**	**939**	**801**	**772**	**594**	**329**	**100**	**199**	**-198**

Source: NERA Analysis of PLEXOS results. NPV to 2020/21.
Note: dates represent fiscal years, e.g. 2026 is fiscal year 2025/26. The figures the in this table are not cumulative across years as they represent reinforcement relative to baseline transmission capacity. We therefore effectively assume that the capacity upgrade can be "right sized" up or down each year.

Table 4.2: Total Net Benefits – Reform Case, No-Reform and Differences ($2020 million, discounted at 7 per cent)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
No Reform	10.4	11.1	11.8	10.1	14.8	16.6	17.2	19.0	19.6	21.4	36.4	27.4	32.2	60.1	66.6
Reform	7.4	9.5	9.6	8.4	15.6	15.5	22.0	20.4	24.0	25.2	84.1	81.7	144.1	142.2	263.6
No Ref. Minus Ref.	**3.0**	**1.6**	**2.2**	**1.7**	**- 0.7**	**1.1**	**- 4.9**	**- 1.4**	**- 4.4**	**- 3.9**	**-47.7**	**-54.3**	**-112**	**-82.1**	**-197**

Source: NERA Analysis of PLEXOS results

Table 4.3: NPV of transmission expansion benefits, No-Reform vs Reform

	NPV 2026-35	NPV 2036-40	NPV 2026-40
No Reform	72.5	74.8	136.8
Reform	73	204.4	277.3
No Ref. Minus Ref.	**-0.5**	**-130**	**-141**

Source: NERA Analysis of PLEXOS results

4.4. Qualitative Discussion of Results

Our analysis of transmission investment relies on a high-level, linearised and offline calculation. The objective of our analysis is to understand the directional impact of not distinguishing between transmission investment in Reform and No-Reform worlds and any necessary adjustments to our broader analysis to account for that. We have made material simplifying assumptions that may limit the benefits of transmission expansion in both the Reform and No-Reform worlds:

- including assuming a constant cost of transmission expansion (of $2,000/km);
- annuitising costs so that transmission expansion may take place if benefits exceed annual capital costs, whilst not ensuring that the assets would be used for their full lives, which may overstate transmission investment and benefits; and
- analysing only reinforcements to the existing grid and not every possible pairwise connection, which may understate the benefits of transmission.

In principle, the value of reinforcement depends on whether other lines have been reinforced. In practice, our method estimates the impact of transmission reinforcement on the assumption that all other nodes faced no constraints and all other constraints had been relieved. A priori, the directional impact of this assumption on our results is unclear. On the one hand, we may overbuild lines because we do not take account of competing reinforcements. On the other hand, relaxing constraints on all competing lines simultaneously may understate the benefits of reinforcement if each line would not cross the threshold for reinforcement individually, given the diversion of flows onto competing routes. From a brief inspection of the results, it appears likely that the latter effect dominates, given the general lack of reinforcement of competing lines in our analysis. As a result, we may understate the volume of reinforcement in both the Reform and No-Reform cases.

Our assessment of transmission expansion is driven by the extent to which constraints appear and are necessary to ameliorate in No-reform that do not appear or are unnecessary to ameliorate in Reform. Accordingly, our estimates will be sensitive to the capacities on the transmission network and assumed expansion projects that occur in both Status Quo and Access Reform. We have assumed that Priority 1 and 2 projects in AEMO's 2020 ISP go ahead plus the Marinus Link Line from 2036. Priority 1 and 2 projects are either listed as "committed" or "actionable" by AEMO. AEMO expects preparatory work for the Marinus Link project to begin by 2023, before the AEMC will have implemented Access Reform. Other Priority 3 projects are currently listed as not actionable and insufficient data exists in AEMO's ISP to identify clearly to which nodes the projects would connect. These choices appear in both our Reform and No-Reform worlds and as a result, they underpin (and limit) the differences between them.

More broadly, the approach we have taken is to analyse whether transmission investment may materially reduce the costs of distorted generation investment incentives under the Status Quo. In doing so, we have assumed that transmission expansion recommendations are given *after the least cost expansion path of generation is known*. Our PLEXOS runs, which do not model transmission expansion endogenously, already identify the least-cost ways of avoiding lost load and/or very high costs of electricity at particular locations (even in the Status Quo world). In practice, AEMO does not co-optimise generation and transmission over time with perfect information either. The reality is somewhere in the middle: that AEMO makes transmission investment recommendations based on current investment and with some foreknowledge/projection of generation investment and generators make investments decisions with knowledge of the existing network and some foreknowledge of future transmission investment.

The directional impact of our assumption on the timing of transmission investment decisions on the overall benefits of Access Reform is unclear. On the one hand, PLEXOS will resolve some of the most material transmission constraints by investing in generation and batteries in high cost areas of the grid. Some of those investments may be more effectively offset by transmission and we may understate the *efficient transmission investment* in both Reform and No-Reform. On the other hand, our modelling does not take into account the potential incentive for generators to locate behind constraints especially in the No-Reform world: If by investing behind a constraint generators can create congestion that it would be rational for AEMO to recommend resolving, current investment incentives could prompt *inefficient transmission investment*, which we do not capture in our modelling.

Developing credible scenarios for transmission expansion is a challenging exercise. Most of the transmission upgrades we identify as being welfare improving are small and likely to be below the minimum threshold for transmission projects.[26] Accordingly, we have not adjusted our overall assessment of the benefits of Reform to account for the increased net benefits of transmission expansion suggested by our analysis. Our analysis suggests it is unclear that transmission has materially-higher net benefits in the No-Reform world (and indeed in our modelling it has lower net benefits). Our analysis of transmission investment therefore further suggests that our estimate of the benefits of Access Reform in Chapter 3 above is not clearly overstated by not allowing transmission investment to differ in the Reform and No-Reform cases and may even be conservative.

[26] Our methodology understates the extent of transmission expansion by assuming 100 per cent utilisation on expanded capacity for simplicity and as a conservative measure. Nonetheless, most of our identified transmission expansion projects are below 5 MW.

5. Increased Efficiency of Dispatch from Eliminating Distorted Bidding

The Status Quo access arrangements in the NEM include at least two potential sources of inefficiency in dispatch:

- Sending inefficient signals to generators about the value of electricity because generators earn the RRP rather than the relevant LMP for their dispatched energy; and
- Lack of firm access to the grid can encourage generators to distort their bids in order to secure:
  - priority dispatch when the RRP is above the LMP, known as race to the floor bidding; or
  - better prices when the RRP is below the LMP, by bidding unavailable and being constrained on by AEMO.

Distorting bids has the potential to increase system costs because AEMO selects the lowest-cost combination of plant to meet load given the bids submitted. Those increases in system costs will ultimately be passed-through, at least in part, to consumers.

In this chapter, we set out our approach to estimating the benefits from eliminating the incentive to distort bids. The chapter proceeds as follows:

- Section 5.1 sets out the theoretical benefits of reform that we seek to quantify in our analysis;
- Section 5.2 sets out our modelling process using PLEXOS;
- Section 5.3 describes our results; and
- Section 5.4 provides a qualitative discussion of the results.

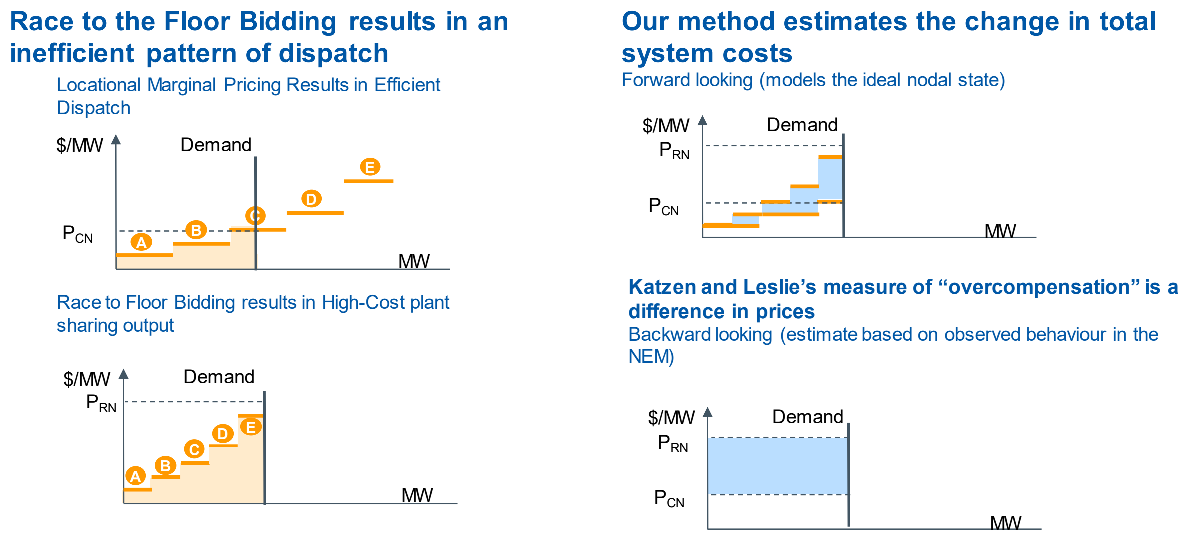
5.1. Theoretical Benefits of Reform

Generators in Australia do not have guaranteed or firm access to the grid and may be constrained off without compensation. AEMO selects between generators for dispatch based on their bids. Generators who have a marginal cost below the RRP but are in an export-constrained node are overcompensated for their generation by the difference between the LMP and the RRP. In such circumstances, they have incentives to bid to the market floor price of *minus* \$1,000/MWh in order to be dispatched by AEMO in preference to lower-cost plant (known as "race to the floor bidding"). In equilibrium all generators with marginal costs below the relevant RRP adjusted by the MLF but above their (shadow) LMP would bid to the floor. In cases of a tie, AEMO divides dispatch between high and low-cost generators in proportion to their participation factors. Katzen and Leslie (2020) estimated that in 2019, generators received overcompensation equivalent to 2.5 per cent of their revenues of \$445 million, which provides a measure of level of the incentive (albeit not the frequency with which it occurs).[27]

[27] Katzen and Leslie (February 2020), Examining distributional impacts from the proposed COGATI reform: An analysis of historical locational marginal prices in Australia's National Electricity Market, Appendix B, Table B2.

Figure 5.1 contains a diagrammatic description of the impact of Race to the Floor bidding. Consider an export-constrained node with five equally-sized generators A-E which have rising marginal cost. In a market with LMP and demand sufficient to accommodate only three generators, units A, B and C would generate and the marginal cost of unit C (potentially marked up to the cost of unit D) would set the LMP at the node P_{CN}. Under the Status Quo, by assumption, the RRP (P_{RN}) is above the marginal cost of units A-E. All five units would have an incentive to bid to the floor and all five would be awarded some production. Total system costs in each case are shown by the orange areas in the diagram. In order to quantify the inefficiency, we estimate the change in total system costs (i.e. the difference in the orange areas, shaded blue in the top right-hand panel). Katzen and Leslie's measure, by contrast, shows the difference in the total revenues earned by generators, shaded blue in the bottom right-hand panel.

Figure 5.1: Diagrammatic Representation of Race to the Floor Bidding



Source: NERA Elaboration from Katzen and Leslie (2020) and modelling methodology

Generators in import-constrained areas can face incentives to bid unavailable if the RRP is less than the 90th percentile of the spot price paid to generators who bid unavailable and are nonetheless dispatched by AEMO.[28] Our analysis of spot prices suggests the large majority of nodes face prices below the RRP rather than above it. Katzen and Leslie's analysis for the AEMC also suggests that Total Overcompensation (i.e. LMP<RRP) comprises the large majority of Total Mispricing (i.e. LMP ≠ RRP).[29] Accordingly, we focus our analysis on Race to the Floor Bidding. We choose this year as it is the first in which Access Reform is likely be implemented; this way, we ensure that we measure the effect of race to the floor with locational signals from the reform in place, to eliminate disturbance in the benefits from other factors, while also choosing a period as close as possible to Katzen and Leslie's data.

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[28] Generators who bid unavailable and are subsequently dispatched by AEMO are paid the 90th percentile of spot market prices.

[29] Katzen and Leslie (February 2020), Examining distributional impacts from the proposed COGATI reform: An analysis of historical locational marginal prices in Australia's National Electricity Market, Appendix B. Katzen and Leslie's analysis of AEMO/AEMC data on historical LMPs shows that (adjusted) overcompensation accounts for 50 to 65 per cent of total (adjusted) mispricing between 2015 and 2019.

Under Access Reform, generators would be remunerated at the Locational Marginal Price and would be incentivized to submit cost-reflective bids. Access reform helps to ensure that the cheapest generators on the system are operating behind constraints by paying generators the locational value of their electricity. We use our PLEXOS model to measure the difference between the total system costs under Status Quo and Access Reform in a single year (2025) for Race to the Floor Bidding. We subsequently extrapolate these results for future years based on the volume of coal plant on the system.

5.2. Modelling Process

Our process for modelling the impact of Race to the Floor Bidding consists of the following five steps:

1. **Identify Pattern of Competitive Dispatch:** Run PLEXOS in granular dispatch mode for 2025/6 using the capacity mix from the Reform Scenario for that year based on our runs described in Chapter 3 above. In this run, generators bid their short-run marginal cost as an offer price and PLEXOS selects the cost-minimising dispatch.
2. **Identify Generators with an Incentive to Race to the Floor:** From the run in step 1, in every half-hour we identify generators that:
   A. Generated below their available capacity;
   B. Had a short-run marginal cost lower than the price they would have received under regional settlement for half-hour;
   C. Satisfy only B) and not A), but *a generator at the same node satisfies both.*

   These generators would have been overcompensated if that had generated and represent those constrained off by the system operator for network constraints. These generators have an incentive to bid to the market floor price in order to secure priority dispatch and earn the regional reference price. We exclude all generators located at regional reference nodes from this set, as they would not realistically face a constraint.
3. **Distort Bidding and Re-run Dispatch:** Re-run PLEXOS such that generators identified in step 2 are constrained to bid *minus* \$1,000/MWh in all half-hours where they have an incentive to race to the floor. In order to ensure that PLEXOS can choose between plant effectively, we add an infinitesimal random premium to their *minus* \$1,000/MWh bids. All generators bid their SRMC in the remaining settlement periods.
4. **Estimate Change in Dispatch Costs:** Compare variable generation costs from the runs in steps 1 and 3, above. The difference between the two runs reflects the additional costs sub-optimal dispatch that results from race to the floor bidding in our upper bound.
5. **Estimate Change in Dispatch Costs Assuming No Displacement of Renewables:** Our modelling process estimates the one-shot incentive to race to the floor for units with higher marginal costs than competitors behind the constraint but lower marginal cost than the RRP. If inframarginal units anticipated that higher-cost units would race to the floor they would also have an incentive to do so. In such circumstances, high and low cost plant would share dispatch. Our upper bound overestimates the impact of race to the floor bidding because high-cost-plant *displace* low-marginal-cost plant in dispatch. As a sensitivity, we construct a lower bound by assuming that no renewables are displaced by thermal plant. This lower bound *understates* the impact of race to the floor bidding on

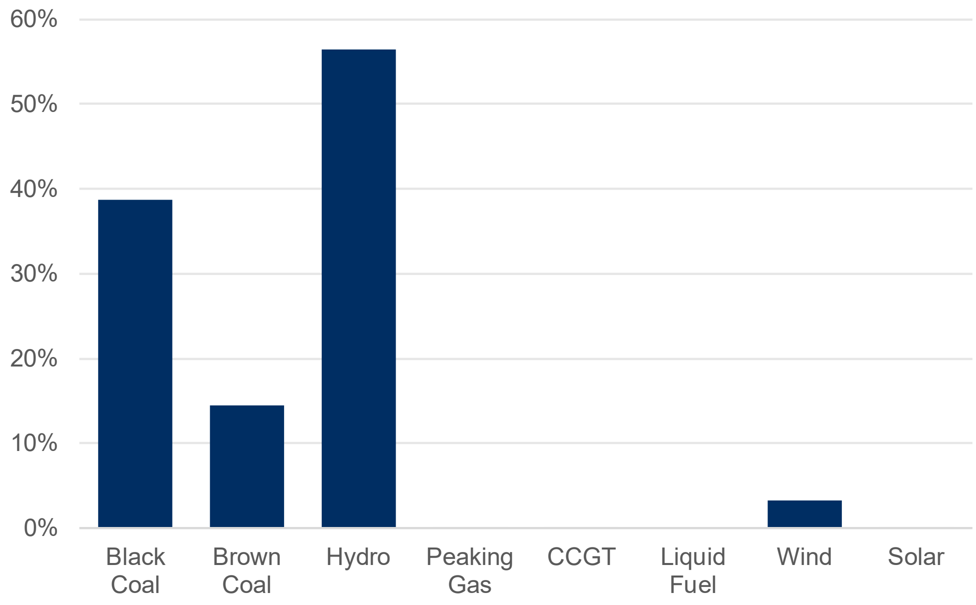
total costs because it gives renewables priority dispatch over thermal plant even when both are bidding the market floor price.

5.3. Results

Our modelling suggests that market participants face a frequent incentive to bid to the floor. Figure 5.2 shows the frequency of the incentive to bid to the floor in our analysis by technology. As can be seen from the Figure, we find that Hydro and Black Coal most frequently have an incentive to race to the floor. Wind and Brown Coal plant both have an incentive to race to the floor in some periods. Solar and gas plant rarely have an incentive to race to the floor in our modelling runs because:

- Gas has high marginal costs which are often higher than the RRP (which does not satisfy criterion B described above); and
- Solar's available capacity is determined by a generation trace, as described in Chapter 2, so usually generation does not exceed that level (thus not meeting criterion A).

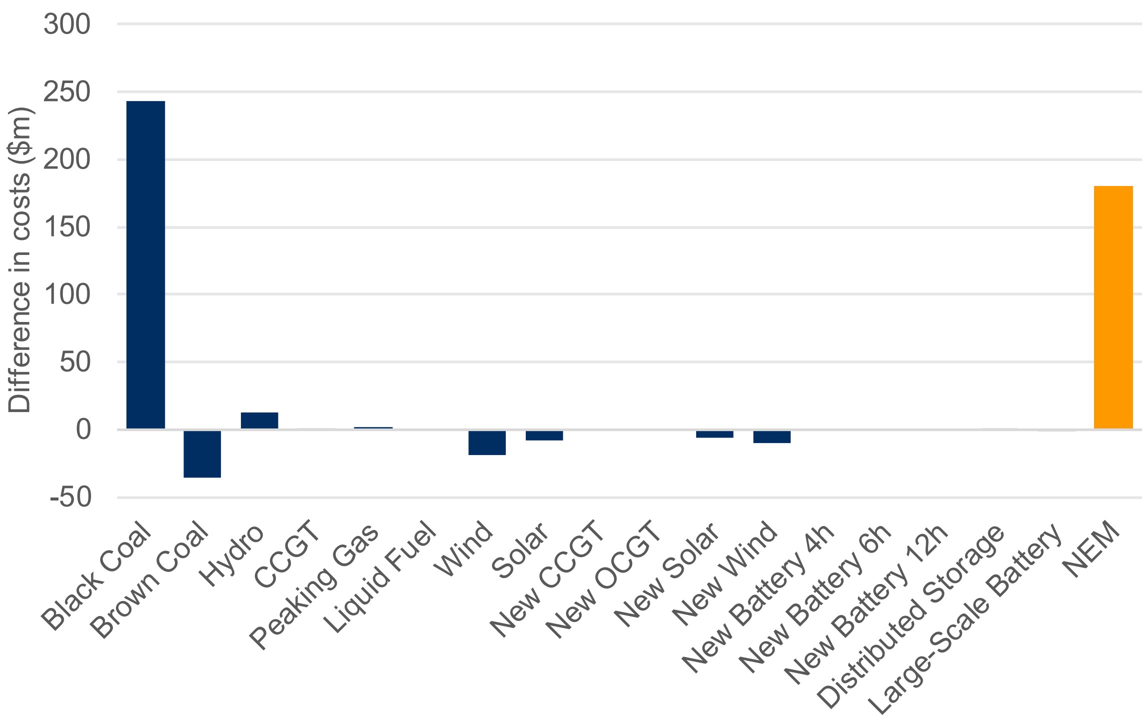
Figure 5.2: Hydro and Coal Plant Most Frequently Race to the Floor in Our Modelling



Source: NERA Analysis

Our analysis suggests that total system costs would decrease by around $180 million per year in our upper bound and $140 million per year in our lower bound due to the elimination of race to the floor behaviour. Figure 5.3 provides a breakdown of these costs by technology. As can be seen from the Figure, the primary increase in total system costs comes from increased production by higher-cost coal plant, including Black Coal displacing Brown Coal or more efficient Black Coal plant.

Figure 5.3: Breakdown of Differences in System Costs by Technology



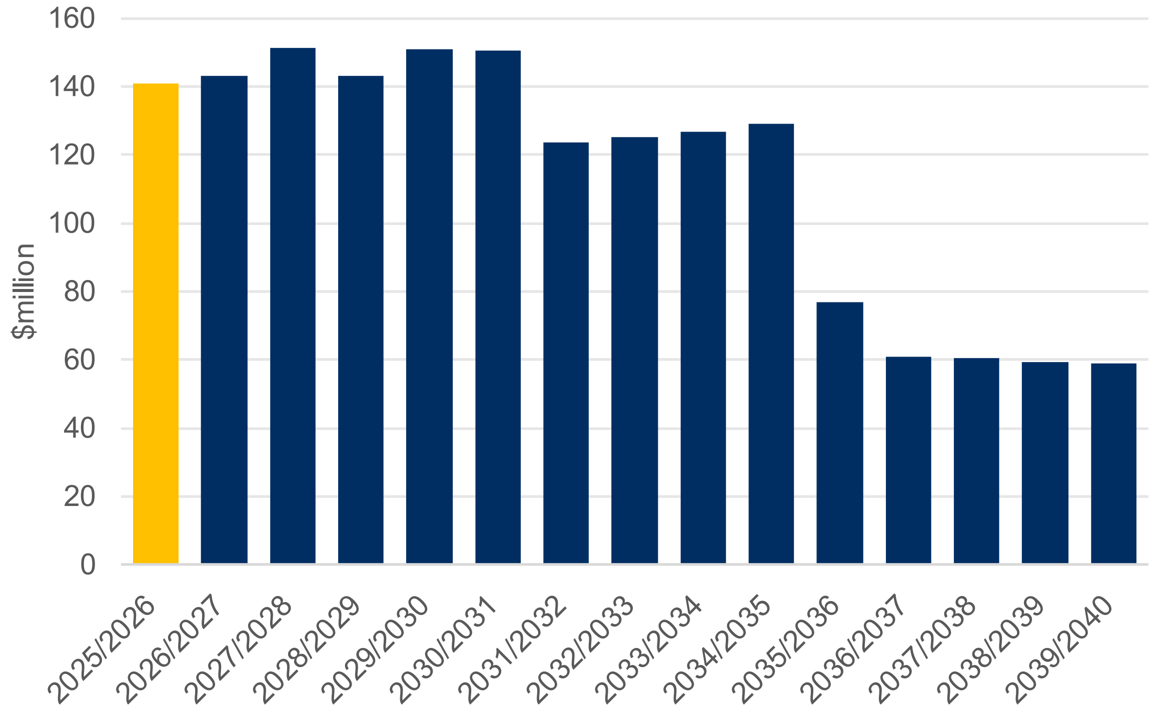
Source: NERA Analysis. Note: the chart represents results in the ***upper bound*** *case.*

The impact on total system costs of racing to the floor depends on the relative costs of the generation technologies on the system. In our analysis, over 90 per cent of the change in system costs as a result of race to the floor bidding arise from higher cost coal plant supplanting cheaper coal plant or other technologies.

In a future scenario where all plant on the system had zero (or extremely low) marginal costs, the increase in system costs from dispatching one or other plant would be minimal, at least from short-run dispatch. Our analysis of the long-term investment in the system, set out in Chapter 3 above suggests that solar and wind power are likely to be the dominant form of generation in the NEM by the end of the modelling period. These technologies have low marginal costs and therefore the costs of distorted dispatch from these technologies is likely to be low. However, our modelling suggests that batteries will become an increasingly important source of power in the NEM over the modelling period. Batteries have a positive opportunity cost and therefore even in a system which relies heavily on renewables, racing to the floor would continue to result in increased system costs.

In order to project the ongoing benefits of eliminating the Race to the Floor over time, we have indexed the additional system costs from Race to the Floor bidding in 2025/6 to our estimate of variable costs of coal production over the modelling horizon. Accordingly, by 2036/7, our estimate of the benefits of eliminating Race to the Floor bidding will be less than half of the level estimated for 2025/6. Our approach is deliberately conservative: As coal plant retire, racing to the floor is likely to result in alternative technologies, some of which have positive and potentially-increasing marginal costs (e.g. batteries, hydro or pumped storage), displacing lower-cost renewable plant. In principle therefore, the benefits from eliminating Race to the Floor bidding may be larger than our long-term projections.

Figure 5.4: Evolution of Benefits from Eliminating Race to the Floor Over Time (Lower Bound)



Source: NERA Analysis. Calculation is on ***lower bound*** *benefits.*

Table 5-1 sets out our modelling results. As can be seen from the Table, we estimate that the change in system costs in 2025/6 falls within the range $140-180 million per annum. The Net Present Value of our projected change in system costs to 2040, discounted at 7 per cent to 2020 terms is ranges between $795 million and $1,020 million.

Table 5-1: Our Final Results Suggest Annual Benefits from Race to the Floor Bidding of $140-180 million in 2026

	Base	Upper Bound		Lower Bound	
	Run 1	**Run 2a**	**Savings**	**Run 2b**	**Savings**
	Bids at marginal cost	*Bids at SRMC or floor*	*2a - 1*	*Bids at SRMC or floor*	*2b - 1*
System Costs 2025/26 ($m, real 2020)	2,650	2,830	**180**	2,790	**140**
System Costs 2026 – 2040 ($m, NPV to 2020)	14,972	15,992	**1,020**	15,757	**795**

Source: NERA Analysis of PLEXOS results

5.4. Qualitative Discussion of Results

Our results are likely to be highly sensitive to our estimate of the frequency of race to the floor bidding. Our estimate of the frequency of Race to the Floor bidding may depart from actual race to the floor bidding in practice. Our analysis depends on a number of assumptions, such as the topography and nodal demand assumed in our PLEXOS model and the frequency of binding constraints. It is also a one-shot estimate designed to reflect the incentive of plant who are not running but would earn a profit from bidding to the floor under the Status Quo arrangements. We assume that these market participants bid to the floor whenever they have the incentive to do so. In practice, market participants may not bid to the floor in these (and only these) circumstances for at least three reasons:

- Market participants have imperfect information. Therefore, they cannot know in advance whether constraints will bind and it will be profitable to bid to the floor. They must therefore balance the risk of bidding a low price and affecting the RRP and ensuring that they get dispatched and earn the RRP if the RRP is likely to be above their costs.
- Our modelling includes minimum generation but does not include start-up costs and ramping. Start-up costs and ramping could increase the incentive to bid to the floor in order to remain operational and/or decrease the incentive to bid to the floor by preventing coal plant from starting up in order to bid to the floor.
- Our modelling is a generator-specific analysis and ignores portfolio effects. Where a generator has market power within a constrained area, they may avoid bidding their higher cost plant to the floor in order to maximise their net revenues.

Katzen and Leslie's work for the AEMC provides one source of comparison for assessing how closely our analysis mimics actual bidding and the frequency of incentives to bid to the floor in the NEM. It is not possible to make direct comparison with Katzen and Leslie's work in our model runs. Katzen and Leslie do not attempt to measure changes in system costs, only total overcompensation. Their estimate of total overcompensation (of $445 million in 2019) is broadly consistent with our estimate of changes in total system costs (of $140-180 million in 2025/6). The precise relationship between overcompensation and the change in total system costs is unclear. On the one hand, racing to the floor could cause no or limited changes in total system costs where the marginal costs of plant behind the constraint are similar and therefore overcompensation may be much higher than the change in system costs. On the other hand, changes in system costs could exceed total overcompensation in circumstances where a small margin (e.g. $1/MWh) incentivizes plant with very high marginal costs just below the adjusted RRP to share output with low cost plant.

More granular comparison is challenging because Katzen and Leslie do not publish the frequency of race to the floor bidding behavior in their analysis. For instance:

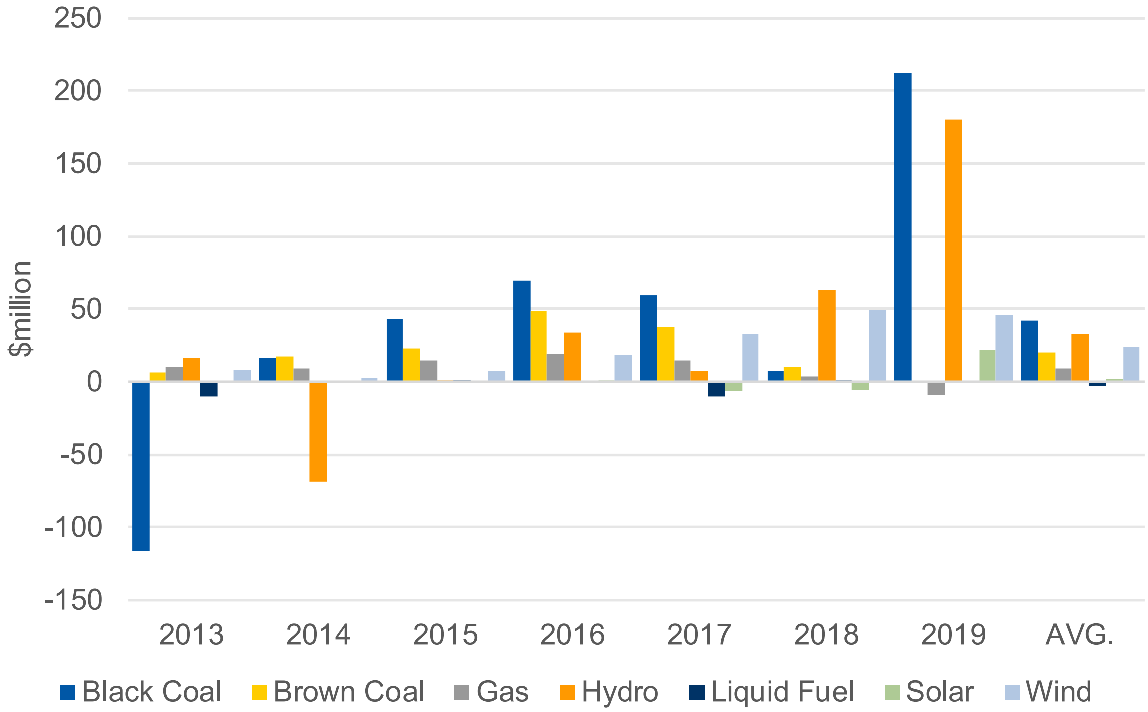
- Katzen and Leslie's work suggests that the degree of overcompensation varies materially across years. In 2019, Katzen and Leslie found that overcompensation of Black Coal plant accounted for $213 million in the NEM, which was nearly three times higher than any previous year and contrasts with *undercompensation* of *minus* $100 million in 2013 (see Figure 5.5). Accordingly, differences between our modelled year and Katzen and Leslie's work are challenging to appraise.
- Katzen and Leslie's estimates depend on actual supply and demand conditions that transpired in reality. Our analysis relates to a hypothetical demand profile and capacity mix in 2025/26 with an assumed pattern of network outages.

However, one potentially-observable difference between our analysis and Katzen and Leslie's work is the relativity between racing to the floor behaviour by plant of different technology types. Our analysis suggests that the primary plant that bid to the floor are Hydro and Black Coal. Katzen and Leslie do not publish the frequency of Race to the Floor bidding by plant time. However, Katzen and Leslie's work suggests that the percentage of *revenue* accounted for by overcompensation is frequently relatively high for Wind plant and accounts for around 4 per cent of total revenues between 2013 and 2019 (see Figure 5.6). These figures are not directly comparable to those from our analysis on the *frequency* of race to the floor bidding because Katzen and Leslie's denominator is revenue and ours is time. However, Katzen and Leslie's work may suggest that wind plant has an incentive to race to the floor more frequently than our modelling would indicate.

That our modelling may understate the extent to which intermittent plant bid to the floor is not entirely surprising: Our modelling is deterministic and relies on generation traces for wind plant and does not take the stochastic and correlated nature of wind production into account. Furthermore, curtailment of wind in real life is mainly due to non-thermal constraints, which are not reflected in our model. In practice, the relative infrequency with which wind bids to the floor in our modelling may not be material:

- To the extent that wind plant bidding to the floor substitute for other wind plant, the impact on total system costs would be negligible and therefore immaterial to our results.
- Our lower-bound sensitivity illustrates that even if wind were never displaced by Black Coal bidding to the floor, the reduction in total system costs would be in any case over $100 million per year.

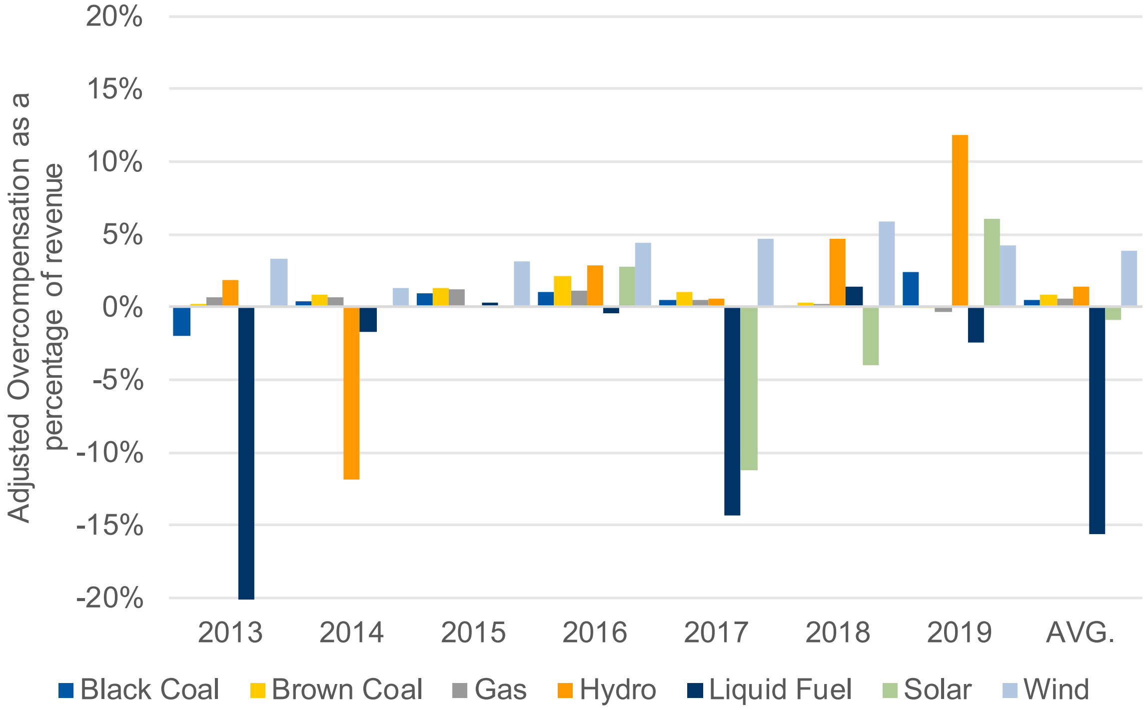
Figure 5.5: Katzen and Leslie find that " Adjusted Overcompensation" is Highest for Wind, Black Coal and Hydro[30]



Source: Katzen and Leslie (2020), Examining distributional impacts from the proposed COGATI reforms

[30] As explained above, Katzen and Leslie (2020) define total overcompensation as "directional" mispriced revenue, that is, the total difference between revenue earned by receiving the RRP and implied revenue under LMP. Total *adjusted* overcompensation excludes LMP values below zero from the calculation, in cases where LMP and RRP diverge. This is done to account for the bidding behaviour of, for instance, wind turbines, which have marginal costs assumed to be zero.

Figure 5.6:Katzen and Leslie's estimate of "Total (Adjusted) Overcompensation as a Percentage of Revenue" May Suggest Wind Has an Incentive to Race to the Floor



Source: Katzen and Leslie (2020)

6. Dynamic Loss Factors

The AEMC's proposals for Access Reform include adjustments to accounting for losses in the NEM. Generators in the NEM currently earn the RRP for their state adjusted by static Marginal Loss Factors which do not vary between the hours of the year, updated by AEMO each year in advance. The NEM Dispatch Engine (NEM-DE) prioritises between plant to meet its forecast of load on the system based on bids submitted by generators adjusted for those static losses. In practice, losses vary with the utilisation of lines and the pattern of dispatch.

This Chapter examines the benefits of reforming the accounting for losses in the NEM to take account of the dynamic profile of losses. It proceeds as follows:

- Section 6.1 sets out the theoretical benefits of reform;
- Section 6.2 describes our modelling approach;
- Section 6.3 sets out our results; and
- Section 6.4 provides a qualitative discussion of those results.

6.1. Theoretical Benefit of Reform

In its Discussion Paper on Access Reform, the AEMC characterised the economic benefit of Access Reform as follows:

> "Under dynamic regional pricing, we are proposing that intra-regional and inter-regional losses would be calculated dynamically in dispatch. The benefits that accrue from adopting dynamic loss factors largely relate to more efficient dispatch. For example, if the static marginal loss factor is very different from the actual marginal loss factor in any given dispatch interval, this could lead to generators with higher loss-adjusted costs being dispatched ahead of lower cost generators. If intra-regional losses were modelled dynamically in dispatch, the productive efficiency of the dispatch engine could be improved."[31]

In principle, inefficiency resulting from the treatment of losses in the NEM-DE stems from at least two sources:

- **Volume effect**: Losses in real time differ by and within settlement periods. Accordingly, in principle at least, the NEM-DE could dispatch the wrong volume of generation in real time. Losses are systematically higher when demand is high and the network is more heavily utilised. As a result, the NEM-DE, could assume systematically too little electricity would be lost at times of higher demand and dispatch too little generation, whilst over-dispatching when demand was low. Under-dispatching when demand was low would either require additional adjustments through reserve markets or potentially, in extreme cases, additional lost load.

- **Price effect**: Whatever the demand forecast, the NEM-DE may meet it in an inefficient manner by relying on static MLFs. For instance, if two plant were offering equal bids to

[31] AEMC (14 October 2019), COGATI Proposed Access Model, page 22.

provide generation, the NEM-DE may select the plant which has the lower MLF but higher actual losses in practice. In such circumstances, system costs would increase.

We understand from discussion with AEMO that the second of these two potential sources of inefficiency is the primary driver of inefficiency resulting from the use of MLFs in the NEM. Although AEMO does not estimate losses directly, it implicitly estimates the quantity of lost energy at each node on the system because the NEM-DE uses a granular forecast of gross load, including losses, at each node on the system. However, modelling dynamic losses directly may improve on the implicit forecasting of losses. If so, system costs could be reduced by reducing the variance between AEMO's estimate and the actual volume of electricity required to cover losses on the system.

6.2. Approach to Modelling

Our process for modelling the impact of Race to the Floor Bidding consists of the following four steps:

1. **Estimate Pattern of Dispatch Based on Static MLFs:** Run PLEXOS in granular dispatch mode for 2025/6 using the capacity mix from the Reform Scenario for that year based on our runs described in Chapter 3 above. In this run, generators bid their short-run marginal cost as an offer price and PLEXOS selects the cost-minimising dispatch. Generators are remunerated based on the regional reference price, adjusted for their MLFs but the electricity system as a whole is lossless.
2. **Impose Pattern of Dispatch from Step 1 in a System with Dynamic Losses:** Run PLEXOS in granular dispatch mode for 2025/6 with Dynamic Losses switched on but constraining plant on to deliver at least the dispatch pattern estimated in step 1. PLEXOS estimates the cost-minimising pattern for delivering additional electricity required by increasing output from remaining resources on the system. The outcome of this step is a sub-optimal dispatch to minimise system costs that takes account of MLFs and gives plants with high MLFs priority dispatch, but ultimately seeks to ensure the system remains balanced respecting the actual losses (observed by AEMO as part of gross demand) on the system.
3. **Estimate Pattern of Dispatch Based on Dynamic Losses:** Run PLEXOS in granular dispatch mode for 2025/6 with Dynamic Losses switched on with no constraints or prioritisation of plant with high MLFs. The outcome of this step represents the optimal dispatch that would occur were the NEM-DE to calculate dynamic losses endogenously.
4. **Estimate Change in Dispatch Costs:** Compare variable generation costs from the runs in steps 2 and 3, above. The difference between the two runs reflects the additional costs sub-optimal dispatch that results from applying static losses.

6.3. Results

Table 6-1 sets out the results of our analysis of the impact of dynamic losses. As can be seen from the Table, the total variable costs of generators in 2025/6 is from the step where we fix generation is lower than the total variable costs of generation where PLEXOS optimizes including dynamic losses. The first step with fixed generation and no losses requires less power generation and particularly at peak times when both prices and losses tend to be high. When we impose the same pattern of generation in the second step in a system with dynamic losses, we obtain some additional output from plant on the system not in the original dispatch but we also observe demand curtailment: Generators produce insufficient energy in a world without losses and the remaining generators on the system are not able to equate supply and demand. This lost load is not a real-world feature of the NEM because in practice, AEMO estimates gross demand including losses and would use ancillary services to ensure grid stability and prevent curtailment. We multiply the volume of unserved energy by the average price of electricity in the NEM in our modelling for 2025/26 ($42.34/MWh) to estimate the marginal cost of serving the additional load (16 TWh). Attributing the average price of electricity over the year to the additional unserved energy is intrinsically conservative because losses tend to be higher when demand and prices are higher. After adjusting for unserved energy, our estimate of total variable costs in the NEM is nearly A$102 million in 2025/6 alone. If the NEM experienced annual losses at that level from 2025/26 to 2039/40, the Net Present Value of savings in real $2020 terms would be over $660 million.

Table 6-1: We Estimate Cost Savings from Adopting Dynamic Losses of Up to $102 million (real 2020 $million, discounted at 7 per cent)

	Dynamic Loss Factors	**Fixed Generation**	**Saving 2025/2026**	**Saving 2026-40**
	Run 3	*Run 2*	*Run 3 – Run 2*	*NPV 2020*
Variable Costs – Generators	3,155.9	2,362.9		
Variable Costs – Batteries	0.7	0.3		
Cost of Unserved Energy and Demand Curtailed	-	895.2		
Total	3,156.6	3,258.4	**101.8**	**661.1**

Source: NERA Analysis

6.4. Qualitative Discussion of Results

Our approach to quantifying the benefits of introducing dynamic losses is likely to be an overstatement, at least insofar as it is an estimate of the increased efficiency of short-run dispatch. Our approach naively dispatches plant as if losses were non-existent and prioritizes plant based on static loss factors. The second step in our method results in AEMO purchasing the wrong quantity of supply (typically too little and results in material lost load, which we assume AEMO can resolve at the marginal cost of energy on the system). Our solution may be over-constrained.

In practice, we understand that AEMO forecasts gross demand including losses and its demand forecasting method adjusts for the volume that it will be necessary to procure dynamically in real time based on that locational forecast. Accordingly, the principle inefficiency that the use of static loss factors leaves in AEMO's current method is likely to be prioritising the wrong plant to resolve losses (i.e. the price effect) rather than failure to procure the correct volume of power to cover losses on the system (the volume effect). Our estimate, however, covers both potential failures. If AEMO's load-forecasting were not to improve as a function of introducing dynamic losses, then only benefits associated with the price effect would be realized following the introduction of Access Reform.

Our method does not address the impact of introducing dynamic loss factors for investment in the system. Introduction of dynamic losses would reward plant based on the losses the system would experience in real time. Accordingly, one would expect a positive impact on the efficiency of investment because it would introduce a more granular price signal which would reflect system costs and needs. Our estimate understates the benefits of Access Reform insofar as it does not include any benefits for the improved efficiency of investment due to dynamic vs static loss factors, noting that static loss factors are updated annually and therefore the distorted signal only exists within years.

7. Impact on Liquidity and Risk

In this section, we assess the likely impact of the reform on the risks faced by generators, and the resulting impact on contract market liquidity across the NEM.

The Access Reform changes the risks that generators face in the market. By eliminating strategic bidding, the Access Reform reduces the inefficient volume risk that generators face under the current access model. On the other hand, by introducing locational marginal pricing, the Access Reform might expose generators to volatile revenues and risk due to differences between the Regional Reference Price and the price at the generators' respective nodes. However, the Reform also introduces a financial instrument – the Financial Transmission Right (FTR) to pay out this price difference and reduce or eliminate the price risk faced by generators.

Assessing the liquidity impacts of reform is a complex undertaking. In the assessment presented in this chapter we have been deliberately conservative in understating the benefits that reform might bring to liquidity in the NEM by:

- Conducting the analysis at generator level and ignoring portfolio effects, for instance that renewable plant may be able to offer more firm power using a combination of FTRs, renewables and batteries or thermal plant.
- Considering only the impact of annual and continuous FTRs on liquidity. The AEMC's policy decision is to allow time of use FTRs in addition to continuous FTRs which will allow generators to purchase FTRs which better-fit their generation profile.
- Assuming that there is no liquid secondary market for FTRs, which may not be the case in practice. A liquid secondary market for FTRs would enable generators to shape their FTRs to match the profile of their generation and hedging.

Despite these conservative assumptions, viewed as a whole, our analysis does not suggest that liquidity is likely to fall in the NEM following Access Reform.

We structure the section as follows:

- In Section 7.1, we discuss the definition of liquidity and the relationship between liquidity and risk that underpins our analysis;
- In Section 7.2, we use a theoretical, worked example to illustrate the changes in risks faced by generators as a result of the reform;
- In Section 7.3, we use our modelling results to assess the risks that we identify in preceding sections. We quantify the changes in half-hourly net revenues of generators arising from the reform, and identify the potential implications for contract market liquidity; and
- In Section 7.4, we briefly describe the potential benefits provided to suppliers and generators by inter-regional FTRs.

In this analysis we have assumed that FTRs are firm. We analyse the firmness of FTRs separately in Appendix A.

7.1. Liquidity in the Short Run Will Reflect an Efficient Response by Generators to the New Risks they Face

Market participants face two main mechanisms to manage risks related to the sale of power:

- **Hedge:** market participants can choose to contract forward to hedge against adverse wholesale cost movements and buy financial derivatives on the forward market. This guarantees a cost of purchase of wholesale power, known as the strike price, and eliminates the risk of adverse price movements, subject to counterparty default. However, participants incur costs from hedging: the two main costs are the transactions costs associated with purchasing the forward contract and the cost of posting collateral when marking to market.

- **Holding risk capital:** Alternatively, market participants can hold capital to manage fluctuations in cashflows due to changes in power prices. For instance, retailers can hold capital to pay the difference between the wholesale cost of electricity and the tariff agreed with its customers. This is in effect a form of self-insurance. The cost of holding this capital is determined by the weighted average cost of capital.

Contract market liquidity and the risks faced by market participants are inherently linked. Hedging is a tool by which market participants can manage the risks that they face, rather than raising and holding capital in order to protect themselves against those risks. In particular, hedging allows generators to reduce risks stemming from:

- The downside risk of a low spot price in any given dispatch interval when selling power at the time of delivery; and
- Volatile returns reflecting a volatile spot price relative to a pre-agreed price for power in a forward contract.

Retailers face similar risks including:

- The downside risk of a high spot price in any given dispatch interval when purchasing power at the time of delivery; and
- Volatile returns reflecting a volatile spot price relative to a pre-agreed price for power in a forward contract which cannot be passed to all customers on all tariff offerings.

To see how hedging can reduce the variation in a generator’s cashflow, consider the following example in Table 7.1. A generator generates 100 MW in each dispatch interval (Row A). The generator is paid the RRN price for its generation (Row B) and faces a constant short-run marginal cost (SRMC) of generation (Row C). Its net revenue is given by its generation multiplied by the difference between the RRN price and the constant SRMC (Row D).

Table 7.1: Worked Example to Illustrate How Hedging Can Stabilize a Generator's Net Revenue

	Dispatch Interval	1	2	3	4	5
A	**Generation (MW)**	100	100	100	100	100
B	**RRN Price ($/MW)**	11	8	9	12	10
C	**SRMC ($/MW)**	5	5	5	5	5
D = A(B - C)*	**Net Revenue ($)**	**600**	**300**	**400**	**700**	**500**
E = 100(10 - B)*	**CfD Pay-Out ($)**	-100	200	100	-200	0
F = D + E	**Net Revenue with CfD ($)**	**500**	**500**	**500**	**500**	**500**

Source: NERA Illustration.

To protect itself against variations in the RRN price, the generator strikes a contract-for-difference (CfD) with another market participant at strike price of $10 per MW.[32] A CfD stipulates that if the RRN price is greater than $10 per MW, the generator must compensate its counter-party for the difference. Equally, if the RRN price is lower than the strike price of $10 per MW, the generator will receive the difference from the counter-party. We assume that the generator purchases a CfD for 100 MW and we depict the pay-out to the generator from the CfD in Row E.

With a CfD, the generator earns its net revenue plus the pay-out from the CfD. Its net revenue with a CfD (Row F) is less variable than its net revenue without a CfD (Row D). The reduction in variability in the generator's cashflow is a measure of the effectiveness of the hedging tool to manage the risk that the generator faces. The generator is incentivised to contract forward in order to reduce the volatility of its cashflow.

The degree to which generators and retailers contract forward for power depends on the types and magnitude of the risks that they face. For instance, a more volatile spot price may incentivise more contracting in the forward market because the risk of buying or selling power at the time of delivery is greater for generators and retailers. Therefore, higher traded volumes in the forward contract market may reflect higher "hedgeable" risks of market participants.

Equally, generators and retailers face other risks that cannot be mitigated by hedging in the forward market. For instance, the risk that a transmission line becomes congested such that a generator cannot be dispatched may not be avoided alone through contracting in the forward market. Increasing the amount of "unhedgeable" risks relative to "hedgeable" risks that market participants face may reduce the incentives to contract forward and the volumes of power traded in the forward market.

In addition, the extent to which contracting forward in markets is an attractive alternative to manage risk rather than raising and holding capital depends on the transactions costs that market participants incur to trade. If transactions costs are higher, then market participants will be more likely to hold risk capital or explore other markets to manage their risks.

32 For simplicity, we do not include the price of the contract (which is fixed and does not affect volatility of cashflows) nor collateral posting.

Moreover liquidity in forward power markets can have benefits that extend beyond the contracting parties. Whilst both seller and purchaser may benefit through the risk mitigation that contracting forward can provide, the agreed price of the trade provides informational benefits to other participants in the market as to the current value and expectations over the future value of power. In this sense, liquidity is self-reinforcing: Information from one trade may lead to incentives for others to trade. Equally, a lack of trade in a market can dissuade others from trading because of a lack of clear price transparency over market expectations of the current or future value of power. Whilst deviations to levels of liquidity may not result in net social benefits of losses, significant deteriorations in contract market liquidity can result in further losses of market liquidity and will likely result in higher transaction costs for market participants.

Therefore, liquidity is not a goal that regulators should necessarily pursue in and of itself. By ensuring market participants have access to power in the forward market, at transparent prices and without excessive movement of market prices, regulators may create benefits for market participants. However, lack of liquidity in a market is itself a symptom as well as a cause of the structure of the wholesale market and efficiencies of related markets. Lack of liquidity may be an efficient response to higher “unhedgeable” risks relative to “hedgeable” risks.

7.2. The Access Reform Changes the Risks Faced by Generators

The COGATI reform changes the risks faced by generators, predominantly by changing the price at which generators are paid for their power. We discuss the changes in risks faced by generators below.

7.2.1. Generators currently face an unhedgeable volume risk that reduces their willingness to contract forward

Under the current access model, generators face volume risk in that, in any dispatch period, there may exist congestion in the network that prevents that generator from being dispatched to meet load. When congestion occurs, and generators are not dispatched, the generator does not receive compensation for the power they would have generated absent congestion.

To illustrate the volume risk that generators face under the current access model, consider the following example in Table 7.2. A generator generates 100 MW in four out of five dispatch intervals (Row A). However, in dispatch interval 4, congestion in the network means that the generator is not dispatched. The generator is not compensated for not generating. In order to more clearly illustrate the volume risk that the generator faces, we assume that the RRN price is stable.

Table 7.2: Worked Example to Illustrate the Effect of Volume Risk

	Dispatch Interval	**1**	**2**	**3**	**4**	**5**
A	**Generation (MW)**	100	100	100	0	100
B	**RRN Price ($/MW)**	10	10	10	10	10
C	**SRMC ($/MW)**	5	5	5	5	5
D = A*(B - C)	**Net Revenue ($)**	**500**	**500**	**500**	**0**	**500**

Source: NERA Illustration.

The volume risk that the generator faces manifests itself in a deviation in its net revenue. If the generator could guarantee to generate in each period, in this example, its cashflow would be stable. However, its net revenue is unstable because the volume risk results in a deviation of net revenue in dispatch interval 4. A measure of the risk could be the mean dispersion of the generator's net revenue, which is 0.5 in the example above.

Generators are unable to hedge the volume risk that they are not dispatched due to congestion in any given dispatch period. Consider the same example but where the generator holds a contract for difference at a strike price of $10 per MW. Its stabilising pay-out from a CfD in dispatch interval 4 would always need to be positive in order to reduce the volume risk that the generator faces. However, the CfD payment purely depends on the RRN price relative to the strike price agreed in the contract. Moreover, because congestion may be positively correlated with higher load, and higher load often results in higher RRN prices, then the generator is more likely to be constrained off when the CfD pay-out is negative, worsening the volatility in its cashflow.

Therefore, one can term the volume risks that generators face as "unhedgeable" and those risks may actively dissuade generators from contracting forward for power. Alleviating congestion, or compensating generators when they are constrained off under the current access model, may reduce the volume risk faced by generators and improve the incentives that they have to contract forward. In turn, improving incentives for generators to contract forward may improve contract market liquidity.

In most power markets, some level of volume risk is likely to occur because the efficient cost of managing volume risk is often lower than the incremental cost of alleviating congestion through transmission investment. We therefore term this level of volume risk as "efficient volume risk". However, the incentives under the current access model may lead to a worsening of the volume risk and "inefficient volume risk".

As we discuss in Section 5, the generator may be incentivised to bid at the market floor price in order to maximise its chances of dispatch despite system congestion. Crucially, generators are incentivised to "strategically" bid to the market floor price, unless they are located at the RRN, because they are not paid their bid price for the power they generate but instead at the RRN price. In dispatch interval 4 in our worked example above, the generator is incentivised to bid to the market floor price because its SRMC of production ($5 per MW) is below the RRN price ($10 per MW), and therefore if it was dispatched at the market floor price it would make positive net revenue in the dispatch interval.

However, "strategic" bidding may worsen the volume risk that each generator faces. Each generator at a location on the network (other than the RRN) with SRMC below the RRN price and that has spare capacity will face an incentive to bid to the market floor price. Moreover, if another generator bids at the market floor price, then all generators that can profitably generate power in the dispatch interval face the incentive to bid to the market floor price. Faced with a number of identical bids, we understand that the dispatch engine will dispatch each generator with identical bids based on their participation factors and therefore shares output between them.

Therefore, generators face additional "inefficient volume risk" that derives from "strategic" bidding at its location on the network.

The introduction of the COGATI reform does not immediately change the level of congestion that efficiently prevails in the power system in the NEM. Therefore, after the introduction of the COGATI reform, "efficient volume risk" remains for generators.

However, the introduction of locational marginal pricing means that generators no longer face the regional price for their power and instead respond in their bidding behavior to an efficient price signal that is the LMP at their node. Consequently, the COGATI reform may eliminate "inefficient volume risk" that results from strategic bidding at nodes. If "inefficient volume risk" is a material problem under the current access reform, then the COGATI reform will reduce the "unhedgeable" risks faced by generators which may in turn encourage them to contract forward for power in the market. If generators face a higher incentive to contract forward for power then contract market liquidity may improve.

7.2.2. The access reform introduces price or "basis" risk

Whilst the reform removes the incentives for strategic bidding by paying generators for the value of the power they generate at their location on the network and may reduce the volume risk faced by generators, the reform introduces price or "basis" risk. Basis risk describes the difference in price received by generators for their power and the price that they contract at in the forward market. In other words, CfDs become less effective at stabilising the net revenues of generators because the contracts are struck against a different price to the price generators are paid for their power.

To illustrate the impact of basis risk on the net revenues of generators, consider again the worked example that we set out in Section 7.2.1. A generator generates 100 MW in each dispatch interval at constant SRMC of $5 per MW. The generator strikes a contract-for-difference (CfD) with another market participant at strike price of $10 per MW.[33] We assume that the generator purchases a CfD for 100 MW.

In Table 7.3, we contrast the difference between the net revenues that the generator receives when it is compensated at the RRN price (Row E) and the net revenues that the generator receives when it is compensated at its LMP (Row G), which is different from the RRN price.

[33] For simplicity, we do not include the price of the contract (which is fixed and does not affect volatility of cashflows) nor collateral posting.

Table 7.3: Worked Example to Illustrate Basis Risk

	Dispatch Interval	1	2	3	4	5
A	**Generation (MW)**	100	100	100	100	100
B	**RRN Price ($/MW)**	11	8	9	12	10
C	**SRMC ($/MW)**	5	5	5	5	5
D = 100(10 – B)*	**CfD Pay-Out ($)**	-100	200	100	-200	0
E = A(B – C) + D*	**Net Revenue at RRN Price with CfD ($)**	**500**	**500**	**500**	**500**	**500**
F	**LMP ($/MW)**	12	7	11	12	8
G = A(G – C) + D*	**Net Revenue at LMP with CfD ($)**	**600**	**400**	**700**	**500**	**300**
*H = G – E = A *(F – B)*	**Basis Risk ($)**	**100**	**-100**	**200**	**0**	**-200**

Source: NERA Illustration.

Whereas previously the generator was perfectly hedged and did not experience variations in its cashflow using the CfD, the introduction of locational marginal pricing creates variation in the net revenues of the generator because the CfD is struck against a different price than the generator is paid. Therefore, "unhedgeable" deviations in prices remain which create variation in the generator's cashflow. One could measure the basis risk by the mean dispersion of the generator's net revenue at LMP (Row G).

The introduction of basis risk means that contracting forward is a less effective instrument for generators to reduce their risks, in absence of FTRs. The generator's incentive to contract forward is reduced because hedging does not necessarily reduce the volatility of its cashflow. Consequently, contract market liquidity may fall if generators bear large basis risk following the reform.

7.2.3. The reform introduces an instrument through which generators can hedge that basis risk

However, the reform also introduces an instrument through which generators may manage the basis risk introduced by the reform: Financial Transmission Rights (FTRs). Financial transmission rights reduce, or eliminate, the basis risk that generators face by paying out the difference between the RRN price and the LMP at the generators' location. We distinguish between two types of FTRs:[34]

- **One-way FTRs (options)** pay-out the difference between the RRN price and the LMP at the generator's location only if the difference is positive. In other words, one-way FTRs pay-out only if the RRN price is above the generator's LMP. One-way FTRs do not eliminate the volatility in generator's cashflows caused by differences between the LMP and the RRN price at which the generator contracts in the forward market. Instead, one-way FTRs limits the volatility to upside volatility (positive pay-outs) to the generator. In other words, one-way FTRs ensure that, after purchase, basis risk cannot make generators worse off.

[34] For simplicity, we do not assume that generators must purchase FTRs in this example. We discuss the purchasing of FTRs in later sections.

- **Two-way FTRs (obligations)** pay-out the difference between the RRN price and the LMP at the generator's location regardless which price is higher. Therefore, under a two-way FTR, generators may have to pay the seller of the FTR in cases where its LMP is greater than the RRN price. Two-way FTRs ensure that, after purchase, generator's cashflows are unaffected by basis risk.

In practice, the Access Reform offers option-like FTRs exclusively. In theory, both one-way and two-way FTRs can either be **continuous** (covering a full day) or **time-of-use** (covering a specified period). Throughout this chapter, we present examples and modelling results assuming a continuous, option-like FTR. We specify whenever outcomes might be different for time-of-use FTRs.

To illustrate the impact of FTRs further, consider again the worked example that we discuss in Section 7.2.2. The introduction of locational marginal pricing illustrates that hedging may no longer as effectively reduce the risk of generator's cashflows because of the basis risk between the price the generator is paid and the price the generator contracts at. However, now assume that the generator owns 100 MW of FTR alongside its 100 MW CfD contract.

The pay-out of one-way FTRs (Row I) or two-way FTRs (Row J) reduces the basis risk faced by the generator (Row K and Row L respectively) and reduces the volatility of its net revenue cashflow relative to the case without an FTR. A two-way FTR eliminates the basis risk faced by generators entirely whereas a one-way FTR results only in upside volatility, or positive pay-outs in dispatch intervals 1 and 3.

Table 7.4: Worked Example to Illustrate the Effect of an FTR

	Dispatch Interval	1	2	3	4	5
A	**Generation (MW)**	100	100	100	100	100
B	**RRN Price ($/MW)**	11	8	9	12	10
C	**SRMC ($/MW)**	5	5	5	5	5
D = 100(10 – B)*	**CfD Pay-Out ($)**	-100	200	100	-200	0
E = A(B – C) + D*	**Net Revenue at RRN Price with CfD ($)**	**500**	**500**	**500**	**500**	**500**
F	**LMP ($/MW)**	12	7	11	12	8
G = A(G – C) + D*	**Net Revenue at LMP with CfD ($)**	**600**	**400**	**700**	**500**	**300**
*H = G – E = A *(F – B)*	**Basis Risk ($)**	**100**	**-100**	**200**	**0**	**-200**
I	**One-Way FTR Payout ($)**	0	100	0	0	200
J	**Two-Way FTR Payout ($)**	-100	100	-200	0	200
K = H – I	**Basis Risk with One-Way FTR ($)**	**100**	**0**	**200**	**0**	**0**
L = H - J	**Basis Risk with Two-Way FTR ($)**	**0**	**0**	**0**	**0**	**0**

Source: NERA Illustration.

With either one or two-way FTRs, the generator faces reduced basis risk relative to the case where it does not own an FTR. As we discuss, basis risk reduces the effectiveness of contracting forward for power. Reduction in basis risk means that hedging becomes a relatively more effective instrument to reduce cashflow risks for generators. Therefore, ownership of FTRs may increase the incentive to hedge, and improve contract market liquidity.

However, under the reform, FTRs must be purchased by generators, at least in the long-term. The uncertainty in FTR returns to owners mirrors the basis risk faced by generators. If generators must purchase FTRs, then they are not absolved of the basis risk but they face that basis risk in their one-off decision to value and purchase an FTR. In other words, the basis risk introduced by the reform is faced by generators in the market to purchase FTRs rather than through its cashflow across dispatch intervals. Having purchased an FTR, the cost of the FTR is effectively sunk and therefore the generator faces reduced volatility in cashflows.

Therefore, within the timeframe of the FTR, ownership of an FTR improves the incentives to hedge. A generator's decision to purchase an FTR, and the risks it faces when doing so, are not relevant to its incentives to hedge *once it has purchased an FTR*. Here the total change in risks faced by generators does not map directly to the incentives those generators have to contract forward in the market, and to market liquidity.

7.2.4. Liquidity will be unlikely to worsen if generators' own sufficient financial transmission rights such that their unhedgeable risks fall

Overall, the reform changes the risks that generators face. Consequently, hedging may become a more or less effective tool to manage cashflow risks as a consequence of the reform. If hedging becomes a more effective tool to manage cashflow volatility then liquidity will likely improve as a consequence of the reform. If hedging becomes a less effective tool to manage cashflow volatility then liquidity will likely worsen as a consequence of the reform, albeit efficiently so.

We summarise the changes in risks as a consequence of the reform, and their likely impact on the incentives to hedge in Table 7.5 below.

Table 7.5: Summary of Change in Risks Facing Generators Due to the Reform

Change	Description	Change Due to Reform	Impact on Incentive to Hedge
Efficient Volume Risk	Efficient volume risk occurs in both access models because all generators face the same risk of being constrained off due to congestion (at least in the short run when the typology of the network is unchanged). It is an unhedgeable risk that reduces the effectiveness of hedging as a tool to manage cashflow volatility.	Unchanged in the short run.	Unchanged in the short run.
Inefficient Volume Risk	Inefficient volume risk occurs in the current access model because all generators are paid for their power at the RRN price. It is eliminated under the reform because of the introduction of locational marginal pricing. It is currently an unhedgeable risk that reduces the effectiveness of hedging as a tool to manage cashflow volatility.	↓	↑
Basis Risk	Basis risk describes the difference between the price the generator receives for its power (LMP) and the price it contracts at (RRN price). The risk is unhedgeable using CfDs.	↑	↓
FTRs	FTRs are a financial product by which generators can hedge basis risk.	Introduced	↑

Source: NERA Analysis.

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

In the next section, we quantifiably assess the likely overall impact of the reform on the extent to which changes in risks result in different incentives that generators have to hedge. From our examination, we assess the likely impact of the reform on contract market liquidity.

7.3. Quantification of the Risks Faced by Generators Before and After the Reform

Liquidity is notoriously difficult to measure, and there does not exist an agreed single definition nor measurement of liquidity in power markets even when one may identify that liquidity has improved or deteriorated in practice. Regulators and policy makers typically utilise measures of relative liquidity, such as bid-ask spreads or churn, and compare the relative measures in the market in question to similar markets deemed to have sufficient liquidity in other jurisdictions.

In our examination of the likely impact of the reform on contract market liquidity in the NEM, we do not measure liquidity directly nor directly assess the social benefits or costs arising from changes to the level of liquidity. Instead, we examine how the introduction of the reform may change the risks faced by generators and their subsequent incentives to contract forward in the power market. If generators face higher "hedgeable" risks, it may increase the incentive for market participants to contract forward to the extent that hedging mitigates those risks. If the reform replaces "hedgeable" risks with "unhedgeable" risks, then hedging may become more ineffective as a tool to manage risk, and the incentives to hedge may fall.

We assume that our analysis of the likely changes to market participants' incentives to hedge represent the likely impact on contract market liquidity. We expect that higher incentives to hedge will result in higher traded volumes and lower transactions costs that increase market liquidity. On the other hand, we expect that lower incentives to hedge will result in lower traded volumes and higher transactions costs. We do not assess that the reform will, in and of itself, have a direct impact on contract market liquidity, other than through the incentives that participants have to hedge in light of the new risks that they face.

7.3.1. We examine the incentives that generators have to hedge in order to reduce the volatility of their cashflows

Our approach measures the risk that generators face by the mean dispersion of the half-hourly net revenues earned by generators across the first financial year of the reform (July 2025 to June 2026 inclusively). We calculate mean dispersion by examining the standard deviation of the half-hourly net revenues normalized by the average half-hourly net revenue of each generator across the year.[35] We need to normalize by average half-hourly net revenue so we can compare the magnitude to volatility across the different worlds. We interpret a higher mean dispersion of half-hourly net revenues as higher risks faced by generators.

We assess the changes in risks that generators face as a consequence of the reform by evaluating the mean dispersion of half-hourly net revenues across four states of the world:

- **Race to the Floor (RTF):** The race to the floor world corresponds to the current access model where generators are compensated at the RRN price for their generation and strategically bid at the market floor price whenever it is in their interest to do so. We explain the construction of the RTF scenario in more detail in Section 5.
- **RRN:** The regional reference node world corresponds to the current access model where generators are compensated at the RRN price for their generation but never strategically bid at the market floor price. Therefore, the dispatch pattern of generation is the same in the RRN world as it is under the reform.
- **LMP:** The LMP world corresponds to the introduction of the reform where generators are compensated at their locational marginal price for their generation. However, in the LMP world generators are unable to hold FTRs to hedge basis risk.
- **FTR:** The FTR world corresponds to the introduction of the reform where generators are compensated at their locational marginal price for their generation. Generators can also hold FTRs in the FTR world. We assume that generators hold FTRs to match the amount of power that they choose to contract forward in the market.

Our choice of the states of the world correspond to the changes in risks that generators incur due to the reform:

[35] For OCGT plant in Victoria, we take the absolute value of mean dispersion because in some scenarios average returns are negative.

- **Efficient volume risk:** Remains constant across all worlds. We utilise the same network typology and load profile in all four worlds. We use the same pattern of efficient dispatch in the RRN, LMP, and FTR worlds.
- **Inefficient volume risk:** One can determine the extent of inefficient volume risk by examining the difference in the volatility of generators' net revenues in the RTF world relative to the RRN world. In both worlds, generators are compensated at the RRN price for the electricity they generate. However, whilst dispatch is efficient in the RRN world, it is inefficient in the RTF world because of strategic bidding. Strategic bidding results in additional risk (volatility in net revenues) for generators.
- **Basis risk:** One can determine the extent of basis risk by examining the difference in the volatility of generators' net revenues in the LMP world relative to the RRN world. The only difference between these two worlds is the price at which generators are compensated. Under the reform (the LMP world), generators are compensated at their LMP whereas in the current access model they are compensated at RRN price.
- **Basis risk, after adjustment for FTRs:** One can determine the extent of basis risk with FTRs as an available instrument to mitigate basis risk by examining the difference in the volatility of generators' net revenues in the FTR world relative to the RRN world. The difference between these two worlds is the price at which generators are compensated and the fact that generators own FTRs alongside their hedges in the contract market under the FTR world.

We use our PLEXOS modelling to efficiently dispatch the system in each state of the world, and to generate the relevant LMP and RRN prices. We use our modelling of the race to the floor scenario in order to estimate dispatch patterns with strategic bidding. We then calculate net revenues as the price less the short run marginal cost of generation multiplied by total generation in each half-hour. We calculate the mean dispersion of the half-hourly net revenues across the year to assess the risk faced by each generator in each state of the world.

We assume that generators hedge in order to reduce the risks that they face. In order to estimate the impact of the reform on generators' incentives to hedge, we adopt the following method:

1. We use our PLEXOS modelling to estimate the relevant prices and pattern of dispatch in each world for each generator in the NEM.
2. We calculate the half-hourly net revenues for each generator in the NEM on a per MW basis of their maximum capacity. We calculate the half-hourly net revenues in each world at different hedging increments. More specifically, we calculate the half-hourly net revenues for each generator at 5 per cent hedging increments i.e. 0 MW, 0.05 MW, 0.1 MW, … , 1 MW. We assume that generators hedge using a flat swap, baseload CfD with a strike price equal to the average RRN price across the quarter they are in.[36] In the FTR world, we assume generators have access to an FTR of the same size as its hedging increment i.e. a generator hedging 0.1 MW would have access to an FTR of size 0.1 MW.
3. We calculate the mean dispersion of the half-hourly net revenues for each generator in the NEM in every world and for every hedging level.

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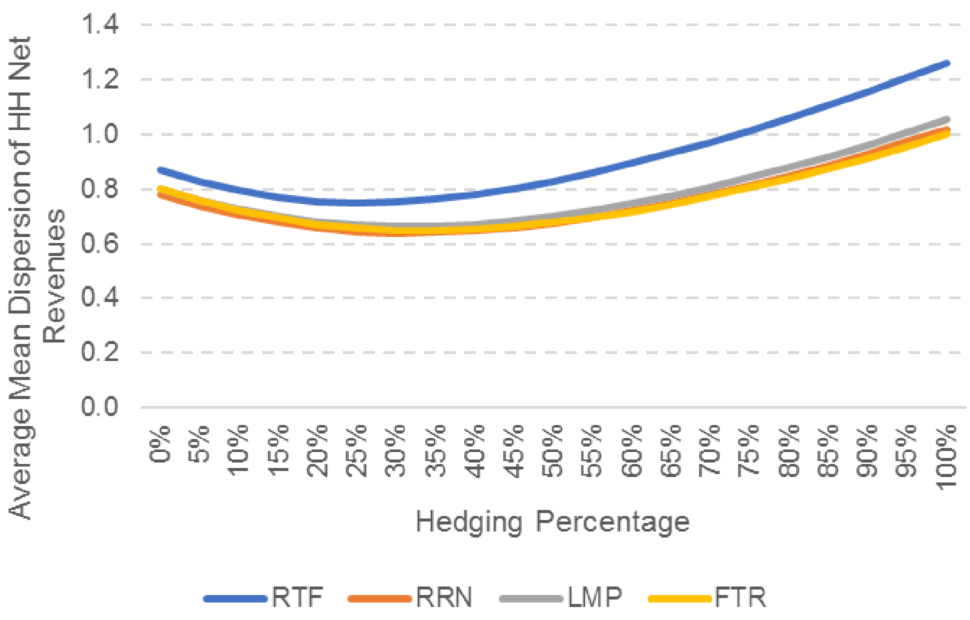
36 The quarters are July-September, October-December, January-March and April-June inclusively.

4. We average the mean dispersion of the half-hourly net revenues across generators of each fuel type in each region.
5. We calculate the hedging increment that minimises the mean dispersion of the half-hourly net revenues across each generator fuel type in each region. The hedging increment that minimises risk for generators is our estimated incentive to hedge for that generator fuel type and region in each world.

   For instance, in Figure 7.1 below we examine how the average mean dispersion of half-hourly net revenues varies across hedging increments and worlds for coal generators in New South Wales. By identifying the hedging increment that minimises the volatility of generator cashflows we estimate that, optimally, coal generators hedge 25 per cent or 0.25 MW in the RTF world, 30 per cent or 0.3 MW in RRN and LMP worlds and 35 per cent in the FTR world.

Figure 7.1: Average Optimal Hedging of Coal Plant in New South Wales



Source: NERA Analysis.

6. We compare the incentives to hedge for generator fuel types in each region across the worlds in order to examine the changes in hedgeable risks across the worlds.

Our simplified approach to determining the optimal hedging of plant means that the levels of optimal hedging that we estimate are likely to differ significantly from the optimal levels of hedging realised in practice. Our simplified model does not allow for portfolio effects, does not account for other reasons to contract forward, and only accounts for quarterly flat baseload swaps as a hedging product. Therefore, we are predominantly interested in directional changes to the degree of optimal hedging as a consequence of moving across different worlds.

We present our results for Victoria, Queensland, New South Wales, and South Australia in Table 7.6 to Table 7.9 below respectively.[37] In each table we summarise the optimal hedging percentage for each fuel type in each world. We also report the average mean dispersion of half-hourly net revenues across the year for each fuel type in each world. In the last two rows of each table, we summarise the change in optimal hedging and volatility of half-hourly net revenues from moving from the current world with strategic bidding ("RTF") to the reform world with FTRs ("FTR"). We interpret increases in optimal hedging as increased incentives for generators to contract forwards to mitigate risks, and likely improvements in contract market liquidity as a consequence of the reform. We assume that FTRs are one-way FTRs, in other words, we assume FTRs do not result in negative pay-outs if congestion flows in the opposite direction to which the FTR is owned.

Table 7.6: Average Incentives to Hedge and Volatility of Half-Hourly Net Revenues Across Fuel Types in Victoria

	World	Wind	Solar	Hydro	Coal*	CCGT	OCGT	All
Optimal Hedging (%)	RTF	5%	5%	45%	80%		0%	5%
	RRN	5%	5%	45%	80%		0%	5%
	LMP	5%	0%	40%	80%		0%	5%
	FTR	5%	5%	55%	80%		0%	10%
Average M.D. of HH Net Revenues	RTF	0.91	1.44	2.32	0.37		3.32	1.49
	RRN	0.90	1.44	2.23	0.37		3.25	1.47
	LMP	0.91	1.43	2.25	0.37		3.23	1.45
	FTR	0.91	1.43	1.95	0.37		3.23	1.44
Total Change RTF to FTR	Hedging (%)	0%	0%	10%	0%		0%	5%
	M.D of Net Revenues	0.00	-0.02	-0.37	-0.01		-0.09	-0.05

Source: NERA Analysis. Note. Here and throughout, M.D. = "Mean Dispersion"; HH = "half-hourly".
** Brown Coal.*

[37] For brevity, and with understanding of the importance for contract market outcomes, we do not examine Tasmania in our analysis.

Table 7.7: Average Incentives to Hedge and Volatility of Half-Hourly Net Revenues Across Fuel Types in Queensland

	World	Wind	Solar	Hydro	Coal	CCGT	OCGT	All
Optimal Hedging (%)	RTF	30%	0%	85%	70%	0%	0%	5%
	RRN	30%	0%	85%	70%	5%	0%	5%
	LMP	20%	0%	70%	45%	5%	0%	0%
	FTR	50%	10%	100%	70%	5%	60%	25%
Average M.D. of HH Net Revenues	RTF	0.83	1.35	1.14	0.52	38.80	22.24	1.17
	RRN	0.67	1.24	0.90	0.47	36.20	37.50	1.05
	LMP	0.70	1.28	0.94	0.60	36.43	46.95	1.05
	FTR	0.63	1.28	0.75	0.41	34.59	14.19	1.01
Total Change RTF to FTR	Hedging (%)	20%	10%	15%	0%	5%	60%	20%
	M.D of Net Revenues	-0.20	-0.07	-0.39	-0.11	-4.22	-8.05	-0.16

Source: NERA Analysis. Note: We interpret the large change in optimal hedging by OCGT plant in the FTR world as noise that is driven by pay-outs on FTRs rather than stabilization of net revenues as a result of generation. OCGT plant in Queensland (approximately 8 GW in 2025/26) are peaking plants and generate with a load factor of 0.4 per cent, meaning that they generate in relatively few half-hours across the year in question.

Table 7.8: Average Incentives to Hedge and Volatility of Half-Hourly Net Revenues Across Fuel Types in New South Wales

	World	Wind	Solar	Hydro	Coal	CCGT	OCGT	All
Optimal Hedging (%)	RTF	15%	0%	40%	25%	0%	0%	0%
	RRN	15%	0%	35%	30%	0%	0%	0%
	LMP	20%	0%	35%	30%	0%	0%	0%
	FTR	35%	5%	65%	35%	0%	5%	20%
Average M.D. of HH Net Revenues	RTF	0.91	1.30	1.97	0.75	49.73	132.4	1.37
	RRN	0.90	1.30	2.07	0.64	71.11	132.4	1.35
	LMP	0.93	1.34	2.08	0.66	73.59	132.4	1.38
	FTR	0.88	1.34	1.79	0.65	73.59	8.83	1.34
Total Change RTF to FTR	Hedging (%)	20%	5%	25%	10%	0%	5%	20%
	M.D of Net Revenues	-0.04	0.04	-0.19	-0.10	23.85	-123.5	-0.03

Source: NERA Analysis. We find that black coal plant in NSW optimally hedges much less than black coal plant in QLD and brown coal plant in VIC. In part, this may be because black coal plant in NSW has a lower load factor (44 per cent) than coal plants in QLD (63 per cent) and VIC (86 per cent). Our measure of optimal hedging is as a percentage of maximum capacity, which means lower load factors likely result in a lower degree of optimal hedging.

Table 7.9: Average Incentives to Hedge and Volatility of Half-Hourly Net Revenues Across Fuel Types in South Australia

	World	Wind	Solar	Hydro	Coal	CCGT	OCGT	All
Optimal Hedging (%)	RTF	10%	0%			0%	0%	0%
	RRN	10%	0%			0%	0%	0%
	LMP	10%	0%			0%	0%	0%
	FTR	15%	5%			0%	0%	0%
Average M.D. of HH Net Revenues	RTF	0.92	1.43			164.6	20.16	1.06
	RRN	0.92	1.43			35.24	29.46	1.04
	LMP	1.75	1.44			35.24	27.80	1.80
	FTR	1.73	1.44			35.24	27.80	1.80
Total Change RTF to FTR	Hedging (%)	5%	5%			0%	0%	0%
	M.D of Net Revenues	0.81	0.01			-129.4	7.64	0.74

Source: NERA Analysis.

7.3.2. We examine the changes to upside risk of generators' cashflows

In order to capture the effect of the reform on specifically the downside risk for generators' net revenues (rather than the total volatility of their cashflows), we also record the average number of instances across the year where the net revenue in any given half-hour is negative. We record the average change in the number of these instances of half-hourly negative returns for each fuel type moving to the reform world with FTRs from the non-reform world with strategic bidding (RTF) and the non-reform world without strategic bidding (RRN). We present our results in Table 7.10 below.

Table 7.10: Average Change in Number of Instances of Half-Hourly Negative Returns

	Wind	Solar	Hydro	Coal	CCGT	OCGT	All
RTF to FTR							
Victoria	-2	-1	-158	-34	0	-4	-52
Queensland	-709	-1369	-1421	-512	-5	-520	-936
New South Wales	-324	-1130	-371	260	0	-1098	-452
South Australia	-10	-43	0	0	-17	3	-1
RRN to FTR							
Victoria	-2	-1	-25	0	0	0	-8
Queensland	-305	-1280	-909	-424	-1	-521	-795
New South Wales	-283	-1130	-628	-41	0	-1098	-621
South Australia	-9	-43	0	0	0	0	0

Source: NERA Analysis

7.4. Our Assessment of the Outcome for Contract Market Liquidity

We summarise our results across our assessments in Table 7.11 below.

Table 7.11: Summary of Our Results (Total Change RTF to FTR)

		Wind	Solar	Hydro	Coal	CCGT	OCGT	All
Victoria	Hedging (%)	0%	0%	10%	0%	0%	0%	5%
	M.D of Net Revenues	0.00	-0.02	-0.37	-0.01	0.00	-0.09	-0.05
	Instances of Neg. Returns (#)	-2	-1	-158	-34	0	-4	-52
Queensland	Hedging (%)	20%	10%	15%	0%	5%	60%	20%
	M.D of Net Revenues	-0.20	-0.07	-0.39	-0.11	-4.22	-8.05	-0.16
	Instances of Neg. Returns (#)	-709	-1369	-1421	-512	-5	-520	-936
New South Wales	Hedging (%)	20%	5%	25%	10%	0%	5%	20%
	M.D of Net Revenues	-0.04	0.04	-0.19	-0.10	23.85	-123.5	-0.03
	Instances of Neg. Returns (#)	-324	-1130	-371	260	0	-1098	-452
South Australia	Hedging (%)	5%	5%	0%	0%	0%	0%	0%
	M.D of Net Revenues	0.81	0.01	0.00	0.00	-129.4	7.64	0.74
	Instances of Neg. Returns (#)	-10	-43	0	0	-17	3	-1

Source: NERA Analysis.

Overall, we find the following impacts on the incentive to hedge:

- In the absence of FTRs, the incentives to hedge generally fall in the reform world (LMP) relative to the non-reform world with and without strategic bidding. We find that optimal hedging particularly falls in the LMP world relative to the RTF and RRN worlds for hydro and black coal plant in Queensland (from 70 per cent to 45 per cent).
- However, with FTRs as an instrument to hedge basis risk, the incentive for generators to hedge does not significantly decrease after the reform across fuel types and regions relative to non-reform worlds with and without strategic bidding.
- In particular, the incentives to hedge for baseload plant such as coal plant do not significantly rise as a consequence of the reform across regions.[38] We find that only in New South Wales does optimal hedging slightly increase for black coal plant. However, the difference in the average mean dispersion of black coal plant net revenues only reduces by 0.02 as a result of the change to hedging strategy relative to the RRN world. Consequently, the change in optimal hedging is likely magnified by our choice of hedging

[38] CCGTs are not considered baseload plant in our analysis due to our modelling assumptions that ignore ramping constraints and therefore treat CCGTs similarly to OCGTs in terms of technical characteristics. We discuss this further below.

increment. In no region do we find that the incentives to hedge forward fall for coal or hydro plant in the reform world relative to the non-reform world with strategic bidding.

- On the other hand, we find the incentives to hedge for wind plant significantly increase due to the reform, particularly in New South Wales and Queensland where they rise by 20 per cent in the FTR world relative to the RTF world. The average change in the optimal hedging across all fuel types in New South Wales and Queensland is likely driven by the increase in optimal hedging by the average wind plant.
- Across regions, we find that optimal hedging for CCGT plants are relatively low at 0 or 5 per cent of maximum capacity. Our findings are likely a consequence of three limiting factors to our approach (which we discuss further below). Firstly, we do not model ramping constraints in our optimal dispatch patterns which means that the technical characteristics of CCGTs are similar to OCGTs. Secondly, we only model optimal hedging using a quarterly baseload CfD. Consequently, because CCGTs have highly volatile dispatch patterns across half-hours (they are inframarginal with no ramping constraints), hedging using a baseload CfD is ineffective at reducing the volatility of their net revenues. Lastly, we conduct our analysis on a generator level and not on a generator portfolio level which likely leads us to understate optimal CCGT hedging. For instance, one would not use a baseload CfD to hedge a CCGT on its own, but may use a baseload CfD to hedge the joint ownership of a CCGT and wind plant together because their aggregate generation output is more stable.

We expect that baseload plant are significantly more important drivers of contract market liquidity than other fuel types that we consider in our analysis such as OCGT or intermittent renewable plants. Therefore, we expect that overall contract market liquidity will not significantly increase nor decrease after the reform.

We draw the following conclusions on the changes to volatilities of generator cashflows after the reform:

- Generators' mean dispersion of cashflows is generally higher in the non-reform world with strategic bidding than the non-reform world without strategic bidding. Higher mean dispersion with strategic bidding may indicate the additional "inefficient" volume risk that generators face operating in that world.
- In the absence of FTRs as a mechanism to manage basis risk, the mean dispersion of generator net revenues generally increases as a result of the reform (the LMP world), in part reflecting the introduction of unhedgeable basis risk. We find this is particularly true in Queensland relative to other regions, where the average mean dispersion for coal plant rises from 0.47 in the RRN world to 0.6 in the LMP world. On the other hand, we find evidence for lower basis risk in Victoria, where the average mean dispersion remains constant at 0.37 for coal plant across the RRN and LMP worlds, and New South Wales, where the average mean dispersion rises from 0.64 in the RRN world to 0.66 in the LMP world for coal plant.
- However, the mean dispersion of generator cashflows generally falls following the introducing of FTRs as an instrument to hedge basis risk. The average mean dispersion for coal and hydro plants falls for all regions in the FTR world relative to the non-reform worlds.
- We find evidence that suggests that the FTRs are not a perfect hedge for generators, and the average mean dispersion of generator net revenues does increase for some generators.

For instance, solar and wind generators in South Australia have a higher mean dispersion of returns following the reform. In part, higher dispersion of returns for solar may reflect that the FTR they hold is not profiled to their generation output. Time-of-use FTRs under the Access Reform, instead of continuous FTRs as we model, may provide means by which solar plants can more closely profile their FTR ownership to their expected generation thereby improving the effectiveness of FTRs as a hedge against the basis risk they face.

- Due to the high penetration of wind and solar in South Australia, the average mean dispersion of returns in South Australia across all fuel types is higher as a consequence of the reform. Our simplistic model of hedging that we adopt in our analysis does not allow generators with highly profiled or intermittent output e.g. wind and solar to effectively procure forward contracts which may explain why we find little optimal hedging in South Australia. We discuss this further below.

On average, generators experience fewer half-hours of negative returns as a consequence of the reform with FTRs. Our assumption of one-way FTRs protects generators from the downside of when their LMP is below the regional price at which they contract. We find one main exception which is black coal geneators in New South Wales. However, our result is driven by a relatively low number of half-hours with negative returns in the no-reform, strategic biding world rather than higher numbers of half-hours with negative returns under the reform. This can be seen in Table 7.10, which shows that the average coal generator experiences more half-hours of negative returns in the reform world relative to the non-reform world without strategic bidding but fewer half-hours of negative returns relative to the non-reform world without strategic bidding.

Our assessment of the likely impact of the Access Reform on contract market liquidity is likely a conservative assessment and overstates any negative impact on contract market liquidity for a number of reasons:

- Firstly, our PLEXOS model does not model ramping constraints or start-up costs for generators. Consequently, we overstate the variability in generator cashflows, the risks that they face, and therefore understate the value of hedging to generators across scenarios. In particular, our model mischaracterizes the technical advantage of CCGT plants relative to OCGT plants and therefore significantly overstates the variability of half-hourly net revenues for CCGT plants.
- Secondly, we assume a simplistic model of hedging and FTRs which cannot be profiled to match generators' expected output. In reality, generators can purchase a suite of forward market products and can tailor its portfolio to best match its expected pattern of dispatch, for instance through peaking, cap products etc. Equally in reality, generators can buy and sell FTRs in the secondary market to better match FTR pay-outs to its contracted position. In our model, we assume that generators may only purchase flat swap, quarterly baseload products. Consequently, in our model, hedging is relatively ineffective at managing generators' risk. Moreover, FTRs are relatively ineffective as tools to manage basis risk in our model relative to reality. Therefore, we likely understate the incentives to hedge in the reform world relative to the current world.
- Thirdly, we do not distinguish between upside and downside risk in our assessment, other than through our calculation of mean dispersion using average half-hourly returns. Arguably, generators predominantly use hedges to protect themselves against downside

risk: that the price of power at the time of delivery is low. Therefore, what should matter for our assessment is the change in downside risks associated with the reform. However, we assess total changes in the volatility of cashflows of generators. Our assessment penalises the risks from downside volatility in cashflows by the same amount as the volatility from one-sided positive pay-outs of FTRs. Our method overstates the risks that matter for the incentives to hedge for generators who hold FTRs and therefore understates the incentives to hedge in the reform world.

- Fourthly, we do not analyse the incentive to hedge for a generator owner with a portfolio of fuel types. In reality, some generator owners manage a portfolio of fuel types which may stabilize their net revenues across their portfolio in any given half-hour. Consequently, our assessment of mean dispersion likely overstates the actual mean dispersion of net revenue cashflows for owners with a portfolio of generation fuel types.
- Lastly, we do not assess the impact of the reform on contract market liquidity beyond the first year of the reform's introduction. As we discuss in Section 3, the reform will likely lead to more efficient siting of generation and transmission investment. To the extent that more efficient siting of generation and investment reduces congestion in the network, the reform is likely to reduce the efficient volume risks faced by generators. Reducing the efficient volume risks faced by generators increases the incentive to hedge which becomes a more effective tool at managing generator cashflow variations. We do not consider this impact in our assessment and therefore likely understate the beneficial impact of the reform on contract market liquidity.

On the other hand, we likely overstate the inefficient volume risk in our assessment of the RTF world. When multiple plants bid to the floor in the RTF world, our PLEXOS model chooses to dispatch the plant at random rather than pro rata generation across plants. This method overstates the volatility of generators' cashflows by overstating the variability in their dispatch due to strategic bidding. Our RTF scenario therefore provides an upper bound on the inefficient volume risk that could occur under the current access reform.

Moreover, our assessment does not include other potential risks or benefits to contract market liquidity. We discuss these other considerations in the sections below.

7.4.1. Liquidity will likely worsen outside of the timeframes of FTR auctions

We find that whilst the incentive to hedge for generators holding an FTR is unlikely to be significantly impacted by the reform, the incentives to hedge for generators who do not own an FTR (in the LMP world) are likely to fall. In our analysis, we do not distinguish how far ahead of delivery forward products are bought and instead assume that all generators have access to a quarterly baseload CfD at a strike price that reflects the average RRN price for the quarter. Moreover, in order to interpret our analysis that contract market liquidity will not worsen under the FTR world, one must assume that generators own an FTR at the point they purchase forward hedges.

Therefore, our conclusion that liquidity is unlikely to decline is limited to forward products within the timeframe of FTR auctions. In other words, our analysis suggests that liquidity will fall for forward products that are purchased so far ahead of delivery that generators cannot access an FTR product that pays-out during the delivery period at the point they purchase the forward product. However, we understand that contract market liquidity outside the proposed timeframes for FTRs is already poor and that the policy design will allow for

FTRs to be allocated up to ten years in advance. In addition, subject to finding a willing counter-party, participants may purchase FTRs on timeframes beyond those specified at auction through secondary markets. As a result, further reductions in liquidity are likely to be negligible and are unlikely to impose large costs on market participants.

7.4.2. We assume that all generators are able to purchase FTRs

We have no test for the simultaneous feasibility of FTRs in our analysis. In reality, the volume of FTRs available will be less than the transmission capacity in order to increase the likelihood that settlement residues are sufficient to ensure FTR pay-outs are firm.

Therefore, it may be possible that actual FTR ownership is less than would be required to facilitate optimal hedging by generators. Consequently, some generators may be dissuaded from hedging forward because they are unable to access FTRs. In other words, some generators may find that some of their generation capacity faces the risks in the LMP world rather than the FTR world which, according to our analysis, results in lower incentives to hedge.

Whilst simultaneous feasibility constraints apply to primary market FTRs sold through auction and backed by settlement residue, participants may be able to purchase FTRs on the secondary market, subject to being able to find a willing counter-party. If the secondary market for FTRs is sufficiently liquid, all generators may be able to purchase as many FTRs as they need at fair market prices.

7.4.3. Inter-regional FTRs provide an upside to contract market liquidity and may change the regional distribution of liquidity

We do not examine the potential benefits of inter-regional FTRs in our analysis of the likely impact of the reform on contract market liquidity. Under the proposed reform, inter-regional FTRs allow generators and retailers to more easily contract for power in forward markets in other regions.

Inter-regional FTRs may provide liquidity benefits to market participants who may more easily access forward contract products in other regions at lower transactions costs. Inter-regional FTRs particularly benefit generators and retailers in regions with relatively higher transaction costs such as South Australia. Market participants in South Australia may be able to access forward contracts for power in other regional contract markets at lower transaction costs. For instance, ownership of an inter-regional FTR by a generator in South Australia linked to the RRN price in Victoria would allow that generator to sell its power forward at the lower bid-ask spreads in Victoria rather than face higher transaction costs in South Australia. Consequently, that generator may be more willing to sell its power forward and improve contract market liquidity.

In our prior work analyzing liquidity in the NEM, we quantified the potential benefits of lower transactions costs to retailers and generators in the NEM. We analysed the trade-offs for suppliers between holding risk capital and hedging to reduce risk capital requirements but incurring transactions costs. The benefit of increasing liquidity in our framework lies both in reducing the costs incurred by suppliers in hedging (part of which is purely a transfer from parties obligated to provide market making services) and in reducing risk capital requirements by enabling market participants to hedge more efficiently. We summarise our estimated benefits from lower transaction costs below:

Table 7.12: NERA's Prior Estimates for the Benefits of Reduction in Transaction Costs

Region	Historical average (2016-18) bid-ask spreads (% bid price)	Reduction in bid-ask spreads (% bid price)	Benefits to Retailers ($m)	Benefits to Generators ($m)
VIC	1.9	0.1	1.53	1.47
SA	6.7	1.6	9.25	3.39
QLD	1.9	0.1	1.31	1.18
NSW	2.0	0.1	3.92	4.28

Source: NERA Analysis.

Therefore, there may be financial benefits arising from accessing contract market products at lower transactions costs. However, a fairly-priced FTR would mean that generators would face an offsetting cost to the benefits we list above in its purchase of the inter-regional FTRs.

Inter-regional FTRs may therefore result in changes to the regional distribution of liquidity as generators can more easily contract in other regional markets at different transaction costs. Liquidity is self-reinforcing so growing liquidity in some regions due to inter-regional FTRs may encourage further transactions to take place by providing a price signal to other market participants leading to a further increase in contract market liquidity. Equally, generators choosing to contract in other regions in which they are not situated instead of their local regional market may lead to a fall of liquidity, which may dissuade others from contracting in the regional market and a further loss of liquidity.

7.5. Summary

Overall, our analysis suggests that liquidity across the NEM is unlikely to worsen following the Access Reform. In particular:

- In the absence of FTRs, the incentives to hedge generally fall following the introduction of LMP relative to the non-reform world (both with and without strategic bidding). The introduction of basis risk, in the absence of any instrument to manage that risk, means hedging is less effective at stabilising generator net revenues.
- However, with FTRs as an instrument to hedge basis risk, the incentive for generators to hedge does not significantly decrease after the reform across fuel types and regions relative to non-reform worlds (i.e. both with and without strategic bidding).
- In particular, the incentives to hedge for baseload plant such as coal plant do not significantly rise as a consequence of the reform across regions. In no region do we find that the incentives to hedge forward fall for coal or hydro plant in the reform world relative to the non-reform world with strategic bidding.

Due to the assumptions we make in our analysis, our assessment of the likely impact of the Access Reform on contract market liquidity is likely a conservative assessment and overstates any negative impact on contract market liquidity following the reform. We list our assumptions and their likely impacts in Section 7.4.

Correspondingly, as measured by the mean deviation of half-hourly net revenues, our analysis suggests that the risks faced by generators are unlikely to increase following the Access Reform:

- We find evidence that generators face inefficient volume risk that results from strategic bidding which is unhedgeable under the current access model. Eliminating the inefficient volume risk reduces the cashflow risks faced by generators.
- We find that the Access Reform introduces basis risk which increases risks for generators in the absence of any mechanism by which generators can hedge the basis risk. We find that the basis risk introduced is larger in magnitude than the inefficient volume risk removed and that overall, in the absence of FTRs, risks faced by generators increase.
- However, we find that continuous FTRs provide a hedge against the basis risk faced by generators due to the introduction of LMP. Despite only considering continuous FTRs (which are not profiled to the expected generation profile of generators) our analysis suggests that FTRs provide a sufficient hedge against basis risk for baseload plants (coal and hydro) such that the overall risk they face does not significantly change following the reform.[39]
- We find that continuous FTRs do not provide an effective hedge for intermittent generation, and that risks for some intermittent generation e.g. solar plant rise following the reform. Time-of-use FTRs under the Access Reform, instead of continuous FTRs as we model, may provide means by which solar plants can more closely profile their FTR ownership to their expected generation, thereby improving the effectiveness of FTRs as a hedge against the basis risk they face.

39 Risk as measured by the average mean deviation of half-hourly net revenues.

8. Impact on Competition

The opportunity to purchase Financial Transmission Rights (FTRs) in place of the current Settlement Residue Auctions (SRA) has the potential to widen markets and increase competition by offering firmer risk management options for generators and load serving entities. This Chapter assesses that potential benefit and proceeds as follows:

- Section 8.1 analyses the likelihood of a benefit to society from increased competition; and
- Section 8.2 analyses the magnitude of any competition benefit, should it transpire.

8.1. Likelihood of a Competition Benefit

8.1.1. FTRs can reduce locational price risk and therefore improve cross regional competition

The introduction of inter-regional FTRs in place of SRAs can provide a benefit in terms of increased competition in wholesale and retail electricity markets. In understanding this competition benefit, it is useful to briefly reiterate the nature of FTRs as a risk reduction tool. Inter-regional transmission constraints and losses create financial risks for generators and retailers, particularly where such constraints or losses result in a material divergence in inter-regional prices. To manage this risk, there can be a tendency (absent any other risk management mechanisms) for market participants to concentrate their generation and load in a single region, so as to provide a natural hedge against different inter-regional prices.

FTRs provide an alternative hedge mechanism, allowing generators and retailers to hedge against transmission constraints and losses and reduce locational price risk, without necessarily needing to concentrate generation and load in the same region. This in turn provides market participants with an incentive to decouple their generation and load locations. At a high-level, this could mean that market participants will have an incentive to:

- Acquire retail customers in regions where they do not currently have any generation assets; and/or
- Build generation assets in regions where they do not currently have any retail customers.

In practice, some regional dispersal of generation and load may already exist, but the introduction of FTRs may nonetheless strengthen the incentives to incrementally widen that dispersal e.g., by expanding existing retail customer bases or adding capacity to existing generation.

It follows that, by providing incentives for new or expanded generation and load, the introduction of FTRs could lead to an improvement in competition in generation and retail markets. FTRs allow the entry or expansion by market participants that may not have typically operated in a particular regional market, or may have operated but without a strong incentive to compete hard for market share, due to the increased locational price risks that such entry or expansion may have otherwise created. This entry/expansion places competitive pressure on incumbent market participants, and ultimately the benefits of this increased competition flow through to consumers in the form of, for example, lower prices and enhanced investment and innovation.

8.1.2. Does the evidence suggest any competition benefit is likely to be material?

The above discussion suggests that, conceptually, a competition benefit is a plausible outcome from the introduction of FTRs. In this section we assess whether, from a practical perspective, a material competition benefit is a likely outcome from the introduction of FTRs in the NEM. We consider that a material competition benefit will be likely if there is evidence:

- That existing risk management mechanisms (specifically, SRAs) are not working effectively to reduce locational price risk, including evidence that the result of this is generation and load concentrated in the same regions;
- In contrast, that FTRs are likely to reduce locational price risk and likely to lead to inter-regional entry/expansion;
- If locational price risk is reduced, that there remain other incentives for future entry/expansion (e.g., capacity shortfalls) and no material barriers to entry/expansion; and
- That if there is entry/expansion, there is evidence of existing competition concerns, such that the result will be a material incremental improvement in competition. To put this another way, if markets are currently relatively competitive, then any entry or expansion may only make a minor improvement to competition. Evidence of existing competition concerns is therefore an important criterion for there to be competition benefits of any materiality.

We assess each of these considerations in the sections below.

8.1.2.1. Evidence that SRAs are not effectively reducing risk

The NEM already uses SRAs as a mechanism to allow market participants to hedge transmission risk. SRAs allow participants to bid for access to an inter-regional settlement residue, which is a pool of funds that pays out should transmission constraints bind in regulated interconnectors between regions of the NEM.[40] However, we understand that SRAs are not firm, due to the inclusion of transmission losses and effects such as counterprice flows.[41] As a result, we understand that they are typically purchased by speculators, rather than generators or load customers.[42] However, beyond these views, and the evidence of regional concentration in generation and load discussed below, we are not aware of any evidence regarding the extent to which SRAs mitigate (or otherwise) location price risk.

Figure 8.1 illustrates the extent to which there is currently regional concentration in generation and load. We have extracted data for the "big three" vertically integrated generator/retailers ("gentailers"), Origin Energy, AGL Energy, and EnergyAustralia, along with a selection of other (non-government owned) retailers with relatively large customer bases that also own generation assets. For each gentailer, we show the percentage of their

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40 AEMO (1 October 2019), Guide to the SRA, p. 6.

41 AEMC (14 October 2019), Coordination of Generation and Transmission Investment Proposed Access Model – Discussion Paper, p. 53.

42 AEMC (14 October 2019), Coordination of Generation and Transmission Investment Proposed Access Model – Discussion Paper, p. 53.

generation capacity located across Queensland, New South Wales, Victoria and South Australia (the bars denoted "G"). Likewise we show the percentage of each gentailer's retail customer numbers located across these four states (the bars denoted "R"). For example, Origin Energy's generation capacity is distributed across the states as 21% in Queensland, 55% in New South Wales, 8% in Victoria and 16% in South Australia (summing to 100%).

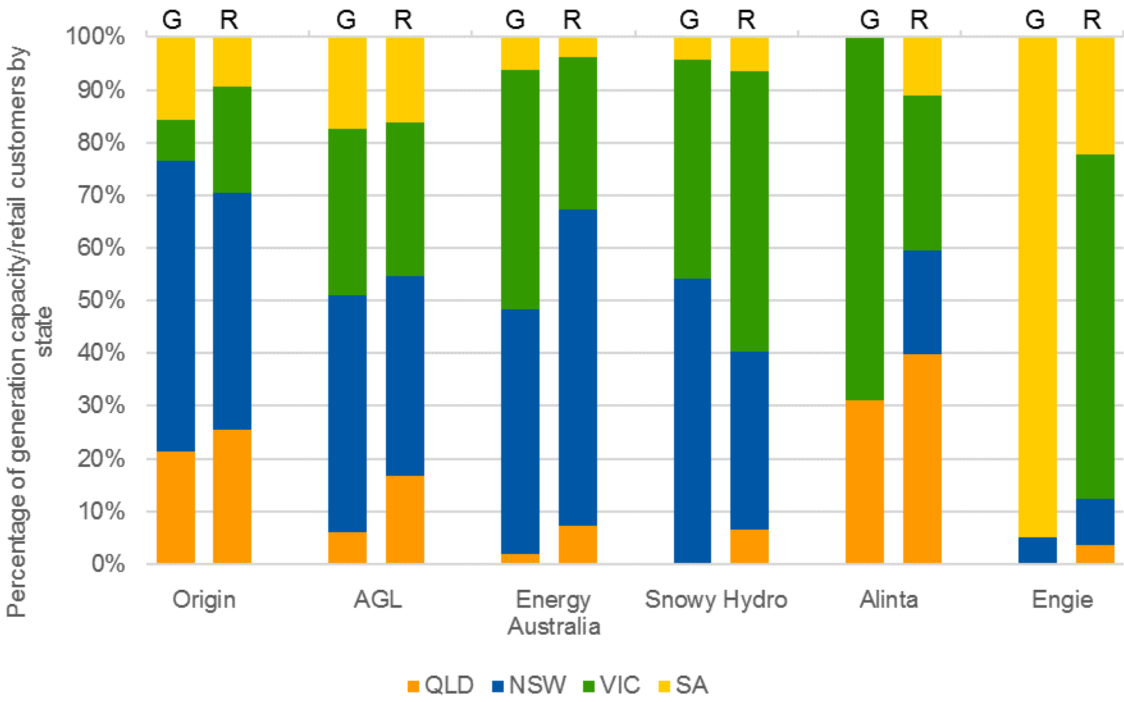
Figure 8.1 shows that, particularly for the big three gentailers, the distribution of their generation and retail across the states shown is similar. EnergyAustralia is particularly apposite: 92% of its generation capacity is located across New South Wales and Victoria, as is 89% of its retail customer base. Of the smaller gentailers, Snowy Hydro shows a similar pattern.

The extent of regional concentration is weaker for Alinta and Engie. For Engie, 95% of its generation capacity is located in South Australia, yet the majority (65%) of its retail customer base is located in Victoria. However, this is likely explained by Engie's ownership of the now decommissioned Hazelwood coal power station, which provided 1,600MW capacity in Victoria until it closed in March 2017. If Engie were still to have this capacity in Victoria, it would give a similar pattern in the distribution of generation and retail to that identified for the other gentailers.

For Alinta, while 69% of its generation capacity is in Victoria and 31% is in Queensland, its retail customer base is spread across Queensland (40%), New South Wales (20%), Victoria (29%) and South Australia (11%). Similar to Engie, part of the explanation for this may lie in Alinta's ownership of the Northern power station in South Australia, a 520MW power station that was closed in May 2016. Nonetheless, we note that Alinta does have a material retail customer base (just over 100,000 customers) in New South Wales, without owning any generation there.

In summary, Figure 8.1 is therefore suggestive of there being some locational price risks, despite the presence of SRAs, as gentailers generally tend to have a large share of their generation capacity and retail customer base in the same state. However, this evidence is not definitive, as recent plant closures have altered the within-state generation/retail mix for Engie and Alinta, so that they may have faced locational price risks in the 3-4 years since these closures. Alinta's retail customer base in New South Wales is also an exception.

Figure 8.1: percentage of generation capacity and retail customer numbers by state for major gentailers



Source: NERA analysis of data in AER (2020), State of the Energy Market – generation data is sourced from Table 2.2, and retail data is sourced from the data underlying Figure 6.7.

8.1.2.2. Evidence that FTRs will reduce locational price risk and lead to inter-regional entry/expansion

As explained above, conceptually there is an argument that FTRs will reduce locational price risk, resulting in inter-regional entry and/or expansion. This conceptual argument is supported in the economics literature. Regarding FTRs as a tool for mitigating locational price risk, Evans and Meade (2005, p.255) state "[d]efining a hedge over nodal price differences that measure the cost of grid congestion, such instruments [i.e., FTRs] protect their owners against price separation across network nodes".[43] Similarly, Lyons, Fraser and Parmesano (2000, p.35) state that FTRs provide "the means at hand to hedge against the risk of locational price differences".[44] Indeed, an early paper that developed the concept of FTRs, Hogan (1992),[45] is described by Benjamin (2013) as developing FTRs as a means of hedging locational price risks.[46]

[43] Lewis T Evans and Richard B Meade (2005), *Alternating Currents or Counter-Revolution? Contemporary Electricity Reform in New Zealand*, Victoria University Press.

[44] Karen Lyons, Hamish Fraser, and Hethie Parmesano (2000), An Introduction to Financial Transmission Rights, *The Electricity Journal*, 13(10), 31-37.

[45] William W. Hogan (1992), Contract Networks for Electric Power Transmission, *Journal of Regulatory Economics*, 4, 211-242.

[46] Richard Benjamin (2013), FTR Properties: Advantages and Disadvantages, Chapter 9 in Juan Rosellon and Tarjei Kristiansen (eds), *Financial Transmission Rights: Analysis, Experiences and Prospects*, Springer.

The extent to which the mitigation of locational price risk through FTRs leads to inter-regional competition benefits is less widely discussed in the literature. A similar concept is discussed in Wolak (2015, p.427), where transmission upgrade investments that reduce congestion result in a competition benefit, because "the upgrade allows more generation unit owners to compete to supply electricity at potentially every location in transmission network".[47] The mechanism for the FTR competition benefit is similar, in that competition occurs at a broader set of locations due to the reduction in locational price risk arising from network congestion.

The only evidence that we are aware of as to locational price risk having an adverse effect on competition comes from the New Zealand Electricity Authority's (EA) consideration of this issue, when it was considering the introduction of FTRs around 2010-11. The EA (known at the time as the Electricity Commission) assessed the "nodal price exposure" of the major generators i.e., the extent to which a generator would be exposed to a high nodal price in one region of the country, if that region is constrained due to transmission congestion or constraints. The EA then considered whether gentailers with a high nodal price exposure for generation in one region also had a low retail market share in that region, and found that there was indeed a strong correlation between exposure to high nodal prices and low retail market share.[48]

The EA also found evidence of retail market share differences across regions, which it considered was "a strong indicator that the present lack [of] suitable locational price risk management tools is an impediment to more robust retail competition".[49] For example, the EA found that Mighty River Power's retail market share was largely concentrated in the upper North Island, Genesis Energy's was in the central North Island, and Meridian's was in the South Island.

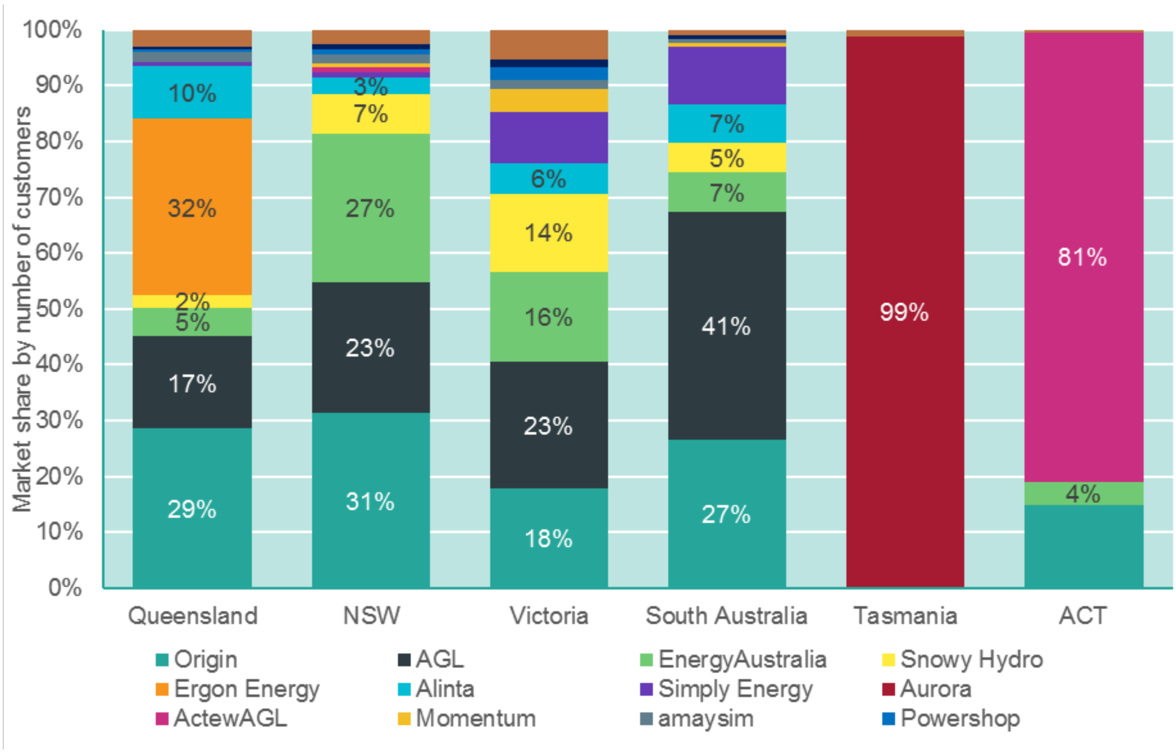
We note that such retail market share disparities are less evident in Australia, at least for the big three gentailers, as they are spread more broadly across the states. As shown in Figure 8.2, Origin has a market share in the range of approximately 20-30% across each of Queensland, New South Wales, Victoria and South Australia. AGL's retail share is approximately 20% in each of Queensland, New South Wales and Victoria, although is around 40% in South Australia. And EnergyAustralia has a retail market share of 27% in New South Wales and 16% in Victoria (but 5% in Queensland and 7% in South Australia).

[47] Frank A. Wolak (2015), Measuring the competitiveness benefits of a transmission investment policy: The case of the Alberta electricity market, *Energy Policy,* 85, 426-444.

[48] Electricity Commission (2010), Managing location price risk proposal, 13 September, at paragraph 4.6.5.

[49] Electricity Commission (2010), Managing location price risk proposal, 13 September, at paragraph 4.6.7.

Figure 8.2: Electricity retail market share



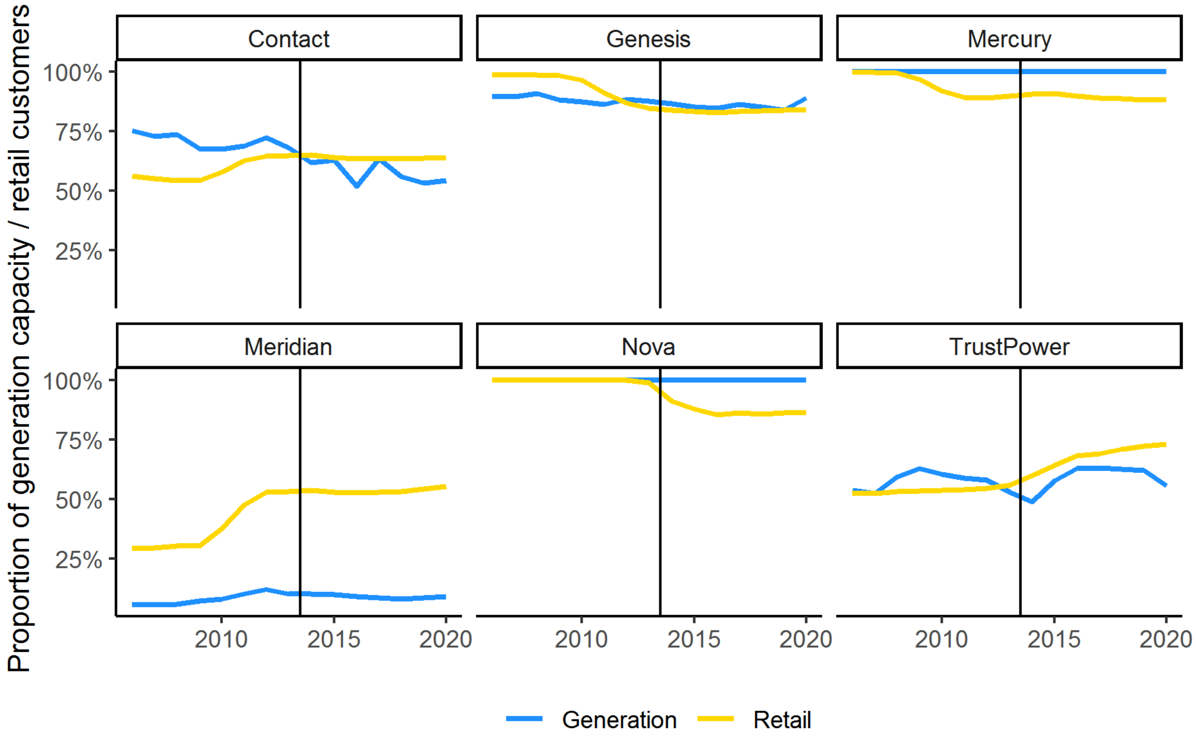
Source: NERA analysis of Figure 6.7 of AER (2020), State of the Energy Market

FTRs were implemented in the New Zealand electricity market in 2013 across two hubs, and were extended in 2014 to include three new hubs, then again with three further hubs in 2018. We have analysed data on the regional share of generation and retail to test what impact the introduction of FTRs has had on competition in regional markets. In particular, in Figure 8.3 below we consider the regional proportion of generation capacity and retail customers in the North Island, for of each of the 6 main gentailers in New Zealand: Genesis, Contact Energy, Meridian, Mercury/Mighty River Power, Trustpower and Todd/Nova Energy. For each gentailer, the graph shows the proportion of the gentailer's retail customers in the North Island (the remaining proportion will be located in the South Island, not shown on the graph), and the proportion of the gentailer's generation capacity in the North Island (again with the remaining proportion in the South Island, which is not shown on the graph). A vertical line is shown at 2013, when FTRs were first implemented at two hubs.

The graphs show some evidence consistent with FTRs having allowed gentailers to break regional vertical integration, albeit that this evidence is not compelling. Nova is of particular interest, as Figure 8.3 shows the proportion of Nova's customers in North Island markets dropping shortly after FTRs were first introduced, due to its entry into South Island retail markets, despite it having all of its generation located in the North Island. The graphs for Mercury Energy/Mighty River Power and Genesis Energy also show a slight downward trend in the proportion of retail customers in the North Island, despite these gentailers having all, or the majority of, their generation in the North Island. Contact Energy has decreased the proportion of its generation in the North Island, despite having a relatively large proportion of its retail customer base there. And Meridian Energy has increased its North Island customer base, despite most of its generation being located in the South Island.

We note, however, that in many cases these trends were evident prior to the introduction of FTRs. Moreover, there have been a number of other reforms occurring over the period of our analysis, to enhance competition in both retail and generation markets, and it is difficult to isolate the impact of FTRs from these other market changes. We therefore interpret these results with some caution. A reasonable conclusion to draw from this is that FTRs do not appear to have undermined other reforms for enhancing competition, and indeed may have supported them. We note also the recent view expressed by the EA, stating that "we are pleased with the current state of the FTR market, and its impact in supporting retail competition".[50]

Figure 8.3: Proportion of each NZ gentailer's total generation capacity and retail customers located in the North Island



Source: NERA analysis of EA EMI data (the https://www.emi.ea.govt.nz/)
Note: The vertical black line is date FTRs were introduced in New Zealand.

8.1.2.3. Evidence of other incentives for entry/expansion

We have established to this point that the introduction of inter-regional FTRs has the potential to lead to inter-regional entry or expansion. However, we need to consider if the incentives for such entry/expansion exist in the first place, and/or there are no material barriers to entry or expansion.

As an underlying principle of economics, firms will enter or expand in a market when there are positive economic profits being earned by the incumbent market participants.[51]

50 Electricity Authority (2018), FTR Enhancements, Decision Paper, 24 April, at paragraph 4.14.

51 See, for example, Dennis W. Carlton and Jeffrey M. Perloff (2005), *Modern Industrial Organization*, Fourth Edition, Pearson, at pp 207-209.

Accordingly, despite an FTRs facilitating inter-regional entry/expansion, we might *not* see entry/expansion occurring if the following conditions hold:

- The generation/retail markets are already workably competitive, such that there are limited (or no) economic profits being earned; or
- The generation/retail markets are characterized by a situation of excess supply, such that even if positive economic profits did currently exist, price post-entry would not be at a level that was profitable for the entrant.

We discuss the competitiveness (or otherwise) of generation and retail markets in more detail in the next section. To foreshadow that analysis, the AER, ACCC and AEMC have found evidence of competition problems in both generation and retail markets. While we have not assessed the rigor of these findings in any detail, if they are correct there is likely to be some ability for existing market participants to earn positive economic profits, providing an incentive for entry or expansion by firms that are currently outside of these markets.

In respect of the second point above, we are not aware of any evidence that suggests that generation or retail markets are characterized by a situation of excess supply, either today or in the foreseeable future. The AER notes that there was surplus generation capacity in the NEM over the 2009-2015 period, however in response to this, new investment has slowed and some capacity has exited the market. This has, according to the AER, "significantly reduced capacity in the NEM and led to AEMO signaling risks of summer power outages".[52]

Of particular relevance is the relatively recent closure of two major coal power stations – Northern, in South Australia, in May 2016, and Hazelwood, in Victoria, in March 2017. The AER identified a supply gap being left by these two closures, and while it has noted that this gap is being filled by wind and solar generation, capacity additions have slowed since 2019.[53]

On a forward-looking basis, AEMO's 2020 Integrated System Plan finds that, over the period through to 2040, over 26GW of grid-scale renewable generation capacity and 6-19GW of more flexible, dispatchable generation (e.g., gas generation) will be needed (beyond that which is already committed and anticipated) to reliably meet electricity demand at all times.[54] This compares to 61GW of generation capacity currently within the NEM.[55] This implies a strong need for new entry or expansion in generation capacity to satisfy this requirement.

It may be, however, that even if incentives for entry/expansion are strong, there are material barriers to this occurring. In generation markets, as noted above, various agencies have found evidence of a lack of vigorous competition. As discussed in the next section, however, this appears to be mostly due to existing concentration rather than material entry/expansion barriers *per se*. The ACCC has noted that some barriers to entry in generation markets exist in the form of financing generation projects where an entrant does not have a stable long-term customer base and uncertainty regarding climate policy.[56] The former is unlikely to be an

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52 AER (2020), State of the Energy Market, at p.92.

53 AER (2020), State of the Energy Market, at p.13.

54 AEMO (2020), 2020 Integrated System Plan for the National Electricity Market, July, p.39.

55 AER (2020), State of the Energy Market, Figure 2.5.

56 ACCC (2018), Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry – Final Report, at pp.98-102.

issue for those with existing customer bases in one region to expand generation in another region. While the latter issue may remain, this uncertainty appears not to have materially limited generation capacity expansion (particularly by existing, and smaller, market players) in recent years, with 6,600MW of generation capacity occurring from January 2018 to March 2020, of which only 31% is associated with the big three incumbents.[57] A further 5,400MW is committed as at March 2020, and none of this capacity is associated with the big three.[58] Moreover, the Australian Government's Underwriting New Generation Investments program provides government support for new generation capacity,[59] which may further mitigate concerns around capacity expansion.

Similarly in respect of retail electricity markets, while there have been findings of competition concerns in these markets (as discussed in the next section), this has not been found to be due to significant barriers to entry. The ACCC has noted the recent proliferation of new entrants in retail markets, and while there are some examples of retailers having difficulty entering, overall the ACCC has found "significant entry into the market following the commencement of retail competition, which strongly suggests that barriers to entry in this market are not significant".[60]

In summary, the evidence discussed in this section implies that, to the extent that FTRs lower locational price risk, remaining incentives for entry/expansion into retail and generation markets exist, and there are few or no material barriers to such entry or expansion.

8.1.2.4. Evidence of a material incremental improvement in competition

We conclude by considering whether there is evidence suggesting that entry and/or expansion in generation and retail markets will lead to a material incremental improvement in competition. In particular, we consider the extent to which generation and retail markets are currently considered to be competitive. If these markets were already relatively competitive, then to the extent that any additional entry or expansion occurs, it may not result in a material incremental improvement in competition.

For example, if prices are relatively close to a workably competitive price (albeit not necessarily at that price, such that there still exists some positive economic profits to incentivise entry), then new entry or expansion may only lower prices by a minimal amount. In contrast, if markets are currently characterized by a lack of competition, then new entry or expansion has the potential to have a much greater price impact.

With respect to electricity generation markets:

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57 Based on data at Table 2.3 of AER (2020), State of the Energy Market.

58 Based on data at Table 2.4 of AER (2020), State of the Energy Market.

59 See https://www.energy.gov.au/government-priorities/energy-programs/underwriting-new-generation-investments-program

60 ACCC (2018), Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry – Final Report, at p.149.

- The AER has found that the market can be vulnerable to the exercise of market power, with a few large participants controlling significant generation capacity and output in most NEM regions;[61] and
- The ACCC has found that the structure of the wholesale market is not conducive to vigorous competition, with concentration of ownership, exacerbated by a tight supply-demand balance, leading to wholesale prices materially above historic levels.[62]

Regarding electricity retail markets, recent findings on the extent of competition in these markets are:

- The AEMC has noted a trend towards a more competitive retail market, with more competitors and decreased market concentration. However, the AEMC noted a slow down in both switching rates and the reduction in market concentration, and expressed concerns that this may decrease competition and lead to higher prices for consumers;[63] and
- The ACCC has found that there have been positive signs of increased retail competition in recent years, however "competition has largely fallen short of expectations". The ACCC expressed concerns regarding high market concentration, relatively limited switching by inactive customer bases, and a counter-productive focus on discounts leading to inflated costs and an inability for smaller retailers to put significant competitive pressure on their larger rivals.[64] We note this is slightly contradictory to the ACCC also finding that entry barriers into retail are not significant, as noted above.

We have not assessed the rigor of these findings in any detail, and have not undertaken our own assessment as to whether there are competition concerns. However, if the AER/AEMC/ACCC findings are correct, they show that competition concerns are present, particularly in electricity generation markets. In retail markets, the AEMC and ACCC have found evidence of recent improvements in competition, however they still expressed concerns regarding competition in these markets.

The competition findings discussed above were at a broad level across the NEM states. There have been some assessments of competition in individual states. For example, the ACCC noted the high market concentration in Queensland, where the state government owned 65% of generation capacity through (at the time) two generators.[65] However, as the AER notes, this concentration has improved (i.e. reduced) in recent years with the introduction of a third state-owned generator, CleanCo.[66] It is also possible that the state

61 AER (2020), State of the Energy Market, at p.107.

62 ACCC (2018), Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry – Final Report, at p.88 and p.98.

63 AEMC (2020), 2020 Retail Energy Competition Review, Final Report, 30 June, p. xiii.

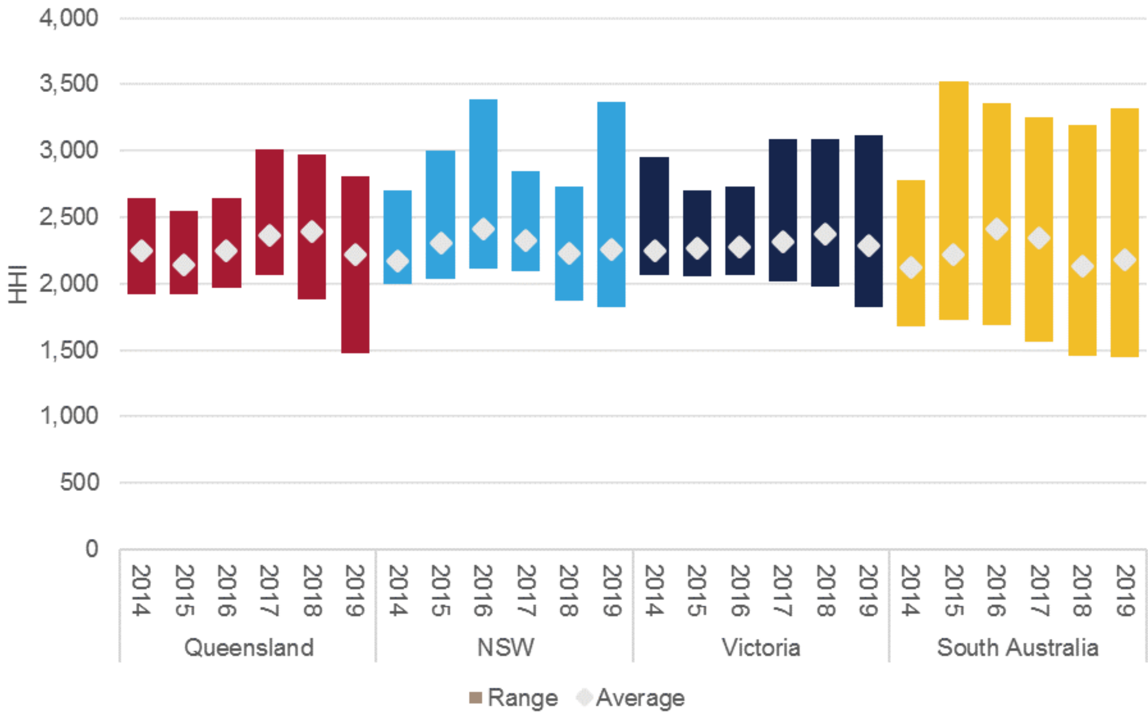
64 ACCC (2018), Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry – Final Report, at p.134.

65 ACCC (2018), Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry – Final Report, at p.92.

66 AER (2020), State of the Energy Market, at p.108.

ownership of Queensland's generators could mitigate any market power they hold.[67] In Figure 8.4 below we show the Herfindahl-Hirschman Index (HHI), which is a measure of market concentration, in generation markets in each state. Variation in the HHI occurs because it is calculated by dispatch interval, so factors such as plant outages can influence market concentration in any interval. Figure 8.4 shows that the largest range of HHI values in 2019 is in South Australia. The maximum HHI value in South Australia is approximately 3,300. For context, when it undertakes merger analysis, the ACCC considers that an HHI in excess of 2000 is more likely to result in competition concerns.[68] Similarly, the US Department of Justice considers an HHI of between 1,500 and 2,500 to be "moderately concentrated" and an HHI of over 2,500 to be "highly concentrated".[69]

Figure 8.4: Generator HHI by state and year



Source: AER (2020), State of the Energy Market, figure 2.34

A more commonly used concept for assessing generator market power is "pivotality". This is the extent to which demand cannot be met without a particular firm's capacity, and therefore that firm may be able to exercise market power. Measurement of the frequency of pivotality by state is shown in Figure 8.5 below. This is based on the residual supply index (RSI), which is the ratio of demand that can be met by all but the largest (RSI-1), two largest (RSI-2) or three largest (RSI-3) generators. An RSI greater than one means that demand can be fully met without dispatching the largest one, two or three generators. Figure 8.5 shows the

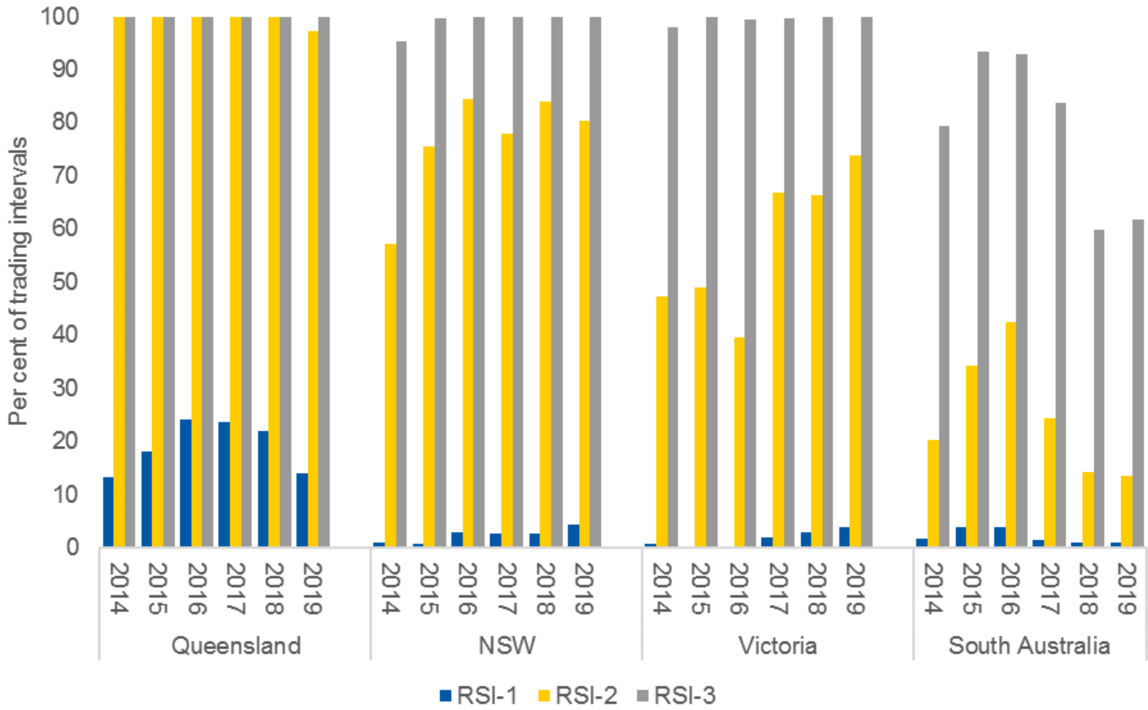
[67] For example, the Queensland government issued bidding guidelines to Stanwell and CS Energy amid concerns they were withholding capacity and driving up wholesale prices. We understand this guidance has recently been lifted. See, e.g. https://reneweconomy.com.au/queensland-drops-bidding-directions-says-wind-and-solar-less-than-50-mwh-75720/

[68] Where the change in HHI as a result of the merger is also greater than 100. See ACCC (2008), Merger Guidelines, November, at paragraph 7.14.

[69] U.S. Department of Justice & FTC (2010), Horizontal Merger Guidelines, Section 5.3.

percentage of trading intervals in the last five years where RSI values were below one. This shows that one generator has been pivotal in Queensland in the early years shown on the graph, although this has improved in 2018 and 2019. It is also interesting to note that, despite the higher concentration in South Australia noted above, one, two or three generators were less pivotal here over the past five years, relative to the other states shown.

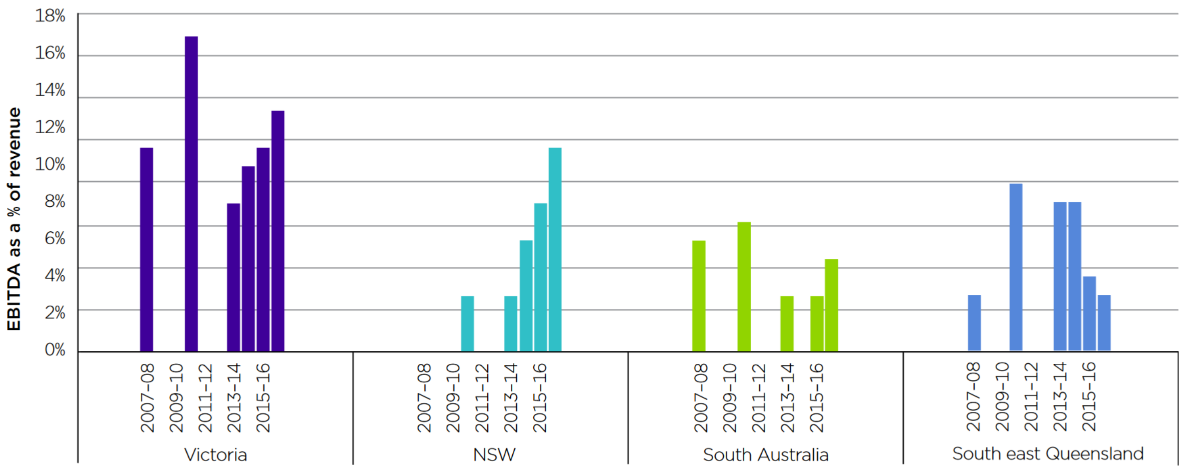
Figure 8.5: Frequency of pivotality of largest generators



Source: Figure 2.35 of AER (2020), State of the Energy Market

In retail electricity markets, we note from Figure 8.2 earlier that there are some differences in concentration across the states. From the data underlying Figure 8.2 we estimate HHIs of approximately 2,200 in Queensland, 2,300 in NSW, 1,400 in Victoria, 2,600 in South Australia and 9,800 in Tasmania. The latter is due to the high market share held by Aurora, owned by the Tasmanian government. While Victoria is relatively less concentrated than the other states, analysis undertaken by the ACCC of EBITDA margins showed that the retail margins in Victoria are generally larger than in the other states – see Figure 8.6.

Figure 8.6: Retail EBITDA margins



Source: Figure 6.3 of ACCC (2018), Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry – Final Report

The state-level evidence shows that, on some measures, competition is weaker in some states than in others e.g., with South Australia being more concentrated on the generator side, or with Victoria being less concentrated in retail. However, other measures show contrary results e.g., the pivotality of generators is less in South Australia, and retail margins are greater in Victoria. Government ownership of generators and retailers is also a relevant consideration, to the extent the government in question is willing to intervene to constrain the exercise of market power by state owned firms. Overall there is not sufficient evidence to suggest that competition concerns are materially different across the states.

8.1.3. Summary of likelihood of competition benefit

From the analysis set out in the above sections, we conclude that FTRs are likely to reduce locational price risk. However, it is difficult to determine the incremental risk reduction relative to the existing SRA approach. While we understand that SRAs are a relatively ineffective risk reduction mechanism, the only evidence of this is generators and retailers seeking other ways to hedge locational price risk, with the main approach being vertical integration in generation and retail and co-location of that generation and retail in the same state. There is evidence of this co-location pattern across all the major retailers, although there are also some exceptions to this.

By providing an alternative risk mitigation mechanism, FTRs allow gentailers to effectively 'break' these regional hedges, freeing them up to enter or expand their generation into regions where they do not have any (or material numbers of) retail customers, and vice versa. There is some evidence from the introduction of FTRs in New Zealand which supports the proposition that FTRs have complemented other retail and generation market changes which together have resulted in generators in one region expanding their market share in retail in other regions. It is important to note we have not been able to determine if FTRs, on their own, have led to enhanced generation and retail competition in New Zealand; rather, their impact appears to have been complementary to other competition-enhancing changes.

We note also that, in the NEM, there has been entry/expansion into generation in recent years by generators other than the big three vertically integrated providers. As previously noted, only 31% of generation capacity expansion occurring in the past two years is associated with the big three and the majority of committed new investment is by non-integrated players.[70]

The ACCC has found that barriers to entry and expansion in the NEM are not material, and the need for new generation capacity in the NEM over the next 20 years to meet rising demand provides a strong incentive for entry and expansion across different regions if locational price risks can be managed.

Finally, we note that various agencies have identified competition concerns in both generation and retail markets (despite the ACCC also finding low barriers to entry), which suggests that there is considerable scope for new entry or expansion to enhance competition in these markets.

Overall our reading of evidence is that there is considerable scope for new entry/expansion in both generation and retail markets, and if there are competition concerns, then such entry/expansion could lead to improvements in competition. The evidence is less clear as to whether FTRs will result in an incremental mitigation of locational price risks relative to SRAs, and whether doing so will in fact promote entry/expansion, all else equal. We consider, therefore, that at one end of the spectrum FTRs will not result in any competition benefit. On the other hand, there is evidence to suggest that a competition benefit is a plausible scenario. We therefore consider two scenarios in our analysis: one in which there is no competition benefit, and one in which there is a small benefit. In the next section we discuss how we have approached quantifying the magnitude of this benefit.

8.2. Magnitude of a Competition Benefit

8.2.1. Overview of quantification approach

To the extent that a competition benefit exists, we can quantify its magnitude by breaking the benefit into the following components:

- Allocative efficiency benefit: the increase in competition will lead to lower generation/retail prices and increased output, allowing additional demand to be served at a value to society which exceeds the cost of production. This results in a reduction in the deadweight cost of the (original) higher prices, and a benefit to society; and
- Productive efficiency benefit: the increase in competition will place pressure on generators and retailers to minimize costs and avoid waste, which (all else equal) creates a benefit to society by allowing a given level of production to be achieved at lower cost.

There may also be a dynamic efficiency benefit, wherein the increase in competition creates incentives for investment and innovation, ultimately benefiting consumers through new and/or improved products or processes. We have not quantified a dynamic efficiency benefit in this report, and we note that this is likely to be very conservative, as dynamic efficiency gains often materially exceed those of allocative and productive efficiency.[71] We note that

[70] Based on data at Table 2.3 of AER (2020), State of the Energy Market.

[71] See, for example, Solow (1957), showing that economic growth attributable to dynamic efficiency gains is approximately seven times growth from static (i.e., allocative and productive) efficiency gains. Robert Solow (1957), "Technical Change and the Aggregate Production Function", *Review of Economics and Statistics*, 39(3), 312-320.

the EA in New Zealand similarly did not quantify dynamic efficiency gains in its assessment of the competition benefit from FTRs in New Zealand, but noted the potential for dynamic efficiency gains to far outweigh allocative and productive efficiency gains.[72]

For each of the allocative and productive efficiency benefits, we estimate the annual benefit in each year over the period 2021 through to 2040, based on forecast price, generation/load, and cost data. We estimate the benefit for each of the retail and generation markets, and in each of the five states in the NEM. More detail on our calculation methodology is set out in the following sections.

8.2.2. Allocative efficiency benefit

The allocative efficiency benefit arises because the increase in competition lowers prices and increases output, reducing the deadweight cost to society of the original higher prices. This is illustrated in Figure 8.7. The market price/quantity combination is initially at P1/Q1. An increase in competition puts downward pressure on prices, which fall to P2 and quantity demanded increases to Q2.

The decrease in price leads to an increase in consumer and producer surplus. Consumer surplus is the total value that the consumer derives from purchasing goods or services, and is given by the area below the demand curve and above the price. Producer surplus is the benefit the producer receives from the supply of goods or services less the costs of production, and is the area above the marginal cost curve and below the price. The price decrease results in an increase in consumer surplus given by the triangle ABC, while producer surplus increases by the rectangle BCDE. The rectangle area given by P1P2AB is also a consumer surplus increase, but this is a result of a producer surplus decrease, and therefore reflects a wealth transfer from producers to consumers, rather than an efficiency gain. We provide a separate estimate of this transfer.

The increase in producer and consumer surplus arising from the price decrease reflects the fact that the price increase leads to additional sales (the difference between Q1 and Q2) to consumers who are willing to pay more than it costs society to produce. At the higher price of P1, such transactions do not occur, but they do at the price P2, producing a benefit to society.

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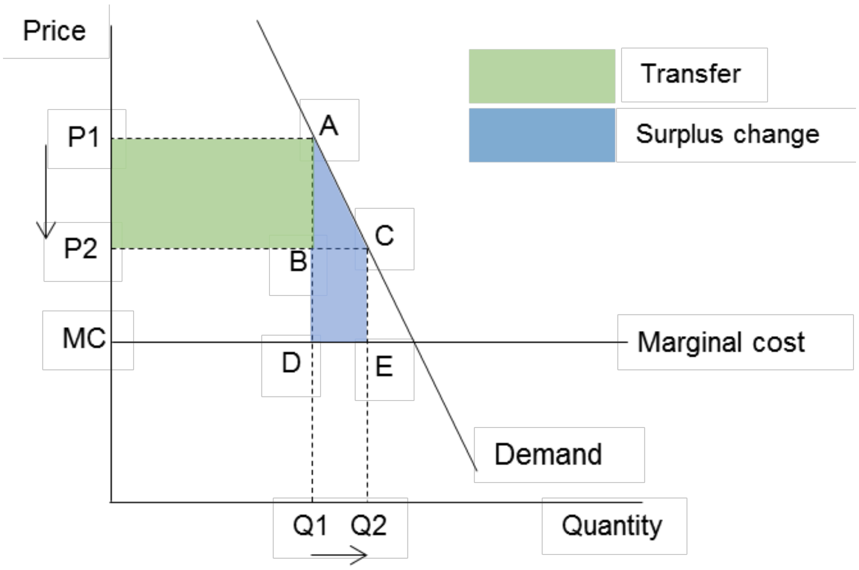
72 Electricity Authority (2011), Consultation Paper – Managing locational price risk: Proposed amendments to code, 28 April, at paragraph 3.7.26.

Figure 8.7: Illustration of allocative efficiency benefit (surplus change) and transfer from a price reduction when demand is relatively inelastic



Source: NERA analysis

Note that we have drawn this graph with relatively inelastic demand to illustrate the typical situation for electricity. In a situation with relatively inelastic demand, price changes unrelated to changes in costs do not have large efficiency implications, since they do not result in large change in output. By contrast they can result in comparatively large transfers between producers and consumers. This is illustrated in the figure above by the transfer (illustrated by the green rectangle) being comparatively larger than the efficiency impact (illustrated by the blue shaded area).

We estimate the allocative efficiency benefit from increased competition in retail and generation markets in each state by using the following assumptions:

- **Demand curve:** we assume a linear demand curve, and have surveyed the literature to determine an elasticity of electricity demand in each state. For the retail electricity market, we use elasticities for final electricity demand of -0.25 for Queensland, -0.35 for New South Wales, -0.285 for Victoria, -0.245 for South Australia, and -0.23 for Tasmania. We have calculated these elasticity estimates by averaging the elasticity estimates for each state from NIEIR (2007)[73] and Doojav and Kalirajan (2019)[74], and we assume that they are unchanged over the 2021-2040 period of our analysis. In the generation market, elasticities are likely to differ from those facing electricity retailers. However, we are not aware of any studies that have estimated the elasticity of demand facing generators. To estimate the generation market elasticities we therefore use the relationship that elasticity of demand at a wholesale level is equal to retail demand elasticity, multiplied by the ratio of wholesale to retail prices, multiplied by the pass-

[73] NIEIR (2007) calculate elasticities of: NSW, -0.37; VIC, -0.38; QLD, -0.29; SA, -0.32; and TAS, -0.23. NIEIR (2007), "The own price elasticity of demand for electricity in NEM regions", Report to NEMMCO, Melbourne.

[74] Doojav and Kalirajan (2019) calculate elasticities of: NSW, -0.33; VIC, -0.19; QLD, -0.21; SA, -0.17; and TAS, -0.23. Gan-Ochir Doojav and Kaliappa Kalirajan (2019), "Income and price elasticities of electricity demand in Australia: Evidence of state-specific heterogeneity", *Australian Economic Papers*, 58, 194-206.

through rate of wholesale to retail prices.[75] We assume a pass-through rate of 50%,[76] and multiply the retail elasticities noted above for each state by the ratio of generation prices to retail prices,[77] to give an elasticity of demand for electricity generation. The derived elasticities are -0.04 for Queensland, -0.05 for New South Wales, -0.05 for Victoria, -0.04 for South Australia, and -0.04 for Tasmania, which we assume are unchanged over the period of our analysis;

- **Counterfactual prices**: In the ***generation*** markets, for our counterfactual price (i.e., P1 in Figure 8.7) in each year from 2021 to 2040 and each state we use real prices (i.e., after accounting for the effects of inflation) determined by our PLEXOS modelling in the "no reform" scenario, and using POE50 demand forecasts. We note that these prices are the simulated competitive market prices, and therefore are likely to understate the counterfactual price (which are prices established in markets that may not be fully competitive). However, an understated price will result in the allocative efficiency benefit being understated (all else equal). In the ***retail*** electricity markets, calculate a counterfactual retail price as follows. We start with the generation, network, environmental and retail cost components of retail prices in each state for 2018/19,[78] and inflate these to 2021 values.[79] As our model is in real terms, we assume that most of the components of this retail price (the network, environmental and retail costs) remain unchanged in real terms over the 2021-2040 period of our analysis. We assume, however, that the generation price component of the retail price changes over this period in line with the percentage change in the generation price from our PLEXOS modelling. We also assume that the retail margin component of the retail price stays constant as a percentage of the generation price.[80] We note that this price is the price faced by residential electricity customers, and as such it may overstate the overall retail price that is also faced by business customers (to the extent that they face lower prices). A higher price would overstate the allocative efficiency benefits;
- **Price change due to competition:** To estimate the price P2 in Figure 8.7, we need an estimate of what impact increased competition in the generation and retail markets is likely to have on competition. However, it is difficult to determine such an estimate without developing a potentially complex model of generation and retail markets, as well

75 See Daniel Hosken, Daniel O'Brien, David Scheffman, and Michael Vita (2002), "Demand System Estimation and its Application to Horizontal Merger Analysis", April, at p.23.

76 With linear demand, a monopolist would pass through 50% of any marginal cost changes. See Bulow, J., and P. Pfleiderer (1983): 'A Note on the Effect of Cost Changes on Prices', Journal of Political Economy, Vol. 91, No. 1, pp. 182-185. While we are not claiming the retail sector sets price monopolistically, this provides a conservative estimate of the elasticity for our generation allocative efficiency calculations. This is because a lower pass through rate results in more inelastic demand for generation and therefore lower allocative efficiency benefits for a given price decrease.

77 We derive this ratio from data for 2018-19 showing the composition of a residential electricity bill (underlying Figure 6.2 of AER (2020) State of the Energy Market), which provides a generation and retail price for each state.

78 Based on the data underlying Figure 6.2 of AER (2020) State of the Energy Market.

79 To inflate to 2020 we use the annual percentage change in the Consumers Price Index (CPI) for the June 2020 quarter (https://www.abs.gov.au/ausstats/abs@.nsf/mf/6401.0). To inflate further to 2021 we use Reserve Bank of Australia CPI forecasts for annual inflation for the June 2021 quarter (https://www.rba.gov.au/publications/smp/2020/aug/forecasts.html).

80 That is, we calculate the retail margin as a percentage of the generation price using the 2018-19 data, and assume that this margin remains constant in percentage terms over the 2021-2040 period of our analysis. Note that the 2018-19 data does not specify a separate retail margin for Tasmania (it only aggregates the retail margin and retail costs), so we assume that the aggregate retail margin/retail costs for Tasmania is split between these component parts in the same proportion as retail margin/retail costs for the NEM.

as having some form of estimate of the nature and extent of entry or expansion into these markets. In the New Zealand EA's assessment of the competition benefit from FTR's, the EA assumed a price decrease in the range of 0.5%-1% in retail and generation markets.[81] In our 9 March 2020 report to the AEMC we suggested that competition benefits based on the EA's analysis should be interpreted with caution. Indeed, we note that the introduction of FTRs in the NEM will not necessarily result in the same competition benefits as in New Zealand, given that the NEM already uses SRAs to allow market participants to hedge transmission risk between regions. It is also possible that the New Zealand and Australian electricity markets have become more competitive over time, implying that the NEM is currently more competitive relative to the electricity market in New Zealand at the time of the EA's assessment (around 2011). Similarly, the large gentailers in Australia operate in most states (see Figure 8.1) already, whereas in New Zealand the concern was that the main gentailers were not competing in all regions. That is to say, the starting point for competition may be better in the NEM than it was in New Zealand when FTRs were introduced. For these reasons, we assume a maximum price decrease due to increased competition of 0.5% in both generation and retail markets. At a minimum, there may be no competition benefit at all, and we therefore use a range of 0-0.5% as the assumed percentage price change due to competition;

- **Counterfactual quantities**: the counterfactual quantity (Q1 in Figure 8.7) is determined in each year and each state by the outputs of our PLEXOS modelling for demand (in retail markets) and generation (in generation markets). Note that the PLEXOS demand relates to all electricity demand, not just that served by retailers, so may overstate total demand. To account for this, to give a proxy for retail quantity, we scale total forecast demand using the proportion of total consumption made up by residential and SME volumes in AEMO's ESOO forecasts;[82,83] and
- **Marginal costs**: as Figure 8.7 shows, the allocative efficiency estimate requires an estimate of the marginal cost of production. We assume that this marginal cost is constant over the range of output (shown by the horizontal marginal cost line in Figure 8.7), and remains unchanged both before and after the price decrease arising from enhanced competition. In generation markets, our estimate of the marginal cost of generation in each year and each state is determined from the generator fuel and other variable (operating and maintenance) costs in our PLEXOS modelling (averaged in each year). In retail markets, we use as the marginal cost our estimates of the generation price, network costs, environmental costs, and retail costs as described above to determine the counterfactual retail price.[84]

81 Electricity Authority (2011), Consultation Paper – Managing locational price risk: Proposed amendments to code, 28 April, at paragraphs 3.7.14 and 3.7.20. Note that the EA expresses the impact of generator completion with respect to *retail* price. The EA appears to implicitly use a 50% passthrough assumption, so the range for generator competition of 0.25% to 0.5% appears to be equivilent to assuming a 0.5% to 1% price change in the wholesale market.

82 Based on the 2019 ESOO, residential and SME consumption makes up the following proportion of forecast consumption in the central scenario: NSW = 76%, QLD = 60%, SA = 0.72%, TAS = 34%, VIC = 81%.

83 This therefore excludes demand by "large industrial customers". To the extent that these customers are served by retailers, this therefore will understate demand and therefore understate the benefit.

84 As noted above, the data are those underlying Figure 6.2 of AER (2020), State of the Energy Market, to which we have applied the adjustments set out above to account for inflation through to 2021 and changes in real generation prices from 2021 to 2040.

Using these inputs we can determine the increase in quantity (Q2 in the graph above) that results from the assumed price decrease,[85] and the resulting areas of the triangle ABC and rectangle BCDE in Figure 8.7 above,[86] which gives the allocative efficiency benefit. We also calculate the wealth transfer from generators/retailers to consumers, which is given by the area of the rectangle P1P2AB.[87]

8.2.3. Productive efficiency benefit

The productive efficiency benefit arises because the increase in competition places pressure on firms to be more efficient, leading to a reduction in costs. Our approach to quantifying this benefit is to draw on the economics literature to determine an estimate of the likely cost reduction arising from increased competition, and apply this to the relevant costs.

There are empirical studies in the economics literature that estimate the annual percentage improvement in firm productivity as a result of increasing or improving competition. In particular:

- Nickell (1996) finds that a firm operating in a more competitive environment in the UK manufacturing sector will have higher annual productivity growth by between 3.8 and 4.6 percentage points (compared to a firm operating in a less competitive environment);[88]
- Disney, Haskel and Heden (2003) analyse a larger sample of UK manufacturing firms than Nickell (1996), and using a similar methodology find that increased competition leads to an increase in annual productivity growth by 1.3 percentage points (again, compared to a firm in a less competitive environment);[89] and
- Daβler, Parker and Saal (2002) provide a similar analysis, testing the impact of liberalisation on productivity growth in the telecommunications market.[90] Their results show that, on average, productivity growth increased by approximately 3 percentage points in the year following liberalisation (i.e., moving from monopoly to competition) of telecommunications markets.[91]

These results indicate that a firm in a relatively more competitive market will have annual productivity growth of between approximately 1 percentage points and 5 percentage points higher than a firm in a relatively less competitive (or monopoly) market. To put this another way, if the annual productivity growth of a firm in a less competitive market is static, all else

85 The formula for demand elasticity is $e = (\frac{dQ}{dP})(\frac{P1}{Q1})$, therefore $dQ = \frac{eQ1dP}{P1}$, or $Q2 = \frac{eQ1(P2-P1)}{P1} + Q1$, since $dQ = Q2 - Q1$ and $dP = P2 - P1$.

86 The area of triangle ABC is given by $0.5(Q2 - Q1)(P1 - P2)$, and the area of rectangle BCDE is $(Q2 - Q1)(P2 - MC)$.

87 This area is given by (P1-P2)Q1.

88 Stephen Nickell (1996), “Competition and Corporate Performance”, *Journal of Political Economy*, 104(4), 724-746.

89 Richard Disney, Jonathan Haskel, and Ylva Heden (2003), “Restructuring and Productivity Growth in UK Manufacturing”, *Economic Journal*, 113, 666-694.

90 Thoralf Daβler, David Parker and David S. Saal (2002), “Economic Performance in European Telecommunications, 1978-1998: A Comparative Study”, *European Business Review*, 14(3), 194-209.

91 Calculated from Daβler et al (2002) Table VIII , page 204 based on the average percentage change in the total factor productivity index for the relevant countries for the year following liberalisation.

equal, the same firm in a more competitive market would have annual productivity growth of between approximately 1 percent and 5 percent.

We note, however, that at least one of the studies referred to above (Daβler, Parker and Saal (2002)) relates to productive efficiencies from a move from pure monopoly to competition, and the other two studies are likely to relate to quite a large increase in competition.[92] In our case, the increase in competition is likely to be relatively more incremental, assuming there is a competition benefit. We also note that in the EA's assessments of productivity benefits, they assumed productivity efficiently in the retail market would result in *retail* prices falling by 0.25% to 0.5%. As noted above, when calculating generation demand elasticities, we assume a 50% pass through rate at retail and we also interpret the EA to have made a similar assumption. This therefore equates to variable cost reduction of 0.5% to 1%. Given our previous discussion that the starting point in the NEM. We therefore think an upper bound on the productive efficiency benefit is likely to be 0.5%, and as a lower bound there may be no competition benefit. Consistent with the EA's approach, we phase in the full productivity benefit over the first 5 years after the reforms come in, on the basis that this effect would not occur immediately.

We therefore estimate the productive efficiency benefit from increased competition by applying a range of 0% - 0.5% to variable costs in each of the generation and retail markets, and in each state. In generation markets, the variable costs are the generator fuel and other variable (operating and maintenance) costs from our PLEXOS modelling. In retail markets, while retailers' variable costs include the wholesale price of electricity, network and environmental costs, and other retail costs, we only apply the 0.5% cost reduction to retail costs. These are the main costs that retailers have control over, and therefore in which they are able to achieve productive efficiencies.

Note that a reduction in variable costs, to the extent that these costs savings are passed through to prices, would also result in an allocative efficiency effect if the resulting price reduction results in an output increase (i.e. demand is not perfectly elastic). For simplicity of exposition and conservativism, we have not modelled this second round impact of productive efficiency.

8.2.4. Competition benefit results

In Figure 8.8 below we report the maximum allocative efficiency benefit (at a 0.5% price decrease) in the generation market, by state and by year, while Figure 8.9 shows the same results for the retail market. We report these benefits from 2026 onwards, being the year from which the benefits are expected to occur if the reforms are put in place.

Some of the key findings from these results are:

- For a given year, the benefit in generation markets is largest in NSW. This is largely due to a combination of higher generation, a higher counterfactual price, and more elastic demand in NSW. This yields a larger benefit as the relatively larger price decrease (in dollar terms) generates greater additional output;

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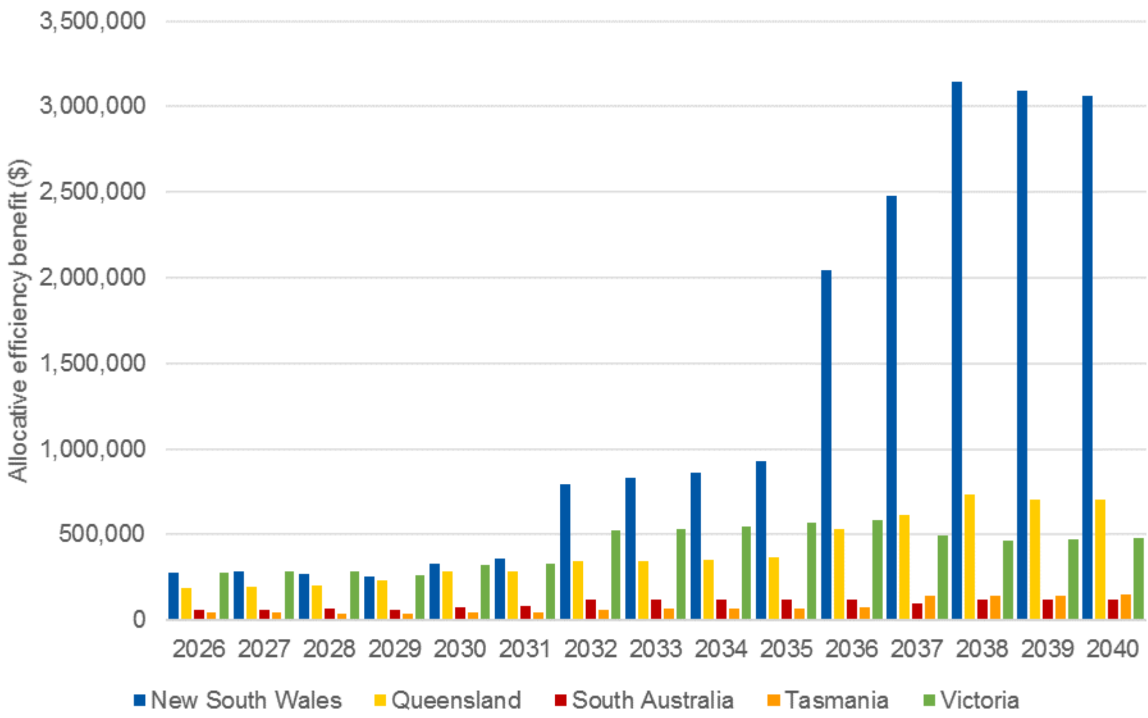
92 This is because both studies calculate productivity gains by comparing firms from the 80th percentile (of economic rents) to firms from the 20th percentile, and the competition difference between these percentiles is likely to be material.

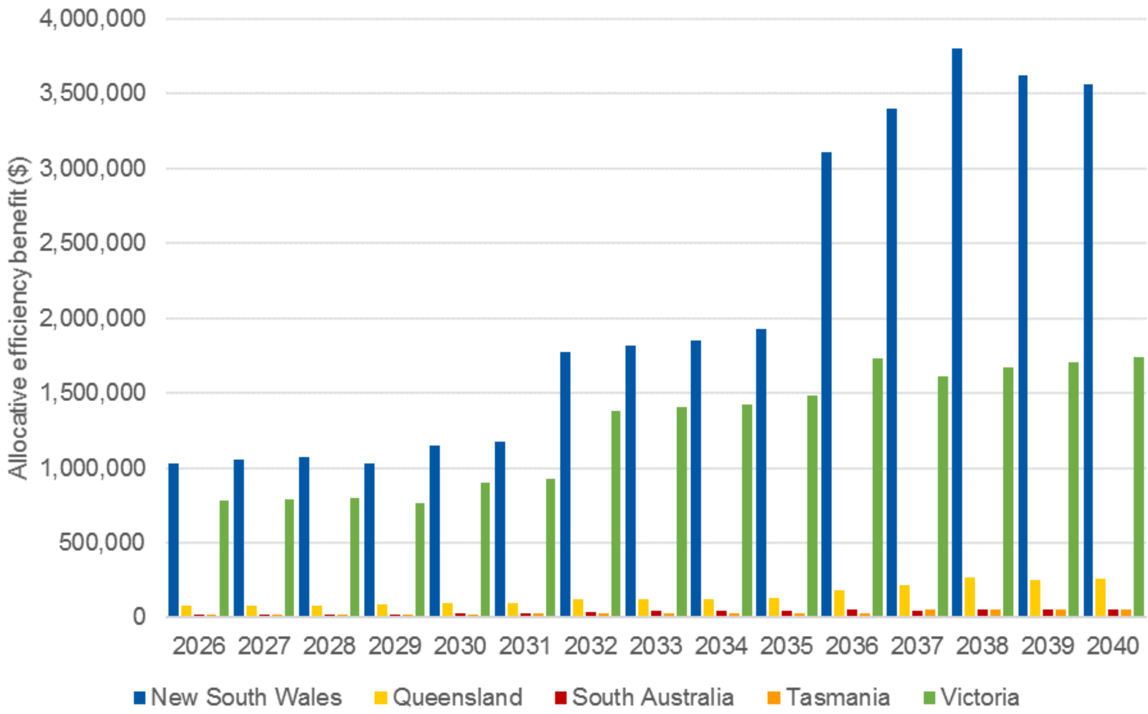
- A similar situation occurs in retail markets, with the benefit being largest in NSW, followed by Victoria. Again this can be attributed to higher and more elastic demand, and a higher counterfactual retail price in these states. In addition, the retail market benefit is lower for Queensland (compared to the relative position of Queensland in generation markets), largely due to there being smaller retail margins in Queensland, particularly relative to NSW and Victoria; and
- Over the 2026-2040 period, the competition benefit generally increases, in both generation and retail markets. This increase is particularly stark for NSW. This can be attributed to large increases in generation and demand arising from our PLEXOS modelling towards the end of this period, combined with higher prices but relatively constant variable costs.

Figure 8.8: Generation market: maximum allocative efficiency benefit by year and by state



Source: NERA analysis

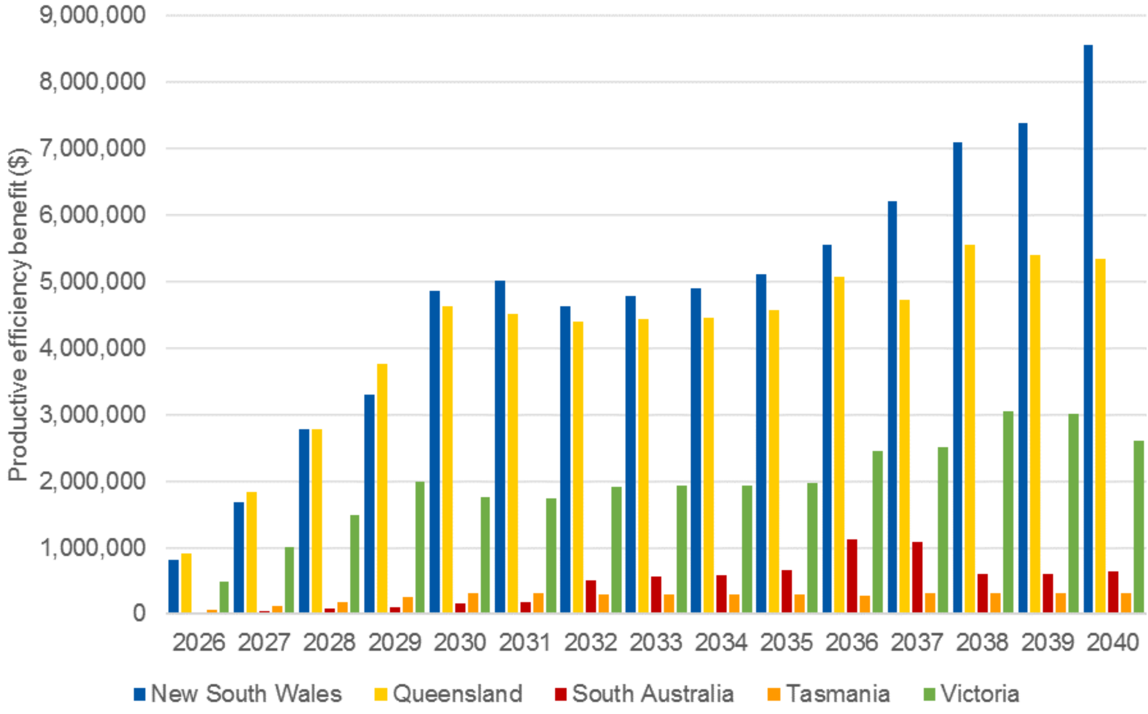
Figure 8.9: Retail market: maximum allocative efficiency benefit by year and by state



Source: NERA analysis

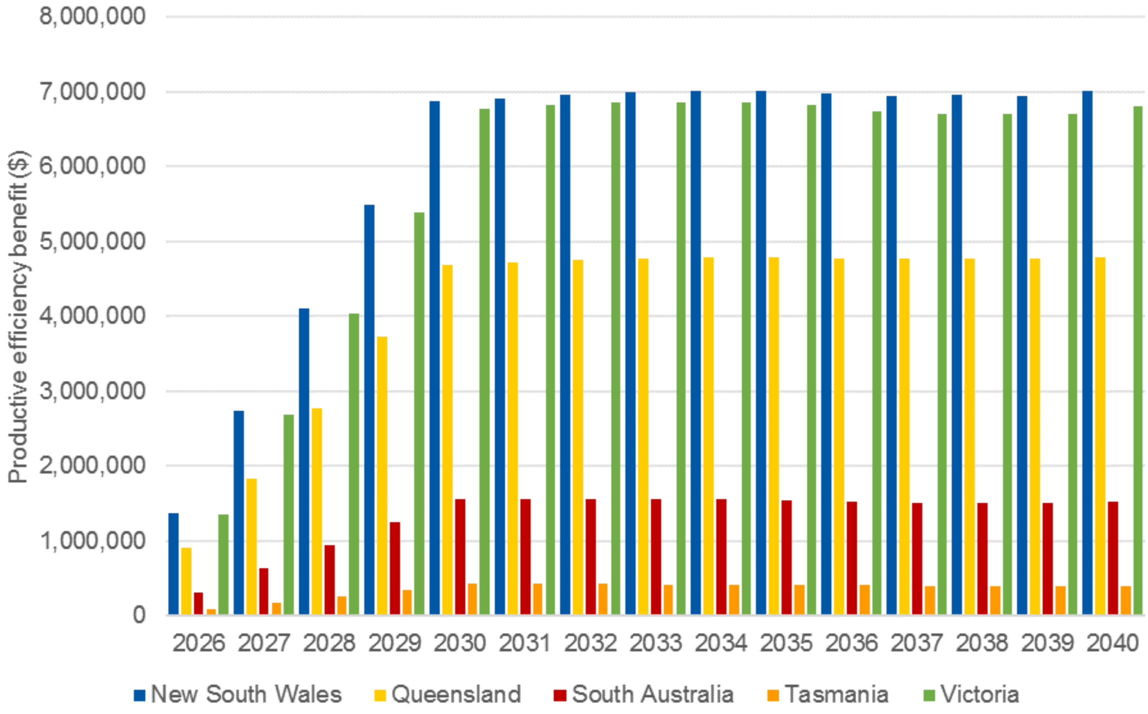
In Figure 8.10 we show the maximum productive efficiency benefits for the generation market, while the equivalent results for the retail market are shown in Figure 8.11. Of note is that the productive efficiency benefit in the NSW generation market increases over time, because variable costs increase over time, while for the other states the benefit is more stable over time.

Figure 8.10: Generation market: maximum productive efficiency benefit by year and by state



Source: NERA analysis

Figure 8.11: Retail market: maximum productive efficiency benefit by year and by state



Source: NERA analysis

We have also calculated the net present value of the allocative and productive efficiency benefits (over the 2026-2040 period), using a 7% discount rate. Results are presented in Table 8.1. We also report in this table the present value of the (maximum) wealth transfer in generation and retail markets, across each state.

Table 8.1: Present value of maximum allocative and productive efficiency benefits and wealth transfers by state (2026-2040 NPV,$2020)

	Generation market			Retail market		
	PV of allocative efficiency benefit	**PV of productive efficiency benefit**	**PV of wealth transfers**	**PV of allocative efficiency benefit**	**PV of productive efficiency benefit**	**PV of wealth transfers**
NSW	$6.4m	$27.8m	$151.4m	$11.8m	$36.4m	$533.0m
Queensland	$2.3m	$24.8m	$83.3m	$0.8m	$24.8 m	$313.0m
South Australia	$0.6m	$2.5m	$16.6m	$0.2m	$8.1m	$104.0m
Tasmania	$0.4m	$1.6m	$13.1m	$0.2m	$2.1m	$26.5m
Victoria	$2.6m	$11.8m	$68.8m	$7.6m	$35.6m	$377.6m

Source: NERA analysis

Summing these values to give aggregate figures for the NEM and including zero as the bottom end of the range gives the following total benefits in NPV terms, as shown in Table 8.2.

Table 8.2: Summary of potential competition benefits and wealth transfers (2026-2040 NPV, $2020)

	Allocative efficiency benefit		Productive efficiency benefit		Wealth transfers	
	min	**max**	**min**	**max**	**min**	**Max**
Generation market	$0	$12.4m	$0	$68.6m	$0	$333.2m
Retail market	$0	$20.7m	$0	$107.1m	$0	$1,354.0m
Total	$0	$33.1m	$0	$175.6m	$0	$1,687.2m

Source: NERA analysis

We therefore find a potential allocative efficiency benefit of between $0m and $33.1m in NPV terms and a potential productivity benefit of between $0m and $175.6m. The relativity between these figures is unsurprising – demand for electricity is relatively inelastic and therefore price changes due to increased competition primarily result in transfers rather than efficiency gains. The much larger productivity gain is driven by the fact that in a large market like the NEM, small cost savings in relative terms can have relatively large impacts in dollar terms.

In our summary results we present both the social benefit and the consumer benefit (efficiency benefits which could be expected to accrue to consumers and transfers). This is because the social benefits we calculate are generally changes in system costs. However, in the present case, part of the allocative efficiency benefit (the blue rectangle in Figure 8.7) is the margin earned by generators and retailers on additional sales. This is an efficiency gain but by nature of not being a change in system costs, it would not be appropriate to include in our measure of consumer benefits. To account for this, we therefore net off the producer surplus portion of the allocative efficiency gain from transfer before adding it to the social benefit to get the consumer benefit. Because of the relatively small allocative efficiency benefit (due to electricity demand being relatively inelastic), this doesn't make much difference – the wealth transfer net of the change in producer surplus is $1,655.1m compared to the raw transfer of $1,687.2m in NPV terms.

8.3. Summary of potential competition benefit

For the introduction of FTRs to result in a competition benefit, a number of conditions must hold:

- FTRs provide a material improvement in locational price hedging compared to SRA units and the alternative methods of mitigating locational price risk (e.g. co-locating generation and retail) stymy competition;
- But-for locational price risk, there are no material barriers to entry/expansion in the markets in question and markets are not expected to be in a situation of excess supply; and
- There must be an existing competition problem in the markets in question, such that an improvement in could competition could actually occur;

Regarding these three points:

- FTRs should theoretically provide a superior hedge against locational price risk, but the evidence available to us that generators consider SRAs to be ineffective is essentially anecdotal. However, it does appear to be true that the vertically integrated generators co-locate their generation and retail. At the same time however, most recent entry in generation has been by non-vertically integrated players which may suggest that a lack of an effective inter-regional hedge may not be an important factor for generator competition.
- The ACCC has found that there are not material barriers to entry and expansion and evidence suggests there is a large need for new generation capacity in the future; and
- The ACCC and AER already have existing concerns about competition in both the retail and generation markets.

We therefore think it is plausible that the introduction of FTRs in the place of SRA units will result in an improvement in retail and generator competition. On the other hand, introducing FTRs simply swaps one *inter* regional hedging product for another and at the same time the reforms change the way *intra* regional risk is managed. Given we have not been able to verify the incremental improvement in risk management from swapping SRAs for FTRs, it is difficult to draw conclusions about the materiality of the improvement in risk management. Similarly, most new generation investment appears to be coming from non-integrated players, which might suggest locational risk is not hindering competition, at least in generation. Therefore, we also can't rule out there being no material impact on competition, based on the evidence before us. We therefore calculate a range for the potential competition benefit with zero as a lower bound and a moderate impact on competition (a price and variable cost decrease of 0.5% in retail and generation markets) as the upper bound. This gives a range in NPV terms of $0 – $209m.

9. Summary of Benefits and Comparisons with International Benchmarks

This report sets out the benefits of Access Reform that accrue from improved efficiency in investment and dispatch. Table 9.1 summarises our findings. In this table we calculate three broad metrics:

- **Social benefit:** The improvement in economic efficiency, which is quantified as the net reduction in system costs, and in the case of improved competition, additional surplus[93] due to increased consumption/generation of electricity;
- **Wealth transfer:** reductions in prices can occur that do not result in any change in the underlying volume of electricity generated/consumed or the costs of producing that volume of electricity. These price reductions redistribute wealth between generators and consumers, making consumers better off without any corresponding improvement in economic efficiency. Economists therefore refer to these effects as “wealth transfers”; and
- **Consumer benefit:** this is calculated as the sum of the social benefit and the wealth transfer, on the assumption that changes in system costs ultimately accrue to consumers;[94]

As can be seen from the Table, we estimate that the overall consumer benefit including the introduction of dynamic losses in the NEM-DE could yield social benefits of over $3 billion in NPV terms, discounted to 2020. More than half of that benefit occurs in the first ten years of the reforms. In the earlier part of the period, most benefits accrue from improved efficiency of dispatch (items 2 and 3 in the Table). However, as investment needs ramp up towards the end of the period, the benefits from improved investment signals exceed the short-term benefits from dispatch as new plant locates in more efficient locations.

Dynamic losses are potentially separable from the introduction of LMP and FTRs. Our estimate of the benefits of dynamic losses may also overstate the current dispatch inefficiency in the NEM. It includes both volume and price distortions, whilst in practice we understand AEMO at least partially mitigates the volume distortion by forecasting demand gross of losses. As a result, our assessment of the benefits of adopting dynamic losses may be considered the addressable inefficiency rather than a central estimate. We present social benefits and consumer benefits with and without the impact of Dynamic Losses.

The Table shows the NPV of the annuitised costs of investment. In other words, the Table presents the reduced capital costs of investment *allocated* to the years within the modelling horizon. In practice, the benefits of improved locational signals for new investments over the period (and therefore the requirement for less investment) would be felt for the remainder of those plants’ lives. We also assume that the benefits from eliminating Race to the Floor bidding fall as the coal capacity on the system declines, whilst the benefits from Dynamic Losses continue at broadly the same level in future years. The scale of both of these potential

[93] Where “consumer surplus” is the difference between a consumer’s willingness to pay for electricity and the price they pay for the additional volumes of electricity consumed. “Producer surplus” is the difference between the price generators receive and the cost of producing the additional output (in effect, the margin on additional sales).

[94] Note that we net off the producer surplus change component of the social benefit when we calculate the consumer benefit, on the basis that this is a pure producer benefit.

sources of inefficiency depend on dispatching plant with higher variable costs for the system in preference to plant with lower variable costs. Our assumption on the decline in benefits from Race to the Floor bidding stems from our observation that coal plant is primarily responsible for the increase in system costs. The benefits from using dynamic losses are less obviously attributable to one particular technology and may continue to accrue in future because technologies with potentially-high variable or opportunity costs (such as storage and batteries). Inefficient investment signals stemming from the use of static loss factors may also feed through into investment decision-making over time.

Benefits to consumers are larger than social benefits. Under the Status Quo, generators receive the congestion rent in the system because they receive the Regional Reference Price (RRP), albeit adjusted for MLFs. Under Access Reform, consumers will pay generators only the locational value of the energy they produce. As a result, our analysis suggests that consumers receive a wealth transfer from generators of approximately a further $3 billion over the modelling horizon in NPV terms, most of which falls in the final five years of the modelling horizon to 2040.

The Table assumes that all reductions in system costs ultimately accrue to consumers. Accordingly, we have added the social cost reductions from introducing dynamic losses and eliminating the race to the floor to the price reduction in our long-term expansion modelling set out in Chapter 3.

Table 9.1: Estimated Social and Consumer Benefits of Access Reform

		Annual benefits 2026 (2026 $m)		NPV of Benefits (discounted at 7 per cent per year, 2020$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		1,738	
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	209
5	**Total social benefit**	**308**	**358**	**1,663**	**2,002**	**1,531**	**1,626**	**3,194**	**3,629**
6	*Social benefit (w/o 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 from generators/retailers to consumers*	*0*	*200*	*0*	*1,119*	*0*	*536*	*0*	*1,655*
9	**Total consumer benefit**	**414**	**662**	**2,839**	**4,297**	**3,316**	**3,948**	**6,155**	**8,245**
10	*Consumer benefit (w/o dyn. losses)*	*312*	*561*	*2,329*	*3,787*	*3,165*	*3,796*	*5,494*	*7,583*

Source: NERA Analysis

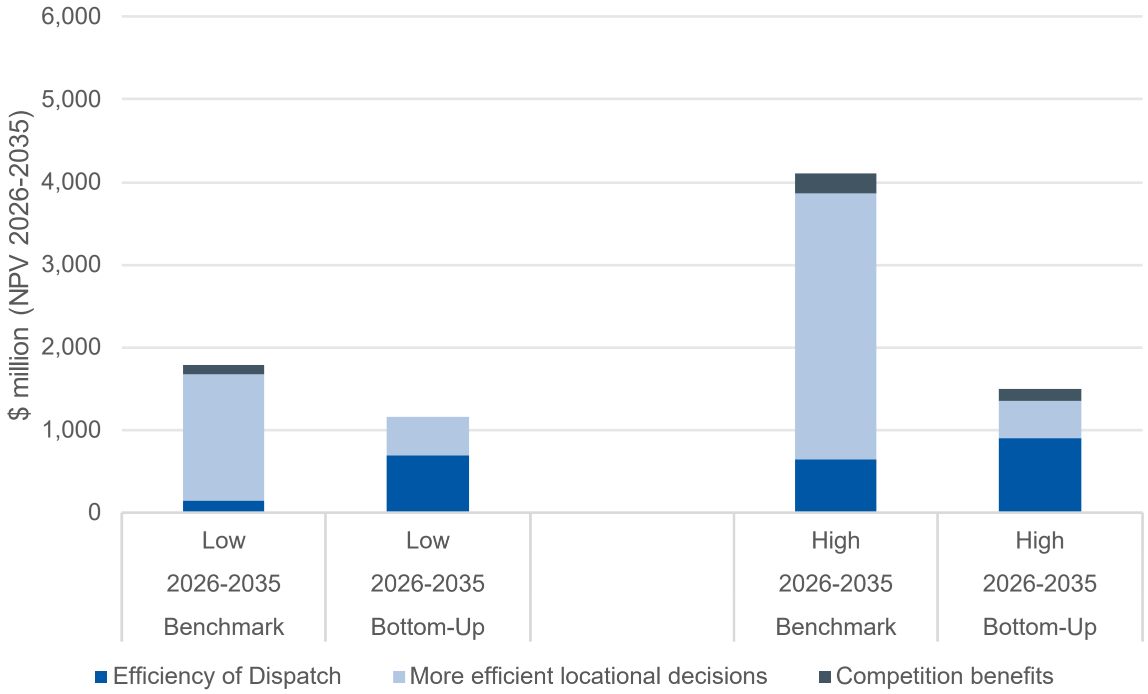
** This figure is net of the producer surplus increase (4), as this should not be counted when adding the social benefit and wealth transfer to give the consumer benefit.*

Our bottom-up modelling is broadly consistent with the top-down analysis we prepared for the AEMC in March 2020. [95] Figure 9.1 to Figure 9.3 below show our bottom-up estimates developed in this report with the top-down estimates we presented in that prior work. Our report considered a wide range of estimates. The high and low estimates we present below are our preferred estimates set out in Table 3 of that report. As can be seen from the Figures:

- Our estimates of the social benefits of reform from 2026-2035 are lower than our adjusted international benchmarks (Figure 9.1). The primary reason for the difference is that our estimate of capital cost savings is lower than our estimate based on international benchmarks. In our March 2020 report, we suggested that the estimate of capital cost savings from our benchmarks was less reliable than our other estimates because it relied on only one study prepared for the New York Independent System Operator and may be overstated. Our estimate of dispatch benefits is greater than international benchmarks. International market designs already offered generators firm access to the transmission network and therefore the benefits for dispatch may reasonably be lower in those jurisdictions.
- Our estimates of the social benefits of reform from 2026-2040 (see Figure 9.2) are more in line with our estimates based on international evidence, largely because we find a larger benefit from investing in efficient locations on the grid.
- Our estimates of the total benefit to consumers is greater in the NEM than our preferred estimate for international markets from our March 2020 report, but broadly within or overlapping the ranges we identified from previous studies set out in our report (see Figure 9.3, below). We based our preferred estimate in our March 2020 on the only available ex-post evaluation, which was of the impact of the introduction of LMP in ERCOT. The study on which we based that analysis estimated consumer benefits of between 28 per cent and 50 per cent of the three ex-ante studies we examined for ERCOT and SPP. Our estimates are broadly consistent with the results of those other ex-ante studies. The ex post study we used for our preferred estimates was published six years after the introduction of LMP. Our analysis suggests that more than half of the transfer to consumers occurs in the last five years of our fifteen-year modelling horizon. Accordingly, part of the difference between our bottom-up and top-down estimates may reflect the time-profile of the benefits incurred.

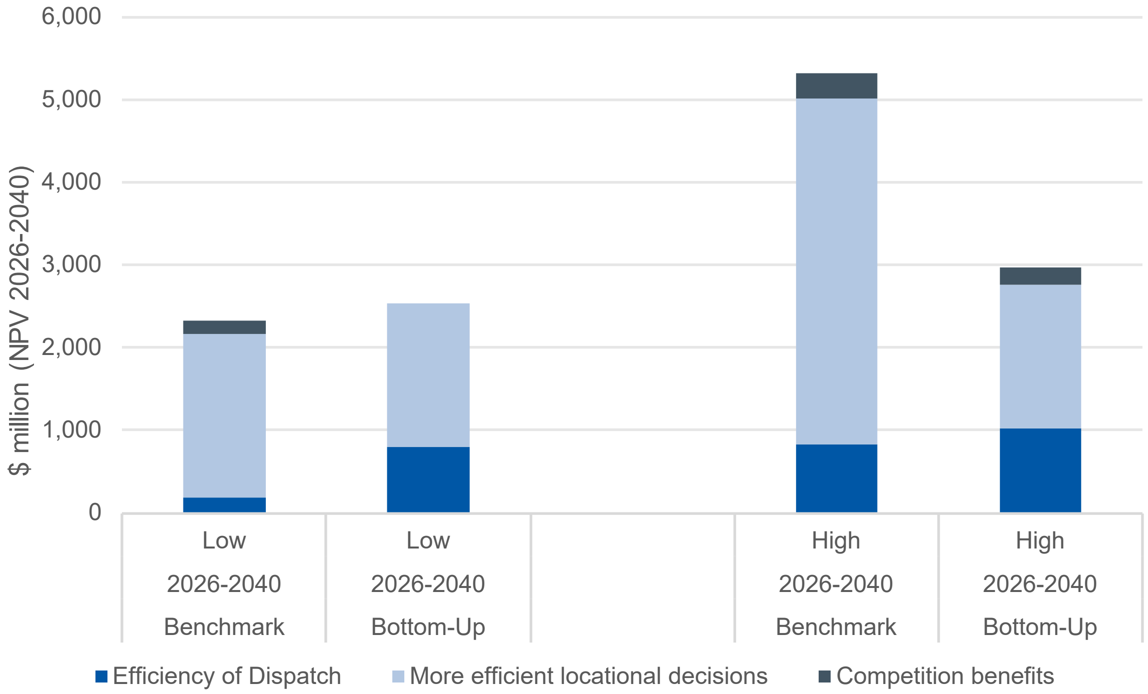
[95] NERA (2020), *Costs and Benefits of Access Reform – Prepared for the AEMC*, 9 March 2020.

Figure 9.1: Our Estimated Social Benefits Are Lower than our Adjusted Benchmarks from International Cost Benefit Analyses for 2026-2035



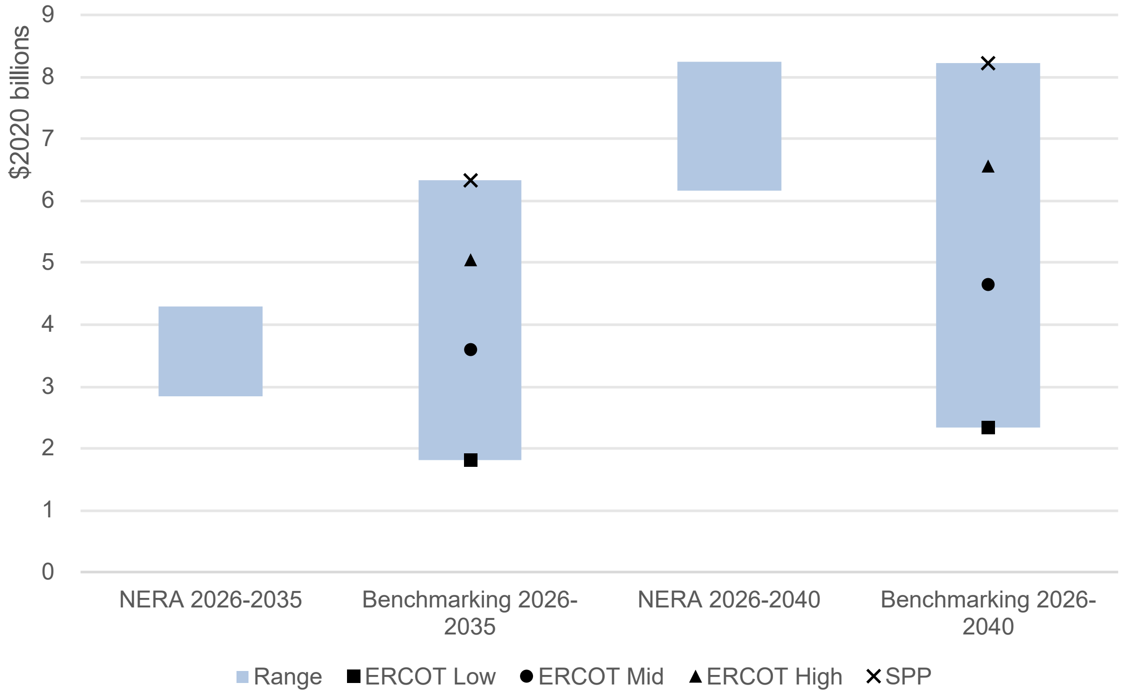
Source: NERA Analysis.

Figure 9.2: Our Estimated Social Benefits Are Broadly in Line with our Adjusted Benchmarks from International Cost Benefit Analyses for 2026-2040



Source: NERA Analysis

Figure 9.3: Our Estimated Transfer to Consumers is Greater than Our Adjusted International Benchmarks



Source: NERA Analysis

Appendix A. Outages and FTR Sufficiency

Under the AEMC's proposed design for Reform, consumers will receive the congestion rent rather than generators as at present. Non-scheduled loads will pay Volume Weighted Average Prices (VWAP) and generators will receive Generator Weighted Average Prices (GWAP). The difference between GWAP and VWAP will be collected by AEMO's settlement residue (abstracting from any revenues that accrue from over recovery of losses).

FTRs are financial instruments that hedge congestion rent by providing a payment equal to the spread between two LMPs on the network. The total pay-out on FTRs will therefore be equal to the settlement residue that AEMO recovers by recovering higher prices from loads than from generators. Provided there are no unanticipated outages, the financial transactions undertaken on behalf of consumers by AEMO with generators will reflect the physical flows of electricity on the system. In such circumstances, settlement residues will be at least equal to the pay-outs that AEMO must make on FTRs and will be sufficient to ensure that FTRs are financially-firm. If, however, the network experiences a material outage on a line for which AEMO has previously sold FTRs, the contractual undertakings on behalf of consumers will not reflect the underlying physical flows. In such circumstances, AEMO risks paying out the congestion rent on a line over which power is not flowing and in respect of which congestion it does not collect any settlement residue. In principle, AEMO could not have sufficient capital to pay-out all of the FTRs it had issued. FTRs that were not firm would not allow generators to hedge congestion rent to the same extent and could have implications for the level of risk and liquidity faced by generators.

FTRs are less likely to be firm if AEMO issues FTRs that covered all of the capacity on the network. If AEMO issued fewer FTRs, then in typical conditions it would collect more settlement residue than it expected to pay out.

The AEMC's design for Reform proposes issuing FTRs equivalent to the full capacity of the network and backing FTRs with both the settlement residues and the revenue collected from the auctions. If markets are competitive, then the FTR will be priced at fair value: each FTR will reflect the expected difference in prices between the nodes it connects and the sum of all FTRs will reflect the expected settlement residues if AEMO issues FTRs equal to the capacity of all of the lines of the network. Consequently, absent a disruption of transmission capacity, there would be approximately twice the revenue available to back the FTRs as required in any dispatch interval.

To examine the resilience of FTRs under AEMO's design we have identified two outages on frequently congested and important lines in the NEM: the Dederang-South Morang ('DDSM') line between New South Wales and Victoria, and the Heywood-South East ('HYSE') between Victoria and South Australia. We ran our PLEXOS model with and without the line in question operating, based on the mean time to repair set out in AEMO's ISP assumptions book – 15 hours on 27 May 2026 for DDSM and 4.5 on 4 February 2026 for HYSE. We selected the two days in question based on the largest congestion rental on the respective lines in 2025/26.[96] Our analysis suggests that under the AEMC's design, FTRs would be very likely to be firm, absent a very material outage: Fair value for the settlement

96 The reason for the choice of 2025/26 is similar to that illustrated in Chapter 5 for race to the floor analysis.

residue in the NEM is around $133 million in our PLEXOS modelling which very materially exceeds the losses observed in the outages shown below.

Table A.1: Sufficiency of Settlement Residue: Example Case of an Outage on the Dederang - South Morang Line on 27 May 2026 ($2020, thousands) presents the case of an outage on the Dederang-South Morang line on 27 May 2026. Absent the outage, total payments by load in the NEM would be approximate $15,689,000, payments to generators would be $14,766,000 and the settlement residues would be $923,000. Once the outage had taken place, total payments by consumers would fall in our modelling to $15,682,000, payments to generators would fall to $14,753,000 and settlement residues would rise to $929,000. The increase in the settlement residue may be necessary to pay to the owners of FTRs, assuming that 100 per cent of the physical capacity on the system were allocated through analogous financial contracts. In addition, AEMO would have to pay a further $2,600 to the holders of FTRs on the Dederang-South Morang line to reflect the difference in prices at the connecting nodes multiplied by the capacity of the line. The fair value for FTRs on that day alone would be $923,000. As a result, the small deficit associated with the outage would make no material impact on AEMO's revenues from allocating FTRs even for the day in question, let alone the entire year.

Table A.2 shows an equivalent calculation for a congested day on the Heywood to South East line on 4 February 2026. As can be seen from the Table, VWAP and GWAP again fall as a result of the outage. In this case, however, settlement residues also fall across the NEM, as do pay-outs on allocated FTRs for lines which are operating. In this case, AEMO must pay-out $156,000 to the owners of FTRs on the Heywood-South East line. Whilst a more material financial impact, the fair value (or expected settlement residue) for the NEM on this day alone is $17,482,000. As a result, the additional FTR pay-out would have only a trivial impact on AEMO's financial position and will be small relative to the FTR revenues received for that day alone.

To exhaust the annual revenues from FTRs at fair value, much more material outages than those shown below would be necessary. For instance, it would take an outage of a 370 MW line that caused spreads between the interconnecting nodes to rise to the approximate gap between the cap and floor in the NEM (i.e. $14,000 and *minus* $1,000) for an entire day to exhaust the fair market value of the FTRs.[97]

Table A.1: Sufficiency of Settlement Residue: Example Case of an Outage on the Dederang - South Morang Line on 27 May 2026 ($2020, thousands)

			No Outage (Expected)	Outage (Disturbance)	Difference (O - N)
1		VWAP x (Load + Pump Load)	15,689	15,682	-7.02
2		GWAP x Generation Sent Out	14,766	14,753	-13.10
3	1 – 2	Settlement Residue	923	929	6.08
4		FTR Payment	-923	-932	-8.67
5		FTR Income	923	923	0.00

97 A line of 370 MW capacity would collect a total rent of $133 million in a day in the case of a price gap of $15,000/MWh , which would offset the $133 million estimated fair value of FTRs. This is calculated as 370 MW * (14,000 – (-1,000))$/MWh * 24 hours.

6	3+4+5	Net Position of System Operator	923	920	-2.60

Source: NERA Analysis of PLEXOS data. Note: in the 'Expected' Case, The FTR payment is equal to the settlement residue, with opposite sign. In the 'Disturbance' case, it is equal to the settlement residue in this case (Line 3 of the table) plus the total congestion rent on the line, which is equal to line capacity times price differential.

Table A.2: Sufficiency of Settlement Residue: Example Case of an Outage on the Heywood - South East Line on 04 February 2026 ($2020, thousands)

			No Outage (Expected)	Outage (Disturbance)	Difference (O - N)
1		VWAP x (Load + Pump Load)	46,392	46,132	-259.31
2		GWAP x Generation Sent Out	28,909	28,659	-250.44
3	1 – 2	Settlement Residue	17,482	17,474	-8.87
4		FTR Payment	-17,482	17,629	-147.14
5		FTR Income	17,482	17,482	0.00
6	3+4+5	Net Position of System Operator	17,482	17,326	-156.00

Source: NERA Analysis of PLEXOS data.

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