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ECONOMIC CONSULTING

Costs and Benefits of Access Reform

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Executive Summary

NERA Economic Consulting (NERA) has been commissioned by the Australian Energy Market Commission (AEMC) to assess the costs and benefits of introducing Locational Marginal Pricing (LMP) and Financial Transmission Rights (FTRs) in Australia's National Electricity Market (NEM), as part of the Coordination of Generation and Transmission Investment Implementation (COGATI) package of reforms. The AEMC has requested analysis of a series of expected benefits from the planned reforms, including the more efficient dispatch of generation resources through the elimination of incentives for strategic bidding behaviour related to transmission system constraints, the better siting of generation, storage and transmission investments, due to the clear price signals from LMP, and improved risk management for market participants due to FTRs. The purpose of this paper is to aid decision-making on the implementation of the COGATI reforms by providing preliminary estimates of the likely costs and benefits of the reform.

This report reviews the evidence available on the costs and benefits of similar reforms implemented in other jurisdictions and provides an estimate of the expected costs and benefits of the reform, based on this evidence from comparator markets. Our high-level conclusions are that international benchmarks provide useful insights into the broad categories of costs, benefits and market impacts of implementing the COGATI reform. The numbers estimated in previous cases may not be directly applicable in Australia. The costs, benefits and market impacts of introducing LMP and FTRs depend critically on local factors such as the prevalence of constraints, the generation mix and the prevailing transmission access regime. In particular, all of the markets we reviewed offered generators firm transmission access prior to the adoption of LMP and FTRs, whilst the NEM does not compensate generators who are constrained-off by the system operator. As a result, international case studies may understate the likely benefits in the NEM. Many of the international studies we reviewed only provided ex-ante assessments of what system operators expected rather than ex post assessments of what actually happened. They also did not estimate potentially-material categories of benefit for the NEM.

Nonetheless, the benefit of introducing LMP and FTRs *for dispatch alone* based on these benchmarks (range of AUD 30 million to AUD 137 million *per year*) exceeds the latest-available estimate of implementation costs (for Ontario, a *one-off* cost of AUD 149 million) on a Net Present Value basis.

In parallel to this benchmarking study, NERA has also been preparing for potential quantitative modelling of the NEM to model the benefits that accrue from LMP, controlling for the specific characteristics of the Australian market and the planned reforms. This report also sets out our proposed methodology to estimate the benefits from LMP based on electricity market modelling.

Case Study Review

We have reviewed the evidence available on the costs and benefits of introducing LMP and FTRs in ten jurisdictions worldwide, that have either already introduced LMP and/or FTRs or are in the process of implementing similar reforms. The markets we have reviewed are:

1. Texas: The Electric Reliability Council of Texas (ERCOT);
2. California: The California Independent System Operator (CAISO);

3. New York: The New York Independent System Operator (NYISO);
4. New England: The New England Independent System Operator (NE-ISO)
5. Midwest USA: The Midcontinent Independent System Operator (MISO);
6. Southwest USA: The Southwest Power Pool (SPP);
7. Eastern USA: The Pennsylvania-New Jersey-Maryland Interconnection (PJM);
8. Ontario, Canada: Independent Electricity System Operator of Ontario (IESO);
9. Singapore: The National Electricity Market of Singapore (NEMS);
10. New Zealand.

Implementation Costs

We have found through our case study review that there is limited evidence on the costs of the implementation of LMP and FTRs in other jurisdictions that is directly relevant to the NEM because:

1. Many of the reforms we have reviewed are significantly broader in scope than the proposed reform in the NEM; and
2. Much of the evidence is outdated, and it is not clear that cost estimates from the 2000s or even the first half of the 2010s are relevant, given the potential speed of changes in relevant costs (such as changes in IT system costs).

The most relevant recent estimate we have identified is from a 2015 study for the IESO market (Ontario), which is currently planning to implement LMP in 2023. This study estimated that the costs of introducing LMP and FTRs in Ontario (the same reform that is planned in the NEM), is AUD 149 million (in 2019 prices).[1] Many of the costs of implementing LMP are likely to be fixed and Ontario is in any case a market of roughly similar size (around two-thirds) to the NEM. Accordingly, one could reasonably argue that the best available evidence from other jurisdictions suggests that the costs of introducing LMP and FTRs in the NEM will be AUD 149 million in the NEM.[2] However, we consider that there is upward risk around this cost estimate for the NEM:

1. The estimate for Ontario is an ex-ante estimate rather than the cost of a programme that was actually delivered. Accordingly, this estimate will not include the costs of any cost escalation that was unforeseen at the time of estimation;
2. There is evidence from some jurisdictions (ERCOT and New Zealand) that implementation costs were higher than originally foreseen. In ERCOT (i.e. Texas), estimates of total implementation costs (associated with a broader set of reforms than planned in the NEM) quadrupled over a 4-year period (from a 2004 CBA to a 2008 CBA), partly due to the greater complexity of the reforms than was expected and partly due to a four-year delay in implementation. In New Zealand, the estimated costs of introducing FTRs approximately doubled in the 2011 study, relative to a 2010 study. While there is very little ex post evidence available on the costs of implementation, these

[1] Throughout this executive summary, all prices reported in AUD terms

[2] We consider that there is no clear rationale for scaling implementation costs for differences in the size of the NEM and the power market in Ontario. The markets are also reasonably similar is size: demand was about 196 TWh in the NEM in 2018/19 vs. expected demand of 135 TWh in Ontario in 2019.

findings suggest that the costs of LMP/FTR reforms may exceed initial estimates, although the timely implementation of reforms may reduce the risk of overruns.

3. The 2015 study for IESO may underestimate the costs of introducing FTRs specifically. Other markets, such as New Zealand and SPP experienced higher FTR implementation costs. Furthermore, the expected costs of implementing FTRs may be higher in the NEM than in the IESO market, because FTRs already exist in the IESO market to hedge the price differentials between Ontario and its neighbouring markets.

A bottom-up quantification of implementation costs would be required to produce a more accurate estimate of the expected implementation costs of LMP and FTRs in the NEM.

Benefits from LMP

There are two key benefits from the move to LMP:

1. **More Efficient Dispatch:** Under the current NEM design, generators have an incentive to manipulate their bids in order to maximise their chances of being dispatched during periods of expected congestion (this behaviour is called "race to the floor bidding") or to bid unavailable where the local value of electricity exceeds the regional reference price. LMP eliminates this incentive because generators earn the locational value of electricity. Accordingly, LMP allows the system operator to dispatch the lowest-cost plant on the system to meet system load; and
2. **Capital cost savings:** LMP offers clear and transparent price signals at each location of the network. Accordingly, generation, storage and transmission investments may locate more efficiently.

Through our case study review, we have found that there is a range of evidence available from other jurisdictions on the benefits from more efficient dispatch. There is little evidence available on the capital costs savings from the introduction of LMP.

Benefits from Efficient Dispatch

We have identified useful evidence on the benefits from more efficient generation dispatch from five jurisdictions, all from North America, that have introduced or are in the process of introducing LMP for generators. Specifically, we identified benefit estimates from both ex ante cost-benefit analyses that estimate benefits using an electricity market modelling or a benchmarking approach, and from ex post studies that assess benefits based on an econometric analysis of actual, historical data. The benefit estimates from these jurisdictions range from about 0.6 per cent to 2.6 per cent of the total variable costs of generation.

We have estimated the expected benefits from the introduction of LMP in the NEM, assuming that the reform in the NEM has a similar impact on the efficiency of dispatch in the NEM as reforms in comparator jurisdictions, using two approaches:

1. **Scaling by Variable Cost:** We estimate the benefits from more efficient dispatch as the product of (1) estimates of the percentage saving in the variable cost of generation in comparator markets (from the studies identified); and (2) our estimate of the variable cost of generation in the NEM in 2018/19; and

2. **Scaling by Market Volume:** We use the reported annual US Dollar efficiency saving benefits from our comparator jurisdictions and apply these to the NEM by scaling for differences in the size of markets (assuming equal benefits in US Dollars per MWh terms).

The benefits of more efficient dispatch are principally felt in the reduced fuel costs of operating the plant on the system. The first approach may provide more accurate results, because, unlike the alternative approach, it controls for differences in the relative costs of generation (in the different markets), on which any efficiency benefits are realised. Table 1 below summarises the results of our analysis for the NEM. We estimate that the annual benefits from more efficient dispatch range from AUD 30 million to AUD 137 million in the NEM, depending on the comparator market relied upon (and the approach used). Average benefit estimates across the comparator jurisdictions amount to AUD 79 million per annum (using the variable costs approach) or AUD 93 million (using the volume approach). These benefit estimates amount to AUD 0.59 billion and AUD 0.74 billion respectively based on a ten-year discounting period (and using a 7% real discount rate based on the Australian Government's Guidance).

Table 1: Summary of Estimated Benefits from Efficient Dispatch

Market	Source	Scaling by Variable Costs – Annual Benefit (AUD million)	Scaling by Market Size – Average Annual Benefit (AUD million)
ERCOT	2004 CBA	**52.7**	**84.1**
ERCOT	2008 CBA	**30.1**	**65.4**
CAISO	2011 Academic Paper (Wolak)	**102.0**	**136.9**
MISO	2009 Ex-post Study	**109.1**	**84.2**
SPP	2005 CBA	**100.4**	**-**
IESO	2017 CBA		**120.9**
Average		**78.9**	**98.3**
10-year NPV (average)		**592.6**	**738.8**
20-year NPV (average)		**819.6**	**1,114.4**

Source: NERA Analysis. We use a real discount rate of 7% based on the Australian Government's February 2016 Guidance Note on Cost-Benefit Analyses. No estimate of benefits is available for SPP based on the approach of scaling by market volume, because the 2005 SPP CBA only reports benefits as a percentage of the variable costs of generation (i.e. it does not report benefits in USD terms). For IESO, we do not have an estimate of benefits based on the approach of scaling by variable costs, because the 2017 IESO CBA does not provide an estimate of the percentage reduction in variable costs that results from the reform.

Various differences between North American (mainly US) markets and the NEM limit the applicability of the benefit estimates from Table 1 above to the NEM. Most importantly:

1. Unlike generators in the NEM, generators in most US markets had firm access (of some form) to the transmission network before the introduction of LMP. This reduces the benefits from nodal pricing reform in US markets. Where generators have firm access to

the network, the system operator will redispatch plant to meet system constraints and compensate generators forced to turn down or turn up. Provided that market for redispatch operates efficiently, the same plant would ultimately generate under a regional market with firm access as would generate given LMP. This finding suggests that US-based estimates likely understate the true level of efficiency benefits to be expected in the NEM, where generators do not currently have firm network access;

2. Further, the estimate of increased efficiency of dispatch assumes a static market in most of the estimates we reviewed. In practice, the efficiency of dispatch may increase further over time as new capacity responds to investment signals that reflect the locational value of capacity. This again suggests that the US-based estimates we have used in our benefits transfer may understate the true level of expected efficiency benefits in the NEM;

3. Most US markets had sub-optimal congestion management processes in place before nodal pricing reform. These sub-optimal congestion management processes led to a lower utilisation of frequently-constrained lines and inefficient dispatch outcomes. In itself, this difference between US markets and the NEM suggests that US-based estimates overstate the true level of efficiency benefits in the NEM, given that these same benefits, from adopting congestion management that better reflect the physical properties of the system may not exist in the NEM.

4. Levels of congestion and the generation mix also differ in the NEM and the comparator markets. These market features are likely to have a material impact on the benefits from efficient dispatch. It is unclear if benefit estimates for the NEM should be increased or decreased to account for these differences.

It is not clear therefore whether the range of benefit estimates for the NEM of AUD 30 to 137 million per annum under- or over-states the true level of benefits from efficient generation dispatch expected in the NEM from nodal pricing reform. A detailed modelling of the electricity market in the NEM is required to estimate expected benefits more accurately.

Benefits from More Efficient Investment Decisions

Under LMP, asset owners and investors will face incentives to locate efficiently because they will have access to a clear and transparent price signal at each location on the network. Benefits from more efficient locational decisions may arise for two reasons:

- the capital cost of investments may decrease, e.g. because investors undertake fewer, but better located generation, transmission and storage investments; and
- the costs of electricity generation (excluding capital costs) may fall relative to the scenario without LMP reform, as a result of better-located plants and storage units.

Only one jurisdiction that we examine, NYISO, estimates the benefits from more efficient siting of generation at USD 500 million after the introduction of LMP.

We scale the estimate from more efficient siting of generation for NYISO to reflect conditions in the NEM which implies the benefits could range between AUD 327 and 690 million per year. However, the estimate is likely to be an overstatement because:

- Non-scheduled generation will continue to face the regional price in the NEM whereas in NYISO they face LMP. Consequently, the generator siting benefits from the siting of renewable generation after the introduction of LMP will likely be lower in the NEM.
- It is unclear how the benefits estimate for NYISO is calculated and it likely also includes the benefits from demand-response management and more efficient dispatch.

In order to better assess the benefits from more efficient siting following the introduction of LMP, one would need to conduct bottom-up modelling of the market in the NEM and future planned investment.

The Distributional Impacts of LMP and FTRs

We identify three sources of benefits that may accrue to generators or consumers after the introduction of LMP:

- **Efficiency gains**: The net social benefits from more efficient dispatch and siting by generators may accrue to generators or consumers.
- **Out of Merit (OOM) payments**: OOM payments will no longer be required with the introduction of LMP because market prices will provide the signal to increase or decrease output at constrained nodes. Unlike the other systems we reviewed, the NEM does not offer firm access and therefore OOM payments to decrease generation output (although generators declaring themselves unavailable may receive OOM payments to increase output).
- **The zonal price relative to the volume-weighted average of generator LMPs**: The higher the zonal price in the NEM relative to the generators' volume-weighted average of LMPs, the higher the benefits that will accrue to consumers from the reform.

The studies that we examine all assume a transfer of benefits from generators to consumers resulting from the introduction of LMP. We report our estimates for the annual benefits accruing to consumers from the introduction of LMP and FTRs in the NEM in Table 2.

Table 2: Our Estimates for the Annual Benefits Accruing to Consumers from the Introduction of LMP and FTRs in the NEM

Market	Ex-ante or Ex-post?	Percentage Reduction in Wholesale Prices	Estimated Annual Consumer Transfer in the NEM (AUD million)
ERCOT	Ex-ante	5.59%	**1,081**
ERCOT	Ex-ante	3.97%	**768**
ERCOT	**Ex-post**	**2.00%**	**387**
SPP	Ex-ante	7.00%	**1,354**

Source: NERA Analysis

We estimate the benefits accruing to consumers as a consequence of introducing nodal pricing range from AUD 387 million to AUD 1,354 million per year. Our best estimate corresponds to the only ex-post study that we examine and suggests benefits accruing to consumers from the introduction of LMP are AUD 387 million per year.

The benefits (or disbenefits) accruing to generators from the introduction of FTRs and LMP will equal the efficiency benefits *minus* the benefits accruing to consumers from the reform.

The introduction of nodal pricing and FTRs in the jurisdictions we examine often coincided with changes to other market structures that were unique to the operation of the market in each of the jurisdictions. Nowhere did we find that the existing market arrangements to alleviate intra-zonal congestion were similar to that currently operated in the NEM. Consequently, using the case studies that we examine to assess the distributional impact of reforms is challenging in the absence of bottom-up modelling of the market before and after the reform. Without such bottom-up analysis, one cannot accurately determine the changes to transfers that arise from the specific market structure in each jurisdiction and the transfers likely to arise from the reform in the NEM.

Cost of Capital Impact of FTRs

We also analyse the initial evidence on the potential impact of the proposed reform on generators' risk and cost of capital.

In general, the AEMC argues that the proposed access reform should improve investment certainty and risk management for generators and therefore reduce the cost of capital. Stakeholders' responses generally argue that the reforms would increase complexity, uncertainty and risk, which would increase the cost of capital.

We start by reviewing any commentary on the proposed reform's impact on the cost of capital from credit rating agencies, equity research analysts, finance literature, and various case studies. There is limited evidence or discussion on this particular subject, which suggests that analysts may consider it too early to comment, or may consider the COGATI reform not to have a material impact on cost of capital.

Our scenario analysis indicates that the impact on risk mainly depends on the magnitude of the constraint risk in the current model, and the likelihood of owning a firm FTR in the proposed model. This is because the generators face a trade-off between the constraint risk in the current model, and the uncertainty of owning a firm FTR and the resulting basis risk in the proposed model. The impact also depends on the relative volatility between the regional reference price under the current model, and the locational marginal prices in the proposed model.

Conceptually, we do not expect any material impact on the cost of equity as a result of access reform under the CAPM. This is because we do not expect the risk factors, such as constraint risks and basis risks, to be strongly correlated with the market return. The market return is driven by macroeconomic variables such as aggregate economic growth, and reflects long-term expectation. In contrast, the constraint risk and basis risks are determined by variations in local electricity prices, which in theory would not co-vary with market return movement.

The cost of debt may change as a result of proposed reform, because debtholders are concerned with the absolute level of risk. The impact on cost of debt could increase or decrease, depending on the relative costs and benefits of the COGATI reform. We would need to assess the change in absolute risk empirically, once we have modelling results to examine the impact of the different offsetting risk factors. In the absence of the modelling results, we present an illustrative scenario of maximum impact on debt risk under the assumption that the reform does reduce risk, by allowing generators to improve its hedging and also have better market framework than the current regime as the net effect of the risk change. Our analysis indicates that the generator's cost of debt could reduce by up to 30 to 50 basis point if the proposed reform is highly successful and the generator's credit rating improves by two notches. The impact on weighted average cost of capital would be the impact on cost of debt multiplied by the debt to asset ratio, which would be likely to be non-material.

Finally, our analysis abstracts from the level of return, as we focus on the forward-looking risks. We note that the return level may be affected too, which is discussed in Section 6.8. Large distributional impacts that could arise in the short run could lead to longer-run effects on the cost of capital due to perceived regulatory risk. Stakeholder responses argue that the proposed reform itself could introduce uncertainty faced by generators due to its scale and complexity, which would lead to an increase in regulatory risk and cost of capital.[3]

We do not consider there to be a material increase in regulatory risk as a result of the proposed reform. While the COGATI reform may lead to a material change to the NEM's market framework, the proposed reform is neither unexpected, nor unjustifiable, hence does not necessarily constitute an increase in regulatory risk. Our review uncovered no evidence or commentary by credit rating agencies or financial analysts on the increased regulatory risk as a result of the COGATI reform. That absence of evidence suggests that the market considers the COGATI reform not to have a material impact on regulatory risk.

The Impact of LMP and FTRs on Contract Market Liquidity

Across the case studies we examine, liquidity was not reported to substantially improve nor decline as a result of the introduction of LMP. However, the *distribution* of liquidity in markets was reported to change due to the introduction of LMP, with the formation of trading hubs throughout the system, not necessarily at regional reference nodes, and relatively stronger liquidity at those hubs compared to the rest of the market. Changes to liquidity in the wholesale market do not necessarily lead to social benefits or costs and may instead be efficient responses to contract market structure. The existing contract market structure in the jurisdictions we examine is very different to that of the NEM, and consequently the reported impacts on liquidity are likely irrelevant comparisons for the impact on liquidity in the NEM.

The Prevalence of Market Power with LMP and FTRs

The introduction of LMP should not exacerbate existing sources nor introduce new sources of market power. LMP highlights market power, because market power that is exercised will be observable through locational prices. Therefore, LMP provides a clearer signal over when local market power is created and exercised, and where policies to mitigate market power should be targeted.

Across all jurisdictions that we examine, local market power is reported to be prevalent but is rarely exercised in practice, typically only in hours of very high demand when most capacity is required. In all jurisdictions, regulators introduced market power mitigation policies alongside the introduction of nodal pricing. Most jurisdictions that we examine impose an offer cap on bidding in any given settlement period. In addition, most jurisdictions

[3] For example, Meridian Energy Australia and Powershop Australia (8 November 2019), COGATI Proposed Access Model, p. 3.

automatically apply tests at nodes to detect local market power in any given settlement period *before* dispatch, followed by the automatic capping of market offers if market power is deemed to exist.

Summary Table of Potential Benefits, Based on Case Study Evidence

In Table 3 below, we summarise our estimates of the potential benefits and implementation costs from the introduction of LMP and FTRs in the NEM.

In practice, the case studies that we examine may not be accurate predictors of the costs and potential benefits arising from the introduction of LMP and FTRs in the NEM, due to differences between the market structure and market arrangements in the NEM and the given jurisdiction at the time of the reform, and due to differences in the specific reforms introduced in the comparator jurisdictions and the reforms proposed in the NEM. Hence, as set out in Table 3 below, it is not clear in most cases if our benefit estimates under- or overstate the expected level of benefit in the NEM. A detailed modelling of the electricity market in the NEM is required to estimate expected benefits and wealth transfers more accurately.

Table 3: The Potential Benefits and Implementation Costs from the Introduction of LMP and FTRs in the NEM

Benefit or Cost	Periodicity	Estimate (AUD million)	Likely bias
Total Implementation Costs	One-off	149	Understate
Efficiency of Dispatch	Annual	30-137	Unclear
Capital Cost Savings from Better Siting	Annual	327-690*	Overstate
Competition Benefits	Annual	25-50	Unclear
Benefits to Consumers (Including Transfers)	Annual	387	Unclear

*Source: NERA Analysis. Note: Numbers are best-available from international benchmarks rather than predictions for the NEM. *: The estimate of capital cost savings is less reliable than the other benefit estimates because it is based on single benefit estimate for NYISO and it is not clear what benefits this estimate includes (e.g. whether it includes or excludes efficient dispatch benefits) and how the benefit figure was estimated.*

1. Introduction

The Coordination of Generation and Transmission Investment (COGATI) review is focussed on the reform of transmission frameworks and generation investment to facilitate the transformation of the electricity market in the National Electricity Market (NEM). Large thermal plants are being replaced by smaller renewable plants and storage at a fast pace. Most of the current generation stock in the NEM is expected to be replaced with new plants by 2040.[4] As such, the Australian Energy Market Commission (AEMC) views that reform to better coordinate generation and transmission network investment is vital to ensure a more efficient energy transition.

The current scope of the COGATI review is focussed on developing a proposed access model which includes the introduction of Locational Marginal Pricing (LMP) and Financial Transmission Rights (FTRs).

The AEMC expects a series of benefits from the planned reforms, including the more efficient dispatch of generation resources through the elimination of generators' incentives for strategic bidding behaviour, the better siting of generation, storage and transmission investments, due to clear price signals from LMP, and improved risk management for market participants due to FTRs.

The AEMC issued a discussion paper on the COGATI reform proposals in October 2019 and received extensive stakeholder feedback on the design and likely costs and benefits of the reform.[5] Following this feedback from stakeholders, the AEMC issued an update paper in December 2019 summarising stakeholder feedback and providing responses.[6]

NERA Economic Consulting (NERA) has been commissioned by the AEMC to analyse the likely costs and benefits arising from the introduction of LMP and FTRs as part of the AEMC's proposed access model. The evidence will be used to help inform the AEMC's report for the March 2020 COAG Energy Council meeting.

Our approach to assessing the likely costs and benefits of reform is split into two work streams:

- We review the evidence available on the costs and benefits of similar reforms implemented in other jurisdictions and provide an estimate of the expected costs and benefits of the reform, based on this benchmark evidence from comparator markets.
- In parallel to this benchmarking study, we have been developing quantitative modelling of the NEM to model the benefits that accrue from LMP, controlling for the specific characteristics of the NEM and the planned reforms.

4 AEMC (14 October 2019), COGATI Proposed Access Model, p. i, para 7.

5 See here: AEMC COGATI Implementation – Access and Charging, Link: https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and, Last accessed: 24 February 2020.

6 AEMC (19 December 2019), COGATI Proposed Access Model – Update Paper.

This report reviews the evidence available on the costs and benefits of similar reforms implemented in other jurisdictions and sets out our proposed methodology to estimate the benefits from LMP based on electricity market modelling.

We have reviewed the evidence available on the costs and benefits of introducing LMP and FTRs in 10 jurisdictions worldwide, that have either already introduced LMP and/or FTRs or are in the process of implementing similar reforms. The markets we have reviewed are:

1. The Electric Reliability Council of Texas (ERCOT) – ERCOT was the latest US market to introduce LMP and FTRs. It transitioned from a zonal pricing market to generator LMP as part of a wide suite of reforms in December 2010, including a move from portfolio bidding to resource-specific bidding, a move from 15-minute to 5-minute dispatch intervals, the implementation of a day-ahead market, and changes to its congestion management practices.
2. The California Independent System Operator (CAISO) – CAISO introduced generator LMP and FTRs in 2009 following the problems with its zonal pricing market highlighted during and after the California Energy Crisis.
3. The New York Independent System Operator (NYISO) – NYISO introduced generator LMP and FTRs alongside a competitive wholesale market in 1999 in place of a power pool model.
4. The New England Independent System Operator (NE-ISO) – NE-ISO introduced generator LMP and FTRs in 2003 in place of a market which had relied on physical bilateral contracts rather than centralised dispatch of resources.
5. The Midcontinent Independent System Operator (MISO) – In Midwest USA, MISO introduced generator LMP in 2005. It also introduced day-ahead and real-time markets alongside a centralised wholesale market, replacing a market which had relied on physical bilateral contracts.
6. The Southwest Power Pool (SPP) – In Southwest USA, SPP introduced generator LMP in 2007 in place of a market which had relied on physical bilateral contracts rather than centralised dispatch of resources. It introduced FTRs as a separate reform in 2014.
7. The Pennsylvania-New Jersey-Maryland Interconnection (PJM) – PJM introduced LMP for both generators and consumers and FTRs in 1998 and 1999 respectively following one year of operation of a zonal pricing market which was deemed to be inefficient due to high intra-zonal congestion.
8. Independent Electricity System Operator of Ontario (IESO) – Ontario is planning on introducing generator LMP in 2023 and is currently undertaking analyses on the likely costs and benefits of the reform. We understand that IESO does not currently plan to introduce FTRs alongside LMP.
9. The National Electricity Market of Singapore (NEMS) introduced LMP for both generators and consumers in 2003.
10. New Zealand introduced a market for FTRs in 2013 to facilitate contracting between the two main islands. New Zealand began operating with full nodal pricing in 1996.

We summarise the case studies that we examine and key characteristics about each jurisdiction in Table 1.1.

Table 1.1: Summary of International Reforms

	New Zealand	NEMS (SGP)	PJM	NYISO	ISO-NE	MISO	SPP	ERCOT	CAISO	IESO	NEM
Generator LMP?	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Consumer LMP?	✓	✓	✓	✗	✗	✗	✗	✗	✗	✗	✗
LMP Year	1996	2003	1998	1999	2003	2005	2007	2010	2009	2023	TBD
FTRs	✓	✓	✓	✓	✓	✓	✓	✓	✓	✗	✓
FTR Year	2013	2003	1999	1999	2003	2005	2014	2010	2009	NA	TBD
Motivation	Facilitate Inter-island trade (FTRs)	Move to comp. market	High intra-zonal congestion	Move to comp. market	Move to comp. market	Move to comp. market	Move to comp. market	High intra-zonal congestion	High intra-zonal congestion and strategic bidding	High intra-zonal congestion	High intra-zonal congestion and strategic bidding
Annual Load in TWh	39 (2013)	32 (2003)	250 (1998)	147 (1999)	131 (2003)	595 (2006)	210 (2007)	319 (2010)	207 (2009)	143 (2021)	196 (2018/9)
Cost estimates available?	✓(FTRs)	✗	✗	✓	✗	✓	✓	✓	✓	✓	✗
Benefits estimates available?	✓(FTRs)	✗	✗	✓	✗	✓	✓	✓	✗	✓	✗

Source: NERA Analysis.

Our report is structured as follows:

- In Section 2, we summarise the AEMC's proposed reform and its arguments as to why the reform will likely result in net benefits and meet the objectives of the COGATI review. We also summarise stakeholder responses provided in the consultation of the proposed access reform model;
- In Section 3, we set out the evidence on the likely costs of implementing LMP and FTRs from the case studies we examine, and draw conclusions on the likely implementation costs in the NEM;
- In Section 4, we discuss the evidence on the efficient dispatch benefits from introducing LMP in other jurisdictions. Based on this evidence, we estimate a range for the expected benefits of introducing LMP in the NEM;
- In Section 5, we discuss other potential benefits arising from LMP and FTRs as observed across the jurisdictions that we examine. In particular, we examine the potential capital cost savings from a more efficient development pathway for generation, storage and transmission investment and the benefits that may arise due to the impact of the reform on competition;
- In Section 6, we examine evidence from other jurisdictions on the likely distributional effects of introducing LMP and FTRs, such as the benefits from the reform that consumers realise;
- In Section 7, we analyse the likely effects of the reform on the cost of capital for generators;
- In Section 8, we set out the evidence on the likely impacts of LMP and FTRs on market power and contract market liquidity, from our case study review.
- In Section 9, we outline our approach to the modelling work stream.

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2. Background on the COGATI Proposed Access Model

2.1. Current Market Context: The Case for Reform

The National Electricity Market (NEM) is a regional gross pool across five states: New South Wales, South Australia, Tasmania, Victoria and Queensland.

Under the current access model, the spot price for electricity is set in each region at 30-minute intervals at a regional reference node. However, a dispatch price is determined every five minutes within that 30-minute interval.[7] Generators submit offers detailing specified volumes for every five-minute dispatch period for up to ten different prices. For every five minutes, the Australian Energy Market Operator (AEMO) selects the combination of offers to dispatch to meet demand: AEMO starts with the cheapest offer, then the next cheapest and so on until demand is met, subject to system constraints.[8] The dispatch price for each five minutes is set by the cost of procuring the next unit of generation at the regional reference node. The 30-minute spot price is the average of the six dispatch prices in that period.[9] The generators receive the regional spot price for the period and not the dispatch price, regardless of their initial offers. The spot price has a market price cap of AUD 14,700/MWh and a price floor of minus AUD 1,000/MWh.[10]

To account for transmission losses under the existing access model, AEMO estimates an annual marginal loss factor for each generation node. The annual marginal loss factor remains static across the year. AEMO dispatches generators after accounting for their annual marginal loss factors, and remunerates them at the regional spot price adjusted for their loss factor. Consequently, AEMO's dispatch does not respond to changes in actual transmission losses across settlement periods within each year.

AEMO may be unable to dispatch all of the cheapest plant to meet load in any given settlement period because of system constraints. Constraints present limits on flows of power between points in the system. Therefore, to ensure that the system operates within its technical parameters, AEMO must constrain off some generators and constrain on others to meet load at times when system constraints are binding.

Therefore, whilst the transmission framework in the NEM is an open-access system, transmission access is not firm, so generators face the risk of being constrained off without compensation.[11] Settlement Residue Auctions (SRAs) allow participants to bid for access to inter-regional settlement residue, a pool of funds which pays out should transmission constraints bind in regulated interconnectors between regions of the NEM.[12] However, SRAs are non-firm and cannot be bought to hedge against the risk of congestion within regions.

Consequently, the current access model provides incentives that result in three main problems:

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7 ACCC (July 2018), Retail Electricity Pricing Inquiry – Final Report, p. 4040. We understand the dispatch price will be settled on a 5 minute basis from 1 July 2021.

8 AEMO relies on its NEM dispatch engine (NEMDE) system. Source: AEMC (July 2017) Fact sheet: How transmission frameworks work in the NEM, p. 2.

9 ACCC (July 2018), Retail Electricity Pricing Inquiry – Final Report, p. 40.

10 ACCC (July 2018), Retail Electricity Pricing Inquiry – Final Report, p. 40.

11 AEMC (July 2017) Fact sheet: How transmission frameworks work in the NEM, p. 1.

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

- Inefficient price signals for where to generate and invest in transmission that do not reflect local congestion because all generators are paid the regional reference price;
- Inefficient dispatch because of distorted incentives to bidding behavior, because participants do not face transmission constraints in the price that they are remunerated, and transmission loss factors that do not dynamically reflect actual transmission losses in a given settlement period; and
- A risk of congestion for generators who are only compensated if they are dispatched and do not have a firm financial instrument to hedge the risk of congestion.

In addition, the current access model likely results in a large proportion of intra-regional congestion revenue accruing to generators thereby resulting in higher costs of electricity for consumers.

The problems caused by the current access model in the NEM are likely to be exacerbated as the generation mix in the NEM is rapidly changing. Thermal plants are being replaced by renewable plants and storage at a fast pace: Most of the current generation stock in the NEM is expected to be replaced with new plants by 2040.[13]

The transformation of the generation mix creates a challenge for the current market structure in the NEM. The new, larger number of small renewable generators will need to be located in areas where generation is efficient (windy or sunny areas) which may not correspond to the areas where sufficient transmission capacity exists to connect those generators such that they can expect to get dispatched at their full capacity.[14] Furthermore, new generation can be built more quickly than the rate at which networks can be expanded to support them.[15]

Consequently, the AEMC expects that congestion will significantly increase, particularly in North Queensland, South West New South Wales and North West Victoria as new generation will likely be located where there is not substantial existing capacity to serve them.[16] In part, congestion arises from a lack of clear incentives for new generators to make use of existing capacity.

2.2. The Proposed Access Reform and its Benefits

The AEMC's proposed access model aims to provide efficient signals to accurately reflect the impact of investment on total system costs. In turn, the efficient signals should coordinate transmission and generation investment decisions in order to facilitate the energy transition.[17] As part of its Coordination of Generation and Transmission Investment (COGATI) reform, the AEMC has proposed a transmission access model[18] to allow "the NEM to effectively manage the current transition underway in generation technologies".[19]

13 AEMC (14 October 2019), COGATI Proposed Access Model, p. i, para 7.

14 AEMC (14 October 2019), COGATI Proposed Access Model, p. i., para 7.

15 AEMC (19 December 2019), COGATI Proposed Access Model - Update Paper, p. 3.

16 AEMC (19 December 2019), COGATI Proposed Access Model - Update Paper, p. 3.

17 AEMC (14 October 2019), COGATI Proposed Access Model, p. ii, para 11.

18 The AEMC outlined its proposed access model in a discussion paper on 13 October 2019 and, after receiving stakeholder responses, published a further update paper on 19 December 2019.

19 AEMC (14 October 2019), COGATI Proposed Access Model, p. i, para 2.

The AEMC intends that its proposed access model will work alongside AEMO's Integrated System Plan which aims to "streamline the regulatory processes to deliver efficient levels of transmission investment".[20]

There are two main features to the AEMC's proposed access model:

1. **Locational Marginal Pricing (LMP):** Under the current gross pool model in the NEM, all market participants pay and receive a regional price for electricity, gross of losses, regardless of their location. Under the proposed access model, generators and storage face LMPs that "better reflects the marginal cost of supplying electricity at their location in the network" by accounting for congestion.[21] The LMPs may also include a dynamic loss factor rather than a static annual marginal loss factor under the current model.[22] Retailers and non-scheduled market participants would continue to receive a regional price under the proposed access model.
2. **Introduction of FTRs to manage financial risks:** Under the current model, the AEMC expects that participants will "increasingly find it difficult to manage the increasing volatility and unpredictability of congestion and losses that arise as a result of the transitioning power system".[23] Generators are only paid the regional price under the current model if they are physically dispatched, which in turn depends on local congestion in their networks. In the proposed access model, generators and storage can better manage congestion risks through financial transmission rights (FTRs).[24] FTRs allow for the partial financial decoupling of generators' revenues from physical dispatch, which may improve the risk management capabilities of generators and storage. Whilst the AEMC suggests participation in the primary auction for intra-regional FTRs would be limited to physical market participants, all market participants would be able to purchase FTRs in the secondary market and the primary auction for inter-regional FTRs.[25]

In its discussion paper, the AEMC identifies the following potential benefits that may arise from the introduction of its proposed access model in the NEM:[26]

- better incentives to operate generation and storage assets efficiently because of more efficient bidding behavior and dispatch;
- better incentives for efficient generation and storage investment because of clearer locational signals of congestion;
- better risk management for market participants through the introduction of FTRs;
- better year-to-year cashflow management for TNSPs due to replacement of the SRA auction with FTRs; and

[20] AEMC (19 December 2019), COGATI Proposed Access Model - Update Paper, p. 3.

[21] AEMC (14 October 2019), COGATI Proposed Access Model, p. iii, para. 20 and Figure 1.

[22] AEMC (14 October 2019), COGATI Proposed Access Model, p. 16

[23] AEMC (14 October 2019), COGATI Proposed Access Model, p. v, para. 34.

[24] AEMC (14 October 2019), COGATI Proposed Access Model, p. iii, para. 20 and Figure 1.

[25] AEMC (14 October 2019), COGATI Proposed Access Model, p. 70.

[26] AEMC (14 October 2019), COGATI Proposed Access Model, p. 18.

- better incentives to operate the transmission network efficiently through clearer locational signals of congestion.

The AEMC has consulted on the development of the proposed access reform and received extensive stakeholder feedback. Nonetheless, to date, detailed analysis on the likely costs, benefits and distributional effects has not been completed at this stage in the process. Sections 2.3 to 2.6 below summarise the views expressed by stakeholders and the AEMC.

2.3. Costs of Implementing the Access Model

Estimating the costs of the proposed access model through a detailed cost assessment is challenging, primarily because the precise details of the model are as yet unformulated.[27] The AEMC does outline a suggested method to estimate the costs of implementation by drawing upon case study evidence as well as a survey of market participants.[28]

Given the lack of a detailed implantation plan of the proposed access model, few stakeholders comment in detail on the potential costs of implementation. Those who did argue that the implementation costs could be high and "indications from independent consultants highlight implementation of FNP/FTR could cost hundreds of millions".[29] The costs would primarily comprise of:

- Investment in new modeling, trading skills and IT systems[30] which may disproportionately impact smaller retailers; [31]
- Collateral costs and costs of any required changes to the NEM's dispatch engine (NEM-DE);[32] and
- Costs of renegotiating existing contracts and power purchase agreements[33] should the reform trigger a Market Disruption Event on International Swaps and Derivatives Association-(ISDA)-based contracts, for example, by changing the formulation of spot prices to volume-weighted average prices (VWAP).[34]

2.4. The Potential Benefits of the Reforms

The AEMC identifies potential benefits of the proposed access reform that arise from the two main elements of the reform:

1. **LMP:** The AEMC argues that LMP improves the incentives for scheduled market participants to bid efficiently, provide improved locational signals for investment, and

27 AEMC (14 October 2019), COGATI Proposed Access Model, p. 84. AEMC (24 January 2020), Request for Proposal for Services.

28 AEMC (14 October 2019), COGATI Proposed Access Model, p. 84.

29 AEMO (8 November 2019), Coordination of Generation and Transmission Investment – Proposed Access Model Consultation Paper 2019, p. 1.1. FNP or Full Nodal Pricing would involve all market participants facing LMPs.

30 ENGIE (8 November 2019), COGATI Proposed Access Model – Discussion Paper EPR0073, p. 5.

31 CEC (8 November 2019), Coordination of Generation and Transmission Investment Proposed Access Model (EPR0073) – Discussion Paper, p. 3.

32 Origin (8 November 2019), AEMC: Coordination of Generation and Transmission Investment Discussion Paper – Proposed Access Model, p. 6.

33 Stanwell (13 November 2019), 2019 COGATI: Response to AEMC COGATI Discussion Papers, p. 12.

34 Snowy Hydro (8 November 2019), COGATI proposed access model Discussion paper, p. 8.

increase the efficiency of dispatch.[35] In the long run, efficiency improvements in bidding and dispatch could result in lower costs to consumers.

2. **FTRs:** The AEMC argues that the introduction of FTRs may allow market participants to more effectively manage the risks of congestion and losses. It argues that improved risk management through FTRs may increase the willingness of generators to offer energy contracts, improving contract market liquidity, as well as allow Transmission Network Service Providers (TNSPs) to more effectively manage its cashflows.[36] The AEMC also states that the arrangements should improve investment certainty (reduce risk) for scheduled market participants and reduce their long-term cost of capital.

We discuss the potential benefits arising from the reform in more detail below. The discussion below presents the AEMC's views on the various benefits and impacts of the reform, and also summarises the views expressed by stakeholders in their responses to the AEMC's discussion paper. Our discussion does not reflect the balance of arguments made by stakeholders. Instead, it attempts to reflect the plurality of views expressed. Therefore, the sections below focus on the concerns raised by stakeholders in response to the AEMC's discussion paper (i.e. areas of disagreement), rather than focusing on stakeholders' agreement with the arguments made by the AEMC.

2.4.1. More efficient dispatch and operation of system assets

The AEMC identifies three areas of potential benefits resulting from more efficient dispatch and operation of system assets under the proposed access model:[37]

- better incentives to operate generation and storage assets efficiently;
- more efficient dispatch of electricity; and
- better incentives to operate the transmission network efficiently.

The AEMC suggest that the proposed access model will result in better incentives to operate generation and storage assets efficiently.[38] In particular, it argues that the current access model distorts the incentives of generators to bid efficiently for dispatch into the market. The AEMC identifies two distortions to generator bidding behavior which it argues that the proposed access model may correct:[39]

- **Race to the floor bidding:** Scheduled market participants behind transmission constraints may not be dispatched at times network constraints are binding (i.e. when congestion occurs in the network). If a scheduled market participant is not dispatched, then it is uncompensated and may lose revenue in the contract market.[40] These market participants therefore may produce forecasts of the settlement periods (i.e. the times) in which congestion occurs. In these circumstances, under the current access model, scheduled market participants may engage in race to the floor bidding whereby they bid

35 AEMC (14 October 2019), COGATI Proposed Access Model, p. 15-16

36 AEMC (14 October 2019), COGATI Proposed Access Model, p. 17.

37 AEMC (14 October 2019), COGATI Proposed Access Model, p. 18-21.

38 AEMC (14 October 2019), COGATI Proposed Access Model, p. 18.

39 AEMC (14 October 2019), COGATI Proposed Access Model, p. 19.

40 AEMC (14 October 2019), COGATI Proposed Access Model, p. 19.

the market floor price (in period where constraints are binding, or when they expect constraints to be binding) in order to increase the likelihood that they will be dispatched. If dispatched, the participant will receive the regional price which is likely to be higher (as congestion rises when demand is higher) and is unaffected by the floor price offered by that particular market participant.[41] The AEMC argues that race to the floor bidding is inefficient because it does not ensure least cost generation assets are dispatched in a given settlement period.[42]

The AEMC argues that LMP may mitigate this phenomenon because the local price at which scheduled market participants are compensated may be highly affected by floor prices bid by those participants. Ignoring the effect of competition, this gives generators an incentive to submit cost-reflective bids (i.e. to submit bids that reflect their marginal costs). Thus, lower cost generation assets may outcompete higher cost generation assets at local nodes.[43]

- **Bidding unavailable:** Under the current access model, generators that are directed to be dispatched receive payment set at the 90th percentile of the spot prices over the previous 12 months.[44] Consequently, if a generator would receive a lower regional price by bidding available, it may instead bid unavailable if it knows that it is likely to be directed and be remunerated with the compensatory price. The AEMC states that there is evidence that bidding unavailable leads to "higher costs and a more unreliable power system for consumers".[45]

  Alternatively, the AEMC argues that LMP under the proposed access model may reduce the incentive to bid unavailable because generators will be remunerated at a local energy price, which may be higher than the regional price.[46]

More efficient bidding behavior and dynamic pricing may improve the overall efficiency of dispatch of electricity in the NEM and reduce long run costs for consumers. Consequently, dispatch may become increasingly efficient, resulting in lower costs for consumers in the long run.[47]

Some stakeholder responses to the AEMC's discussion paper argue that inefficient bidding is not a material problem, and state:

- Bidding unavailable is not efficient for generators "given the opportunity cost and wear and tear associated with continual directions".[48]

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41 AEMC (14 October 2019), COGATI Proposed Access Model, p. 19.

42 AEMC (14 October 2019), COGATI Proposed Access Model, p. 19.

43 AEMC (14 October 2019), COGATI Proposed Access Model, p. 20.

44 AEMC (14 October 2019), COGATI Proposed Access Model, p. 19.

45 AEMC (14 October 2019), COGATI Proposed Access Model, p. 19.

46 AEMC (14 October 2019), COGATI Proposed Access Model, p. 20.

47 AEMC (14 October 2019), COGATI Proposed Access Model, p. 21.

48 Origin (8 November 2019), AEMC: Coordination of Generation and Transmission Investment Discussion Paper – Proposed Access Model, p. 3.

- Race to the floor bidding occurs infrequently in the market and at minimal cost to the consumer.[49] Efficient dispatch should not be defined only by the short-run marginal cost of generation. In reality, generators consider a number of reasons beyond short run marginal cost to bid low for short periods of time (for example, fuel and plant constraints and contract market positions), which is an efficient outcome.[50]
- The phenomenon of race to the floor bidding may not be affected by the reform. Recent generation investment has often occurred under long term offtake agreements to minimise risk to the pool price. A common offtake arrangement is the whole-of-meter swap whereby generators are incentivised to maximise generation for maximum revenue. "Early versions of these agreements incentivised volume maximisation in all market conditions while contemporary agreements are reported to include some exceptions such as during periods of negative wholesale price".[51] Consequently, efficient dispatch may not just reflect short run marginal costs, but offtake arrangements, and the incentive to bid low with LMP may remain.

On the other hand, some stakeholders agreed with the AEMC's assessment of inefficient pricing under the current access model, and highlight the perverse incentives provided to generators behind transmission constraints to generate when the regional price is high.[52] Therefore, whilst some stakeholders argue that LMP should be adopted for all market participants to ensure efficiency,[53] others recognised that the proposed access model is a pragmatic alternative to mitigate the risks of splitting liquidity in the contract market.[54]

The AEMC argues that with the introduction of dynamic loss factors under the proposed access reform, the efficiency of dispatch may be improved by reducing the difference between actual losses and losses modelled in the dispatch engine.[55] Under the current system of setting static annual marginal loss factors, the actual marginal loss factor in any given settlement period may be higher or lower than that assumed by the dispatch engine. The AEMC recognises that marginal loss factors may increasingly differ from static marginal loss factors as the generation mix changes and the system moves to five-minute settlement of pricing. The AEMC expects that more volatile loss factors through dynamic pricing could be hedged through FTRs.[56]

Stakeholders express concerns over the additional risks that would be introduced by dynamic loss factors. If FTRs are not fully firm or generators could not purchase FTRs then generators would be unable to manage the risk of dynamic loss factors which may lead to higher risks and costs.[57] Consequently, generators may also contract less in the forward

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49 Snowy Hydro (8 November 2019), COGATI proposed access model Discussion paper, p. 1.

50 Snowy Hydro (8 November 2019), COGATI proposed access model Discussion paper, p. 6.

51 Stanwell (13 November 2019), 2019 COGATI: Response to AEMC COGATI Discussion Papers, p. 11.

52 ENGIE (8 November 2019), COGATI Proposed Access Model – Discussion Paper EPR0073, p. 2.

53 ENGIE (8 November 2019), COGATI Proposed Access Model – Discussion Paper EPR0073, p. 2.

54 AER (12 November 2019), Submission to Discussion Paper on the Proposed Access Model for the Coordination of Generation and Transmission Infrastructure, p. 6.

55 AEMC (14 October 2019), COGATI Proposed Access Model, p. 22.

56 AEMC (14 October 2019), COGATI Proposed Access Model, p. 22.

57 CEC (8 November 2019), Coordination of Generation and Transmission Investment Proposed Access Model (EPR0073) – Discussion Paper, p. 10.

market.[58] In addition, stakeholders highlighted a potential contradiction in policy because a move to more dynamic loss factors is in contradiction to the Transmission Loss Factors rule change, which attempts to create a less volatile marginal loss factor to provide more investment certainty.[59]

The AEMC also plans to enhance the existing Service Target Performance Incentive Scheme (STPIS) for Transmission Network Service Providers (TNSPs) in the new proposed access reform to incentivise TNSPs to operate their networks efficiently and provide enough capacity to meet FTR payouts.[60] The enhanced scheme would cover all settlement periods and would be tied to better measures of market value relative to the existing scheme.[61]

2.4.2. Capital cost savings from a more efficient development pathway (generation, transmission, storage)

The AEMC argues that the proposed access model would provide better incentives for efficient generation and storage investment, which may result in capital cost savings. It argues that LMP in the proposed access model provides a clearer signal of the value of locating in different parts of the network.[62] The AEMC states that the price signals would indicate the incremental cost of congestion, resulting in more efficient investment decisions and ultimately in lower costs for consumers.[63]

Stakeholders remain less convinced that the price signals would significantly impact long run investment and consider that the reforms may instead simply reduce short run investment in generation. In particular, stakeholders suggested:

- A local price “may not be a strong signal to influence generator location decisions” and other signals such as fuel source availability may be more important.[64]
- Clear congestion signals are already available for investors to assess congestion risk.[65] Consequently, whilst LMPs may provide a marginally more effective locational signal to generators, the benefits may be outweighed by the cost to consumers.[66]
- Uncertainty over the design and implementation of the proposed access model would likely lead to a disruption to short term investment.[67]

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58 AGL (13 November 2019), Coordination of Generation and Transmission Investment – Access Reform: Discussion Paper (EPR0073), p. 12.

59 Origin (8 November 2019), AEMC: Coordination of Generation and Transmission Investment Discussion Paper – Proposed Access Model, p. 4.

60 AEMC (14 October 2019), COGATI Proposed Access Model, p. 24.

61 AEMC (14 October 2019), COGATI Proposed Access Model, p. 24.

62 AEMC (14 October 2019), COGATI Proposed Access Model, p. 20.

63 AEMC (14 October 2019), COGATI Proposed Access Model, p. 21.

64 AEMO (8 November 2019), Coordination of Generation and Transmission Investment – Proposed Access Model Consultation Paper 2019, p. 4.

65 Meridian Energy Australia and Powershop Australia (8 November 2019), COGATI Proposed Access Model, p. 2.

66 Meridian Energy Australia and Powershop Australia (8 November 2019), COGATI Proposed Access Model, p. 3.

67 Snowy Hydro (8 November 2019), COGATI proposed access model Discussion paper, p. 6.

2.4.3. Lower capital costs from improved risk management

Under the current access model, existing generators may be constrained off by other generators subsequently locating their assets nearby. The sector benefits from the investment made by subsequent generators may also be undermined by the increase in congestion.[68] In addition, the AEMC reports that TNSPs have advised it that “they are experiencing issues arising from year-to-year cashflow management as a result of managing the funds for inter-regional SRA units”.[69]

The AEMC states that its proposed access model will improve financial certainty for generators and storage devices who may purchase FTRs to manage their dispatch risk during times of congestion. The AEMC argues that those participants with FTRs “would face a lower risk that other participants may undermine their business case by locating nearby and causing congestion in the local transmission system”.[70] The AEMC also states that inter-regional FTRs will allow TNSPs to manage inter-year cashflow more effectively.[71]

Consequently, the AEMC argues that management of risk through FTRs may increase investment certainty and reduce the long run cost of capital for scheduled market participants. It states that the proposed access model provides a regime “in which generators have greater certainty in the face of transmission constraints” and therefore “are likely to face lower risks to the cashflows of their existing generation assets”.[72] If the cost of capital is lower, the AEMC states that more generation investments will be made over time which may benefit consumers in the long term.[73] The AER agrees that firm FTRs may reduce the cost of capital of market participants and reduce costs for consumers.[74]

Stakeholder responses generally argue that FTRs may not be fully firm, and therefore stakeholders remain generally unconvinced that there would be a reduction in the cost of capital for generators under the proposed access model:

- FTRs may increase the cost of capital for new projects because:
  - “FTRs represent a fixed cost for generators (as they do not vary with changes in electricity generation), so are likely to be treated as a noncurrent liability or lease. This would likely increase the amount of equity required for a project, increasing the weighted average cost of capital or the revenue requirement to achieve minimum debt service coverage ratios”.[75]

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68 AEMC (14 October 2019), COGATI Proposed Access Model, p. 22.

69 AEMC (14 October 2019), COGATI Proposed Access Model, p. 23.

70 FTRs allows for financial outcomes to the scheduled generator to be decoupled from physical dispatch. AEMC (14 October 2019), COGATI Proposed Access Model, p. 23.

71 AEMC (14 October 2019), COGATI Proposed Access Model, p. 23.

72 AEMC (14 October 2019), COGATI Proposed Access Model, p. 85.

73 AEMC (14 October 2019), COGATI Proposed Access Model, p. 85.

74 AER (12 November 2019), Submission to Discussion Paper on the Proposed Access Model for the Coordination of Generation and Transmission Infrastructure, p. 11.

75 Stanwell (13 November 2019), 2019 COGATI: Response to AEMC COGATI Discussion Papers, p. 8.

  - "Financiers could penalise potential projects on both unsecured volume (i.e. any shortfall between FTRs and expected capacity) and the variable firmness of the FTRs they have purchased."[76]

- If FTRs are not fully firm, generators would face both price and volume risk which may lead to overall higher risk and costs.[77] The additional basis risk may outweigh the benefits from more efficient dispatch.[78]
- FTRs may not lower the cost of capital because FTRs are only available on a shorter timeframe than most asset lives. FTRs could be made available over the lifetime of the asset to reduce transmission risk across the project and lower the cost of capital.[79] Otherwise, incumbents may continue to face the risk of new entrants as new entrants can bid for FTRs resulting in higher losses, congestion, competition for FTRs, and costs for the incumbent.[80]
- The reform itself could create uncertainty as to how the risks of price and dispatch would be allocated between generators, retailers and financiers looking to commit to new generation projects.[81]

2.4.4. Benefits to competition

The AEMC expects that the implementation of the proposed access model will increase competition in the wholesale electricity market because:[82]

- Generators will be able to more effectively manage their risks through FTRs and will therefore offer more power into the contract market; and
- FTRs will allow for more inter-regional transmission hedges, which will improve cross regional risk management and competition.

In its discussion paper, the AEMC recognises that local marginal pricing behind transmission constraints may lead to smaller "sub markets" where market concentration is greater and therefore competition does not ensure efficient bidding behavior.[83] The AEMC considers that market power in sub markets would not occur often because a regional contract market will allow participants to mitigate operating risks and depress the incentives to exercise market power.[84] However, should the increased use of market power be identified as being likely in the assessment of the proposed access model, the AEMC will consider policies that could be used to mitigate market power at nodes.

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76 Stanwell (13 November 2019), 2019 COGATI: Response to AEMC COGATI Discussion Papers, p. 8.

77 Origin (8 November 2019), AEMC: Coordination of Generation and Transmission Investment Discussion Paper – Proposed Access Model, p. 6.

78 Snowy Hydro (8 November 2019), COGATI proposed access model Discussion paper, p. 1.

79 ENGIE (8 November 2019), COGATI Proposed Access Model – Discussion Paper EPR0073, p. 4.

80 Stanwell (13 November 2019), 2019 COGATI: Response to AEMC COGATI Discussion Papers, p. 8.

81 Meridian Energy Australia and Powershop Australia (8 November 2019), COGATI Proposed Access Model, p. 3.

82 AEMC (24 January 2020), Request for Proposal for Services.

83 AEMC (14 October 2019), COGATI Proposed Access Model, p. 44.

84 AEMC (14 October 2019), COGATI Proposed Access Model, p. 44.

Stakeholders also identify the risk of market power in sub markets created by LMP: When transmission constraints are binding, market power may emerge in sub markets whereby some participants may be able to influence the local price.[85] FTRs and hedging contracts may either enhance or mitigate market power.

Stakeholders argued that generators may contract less in the contract market in response to higher risk arising under the proposed access model. Consequently, generators may face more exposure to their local marginal price and any localised market power. Lower contracting volumes may disproportionately impact retailers who cannot rely on vertically-integrated generation portfolios.[86]

Stakeholders also identify the potential for market power in the FTR market. Market power and gaming in the FTR market may distort market outcomes. For example, if well-funded participants in unconstrained parts of the market bid for FTRs in more constrained parts of the market to prevent generators in those constrained areas from purchasing them.[87]

2.5. The Potential Impact on Contract Market Liquidity

In its discussion paper, the AEMC argues that access reform should improve contract market liquidity.[88] It argues that the introduction of FTRs may encourage generators to enter into more contracts across different regions of the NEM. Inter-regional contracting may improve liquidity in the contract market because:[89]

- Market participants in regional markets with relatively low levels of liquidity (for example South Australia) may contract in regions with relatively more liquid markets (for example New South Wales) with less risk; and
- Market participants may be able to contract with a greater number of counter-parties whilst obtaining more effective hedges to manage the risk of those contracts.

The AEMC argues that replacing the Settlements Residue Auction (SRAs) with FTRs should also improve contract market liquidity. Under the current system, generators may only purchase imperfect hedging instruments against the risk of congestion. SRAs provide a non-firm hedge against congestion because they include transmission losses and effects such as counter-price flows.[90] Consequently, to manage the risk of congestion and other risks, thermal generators only contract around 75 per cent of their expected output in the market.[91] Moreover, “generators and market customers are somewhat unwilling to enter into wholesale hedges where each counter-party is exposed to different regional prices”.[92]

85 AER (12 November 2019), Submission to Discussion Paper on the Proposed Access Model for the Coordination of Generation and Transmission Infrastructure, p. 3.

86 Alinta Energy (8 November 2019), Coordination of Generation and Transmission Investment Implementation – Access and Charging EPR0073, p. 6.

87 CEC (8 November 2019), Coordination of Generation and Transmission Investment Proposed Access Model (EPR0073) – Discussion Paper, p. 10.

88 AEMC (14 October 2019), COGATI Proposed Access Model, p. 17.

89 AEMC (14 October 2019), COGATI Proposed Access Model, p. 17.

90 AEMC (14 October 2019), COGATI Proposed Access Model, p. 53.

91 AEMC (14 October 2019), COGATI Proposed Access Model, p. 52.

92 AEMC (14 October 2019), COGATI Proposed Access Model, p. 53.

The AEMC argues that access to FTRs will encourage generators to contract more of their capacity into the forward market and improve contract market liquidity.[93] FTRs allow thermal generators to access any regional price regardless of whether they are physically dispatched. Hence, FTRs provide generators with a firmer hedging instrument against the risk of congestion.

On the other hand, the introduction of LMP for generators whilst maintaining regional pricing for suppliers and non-scheduled entities in the contract market introduces a basis risk between the price received by generators and the price at which contracts for power are settled. In the absence of hedging products, AEMO states that the introduction of basis risk will likely reduce contract market liquidity and may increase spot market volatility.[94]

The introduction of FTRs could provide a firmer hedging instrument by which generators could manage the introduction of basis risk. However, should the allocation of FTRs prohibit some generators from using the instrument to manage basis risk, overall liquidity in the contract market may fall as a result of the introduction of basis risk. On the other hand, volume risk in the market may rise under the current access model because of higher penetration of renewables and higher generation investment. Therefore, contract market liquidity may fall in the absence of the introduction of the proposed access model.

Whilst stakeholders broadly agreed that firm FTRs would increase liquidity under the proposed access model, they highlighted a number of risks that may result in higher costs and lower liquidity:

- If FTRs were not fully firm, then both price and volume risk would remain which could reduce contract market liquidity; [95]
- If generators were unable to access FTRs in the primary auction because of higher prices due to speculation from non-physical participants, [96] then liquidity may fall because physical participants would face higher basis risk.[97]
- Snowy Hydro states that “since the abolition of the Snowy node, Snowy Hydro have been able to offer additional contracting volume against the Victorian and NSW reference prices, providing market participants with hedging products aligned to their own retail exposure”.[98]
- There is uncertainty around how the FTR market would interact with existing obligations such as the Retailer Reliability Obligation and the associated Market Liquidity Obligation

93 AEMC (14 October 2019), COGATI Proposed Access Model, p. 53.

94 AEMO (8 November 2019), Coordination of Generation and Transmission Investment – Proposed Access Model Consultation Paper 2019, p. 2.

95 Origin (8 November 2019), AEMC: Coordination of Generation and Transmission Investment Discussion Paper – Proposed Access Model, p. 8.

96 AGL (13 November 2019), Coordination of Generation and Transmission Investment – Access Reform: Discussion Paper (EPR0073), p. 13.

97 EnergyAustralia, (8 November 2019) AEMC 2019, Co-ordination of Generation and Transmission Investment – Access Reform, Discussion Paper, p. 4. Stanwell (13 November 2019), 2019 COGATI: Response to AEMC COGATI Discussion Papers, p. 9.

98 Snowy Hydro (8 November 2019), COGATI proposed access model Discussion paper, p. 7-8.

(MLO).[99] In particular, an obligated party under the MLO may not purchase enough FTRs to cover its obligation to provide hedges under the MLO.[100]

2.6. Potential Distributional Impacts of the Reforms

Under the proposed access model, some of the revenue from the sale of FTRs will be redistributed to TNSPs to offset Transmission Use of Service (TUoS) charges paid by consumers. Consequently, there is a proposed redistribution of revenue from purchasers of FTRs (i.e. typically from scheduled market participants) to consumers.[101]

The AEMC argues that no particular generation technology is favoured or penalised under the reform because all generation technologies will face stronger incentives to locate where there are fewer transmission constraints.[102]

Stakeholder responses to the AEMC identified other potential consequences of the proposed access model that may result in distributional impacts:

- Larger implementation costs, particularly for the internal modelling and upskilling required to manage the FTR market, will particularly impact newer and smaller renewable generators who do not already have the expertise. [103]
- Higher costs for generators arising from the cost of purchasing FTRs or the management of higher basis risk will result in higher long run average costs of electricity that will be passed to customers. [104] The higher-long run average costs of electricity may be large enough to offset the reduction in TUoS in the proposed access model for consumers. [105]

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99 Hydro Tasmania (8 November 2019), Coordination of Generation and Transmission Investment – Access and charging (EPR0073), p. 4-5.

100 Stanwell (13 November 2019), 2019 COGATI: Response to AEMC COGATI Discussion Papers, p. 3.

101 AEMC (19 December 2019), COGATI Proposed Access Model - Update Paper, p. 10.

102 AEMC (19 December 2019), COGATI Proposed Access Model - Update Paper, p. 11-12.

103 CEC (8 November 2019), Coordination of Generation and Transmission Investment Proposed Access Model (EPR0073) – Discussion Paper, p. 8.

104 Snowy Hydro (8 November 2019), COGATI proposed access model Discussion paper, p. 8.

105 Stanwell (13 November 2019), 2019 COGATI: Response to AEMC COGATI Discussion Papers, p. 7.

3. Costs of Implementation

We have reviewed a total of ten jurisdictions where LMP and/or FTRs have been introduced, to identify the costs and benefits of reforms similar to the COGATI proposal. Through this case study review, we have found that only six of the ten jurisdictions considered had useful, transferable information on the implementation costs of LMP and/or FTRs.[106]

We set out these six jurisdictions and the associated implementation cost estimates in Table 3.1 below. We find that five North American jurisdictions (IESO, ERCOT, MISO, SPP and NYISO) and New Zealand had information available on the costs of implementing LMP and/or FTRs. Five of the six jurisdictions implemented (or are implementing) generator LMPs (of which three simultaneously introduced FTRs). These jurisdictions simultaneously implemented wider reforms in most cases. The implementation cost estimates (including wider reforms) from these five jurisdictions range from AUD 149 million to AUD 971 million in Net Present Value (NPV) terms. A study of the implementation of LMP and FTRs in IESO (Ontario) puts the implementation costs of reform at AUD 149 million – this is the only study we have identified that does not include the costs of a wider set of reforms than planned in Australia. In the sections that follow, we discuss the relevant CBAs and ex post studies in more detail and explain which studies we believe are most appropriate for estimating the expected costs from LMP in the NEM.

[106] For the other case studies, i.e. the California Independent System Operator (CAISO), the New England Independent System Operator (NE-ISO), the National Electricity Market of Singapore and the Pennsylvania-New Jersey-Maryland (PJM) marketplace, we have not identified any information on the implementation costs of LMP or FTRs.

Table 3.1: Case study implementation costs

	New Zealand		IESO (Ontario)			ERCOT (Texas)		MISO	SPP		NYISO
Study	EC (2010)	EA (2011)	**Market Reform (2015)**	Brattle (2017)	IESO (2019)	ERCOT, TCA and KEMA (2004)	CRA and Resero (2008)	FERC (2004)	CRA (2005)	Ventyx (2009)	Analysis Group (2007)
Generator LMP?	✗	✗	✓	✓	✓	✓	✓	✓	✓	✓	✓
FTRs?	✓	✓	✓	✗	✗	✓	✓	✓	✗	✓	✓
Other Reforms?	✗	✗	✗	✓	✓	✓	✓	✓	✓	✓	✓
Ex post/ex ante?	Ex Ante	Ex Ante	**Ex Ante**	Ex Ante	Partially ex post	Ex Ante	Partially ex post	Ex Ante	Ex Ante	Ex Ante	Ex Post
Market Size (TWh)	39	39	**135**	135	135	319	319	594	210	235	155
Price Base	2010	2011	**2013**	2019	2019	2003	2008	2004**	2005	2009	2006
Total Costs (NPV) (Local currency, million)	12.80	27.79	**133.30**	193.71	170.00	132.22	660.00	127.00*	212.40	212.50	133.10*
SO Cost	3.10	16.28	**50.70**		170.00	68.03	485.00		104.80		133.10
Market Participant Cost	9.70	11.51	**82.60**			64.19	175.00		107.60		N/A
Total Costs (NPV) (2019 AUD million)	12.00	24.68	**149.39**	209.99	184.29	293.30	971.42	245.74	387.48	328.05	347.72
SO Cost	2.91	14.46	**56.82**		184.29	150.92	713.85		191.18		235.47
Market Participant Cost	9.09	10.22	**92.57**			142.38	257.57		196.29		
SO Costs (%)	24%	59%	**38%**		100%	51%	73%		49%		100%

*Notes: We converted implementation costs from local currency to 2019 AUD by first converting from the local currency to AUD using the exchange rate that applied at the time, and then rolling forward the estimate to 2019 prices using Australian inflation data. *: For MISO any NYISO, figures reported are implementation cost estimates per annum. **: For MISO, the price year of cost estimation is unclear. We have assumed 2004 since this is the reporting year.*
Sources: Inflation data: Australian Bureau of Statistics, Exchange rate data: Reserve Bank of Australia.

3.1. Findings from Individual Case Studies

Below, we discuss our findings from each of the relevant case studies and draw conclusions for the expected implementation costs of LMP reforms and FTRs for the NEM. For comparability, we report cost estimates in 2019 Australian Dollars (AUD) for all case studies.[107]

3.1.1. IESO (Ontario)

IESO began work on reforms to introduce a nodal electricity market in 2016,[108] as part of its wider Market Renewal Program, which is expected to be implemented in 2023.[109] The reforms will not introduce FTRs as the IESO believes they are not needed because Ontario has no load-serving entities.[110]

We have reviewed three studies estimating the total implementation costs of LMP reform in IESO (see Table 3.1): (1) the 2015 Market Reform study (estimated costs of AUD 149 million), (2) the 2017 Brattle study (estimated costs of AUD 210 million); and (3) the 2019 IESO study (estimated costs of AUD 184 million). The latter two studies estimate the implementation costs of the fuller suite of planned energy market reforms, including the introduction of a day-ahead market and enhanced real-time unit commitment, but excluding the costs of introducing FTRs, given IESO's decision that FTRs are not required in Ontario. By contrast, the earlier 2015 Market Reform study estimates the effect of both LMP and FTRs, but does not include the costs of the other elements of the planned reform.[111] Therefore, the most relevant estimate for the planned COGATI reforms in the NEM of the expected implementation costs of LMP and FTRs in Ontario is AUD 149 million, based on the estimates in the 2015 Market Reform study.[112]

The Market Reform study estimates that 38 per cent of this cost is borne by the System Operator (SO), whilst 62 per cent will is borne by market participants. Converting Market Reform's findings to AUD, we find that, out of the total costs of reform of AUD 149 million,

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107 We convert implementation costs from local currency to 2019 Australian Dollars (AUD) by first converting from the local currency to AUD using the exchange rate that applied at the time, and then rolling forward the estimate to 2019 prices using Australian inflation data.

108 IESO (22 October 2019), Market Renewal Program: Energy Stream Business Case, p.9.

109 IESO Website: Market Renewal. URL: http://www.ieso.ca/en/Market-Renewal. Visited on 30 January 2020.

110 IESO (August 2019), Day-Ahead Market: High-Level Design, p.52.

In the United States, load-serving entities (LSEs) are power suppliers that take power at particular locations to serve their customers. If an LSE wants to contract with a generator for power at a different location, or if it itself owns generation that it wants to use to serve its customers, then it may purchase FTRs, which give financial assurance that it can contract for that power (or assume delivery from its own resources). LSEs in the United States are often vertically integrated utility companies.

By contrast, we understand that Ontario is unique amongst other markets in North America in that IESO, the system operator, is the only load-serving entity (LSE) in the market in practice: it is the only purchaser of power in the wholesale market and it in turn sells electricity to all retailers.

See: Ontario Energy Association (16 September 2019), Utility Remuneration and Responding to DERs, p. 3.

111 We understand that the decision not to introduce FTRs was made after the 2015 Market Reform study. Market Reform (February 2015), The Energy Market Pricing System Review: Presentation of Results and Conclusions, p 4.

112 Market Reform (February 2015), The Energy Market Pricing System Review: Presentation of Results and Conclusions, p 34-35.

the costs of implementing an FTR market are approximately AUD 16.5 million, of which AUD 6.7 million is borne by the SO and AUD 9.8 million is borne by market participants.

It is not clear if the AUD 149 million implementation cost estimate from the 2015 Market Reform Study includes any incremental operating costs post-implementation. The 2019 IESO Study estimates incremental ongoing costs post-implementation costs to be about AUD 6.5 million in the first ten years following the implementation of the reform (for a wider set of reforms than planned in the NEM, but without FTRs). This suggests that even if the ongoing costs of operating a market with LMP are higher than the costs of operating a zonal market, these incremental ongoing costs are low, relative to the one-off implementation costs.

3.1.2. ERCOT (Texas)

ERCOT moved from zonal to nodal pricing in December 2010.[113] The reform in ERCOT included elements beyond the introduction of generator LMP and FTRs, including a move from portfolio bidding to resource-specific bidding, a move from 15-minute to 5-minute dispatch intervals, the implementation of a day-ahead market, and changes in the way the SO manages congestion.[114] In other words, the reform in ERCOT was broader in scope than the reform proposed in the NEM, thus increasing implementation costs relative to what would be expected in the NEM. By contrast, costs of the reform may be higher in the NEM than suggested by the ERCOT experience, because inter-zonal FTRs already existed in ERCOT before the implementation of the reform, and hence market participants (and the SO) had some prior experience in FTR markets.[115] This is not the case in Australia, although non-firm SRAs substitute, to an extent, for the lack of inter-zonal FTRs.

Two ex ante studies estimate the implementation costs of the market reform in ERCOT:

1. The 2004 CBA, by TCA and KEMA, estimates the costs of implementation prior to implementation; and
2. The 2008 CBA, by CRA and Resero, estimates implementation costs mid-way through implementation.

The 2008 CBA estimates significantly higher implementation costs than the 2004 CBA, with the estimate of total implementation costs increasing by about AUD 678 million from AUD 293 million to AUD 971 million (almost half of which had already been incurred).[116] The study attributed the cost escalation to the greater complexity of the nodal market than anticipated in 2004 and to delays in implementation.[117] Originally, the nodal market was scheduled for implementation in 2006, four years earlier than actual completion.[118]

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113 NWRED (2011), Mapping of selected market with Nodal pricing or similar systems, p.39.

114 Daneshi and Srivastava (2011), ERCOT Electricity Market: Transition from Zonal to Nodal Market Operation, p.6.

115 Daneshi and Srivastava (2011), ERCOT Electricity Market: Transition from Zonal to Nodal Market Operation, p 2.

116 In addition to these costs, the 2008 CBA estimates additional incremental operating costs post-implementation of (operating a nodal as opposed to a zonal market) of approximately USD 14 million per annum (in 2008 prices, or of approx. AUD 21 million per annum).

CRA and Resero Consulting (18 December 2008), Update on the ERCOT Nodal Market Cost-Benefit Analysis, p 12.

117 CRA and Resero Consulting (18 December 2008), Update on the ERCOT Nodal Market Cost-Benefit Analysis, p 11, 42 and 57.

118 Electric Utility Comission (May, 2011), Texas Nodal Market Implementation, p 3.

The 2008 ERCOT CBA is the only study we have identified through our case study review that included any ex post estimate of implementation costs: it estimated that the costs incurred to date in implementing the reform amounted to AUD 455 million. Due to this cost escalation, it is not clear that the ERCOT reform would have been NPV positive, after considering the total costs of implementation (including costs already incurred) and the expected benefits from implementation over a ten-year period.
The 2008 ERCOT CBA also provides evidence of the differences in implementation costs for market participants with no prior nodal market experience and market participants with prior nodal market experience. Specifically, the study finds that:

1. The average cost of the ERCOT reforms to a market participant without prior nodal market experience is USD 673,469 (or USD 2,796 per MW of capacity, in 2008 prices); and
2. The average cost of the ERCOT reforms to a market participant with prior nodal experience is USD 51,563 (or USD 225 per MW of capacity, in 2008 prices).[119]

This analysis suggests that the costs of the reform to market participants with no nodal market experience is about 12.5 times the cost that market participants with nodal experience expect to incur. This suggests that market participants in the NEM may incur significantly higher implementation costs than in other jurisdictions, given the likely lack of experience of (most) market participants in markets with LMP.

3.1.3. MISO

MISO introduced LMP upon establishing the Midwest Energy Markets in April 2005.[120] Reforms were broader than introducing LMP and FTRs and included creating a centralised, formal wholesale market out of many local mainly bilateral markets and introduced day-ahead and real-time markets.[121] FERC quotes estimated annual implementation and operating costs of the market of AUD 246 million in 2004.[122] However, calculations involved in determining this figure are not transparent. Given the lack of traceability, and wide scope of the MISO reform, we do not consider this estimate to be relevant to the expected implementation costs of the planned reform in the NEM.

3.1.4. SPP

SPP first implemented GNP in 2007 upon the introduction of the Energy Imbalance System (EIS) market.[123] The EIS market constituted the SPP's first real-time market and involved a move away from a bilateral model.[124] FTRs did not exist under the EIS regime. A 2005

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119 These same market participants costs may not apply in the NEM, because the cost to each market participants may depend on the scale and operations of the given market participants. Very small market participants may be able to avoid or reduce the costs associated with the reforms by merging with other market participants or outsourcing relevant functions (e.g. FTR purchases) to larger participants or other parties.

120 MISO Website: Timeline. URL: http://timeline.misomatters.org/. Visited on 3 February 2020.

121 MISO Website, Timeline, URL: http://timeline.misomatters.org/. Visited: 3 February 2020.

122 It is not clear over what period the annual cost estimates apply. See: FERC (16 September 2004), 108 FERC 61,236, p.18.

123 Brattle (April 2017), The Future of Ontario's Electricity Market, p 30.

124 Brattle (April 2017), The Future of Ontario's Electricity Market, p 29,31.

study estimated implementation costs of around AUD 387 million (Table 3.1). Since the estimate pertains to a broader reform but without FTRs, we do not consider this estimate to be particularly relevant to the planned Australian reform.

SPP ultimately implemented FTRs in 2014 as part of a broad reform which also introduced a day-ahead market (DAM), centralised unit commitment and an ancillary services market. A CBA estimated the costs of these reforms. Benefit estimates from this study are largely irrelevant due to the earlier introduction of nodal pricing and the wider scope of reforms (than just FTRs).

However, the study provided a detailed estimate of the costs of implementing FTRs per market participant (see Table 3.2), described as hedging implementation costs.[125]

Table 3.2: Costs of Implementing Congestion Hedging (2009 USD thousand / participant)

Participant	System Costs						Personnel Costs	
	Initial Install Costs		SPP Change Case Adaptation Costs		Ongoing Costs		(Training, testing, etc.)	
	Small	*Large*	*Small*	*Large*	*Small*	*Large*	*Small*	*Large*
Simple	100	200	0	100	5	25	175	350
Complex	100	200	0	100	25	35	175	350

Note: A simple participant is defined as having only hydro and/or nuclear generation with straightforward Power Purchase Agreement (PPA); a complex participant is defined as having coal, gas, and/or wind generation with compound PPA (i.e., a unit that does not run all hours it is available, or at full capacity all hours that it does run).
Source: Ventyx (7 April 2009), Southwest Power Pool: Cost Benefit Study for Future Market Design, Appendix D

However, it is not clear how these cost estimates were used in the study to estimate total implementation costs (e.g. it is not clear which costs are one-off expenses and which are incurred annually as a result of the introduction of FTRs).[126] Assuming for simplicity that all costs are one-off expenditures, and based on the 23 market participants in SPP at the time of the reform, we find that implementation costs for market participants only from FTRs could range from AUD 10 million to AUD 24 million.[127]

[125] Ventyx (7 April 2009), Southwest Power Pool: Cost Benefit Study for Future Market Design, Appendix D

[126] For instance, some personnel costs may be one-off, while others may be ongoing.

[127] AEMO (January 2018), National Electricity Market Fact Sheet, p 1. Note: We assume that the average market participant's costs are the average of a simple and complex market participant's costs. These same market participants costs may not apply to each market participant in the NEM, because the cost to each market participants will depend on the scale and complexity of operations of the given market participant. Very small market participants (e.g. small generators) may be able to avoid or reduce the costs associated with the introduction of FTRs by merging with other market participants or outsourcing relevant functions (e.g. FTR purchases) or associated risks to larger participants or other parties (e.g. by adjusting their contracting practices).

3.1.5. NYISO

NYISO began operating a nodal electricity market with FTRs in November 1999.[128] An ex post assessment carried out by Analysis Group in 2007 reported annual implementation costs of AUD 235 million in 2006.[129] The NYISO reforms were broader than those proposed for Australia, and included the introduction of the first competitive wholesale market in New York.[130] However, these implementation cost estimates do not account for the costs incurred by market participants. Given the very broad nature of the reforms in New York, we do not consider these cost estimates to be relevant to the proposed COGATI reforms in the NEM.

3.1.6. New Zealand

New Zealand introduced FTRs in 2013, and two CBAs (from 2010 and 2011) estimate the implementation costs of this reform:[131]

1. The 2010 CBA estimated implementation costs of AUD 12.0 million; and
2. The 2011 CBA estimated implementation costs of AUD 24.7 million (about 106% higher than the 2010 cost estimates).[132]

At the time of the CBAs, New Zealand planned to introduce FTRs only for a single inter-island link. Therefore, these implementation cost estimates likely understate the expected costs of implementing FTRs in the NEM.[133]

3.2. Conclusions on Implementation Costs for the NEM

We have reviewed the evidence available on the costs of implementing LMP in six jurisdictions. We find that there is little evidence on implementation costs that is relevant to Australia, because:

- Many of the reforms we have looked at are significantly broader in scope than the proposed reform in Australia, which involves the introduction of generator LMP and FTRs, as well as the move to dynamic marginal loss factors;
- Some of the reforms we have reviewed covered only the costs of implementing LMP (amongst the costs of other reform elements), and did not cover the costs of FTRs, or vice versa;

128 Frontier (April 2008), Generator Nodal Pricing – a review of theory and practical application, p 42.

129 It is not clear over what period the annual cost estimates apply.

130 FERC (2010) 2010 ISO RTO Metrics Report Appendix G, p 197.

131 The New Zealand market began trading in 1996 with full nodal pricing. We have not identified any cost estimates associated with this reform.

132 Energy Market Services (2018), FTR Allocation Plan 2018, 2018, p A6.

133 The 2010 CBA considered three alternative reforms: (1) the introduction of the single inter-island FTR; and (2) two more complex reforms, which included the introduction of additional FTRs. For comparison with the 2011 CBA which only considered cost of the single inter-island FTR, we site the cost estimate for the inter-island FTR option from the 2010 CBA above. The 2010 CBA estimates higher implementation costs for alternative reform options of an “extended FTR” (AUD 17.3 million) and an “augmented FTR” (AUD 21 million).

- Much of the evidence available is outdated, and it is not clear that any cost estimates from the 2000s, or even the first half of the 2010s are relevant, given potential fast changes in relevant price indices (such as changes in IT systems costs).

Given the above observations, we find that the best available evidence on the likely cost of the planned reform in the NEM comes from the 2015 Market Reform study for Ontario. This study specifically estimated the costs of implementing generator LMP and FTRs in Ontario (without any further reform elements). Except for the later Ontario studies that estimated the costs of a wider set of reforms and did not include the costs of implementing FTRs, the 2015 Market Reform study is by far the most recent study available of implementation costs: all other studies of LMP reform date back to the 2000s.[134] The Market Reform study found that the costs of implementing generator LMP and FTRs in Ontario will amount to AUD 149 million. Therefore, our best estimate of the expected implementation costs of LMP and FTRs in the NEM are AUD 149 million.

We consider that there is upward risk around this cost estimate for the NEM, for the following reasons:

- There is evidence from some jurisdictions (ERCOT and New Zealand) of an escalation in implementation costs, i.e. that expected costs will grow over time. In ERCOT, estimates of total implementation costs for a broader set of reforms quadrupled over a 4-year period (from the 2004 CBA to the 2008 CBA, in real USD terms), partly due to the higher-than-expected complexity of reforms and partly due to a four-year delay in implementation. In New Zealand, the estimated costs of introducing FTRs approximately doubled in the 2011 study, relative to a 2010 study. This suggests that the costs of similar reforms may exceed initial estimates, although the timely implementation of reforms may reduce the risk of overruns;[135]
- Evidence from a 2009 study for SPP and a 2011 study for New Zealand suggests that the 2015 Market Reform may underestimate the costs of implementing FTRs. This is true even though New Zealand initially introduced FTRs for the single constraint (the inter-island link);
- The expected costs of implementing FTRs may be higher in Australia than in Ontario, because FTRs already exist to hedge price differentials between Ontario and its neighbouring markets. Hence, both the system operator and market participants seeking to hedge against price differences between Ontario and other electricity markets already have experience with FTRs in Ontario, decreasing costs relative to the NEM where the AEMO and market participants do not have experience with FTRs;
- The implementation cost estimate of AUD 149 million from the 2015 Market Study for Ontario does not include any costs associated with the implementation of dynamic

[134] There are two cost-benefit analyses for New Zealand from 2010 and 2011, however, these considered FTRs exclusively (i.e. not nodal pricing reform).

[135] We have not identified any studies that provide figures of actually incurred implementation costs, as opposed to pre-implementation estimates of costs from cost-benefit analyses. Hence, we do not have information on whether actual total implementation costs exceeded initial estimates for any of the jurisdictions, except for Texas, where the already incurred implementation costs reported in the 2008 CBA exceeded the total estimated implementation costs in the 2004 CBA. (There is ex post evidence available for the NYISO reform, however, this reform was much broader than simply the introduction of nodal pricing and included the creation of a competitive wholesale market in NY.

marginal loss factors, which is a potential element of the planned reforms in the NEM, but not in Ontario.

We have considered whether there may be a need to scale the 2015 Market Reform study estimate of implementation costs of AUD 149 million for the specific circumstances of the NEM. For instance, the electricity market in Ontario (135 TWh of generation in 2019) is smaller than the NEM (196 TWh). However, there is no clear economic rationale to scale implementation costs based on the size of an electricity market (or any other variable).

We therefore conclude that the best available evidence from our case study review, the 2015 Market Study for Ontario, suggests that the costs of the introduction LMP of FTRs in the NEM will amount to AUD 149 million. We consider that this is best used as a lower bound estimate of the expected implementation costs of LMP in Australia, because (1) it may underestimate the costs of introducing FTRs, given FTR implementation cost estimates in other jurisdictions and given AEMO's and Australian market participants' lack of experience with FTRs; and (2) because there is a significant risk of cost escalation as evidenced by cost-benefit analyses in other jurisdictions.[136] A bottom-up quantification of implementation costs will be required to produce a more accurate estimate of the expected implementation costs of LMP and FTRs in the NEM.

[136] Note also that the IESO-based implementation cost estimate does not include the costs of moving to dynamic marginal loss factors, which is an additional reform element under consideration in the NEM. If this reform is implemented alongside LMP, the implementation costs of the reform will increase.

4. Efficient Dispatch Benefits of Locational Marginal Pricing

Through our case study review, we have found that there is range of evidence available on the benefits from more efficient dispatch, but little evidence available on the other benefits of LMP, such as the capital cost savings from the improved generation, storage and transmission investment decisions that may result from the clear price signals of LMP. Benefits from more efficient dispatch arise because LMP pricing eliminates generators' incentives to manipulate their bids to maximise their chances of being dispatched during periods of expected congestion ("race to the floor bidding") or to bid unavailable in areas where the local value of electricity exceeds the regional reference price. Accordingly, LMP allows the system operator to dispatch the lowest-cost plant on the system to meet system load.

We discuss the evidence on the benefits from more efficient dispatch in this Section and discuss other benefits (i.e. cost of capital savings and potential benefits from increased competition) in Section 5. The rest of this section is structured as follows:

- Section 4.1 summarises the findings on efficient dispatch benefits from our review of case study evidence;
- Section 4.2 sets out our estimates of expected benefits in the NEM from more efficient dispatch of generation resources due to the introduction of LMP, based on the case study evidence;
- Section 4.3 reviews the evidence available on the benefits from moving to dynamic marginal loss factors, and estimates the expected benefits from introducing dynamic marginal loss factors in the NEM;
- Section 4.4 sets out the challenges to applying the estimated benefits from more efficient dispatch to the NEM; and
- Section 4.5 summarises our findings on the expected benefits from more efficient dispatch in Australia.

4.1. Overview of International Case Studies

We have reviewed a total of ten jurisdictions where LMP and/or FTRs have been introduced, to identify the costs and benefits of reforms similar to the COGATI proposal. Through this case study review, we have found that only five of the ten jurisdictions considered had useful, transferable information on the efficiency benefits of LMP:

1. The Electric Reliability Council of Texas (ERCOT) moved from a zonal market configuration to LMP for generators in December 2010.[137] After the reform, load in ERCOT paid the regional VWAP.[138] Along with the introduction of LMP for generators and Congestion Revenue Rights (CRRs, i.e. FTRs), ERCOT also implemented other reforms, including (1) the move to 5-minute dispatch intervals from 15-minute dispatch intervals; (2) unit-specific bidding for generators (versus the previous system of portfolio-

137 Potomac Economics (August 2011), 2010 State of the Market Report for the ERCOT Wholesale Electricity Markets, p. i.

138 CRA and Resero Consulting (18 December 2008), Update on the ERCOT Nodal Market Cost-Benefit Analysis, p.3-4.

bidding); (3) the introduction of a day-ahead market.[139] Two studies estimate the social benefits of the introduction of LMP in ERCOT: a 2004 CBA (by TCA and KEMA) and a 2008 CBA (by CRA and Resero).[140] Both of these ex ante studies estimate social benefits (i.e. efficiency gains) from more efficient generator dispatch under LMP, including the efficiency gains realised from better generator siting.[141]

2. The California Independent System Operator (CAISO) introduced LMP for generators in April 2009, as part of its reform package, the "Market Redesign and Technology Upgrade".[142] After the reform, load continued to pay a zonal price, determined on the basis of the zonal VWAP. CAISO also introduced CRRs (i.e. FTRs) along with LMP, and operated an integrated day-ahead forward market and real-time imbalance market after the reform.[143] We have not identified any ex ante CBAs of the CAISO reform. However, Wolak's 2011 article estimates the reduction in the variable costs of gas-fired generators in California due to the reform. This paper therefore provides an estimate of the efficient dispatch benefits of the introduction of LMP, assessed post-implementation.[144]

3. The Midcontinent Independent System Operator (MISO) introduced LMP for generation in April 2005, alongside a much wider market reform that (1) created a single, centrally dispatched market covering the whole MISO region out of many local, mostly bilateral markets, (2) introduced day-ahead and real-time markets; and (3) introduced FTRs.[145] Before the introduction of LMP, MISO managed congestion by requesting local re-dispatch from local balancing authorities.[146] Several studies estimate the benefits of the MISO reform, including an ex-ante MISO study from 2005, an ex-post 2007 study (by ICF) that estimates realised benefits based on data for less than a year, and an ex-post 2009 study (by Brattle) that estimates the fall in the variable costs of a constant set of generators due to the reform, over a longer time horizon.[147]

4. The Southwest Power Pool (SPP) introduced its real-time Energy Imbalance Market (EIS) with LMP for generators in 2007.[148] SPP introduced FTRs much later in 2014 as

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139 ERCOT, TCA and KEMA (30 November 2004), Market Restructuring Cost-Benefit Analysis, p. 2-1.

140 ERCOT, TCA and KEMA (30 November 2004), Market Restructuring Cost-Benefit Analysis; CRA and Resero Consulting (18 December 2008), Update on the ERCOT Nodal Market Cost-Benefit Analysis

141 I.e. benefit estimates from the Texas studies include the benefits realised from lower fuel and variable O&M costs as a result of better generator siting decisions. They do not cover the savings from lower capital costs that may also result from more efficient generator investment decisions. We discuss these benefits separately in Section 5.1.

142 Ziad Alaywan, Tong Wu, and Alex Papalexopoulos (2004), Transitioning the California Market from a Zonal to a Nodal Framework: An Operational Perspective, p. 1; CAISO (15 December 2010), Appendix C – Locational Marginal Pricing.

143 Frank Wolak (2011), Measuring the Benefits of Greater Spatial Granularity in Short-Term Pricing in Wholesale Electricity Markets, p. 247.

144 Frank Wolak (2011), Measuring the Benefits of Greater Spatial Granularity in Short-Term Pricing in Wholesale Electricity Markets

145 MISO Website: Timeline. URL: http://timeline.misomatters.org/. Visited on 3 February 2020.

146 ICF (28 February 2007), Independent Assessment of Midwest ISO Operational Benefits, pp.25-28.

147 See: (1) MISO (25 June 2004), Testimony of Dr McNamara before the FERC; (2) ICF (28 February 2007), Independent Assessment of Midwest ISO Operational Benefits; (3) Brattle (1 October 2009), Generation Cost Savings from Day 1 and Day 2 RTO Market Designs.

148 Brattle (April 2017), The Future of Ontario's Electricity Market, p 30.

part of the "Integrated Market" reforms (which included, e.g. the integration of 16 local balancing authorities into a centralised balancing authority, and the introduction of integrated day-ahead and real-time markets).[149] A 2005 ex ante study (by CRA) estimates the efficiency benefits from LMP using electricity market modelling.[150] The study assumes that benefits accrue from two sources: (1) more efficient congestion management processes under LMP (as congestion was previously managed conservatively in SPP); and (2) more efficient dispatch under LMP, due to the elimination of priority access to the transmission network for some plants.[151]

5. Ontario's Independent Electricity System Operator (IESO) is due to implement LMP for generators in 2023.[152] After the reform, load will continue to be settled at the province-wide price. The IESO does not plan to introduce FTRs in Ontario, given that Ontario has no load-serving entities, however the reform has additional elements beyond the implementation of LMP, including introduction of a day-ahead market and enhanced real-time unit commitment.[153] A 2017 CBA (by Brattle) estimates the expected social benefits (i.e. efficiency savings) from the planned reform, relying on evidence on benefits realized in other jurisdictions.[154] In other words, the 2017 CBA for IESO attempts to estimate the expected benefits of introducing LMP based on evidence from other jurisdictions, similar to this report.

The other five further jurisdictions we have reviewed as part of our case study review (New Zealand, the New York Independent System Operator (NYISO), the New England Independent System Operator (NE-ISO), the National Electricity Market of Singapore (NEMS) and Pennsylvania-Jersey-Maryland (PJM) market) did not have any useful evidence available on the benefits of LMP. We discuss our findings for these jurisdictions in more detail in Appendix A.

Table 4.1 below sets out the jurisdictions and studies (CBAs and ex post assessments) that we consider provide useful, transferable information on the benefits from more efficient dispatch. We find that information is available on the benefits from more efficient generation dispatch from five jurisdictions, all from North America, that have introduced or are in the process of introducing LMP for generators. We have identified evidence on the benefits of LMP from four ex ante CBAs that estimate benefits using electricity market modelling or a benefits transfer approach, and two ex post studies that estimate benefits based the econometric analysis of actual, historical data. The benefit estimates from these jurisdictions range from about 0.6% to about 2.6% of the variable costs of generation, or from AUD 0.27 per MWh to AUD 0.85 per MWh of load. Most of these studies only estimate the benefits from the more efficient dispatch of the same set of generators (due to LMP), and do not assess the benefits that accrue from more efficient generator siting, except for the ERCOT CBAs.

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149 SPP (May 2014), 2013 State of the Market, p 12; SPP (September 2012), Introduction to Integrated Marketplace, p 23., 21-22.

150 CRA (April 2005), Southwest Power Pool Cost-Benefit Analysis

151 CRA (April 2005), Southwest Power Pool Cost-Benefit Analysis, p. 3-2, 3-3.

152 IESO Website: Market Renewal. URL: http://www.ieso.ca/en/Market-Renewal. Visited on 30 January 2020.

153 IESO (22 October 2019), Market Renewal Program: Energy Stream Business Case, p.9.

154 Brattle, (20 April 2017), A benefits case assessment of the Market Renewal Project, p.38.

In the sections that follow, we: (1) discuss the relevant CBAs and ex post studies in more detail; (2) set out our approach to estimating the expected benefits from LMP in the NEM, based on the evidence identified; and (3) discuss the challenges to assuming that these benefits apply to the NEM, given differences between the NEM and these five comparator markets, differences in the reforms planned in the NEM and the reforms implemented in other jurisdictions, and differences in the benefits quantified by each of the studies relied upon.

Table 4.1: Case Study Review - Benefits of Locational Marginal Pricing

Market	ERCOT	CAISO	MISO	SPP	IESO
Time of reform	2010	2009	2005	2007	2023 (Planned)
Size of market	319 TWh (2010)	207 TWh (2009)	595 TWh (2006)	210 TWh (2007)	143 TWh (2021)
LMP for generation	✓	✓	✓	✓	✓
Relevant studies	2004 CBA (TCA, KEMA) 2008 CBA (CRA, Resero)	Wolak, 2011	Brattle, 2009	2005 CBA (CRA)	Brattle, 2017
Ex ante vs. ex post	Ex ante	Ex post	Ex post	Ex ante	Ex ante
Estimated benefits (per annum)	USD 76.3 m. (2003) USD 73.6 m. (2008)	USD 105 m (2010)	USD 172 m. (2007)	Not reported	CAD 84 m. (2021)
Benefits as a % of variable costs of generation	**1.05% (2004 CBA) 0.60% (2008 CBA)**	**2.1%**	**2.61%**	**2%**	**Not reported**
Benefits per MWh (2019 AUD) (NERA Analysis)	**AUD 0.27 to 0.53 per MWh**	**AUD 0.55 to 0.85 per MWh**	**AUD 0.34 to 0.51 per MWh**	**-**	**AUD 0.62 per MWh**
Benefits from more efficient dispatch	✓	✓	✓	✓	✓
Efficient dispatch benefits from efficient generator siting	✓	✗	✗	✗	✗

Sources: Various, based on NERA Analysis.

Notes: Further studies are available for MISO that estimate the social benefits of reform, including an ex ante study by MISO and an ex post study by ICF. We report the 2009 Brattle study only in the table above, because we consider that this has the best, most recent ex post estimate of the benefits of reform. (The ICF study only estimates the benefits of the reform based on data from June 2005 to March 2006, i.e. based on less than a year of data after the introduction of the reform.) Further studies are also available for IESO, however, these estimate the benefits to consumers and not the social benefits of reform. The 2008 ERCOT CBA does not explicitly report the annual benefit estimate of USD 73.6 million; we estimate this based on the NPV benefit estimate figures reported. The size of market is measured based on load, except for CAISO where generation data was available. Note that the benefits per MWh estimate (reported in 2019 AUD) is based on NERA analysis discussed in Section 4.3.

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4.2. Estimating Benefits from More Efficient Dispatch in Australia Based on International Case Studies

4.2.1. Introduction to “benefits transfer” – studies relied upon

We use six studies from the five jurisdictions (ERCOT, CAISO, MISO, SPP and IESO) to estimate the expected efficiency benefits from introducing LMP in Australia. We summarise these studies (including the methods used and the benefits quantified) in Appendix B.

Most of these studies have reported headline benefit estimates in USD terms (either as benefits in USD per annum, or as the Net Present Value (NPV) benefits in USD). These benefit figures, whilst interesting in and of themselves for the contexts in question, may not reflect the benefits from more efficient dispatch that are likely to occur in Australia following the introduction of LMP. For instance, the markets cited are larger on both a capacity and volume basis (except for IESO), have a different generation mix and costs, suffer from a differing degree of congestion before the reform and because both the access arrangements before and after the reform are likely to differ.

It is challenging to control for congestion between markets due to lack of consistent data and for differences between access arrangements which are codified in different sets of regulatory rules. The total variable costs of generation provide a measure which allows us to control for both scale and generation mix. The benefits from more efficient dispatch are primarily the reduced fuel costs and variable operating and maintenance costs resulting from using a more efficient combination of plant to meet system needs. All of the aforementioned studies, except for the IESO study, cite the benefits from more efficient dispatch as a proportion of the total variable costs of the system.

Hence, one approach we follow to estimate expected benefits in the NEM based on the experience used in other jurisdictions is to apply the estimated percentage reduction in total variable costs (from the given jurisdiction) to estimated total variable costs in the NEM in 2018/19. This provides a simple and transparent basis for the transfer of benefits to Australian conditions. Relying on the proportion of variable costs to estimate the benefits from more efficient dispatch also removes some of the subjective methodological choices that introduce variation in figures expressed as a Net Present Value for society, such as the choice of the discount rate and the length of the modelling period.

As an alternative to the above approach, we also estimate benefits for Australia using the annual USD benefit estimates figures from the case studies, scaling benefits only to account for differences in the size of the comparator market at the time of the reform (as measured by consumption in TWh) and the NEM in 2018/19.

Hence, we estimate the social benefits from efficient dispatch that may apply in the NEM based on the experience in other jurisdictions as discussed above, using two “benefits transfer” approaches. Both approaches assume that the planned COGATI reforms in the NEM have a similar impact on the efficiency of dispatch as experienced in other jurisdictions that have introduced similar reforms. We discuss both these approaches in more detail and our estimated benefits for Australia below. (We discuss reasons that the benefits realised in the NEM may be higher or lower than our estimates in Section 4.4 below).

4.2.2. Estimating benefits as a percentage of total variable costs in the NEM

We estimate the expected benefits from efficient generation dispatch in the NEM based on (1) the percentage variable cost reductions estimated in the five studies identified (see Table 4.1 and Table B.1); and (2) based on the variable costs of generation in the NEM in 2018/19 (defined as the sum of fuel costs and variable O&M costs).[155] We discuss our approach in more detail in Appendix A, and present our benefit estimates for the NEM in Table 4.2 below.

Table 4.2: Estimated Benefits from More Efficient Dispatch in the NEM
Reduction in Variable Generation Costs from LMP

Market	Source	% Benefit	Reduction in	Annual Benefit in the NEM (in 2019 AUD million)
ERCOT	TCA and KEMA (2004 CBA)	1.05%	Variable costs of generation	**52.71**
ERCOT	CRA and Resero (2008 CBA)	0.60%	Variable costs of generation	**30.12**
CAISO	Wolak (2011)	2.10%	Variable costs of gas generation (proxied by thermal generation in NEM)	**101.96**
MISO	Brattle (2009)	2.61%	Fuel costs of generation	**109.06**
SPP	CRA (2005)	2.00%	Variable costs of generation	**100.40**
Average				**78.85**

Source: NERA Analysis, based on studies listed.
Notes: The benefit estimates for the ERCOT studies include the estimated benefits from the more efficient siting of generators (through lower cost dispatch). The other studies do not include any benefits from more efficient generator siting. For the ERCOT and SPP studies, we apply the % variable cost reduction figure to our estimate of the variable costs of production in the NEM (i.e. the sum of fuel and variable O&M costs). For CAISO, we apply the 2.1% cost reduction figure to the variable costs of thermal generators, following Wolak's approach (who estimates savings for gas plants only, which comprise 70% of thermal generation in CAISO). For MISO, we apply the 2.61% savings estimate to estimated fuel costs in 2018/19 in the NEM, following the approach of the 2009 Brattle study (which estimates fuel cost savings).

We estimate that the annual benefits from more efficient dispatch range between AUD 30 million and AUD 109 million across the NEM, depending on the source of the percentage benefit figure applied (i.e. the jurisdiction and study relied upon). The average annual benefit from more efficient dispatch in the NEM is AUD 79 million per annum, or AUD 0.40 per MWh.

Our estimates of efficiency benefits (of between AUD 30 million and AUD 109 million per annum) may underestimate the actual annual cost savings resulting from more efficient dispatch, due to the following methodological choices:

155 Our approach accounts for both fuel costs and variable O&M costs but does not account for start-up costs or environmental/emissions costs.

1. The average fuel costs and variable O&M costs for specific technologies are likely understated in our analysis. We discuss this further in Appendix C;

2. Further, as explained in Appendix C, we use total power consumption in 2018/19 in the NEM to estimate the total variable costs of production (as opposed to using data on the total amount of power generated), due to data availability constraints. Consumption is slightly lower than power generation, hence our estimates slightly understate the true level of benefits;

We convert annual efficiency benefit estimates to Net Present Value terms (discounted to 2019 mid-year values), assuming that benefits are realised for 10 and 20 years, using a real discount rate of 7 per cent following the Australian Government's February 2016 Guidance Note on Cost-Benefit Analyses.[156] We assume that annual benefits are realised over a ten-year period as a conservative scenario, based on assumptions used in cost-benefit analyses in other jurisdictions (e.g. the ERCOT CBAs and the 2005 CBA for SPP). In practice, we expect that the benefits from more efficient dispatch would continue to be realised after the first ten years following the reform. We have therefore also estimated an "upper bound" estimate of the benefits from more efficient dispatch, discounting annual benefits over a period of 20 years.[157]

Table 4.3: Estimated Benefits from More Efficient Dispatch in the NEM
Reduction in Variable Generation Costs in NPV terms (in AUD million, 2019 prices)

Case	Annual Benefit	10-year NPV	20-year NPV
Low	30.12	226.36	341.43
Average	78.85	592.58	893.82
High	109.06	819.63	1236.29

Source: NERA Analysis

The NPV of the benefits from more efficient generation dispatch falls between AUD 226 million and AUD 819 million (assuming benefits are realised for ten years), and between AUD 341 million and AUD 1.2 billion (assuming benefits are realised for twenty years). Using the average annual benefit estimate of AUD 78.9 million, we estimate an NPV benefits figure of AUD 0.6 billion (10-year NPV) and AUD 0.9 billon (20-year NPV).

4.2.3. Estimating benefits by scaling for differences in market volume

We also estimate the expected benefits from more efficient dispatch under LMP in the NEM following a different approach, which converts reported annual benefits (in USD terms) from our case studies to the NEM, based on the ratio of total consumption in the comparator market at the time of the reform to total consumption in the NEM in 2018/19. This approach assumes that the NEM will experience similar annual levels of benefits in USD per MWh of load, as other markets that have implemented (or are planning to implement) similar reforms.

[156] This is consistent with the Office of Best Practice Regulation's (OBPR's) requirements. See: Australian Government (February 2016), Guidance Note: Cost-Benefit Analysis, p. 7.

[157] Our 10 and 20-year NPV estimates assume that the benefits remain constant in real terms, at the level we estimate for the NEM for 2018/19. This is a significant simplification, as the total variable costs of generation are not expected to remain constant in the NEM over time, e.g. due to (1) the retirement of relatively low cost coal plants over time; and (2) the expected further expansion of solar and wind generation capacity.

For this benefits transfer approach, we use the same case studies as above except that we additionally estimate benefits based on the IESO 2017 study (by Brattle), which estimates annual benefits in USD terms but does not estimate the percentage reduction in the total variable costs of generation. We do not estimate benefits based on the 2005 SPP study under this alternative approach, because this study does not report the social benefits of the reform in USD terms.

As benefit estimates are reported in a price base from the time of the study, and in USD (or Canadian Dollar (CAD) in the case of the IESO study), we convert these estimates to Australian Dollars (AUD) and 2019 prices following a number of alternative approaches:

A. We convert benefits from USD/CAD to AUD, and then inflate figures using general inflation in Australia to 2019 prices;

B. We inflate benefits in the local currency (USD/CAD) to 2019 prices (based on general inflation in the local market), and then convert to AUD using the current exchange rate.

C. We convert benefits using the current exchange rate, and do not account for inflation;

D. We convert benefits using the exchange rate from the time of the reform, and do not account for inflation.

Our rationale for estimating benefits based on all four methods is that: (1) there is no single "correct" approach to changing the currency and price base of a reported benefits estimate; (2) while it is theoretically appropriate to control for inflation, fuel prices (the key component of variable generation costs, to which these benefits relate) do not follow general inflation; and (3) we do not have access to any price indices that would accurately capture inflation in the variable costs of generation. Estimating a range of benefits for the NEM using the four approaches above ensures that our estimates are robust to the treatment of inflation and currency conversion. We present our range of benefit estimates based on this alternative approach in Table 4.3.

We estimate that the annual benefits from more efficient dispatch range from AUD 65 million to AUD 137 million in the NEM, depending on the comparator market relied upon. The method for currency conversion and inflation adjustment has a significant impact on the results: the difference between the highest and lowest estimate for each jurisdiction is about 50%. The average annual benefit from more efficient dispatch in the NEM is AUD 98 million per annum, or AUD 0.50 per MWh.

Table 4.4: Estimated Benefits from More Efficient Dispatch in the NEM
Estimates Benefits Based on Per MWh Benefits Transfer

Market	Source	Market Size (TWh)	Annual Benefit (million)	Range of Annual Benefits in the NEM (AUD million)	Average Annual Benefits in the NEM (AUD million)
ERCOT	TCA and KEMA (2004 CBA)	319	USD 76.3 (2003 prices)	**67.4 to 104.0**	**84.1**
ERCOT	CRA and Resero (2008 CBA)	319	USD 73.6 (2008 prices)	**53.1 to 77.1**	**65.4**
CAISO	Wolak (2011)	207	USD 105 (2010 prices)	**108.7 to 167.4**	**136.9**
MISO	Brattle (2009)	595	USD 172 (2007 prices)	**67.2 to 100.4**	**84.2**
IESO	Brattle (2017)	143	CAD 84 (2021 prices)	**120.9**	**120.9**
Average					**98.3**

Source: NERA Analysis. Note: To scale benefits, we use the size of the comparator market at the time the reform was implemented (or is planned to be implemented). This may differ from the market size that was assumed in the given ex ante study (e.g. 2004 ERCOT CBA), due to delays in the implementation of the reform.

Table 4.5 summarises our estimate of benefits from efficient dispatch on an NPV basis, assuming that annual benefits remain constant in real terms for a period of ten-years (10-year NPV) and a period of twenty-years (20-year NPV).

Table 4.5: Estimated Benefits from More Efficient Dispatch in the NEM
Reduction in Variable Generation Costs in NPV terms

Case	Annual Benefit	10-year NPV	20-year NPV
Low	65.4	491.7	741.6
Average	98.3	738.8	1,114.4
High	136.9	1,029.2	1,552.4

Source: NERA Analysis

4.2.4. Summary of Efficient Dispatch Benefit Estimates for Australia

Table 4.6 below presents our benefits estimates for the NEM based on our two benefits transfer approaches. Benefit estimates from the two approaches are of similar magnitude, however, on average, benefits estimates are higher when scaling for differences in the relative sizes of markets than when estimating benefits based on the percentage reduction in total variable costs. We consider that the percentage benefits transfer approach may produce more accurate results, since, unlike the alternative approach, it controls for differences in the relative costs of generation (in the different markets), on which any efficient dispatch benefits are realised. Nonetheless, we recognise that additional differences in the reforms and comparators markets, such as differences in the generation mix (and the relative marginal costs of different peak and mid-merit generation technologies), differences in access arrangements, and differences in the levels of congestion across the markets all affect the applicability of these benefit estimates to the NEM. We discuss the reasons that benefits in the NEM may be higher or lower than our estimates in Section 4.4.

Table 4.6: Summary of Estimated Benefits from Efficient Dispatch

Market	Source	Percentage Benefits Transfer (Scaling for Variable Costs) – Annual Benefit (AUD million)	Per MWh Benefits Transfer (Scaling for Market Size)– Average Annual Benefit (AUD million)
ERCOT	TCA and KEMA (2004 CBA)	**52.7**	**84.1**
ERCOT	CRA and Resero (2008 CBA)	**30.1**	**65.4**
CAISO	Wolak (2011)	**102.0**	**136.9**
MISO	Brattle (2009)	**109.1**	**84.2**
SPP	CRA (2005)	**100.4**	**-**
IESO	Brattle (2017)		**120.9**
Average		**78.9**	**98.3**

Source: NERA analysis

4.3. Benefits from the Introduction of Dynamic Marginal Loss Factors

Above, we have reviewed the evidence available on the benefits from the introduction of LMP. However, we understand that as part of the COGATI reforms, the AEMC is also considering a move to dynamic marginal loss factors (from static marginal loss factors). We have reviewed the evidence available on the benefits of this reform, as we explain below.

Most jurisdictions that we examine already implement dynamic marginal loss factors alongside LMP. We summarise the loss factors used across the jurisdictions that we examine in Table 4.7 below.

Table 4.7: Summary of Dynamic Marginal Loss Factors Across Jurisdictions

		Update Frequency	
ISO	**Used in Dispatch**	*DAM*	*RTM*
CAISO	✓	Hourly	Five Mins
ERCOT	×	NA	NA
ISO-NE	✓	Hourly	Five Mins
MISO	✓	Minutes	Minutes
NYISO	✓	Between DAM and RTM clearing	
PJM	✓	Hourly	Five Mins
SPP	✓	Hourly	Five Mins

Source: NERA Analysis of Brent Eldridge, Richard O'Neill and Anya Castillo (24 January 2017), Marginal Loss Calculations for the DCOPF.

Across the jurisdictions we examine, we could not find any CBAs or ex post studies assessing the transition from marginal loss factors to dynamic marginal loss factors. ERCOT is the only jurisdiction that we examine that does not already implement dynamic marginal loss factors and instead compensates for losses on a "system-wide average basis".[158] We understand that ERCOT was planning to transition to dynamic marginal loss factors but in January 2019 the Public Utility Commission of Texas ruled against the inclusion of losses.[159] It states that it does "do not believe that the incremental benefit of applying marginal losses in the ERCOT market is worth the implementation cost and market disruption".[160]

The only relevant study we have identified that assess the benefits of a reform to transmission loss factors is a CBA for ERCOT, which assesses the benefits of a move from average loss factors to dynamic marginal loss factors.

4.3.1. Cost-benefit analysis of the transition to dynamic marginal loss factors in ERCOT

ERCOT currently does not use loss factors in its dispatch of the system in any given settlement period. Losses are instead added back in the settlement process and are based on "linear interpolation or extrapolation of forecasted on-peak and off-peak transmission loss factors".[161] Consequently, ERCOT could expect benefits from more efficient dispatch of plant should it use dynamic marginal loss factors as part of system dispatch.

ERCOT estimates that the transition from average loss factors to dynamic marginal loss factors will result in a reduction in annual production costs of USD 11.4 million (or 0.12 per cent of total production costs) due to more efficient dispatch to meet load. The reduction in annual production costs stems from reduced total load of approximately 1,000 GWh per year

158 ERCOT (29 June 2018), Study of the System Benefits of Including Marginal Losses in Security-Constrained Economic Dispatch, p. 1.

159 Public Utility Commission of Texas (16 January 2019), Memorandum RE Open Meeting of January 17 2019.

160 Public Utility Commission of Texas (16 January 2019), Memorandum RE Open Meeting of January 17 2019, p. 3.

161 Brent Eldridge, Richard O'Neill and Anya Castillo (24 January 2017), Marginal Loss Calculations for the DCOPF, p. 4.

(or 0.25 per cent of total load).[162] To estimate the reduction in annual production costs, ERCOT uses energy market modelling. In the first scenario, it models the market using the current system of dispatch (average loss factors). In the second scenario, ERCOT dispatches the system under dynamic marginal loss factors. It compares the differences between the outputs of the two scenarios to estimate the benefits of dynamic marginal loss factors.[163]

4.3.2. Benefits transfer approach to estimate savings from the implementation of dynamic marginal loss factors in the NEM

We apply ERCOT's estimate for savings in annual production costs to our estimate of annual production costs in the NEM, that we calculate using the methodology set out in Appendix C.

Table 4.8: Estimate of Production Cost Savings from Dynamic Marginal Loss Factors

Market	Cost Reduction	Savings
ERCOT	0.12 per cent	USD 11.4 million
NEM	0.12 per cent	AUD 5.9 million

Source: NERA Analysis.

Our analysis suggests that the implementation of dynamic marginal loss factors would result in an annual saving of AUD 5.9 million. However, our estimate is likely to be an overstatement of the efficiency savings resulting from the introduction of dynamic marginal loss factors in the NEM because the NEM already implements marginal loss factors albeit on a static annual basis. Therefore, whilst we understand that ERCOT is proposing to move from average system-wide loss factors to dynamic marginal loss factors, the NEM is proposing the relatively smaller change to move from static marginal loss factors to dynamic marginal loss factors. Consequently, the changes to the dispatch pattern in ERCOT are likely to result in higher cost savings than the changes to the dispatch pattern in the NEM.

A quantitative modelling of the NEM and the potential reform of marginal loss factors is required to more accurately assess the expected benefit of introducing dynamic marginal loss factors in the NEM.

4.4. Challenges for Application to Australia

In the sections above, we estimated the expected benefits of LMP based on two simple approaches that the assumed that the benefits from LMP in the NEM will be equal to benefits realised from similar reforms in other jurisdictions, defined as a percentage reduction of variable generation costs (under one approach) and the annual USD saving per MWh of load (under the alternative approach). These efficiency benefit figures vary widely across our case study jurisdictions: e.g., from an annual efficiency saving of 0.6% of variable costs (i.e. fuel and O&M costs) to an annual efficiency saving of 2.6% of the fuel costs of generation. Beyond identifying a set of studies that introduced generator LMP, similar to the planned

162 ERCOT (29 June 2018), Study of the System Benefits of Including Marginal Losses in Security-Constrained Economic Dispatch, p. 2.

163 ERCOT (29 June 2018), Study of the System Benefits of Including Marginal Losses in Security-Constrained Economic Dispatch, p. 1.

COGATI reforms in the NEM, we have not in the previous sections of this report considered to what extent these efficiency benefit estimates might apply in the NEM, given:

1. Differences in conditions between the current NEM and the given jurisdiction at the time of the reform, such as the differences in the frequency of congestion or differences in the share of renewables;

2. Differences in the reform packages implemented (e.g. were a wider set of reforms implemented in the other jurisdictions that could have also led to efficient dispatch benefits);

3. Differences in how electricity markets operated before the reform in the jurisdictions considered and in the NEM.

These aspects of the markets / reforms are important to understanding whether the percentage benefits estimated/realised from a similar reform in the given jurisdiction are likely to under- or overestimate the expected benefits from the COGATI reform proposal in the NEM. This section attempts to provide a qualitative assessment of this, i.e. we qualitatively assess whether each estimate is expected to under- or overestimate benefits in Australia.

For this assessment, it is important to understand for each of the "comparator markets" in our benefits transfer analysis: (1) how the market operated in the given jurisdiction before the reform; (2) what the reforms introduced at the time entailed; and (3) what benefits are included within the given benefits estimate figure for the given jurisdictions. We present our understanding of the above features of each reform and the associated benefit estimates in Appendix D.

Below, we qualitatively assess whether the efficiency benefit estimates from LMP (and the move to dynamic marginal loss factors) recorded in other jurisdictions are likely to under- or overstate the benefits from introducing LMP in Australia, for the following reasons:

1. Differences in access arrangements for generators;

2. Differences in the efficiency of congestion management processes;

3. Differences in the benefits included in the given study;

4. Differences in the level of congestion;

5. Differences in the generation mix.[164]

4.4.1. The NEM lacks firm generator access, unlike many comparator jurisdictions

In theory, as long as generators are paid compensatory out-of-merit (OOM) payments when they are constrained on or off the system due to local congestion, the same generators should

[164] We consider all jurisdictions we have relied upon except Ontario, because the Ontario benefits estimate is based on benefit estimates from other comparator jurisdictions in the US (i.e. its not a "primary" estimate but is itself based on benefit estimates from other jurisdictions). Therefore, the specific market arrangements in Ontario are irrelevant to the whether the benefit estimate for Ontario under- or overestimates expected benefits in the NEM.

be dispatched under both zonal and nodal pricing.[165] Hence, assuming that generators had firm access to the transmission network prior to the reforms, and methods to redispatch plant are efficient, there should be no benefits from increased dispatch efficiency from the adoption of zonal pricing (as dispatch should already be efficient given out-of-merit payments). In theory therefore, efficient dispatch benefits from the move to LMP only arise in markets without firm access for generators, such as the NEM.[166] We have discussed in Section 2 the economic theory behind the benefits expected from introducing LMP in the NEM, from the elimination of strategic bidding behaviour (such as race to the floor bidding and bidding unavailable), as explained in the AEMC's October 2019 Discussion Paper.

In practice, there may be efficiency benefits from the adoption of LMP as a result of inefficiencies in the bidding and dispatch processes even in the presence of firm access. For instance, the system operator may redispatch plant using a balancing market in real time after units have already committed capacity in anticipation of generation. In such circumstances, the system operator may need to ensure that units that would not have committed in a nodal market recover their unit commitment costs, at least over the long term.

In any case, in the NEM, given the lack of generator's firm access to the transmission network, and the resulting "race to the floor bidding", there are additional efficiency savings to be had from the move to LMP than in a market that has firm access.

Most of the jurisdictions we have relied upon for our "benefits transfer" analyses offered (prior to the reforms) some form of compensation for generators constrained on or off the network due to local congestion:

- ERCOT paid out-of-merit payments to generators constrained on/off the system (called OOM Up or Down payments). OOM Down payments compensate generators that are constrained off from the system by paying them the difference between the market price and marginal cost of production (based on generators' bids). OOM Up payments compensate generators that are constrained on by paying them the difference between their marginal cost and (the lower) market price (in addition to the market price for the power produced).[167] Generators in Texas had firm access to the network before the introduction of LMP in 2010, due to the OOM Up and Down payments.

- CAISO also paid out of merit payments to generators, similar to ERCOT. As Wolak (2011) explains, "a supplier that had to move up relative to its day-ahead schedule would be paid as offered for the additional energy and a supplier that had to move down would buy back this energy as offered. Suppliers quickly figured out when their generation units were likely to be called "out of merit order" in a zone to provide more or less energy and would alter their supply offers to take advantage of that fact. This led to the implementation of mechanisms that paid or charged these suppliers regulated prices to manage what was called intrazonal congestion".[168] Hence, CAISO also offered some sort

165 As we also explain in Section 6, this does not mean that there would be no wealth transfers from the adoption of nodal pricing in a zonal pricing market with firm network access.

166 In practice, the adoption of LMP ensures firm access to the network, as congestion will be reflected in the network through LMPs.

167 ERCOT, TCA and KEMA (30 November 2004), Market Restructuring Cost-Benefit Analysis, p. 3-26.

168 Frank Wolak (2011), Measuring the Benefits of Greater Spatial Granularity in Short-Term Pricing in Wholesale Electricity Markets, p. 247.

of compensation for generators constrained on/off the network (although not based on bids but based on regulated prices).

- MISO and SPP were both in an earlier stage of development at the time LMP was introduced than ERCOT or CAISO:
  - Before the wide-ranging 2005 reform, which created a centralised, formal wholesale market, MISO was served by 35 control areas each with its own local dispatch, and its electricity market was bilateral and dominated by vertically integrated utilities.[169] We have not found information on access rules / out-of-merit payments in MISO before the 2005 reform.[170] However, generators in MISO could purchase physical transmission rights (of varying levels of firmness) which provided a guarantee of transmission network access similar to out-of-merit payments.
  - We understand that SPP's market before the reform did not guarantee firm access to generators. Resources designated as "network resources" for serving native load were given priority access to the transmission system in times of scarcity, which would necessarily introduce some inefficiency in dispatch.[171] However, like generators in MISO, generators in SPP could also purchase physical transmission rights and therefore at least some generators had firm access to the transmission system prior to the reform.

Due to the lack of firm access currently, the NEM would be likely to experience higher benefits from efficient dispatch than other jurisdictions (such as ERCOT and CAISO) that guaranteed firm access to generators – all else equal.

4.4.2. The management of congestion was sub-optimal in many US markets before the introduction of LMP

Many of the comparator markets we have relied upon for our analysis did not manage congestion efficiently before LMP:

- Prior to LMP, "virtually all of the congestion management for Midwest ISO transmission facilities was accomplished by invoking the TLR [*Transmission Line-Loading Relief*] procedures".[172] "The TLR process is a much less efficient and less controllable means to reduce the flow over a given transmission facility than economically redispatching generation in the area".[173] In essence, congestion management was less efficient under the TLR process than under LMP because the TLR process in effect enforced transmission constraints that were lower than the physical transmission constraints on the network. For this reason, dispatch was less efficient before the reform was introduced.

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169 MISO Website: Timeline. URL: http://timeline.misomatters.org/. Visited on 3 February 2020; MISO (25 June 2004), Testimony of Dr McNamara before the FERC, Docket ER04-691-000, p.5.

170 It is therefore possible that the different dispatch areas associated with MISO's current footprint had different arrangements in place, with dispatch areas with and without firm access.

171 CRA (April 2005), Southwest Power Pool Cost-Benefit Analysis, p. 3-3.

172 Potomac Economics (July 2006), 2005 State of the Market Report – The Midwest ISO, p.59.

173 Potomac Economics (July 2006), 2005 State of the Market Report – The Midwest ISO, p.59.

- Congestion management also followed the TLR process in SPP before LMP reform in 2007. The 2005 cost-benefit analysis, which estimates a 2% reduction in the variable costs of generation from LMP, assumes in its Base Case electricity market modelling that “transfer limits on all flowgates in the SPP region were decreased by 10% to reflect the inefficiency of congestion management through the TLR process [*relative to transfer limits in the LMP scenario*]. The 10% figure was determined in consultation with SPP based on historical tie-line flows during TLR events. Because of uncertainty in exactly which units will be redispatched under a TLR call, and because of the time lag inherent in this process, it is difficult to achieve full system utilization when congestion is managed through the TLR process”.[174] In other words, the cost-benefit analyses explicitly imposed sub-optimal congestion management in the base case modelling, on advice from SPP.
- ERCOT did not follow TLR processes before the introduction of LMP, but also followed an inefficient congestion management process based on “average shift factors”. Specifically, before LMP, ERCOT managed the system conservatively through the use of transmission line operational limits, assuming that each generator within a zone has an equal effect, relative to other generators in their zone, on flows on the zonal boundaries (i.e. based on “average shift factors”).[175] By contrast, under the nodal case (i.e. under LMP), each element of the transmission system is treated explicitly due to locational marginal pricing.
- We have not been able to identify the congestion management arrangements that were in place in CAISO before the introduction of LMP in 2009.

In comparison to these markets (SPP, MISO and ERCOT), congestion management already occurs optimally in the NEM, in the sense that the dispatch engine dispatches in a least cost manner, given bids. Specifically, we understand that AEMO fully utilises constraints when congestion occurs in the NEM, and does not manage the system more conservatively now than it would under LMP. In other words, congestion management is not sub-optimal in the NEM, and inefficiency in dispatch is the result of generator bidding behaviour (race to the floor bidding), and not inefficiencies in AEMO’s management of congestion. For this reason, benefit estimates based on US experience may overestimate the level of benefits from LMP reform in the NEM.

4.4.3. Only the ERCOT studies capture the benefits from efficient generator siting

Dispatch may be more efficient under LMP for two reasons: (1) out of the same set of plants, lower marginal cost plants generate more frequently; and (2) due to more efficient generator siting (i.e. better located new plants), the average variable cost of generation falls in the market. LMP may have additional benefits through the more efficient siting decisions of generators, such as lower capital costs of new generation investments. We discuss this separately in Section 5.1.

Out of all the studies we have relied upon for our benefits transfer analysis for the NEM, only the two ERCOT studies capture the impact of the benefits from more efficient dispatch from better generator siting decisions. All other studies exclusively capture the efficient dispatch

[174] CRA (April 2005), Southwest Power Pool Cost-Benefit Analysis, p. 3-3.

[175] ERCOT, TCA and KEMA (30 November 2004), Market Restructuring Cost-Benefit Analysis, p. VIII.

benefits realised from the more efficient deployment of existing plants. Hence, except for the ERCOT studies, all other studies underestimate the total social benefits from LMP (from more efficient generation dispatch).

The 2008 ERCOT CBA estimates that the benefits from the more efficient dispatch of existing plants is USD 339 million in NPV terms, while it estimates that total efficient dispatch benefits (including from better generator siting decisions) amount to USD 520 million (in NPV terms, 2008 prices).[176] Hence, this study estimates that accounting for generator siting benefits increases the estimate of benefits from more efficient dispatch by about 53%.

Because the CAISO, MISO and SPP efficiency benefit estimates do not include the impact of better generation siting on the variable production costs of generation, estimates based on these studies tend to understate the expected level of benefits from LMP reform in the NEM.

4.4.4. The level of congestion in the market drives benefits

In a hypothetical market where transmission constraints never bind (due to excess transmission capacity), the benefits from introducing LMP will be zero, as there will be no price deviation between zonal and nodal prices (and market outcomes will be exactly the same).[177] Hence, the level of congestion seen in a market has a significant impact on the efficiency benefits from LMP. The level of congestion also impacts the benefits from the move to dynamic marginal loss factors, given that loss factors are especially high at times of congestion (i.e. when lines are fully utilized).

ERCOT provides a good example of the impact of congestion on benefits from introducing LMP. As explained above, two CBAs estimate the benefits of LMP reform in ERCOT, the first in 2004 and the second in 2008. The 2004 CBA estimates a 1.05% reduction in variable generation costs, and the second CBA estimates a reduction of only 0.6%. During the period between the two case studies, transmission owners in ERCOT “invested over $2.8 billion in upgrading the ERCOT high voltage transmission infrastructure by adding over 3000 miles of in new high voltage transmission lines and over 30,300 MVA in new transformer capacity”.[178] The reduction in the benefits from efficient dispatch may partly be due to the increase in transmission capacity, and the resulting reduction in the levels of congestion seen in ERCOT.

However, we have found no evidence that allows for a clear comparison of the levels of congestion experienced in the NEM and our comparator jurisdictions. It is therefore not clear if current levels of congestion in the NEM are higher or lower than the levels of congestion experienced in ERCOT, CAISO, MISO and SPP at the time of LMP reform.

4.4.5. Variation in the generation mix across jurisdictions also impacts efficiency benefits

Differences in the generation mix in different jurisdictions also have an impact on expected efficiency benefits. For instance, in a hypothetical scenario where a single generation

176 CRA and Resero Consulting (18 December 2008), Update on the ERCOT Nodal Market Cost-Benefit Analysis, p. 33.

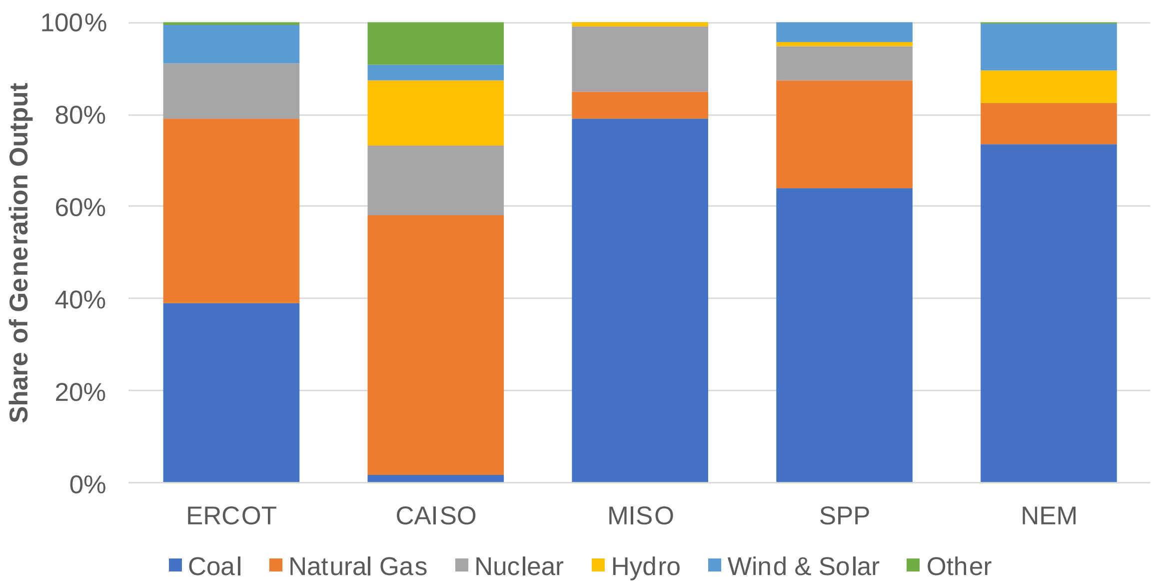
177 This ignores transmission losses and any other constraints (such as system strength).

178 CRA and Resero Consulting (18 December 2008), Update on the ERCOT Nodal Market Cost-Benefit Analysis, p. 29.

technology (with a uniform marginal cost across all plants) operates in a jurisdiction, no benefits could arise from more efficient dispatch, because it is not possible to substitute higher-cost generation with lower-cost generation. More broadly, if the supply curve in a given jurisdiction is steeper, i.e., if marginal cost differentials between different plants (and different technologies) are relatively large, then the expected benefits from more efficient generation dispatch (due to LMP) are also larger. By contrast, we would expect lower efficiency benefits if there is little variation in the marginal costs of different plants (i.e. if the supply curve is relatively flat). Benefits from efficient dispatch depend not just on the steepness of the supply curve, but also where on supply curve this steepness occurs. Because congestion and hence price divergence occurs when demand is high, steepness at higher demand levels matters much more than the steepness of the demand curve at low levels of demand.

Figure 4.1 below presents the generation mix of our comparator jurisdictions at the time of the introduction of LMP, as well as the generation mix in the NEM in 2019. The structure of generation varies widely across these jurisdictions. The NEM's generation mix is most similar to MISO and SPP, due to the large share of coal in the mix, suggesting that experience from these jurisdictions may be most relevant to the NEM. Nonetheless, the NEM differs from these markets in that (1) it has no nuclear generation; and (2) has a substantially higher share of intermittent renewables than either MISO or SPP at the time of LMP reform. Further, the NEM's generation mix is likely to change substantially in the medium term, with the share of intermittent renewable generators increasing over time. These changes will again impact the expected benefits from more efficient dispatch in the NEM.

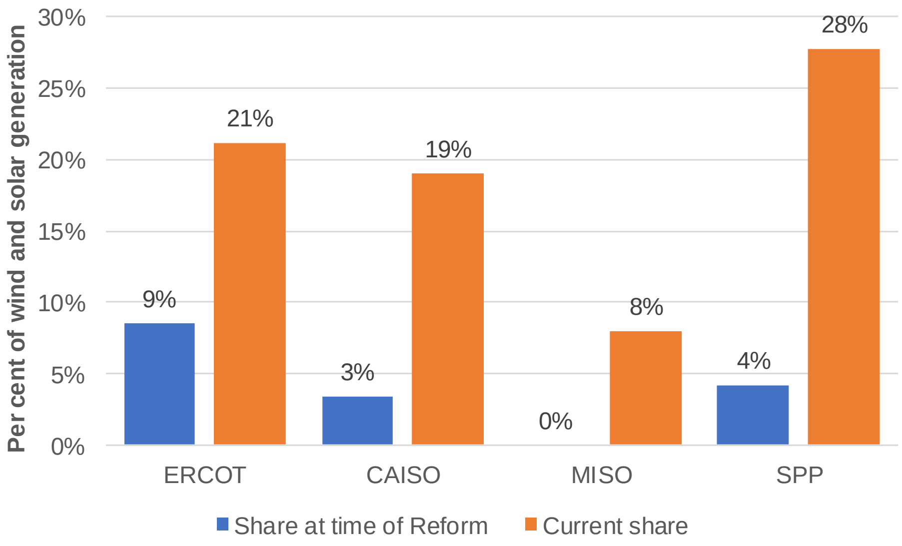
Figure 4.1: Generation Mix at Case Study Jurisdictions at the Time of LMP Reform
Share of Generation Output



Source: NERA Analysis

We understand from the AEMC that stakeholders have voiced their concern about the timing of the proposed reform, arguing that experience from other jurisdictions may not be relevant as the NEM is, at the moment, going through an energy transition. We understand that stakeholders are concerned that LMP may discourage further investment in solar and wind generation in the NEM. However, evidence from other markets suggest that the share of intermittent renewables has increased fast in markets that have introduced LMP (see Figure 4.2 below). Hence, we see no evidence that the introduction of LMP should deter efficient solar or wind investment in the NEM.[179]

Figure 4.2: The Share of Solar and Wind Generation Has Increased in Markets with LMP



Source: NERA analysis

In addition to the generation mix, the geographic distribution of plants also matters to the efficiency benefits from LMP. For instance, two jurisdictions may have similar levels of congestion and reasonably similar supply curves, but also have differences in the geographical distribution of generators such that (1) in one jurisdiction high-priced generators are on the low demand side of the constraint, (2) in the other jurisdiction, the same high-priced generators are on the high demand side of the constraint. Benefits from more efficient dispatch would be higher under jurisdiction (2), because there would be no difference in locational marginal prices under jurisdiction (1) (as both the high and low demand nodes would have the high LMP).

179 One difference between the proposed reforms in the NEM and the reforms implemented in other markets is that in the NEM, under the AEMC's current proposals, solar and wind generators will receive the regional price, whereas in all our comparator markets, intermittent renewable generation technologies receive the LMP. There are limited efficient dispatch benefits from the introduction of LMP for intermittent solar and wind generation, given that these zero marginal cost technologies are expected to generate under both nodal and zonal pricing, when available. However, benefits could arise from better siting of intermittent generators under zonal pricing (and the associated efficient dispatch benefits). We expect these benefits to be lower in the NEM than in our comparator markets, because in the NEM, intermittent renewable generators have limited incentives to locate efficiently in the network, since they can expect to receive the zonal price under the current proposals (as long as they are dispatched). Benefits could therefore be higher in the NEM if LMP applied to all generators, not just to dispatchable generation.

Differences in the generation mix similarly impact efficient dispatch benefits from the move to dynamic marginal loss factors, in addition to benefits from the introduction of LMP.

4.5. Summary of Findings

The table below presents our qualitative conclusions on whether each case study (i.e. each percentage efficiency benefit estimate) is likely to under- or overestimate the benefits of LMP from more efficient generation dispatch.[180]

Table 4.9: Summary Table of Benefits Estimates for Australia

Aspect	ERCOT	CAISO	MISO	SPP	IESO
% benefit estimate	0.6%-1.05%	2.10%	2.61%	2%	
Annual benefit – NEM (AUDm) - % of variable costs approach	30.1 to 52.7	102.0	109.1	100.4	
Annual benefit – NEM (AUDm) – volume-based scaling approach	65.4 to 84.1	136.9	84.2		120.9
Firm Access / OOM payments	▲	▲	▲	-	▲
Sub-optimal congestion mgmt.	▼	?	▼	▼	▼
Generator siting benefits	-	▲	▲	▲	▲
Level of congestion	?	?	?	?	?
Generation mix	?	?	?	?	?

Source: NERA Analysis. Note: A green triangle indicates that the benefits estimate for the NEM should be increased to account for differences between the NEM and the comparator market/reform. By contrast, a red triangle indicates that benefit estimates for the NEM should be reduced. A question mark indicates that it is not clear based on our qualitative analysis whether the benefit estimate for the NEM should be increased or decreased to account for differences between the NEM and the comparator market/reform.

Broadly, we find that:

- Benefit estimates from our US comparators markets tend to underestimate the expected benefits from efficient dispatch for the NEM, because, unlike generators in the NEM, generators in US markets had firm access to the transmission network in some form before the introduction of LMP;

- Benefits estimates based on US comparators tend to overestimate the level of benefits from LMP in the NEM, because US jurisdictions, unlike the NEM, had sub-optimal congestion management processes in place before the introduction of LMP, which reduced the utilisation of network constraints and therefore increased the inefficiency of generation dispatch;

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180 The IESO study estimates the benefits of LMP in Ontario based on evidence from other jurisdictions (CAISO, MISO and SPP). We have therefore not specifically reviewed market arrangements in Ontario in Section 4.4, but instead assumed in Table 4.9 below the same directional impact for the IESO estimate for each market/reform feature (e.g. firm access) as for the CAISO, MISO and SPP markets.

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- Most US estimates understate the total level of benefits realised from the more efficient dispatch of generation resources, because they only include the benefits that accrue from the same group of generators being dispatched more efficiently, and do not account for the lower dispatch costs that result from more efficient generator siting under LMP.
- It is unclear whether differences between the level of congestion and the generation mix in the NEM and comparator markets lead to us under- or overestimating benefits in the NEM through our benefits transfer approach.

In summary, we find that the efficient dispatch benefit estimates for similar reforms in comparator markets range from 0.6% to 2.6% of the total variable costs of generation, or from AUD 0.27/MWh to AUD 0.85/MWh (see Table 4.1). Assuming that these estimates apply to the proposed COGATI reform in the NEM, we find that the annual benefits from more efficient dispatch fall between AUD 30 million and AUD 137 million per annum, based on the modelled total variable costs of generation in the NEM in 2019.

However, various differences between the US markets and the NEM limit the applicability of benefit estimates from the US to the NEM. Most importantly:

1. Generators in most US markets had firm access (of some form) to the transmission network before the introduction of LMP. This reduces the benefits from LMP, because, ignoring distortions in generators' optimal bidding behaviour and assuming firm transmission access, the same generators should be dispatched with and without LMP. This finding suggests that US-based estimates likely understate the true level of efficiency benefits to be expected in the NEM, where generators do not have firm network access;

2. Further, most US-based estimates fail to account for the benefits from more efficient generator siting under LMP that can be realised through more efficient dispatch. This again suggests that the US-based estimates we have used in our benefits transfer may understate the true level of expected efficiency benefits in the NEM;

3. However, most US markets had sub-optimal congestion management processes in place before the introduction of LMP, unlike the NEM. These sub-optimal congestion management processes led to a lower utilisation of constraints and inefficient dispatch outcomes. In itself, this difference between US markets and the NEM suggests that US-based estimates overstate the true level of efficiency benefits in the NEM, given that these same benefits, from adopting efficient congestion management processes, do not exist in the NEM.

It is not clear therefore whether the range of benefit estimates for the NEM of AUD 30 to 137 million per annum under- or over-states the true level of benefits from efficient generation dispatch expected in the NEM from LMP. A detailed modelling of the electricity market in the NEM is required to estimate expected benefits more accurately. This modelling needs to control for the specific characteristics of the NEM (power plants, generation mix, level of congestion, etc.) as well as important aspects of the proposed COGATI reform (e.g. that it will eliminate race to the floor bidding).

In addition to the benefits from LMP, we have also reviewed evidence on the benefits from the move to dynamic marginal loss factors in other jurisdictions. We have identified a single study of the benefits of dynamic marginal loss factors for ERCOT. This suggests that the benefits in the NEM from adopting dynamic marginal loss factors could amount to AUD 5.9

million a year. However, this provides an upper bound estimate of likely benefits in the NEM, because the NEM is proposing a smaller change to loss factors than ERCOT.[181] Various characteristics of the market, such as the levels of congestion and the generation mix have an impact on expected benefits from the move to dynamic marginal loss factors. Hence, a detailed modelling of the electricity market in the NEM is required also to estimate the expected benefits of this reform more accurately.

[181] ERCOT is planning a move from average system-wide loss factors to dynamic marginal loss factors, whereas the planned reform in the NEM involves a smaller change to move from static marginal loss factors to dynamic marginal loss factors.

5. Other Benefits of Locational Marginal Pricing and Financial Transmission Rights

In Section 4 above, we set out the evidence available on benefits from more efficient dispatch from LMP and estimated the expected benefit of introducing LMP in the NEM. As discussed in Section 3 however, the introduction of LMP may lead to other benefits, such as improved generation, storage and transmission investment decisions (i.e. lower capital costs) due to the clear locational price signals provided by LMP. Furthermore, FTRs may increase competition between market participants and hence lead to efficiency gains. We found limited evidence through our case study review on these other benefits from LMP and FTRs. We discuss this limited evidence, as well as the applicability of benefit estimates for cost of capital savings and competition benefits for the NEM below.

5.1. Capital Cost Savings from More Efficient Development Pathway

In addition to the benefits from the more efficient dispatch of generation resources, there may be significant social benefits from the LMP reform due to material improvement in investment in generation, transmission and storage. Under LMP, asset owners and investors will have access to a clear and transparent price signal at each location on the network, which will provide incentives to locate efficiently. Benefits from more efficient locational decisions may arise for two reasons:

A. the capital cost of investments may itself decrease, e.g. because investors undertake fewer, but better located generation and storage investments or because fewer transmission network investments are required because, due to LMP, generation and storage investors make better use of existing transmission infrastructure;[182]

B. the costs of electricity generation (excluding capital costs) may fall relative to the scenario without LMP reform, as a result of better-located plants and storage units.

This section focusses on point ‘A’ above, i.e. any savings from lower capital costs of generation, transmission and storage investments than under zonal pricing. We have discussed point ‘B’ in Section 4.4.3. On point ‘B’, we have found that only the cost-benefit analyses conducted for the ERCOT market estimate the social benefits of more efficient generator siting (due to lower variable generation costs). The ERCOT studies find that accounting for generator siting benefits (through more efficient dispatch) increases the benefits estimated from the more efficient dispatch of the same plants under LMP by about 53 per cent.[183]

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182 Less capacity may be needed under LMP than under zonal pricing because the new generation capacity that enters the market may be better located geographically. Specifically, an inefficiently located generation investment may be constrained off the network at times of congestion, and additional investment may therefore be needed (in the constrained high demand zone) to meet demand. Had the generator located more efficiently it may have been able to generate more frequently (as it would have been constrained off less frequently), thus reducing the need for additional generation capacity.

Capital costs may be lower under LMP because investors may undertake fewer, but better located generation investments. This is because, assuming that a generation investment is made in the wrong place,

183 This 53% estimate applies in NPV terms. For annual estimates, generator siting benefits (through more efficient dispatch) increase the benefits estimated from the more efficient dispatch of the same plants under LMP by about 70 per cent. However, the studies assume that there are no generator siting benefits for the first four years of the modelling period. See: (1) ERCOT, TCA and KEMA (30 November 2004), Market Restructuring Cost-Benefit Analysis, p. 3-22.;

As explained in Section 1, we have reviewed a total of ten jurisdictions that have introduced or are planning to introduce electricity market reform involving LMP (and/or FTRs). As part of this case study review, we have only identified a single jurisdiction where an estimate of capital cost savings from the more efficient development pathway of generation, storage and transmission assets was available. Specifically, we found evidence of benefits from better generator and storage siting decisions in NYISO. New York restructured its electricity market in 1999, moving from a power pool system to a competitive wholesale market with generator LMP. The FERC's 2010 report states that:

> "*Locational price signals in the NYISO energy and capacity markets have driven investments in areas where the demand for electricity and, consequently, the prices are the highest. Investments in generation and demand side resources followed the price signals, resulting in the development of cleaner, more efficient resources in the downstate New York City area. These investments have enabled New York to reliably serve its demand within a competitive market with limited investment in transmission. The savings associated with location of generation and demand-response resources are estimated at $500 million annually. This estimate is based on the transmission congestion costs that would have been incurred to transport power from other regions and the costs that would have been incurred to add new transmission capacity*".[184]

We scale the estimate for NYISO to reflect conditions in the NEM. We scale the benefits estimate through two methods:

- **Scaling by generation capacity:** We scale the estimate by relative total generation capacity in the NEM in 2019 and in NYISO in 2009. We also perform a currency conversion to report benefits in AUD millions.
- **Scaling by investment in new capacity:** We scale the estimate by the ratio of investment in new capacity over 10 years in NYISO (from 2000-2009) and planned investment in new generation capacity in the NEM (from 2019-2029) as reported in the ESOO Assumptions book. We also perform a currency conversion to report benefits in AUD millions.

Our results are reported in Table 5.1 below.

and (2) CRA and Resero Consulting (18 December 2008), Update on the ERCOT Nodal Market Cost-Benefit Analysis, p. 33.

[184] NYISO (2011), 2010 ISO/RTO Metrics Report, p. 257.

Table 5.1: Our Scaled Savings from More Efficient Generator Siting

	Scaling by Generation Capacity	Scaling by Investment in New Generation Capacity
Total Annual Benefits (2019 AUDm)	690	327
Equivalent Reduction in 2019 Wholesale Prices	3.57%	1.69%

Source: NERA Analysis.

The evidence from NYISO and our analysis suggests that there may be large benefits to be realised from more efficient siting of generation and storage assets resulting from the clear price signals provided by LMP. We estimate the annual benefits to the NEM would range between AUD 327 and 690 million, corresponding to an equivalent reduction of 2019 wholesale prices of 1.69 to 3.57 per cent respectively.

However, it is unclear how the savings estimate of USD 500 million per annum was estimated and more importantly what benefits are included within this estimate:

- For instance, the NYISO estimate includes the benefit from demand-response management although NYISO does not report what fraction of the benefits are attributed to this management.
- The estimate may include savings made by the NYISO (e.g. through lower transmission network investment), and likely does not accurately capture the social benefits from more efficient investment in generation, storage and transmission assets that could only be estimated based on a comparison of the capital costs incurred given LMP (the "factual scenario") and the capital costs investors would have incurred under zonal pricing (the "counter-factual scenario"). The estimate may also include the benefits from more efficient dispatch of both existing and new generation.
- We understand NYISO is a special case because at any time, 80 per cent of New York City generation has to be provided by units situated in New York City and various environmental constraints make those plants costly to operate, and the cost-savings from more efficient siting greater.
- Given that non-scheduled generation will continue to face the regional price in the NEM whereas in NYISO they face LMP. Consequently, the generator siting benefits from the siting of renewable generation will likely be lower in the NEM.

Therefore, the NYISO estimate likely overstates the benefits of generator siting.

While the FERC's 2010 report and economic theory both indicate that the potential capital cost savings from nodal pricing reform could be significant, we cannot, based on the evidence available, provide any quantitative estimate of the likely reduction in capital costs in the NEM from the introduction of LMP.

5.2. Competition Benefits

As described earlier, the AEMC expects that the implementation of the proposed access model will increase competition in the wholesale electricity market because FTRs will allow for more inter-regional transmission hedges, which will improve cross regional risk management and competition.

The introduction of inter-regional FTRs in place of the SRA could broaden the geographic market and reduce the risk of locating generation in areas where the firm doesn't have load (either through its own retail arm or contracts with end users). Therefore, FTRs may reduce the risk of acquiring retail customers that are not close the given firm's generation assets (or the assets which it contracts to acquire power from).

Of the case studies we have examined, only New Zealand considers competition benefits from implementing similar reforms. In that situation New Zealand already had LMP and was only considering the introduction of FTRs. At the time, a lack of financial products to manage locational price risk meant that the vertically integrated gentailers managed locational price risk through regionally balancing their generation and load. That is to say, they did not enter at retail in areas where they did not have generation. The view of the Electricity Authority (EA) was that this resulted in a reduction in competition.[185]

As a result of this, the EA considered that introducing FTRs, by nature of giving firms a means to manage locational price risk other than regional balancing, would result in an increase in both retail and generation competition:

- The EA argued that retail competition will increase "as a result of retailers supplying regions that they would not have supplied otherwise due to locational price risk".[186]
- The EA argued that generator competition will increase because of the reduction in locational price risk for generators. It stated that "access to a locational hedge to cover locational price risk improves the economics of generators locating distant from their customers or entry by non-vertically-integrated generators".[187] Consequently, the EA argues that generators can take advantage of cost savings from location decisions based on access to fuel and transmission, resulting in more competition.

The EA posits that an increase in competition in generation and retail would result in both productive and allocative efficiency benefits. The EA states that the "magnitudes of efficiency benefits from the inter-island FTR are unknown".[188] Therefore, the EA assesses the benefit from increased retail competition by assuming a reduction in retail prices and estimating the resulting benefits from improvements to allocative and productive efficiency:

- The EA assesses that retail prices would fall by NZD 0.71 to 1.43 per MWh because of the introduction of FTRs.[189] It estimates that annual demand for power would increase by 14 to 28 GWh per year as a result of the reduction in prices.[190] It then estimates that the

[185] Electricity Authority (2011), Managing locational price risk: Proposed amendments to Code, para. 3.5.6

[186] Electricity Authority (2011), Managing locational price risk: Proposed amendments to Code, p. 85.

[187] Electricity Authority (2011), Managing locational price risk: Proposed amendments to Code, p. 86.

[188] Electricity Authority (2011), Managing locational price risk: Proposed amendments to Code, p. 85.

[189] Electricity Authority (2011), Managing locational price risk: Proposed amendments to Code, p. 85.

[190] The EA assumes that the price elasticity of demand for electricity is -0.26 and estimates the increase in demand resulting from its assumed reduction of retail prices. It applies its assumed elasticity and price reduction to the fraction of each industry that it argues are subject to weak competitive and retail pressure i.e. 50 per cent of annual residential consumption, 30 per cent of commercial consumption etc.

allocative efficiency benefits associated with the increase in consumer surplus from the increase in annual demand for power are NZD 5,056 to 20,222 per year.

- The EA estimates the productive efficiency benefit by assuming that the retail price reduction will result in a fall of production costs by NZD 0.36 to 0.71 per MWh. It applies the cost reduction to the production costs of serving the fraction of each industry that it argues are subject to weak competitive and retail pressure to calculate that the total productive efficiency benefits will be between NZD 3.889 and 7.778 million per year.

The EA asserts that the introduction of inter-island FTRs will reduce locational price risk for generators who will therefore be able to locate in more efficient locations (in terms of fuel transmission etc.).[191] The EA assumes that more efficient siting decisions by generators will also reduce retail prices. It estimates the allocative efficiency benefits by:

- Assuming that improved generator siting will reduce retail prices by NZD 0.36 to 0.71 MWh per year resulting in an increase in demand of 7 to 14 GWh per year. It uses the same method it uses for retailers to estimate that the reduction in prices will result in allocative efficiency benefits of NZD 1,246 to 5,056 per year.
- The EA also assumes that generator competition from more efficient siting decisions will lead to a productive efficiency gain from a reduction in generator costs. The EA assumes that generators costs will fall by NZD 0.18 to 0.36 per MWh resulting in efficiency benefits of NZD 1.944 to 3.889 million per year.[192]

Therefore, in total, the EA estimates that the competition benefits from the introduction of inter-island FTRs are NZD 5.84 to 11.69 million per year. We convert EA's estimates of competition benefits to estimates for the NEM by scaling by total consumption (in GWh), and converting currency and inflation, see Table 5.2.

Table 5.2: Our Benefits Transfer Approach to Apply the EA's Estimates for the Benefits from Improved Retail and Generator Competition after the Introduction of Inter-Island FTRs to the NEM

(2019 AUDm per year)	**Allocative Efficiency Benefit**		**Productive Efficiency Benefit**		**Total Efficiency Benefit Per Annum**	
	Low	High	Low	High	Low	High
Improved Retail Competition	0.02	0.09	16.77	33.54	16.79	33.63
Improved Generator Competition	0.00	0.02	8.38	16.77	8.39	16.79
Total Competition Benefit	0.03	0.11	25.15	50.31	**25.18**	**50.42**

Source: NERA Analysis

191 Electricity Authority (2011), Managing locational price risk: Proposed amendments to Code, p. 86.

192 Electricity Authority (2011), Managing locational price risk: Proposed amendments to Code, p. 86.

The scaled competition benefits estimated by the EA imply that should similar competition benefits be realised in the NEM, they would equate to a total efficiency benefit of AUD 25.18 to 50.42 million per year.

However, we interpret these estimates with caution:

- The EA does not explain how it arrives at its assumed price reductions resulting from the introduction of inter-island FTRs. It does not, to our knowledge, provide evidence that such price and cost reductions could be realised in practice. Our understanding is that the EA assumes a price reduction without justification and estimates the “competition benefits” resulting from that assumed price reduction.
- The allocative efficiency benefits result from the EA assuming, rather than demonstrating, that current prices include market power rents. Hence the EA’s analysis is more of a “what if” analysis rather than a considered view of likely price reductions from increased competition.[193]
- The EA’s study examines the impact on competition from the introduction of inter-island FTRs only. In the NEM, the reform will introduce LMP instead of zonal pricing and therefore introduces a new intra-regional price risk, which could have opposite impact on competition. The introduction of basis risk is countered by the proposed simultaneous introduction of intra-regional FTRs between the reference node and individual nodes. However, to ensure such FTR products are firm, FTRs covering only a fraction of total transmission capacity will be available, resulting in basis risk for participants over the remaining capacity.
- The EA argues that competition benefits arise from the introduction of FTRs because retailers need not have generation (or contracts) in the same region as the load they serve. The NEM already uses SRAs to allow market participants to hedge transmission risk between regions. Therefore, it is not clear the introduction of FTRs will result in the same benefits as estimated by the EA. However, we understand that the non-firm nature of SRAs means they are primarily purchased by speculators as opposed to physical participants. This suggests that a more firm FTR may actually “broaden the market”, if the lack of locational hedging products is restraining cross-regional competition today.
- Stakeholders have raised concern that incumbents could strategically acquire FTRs to prevent others from entering[194] – therefore, if these benefits exist their realization will crucially depend on the way that FTRs are allocated.

Balanced against these reservations, in Australia we note that:

- The ACCC’s Retail Electricity Pricing Inquiry expressed concerns about competition in both generation and retail and liquidity in contract markets; and

[193] The EA effectively acknowledges this point in its discussion of increased retail competition when it states “The magnitudes of efficiency benefits from the inter-island FTR are unknown.” Electricity Authority (2011), Managing locational price risk: Proposed amendments to Code, p. 85.

[194] CEC (8 November 2019), Coordination of Generation and Transmission Investment Proposed Access Model (EPR0073) – Discussion Paper, p. 10.

- There is expected to be significant turn-over in the generation stock over the coming the decades,[195] which presents opportunities for new firms to enter the market

Overall, the competition benefits from the introduction of LMP and FTRs in the NEM are hard to define and unknown without more detailed modeling of the market in the NEM before and after the reform. On the one hand, the large degree of turnover in generation and stock and evidence of lack of competition in the retail market means that the potential for competition benefits from the introduction of LMP and FTRs in the NEM are high. On the other hand, the introduction of basis risk for part of the market alongside FTRs may lead to higher costs of entry for generators (and retailers if the contract market moves to generators' LMPs).

195 AEMC (14 October 2019), COGATI Proposed Access Model, p. i, para 7.

6. Distributional Impact of Reforms

In order to use studies in the jurisdictions we examine to inform our discussion of the potential distribution impact of the introduction of LMP and FTRs in the NEM, we need to understand how the markets in those jurisdictions operated prior to reform. Studies that report transfers in existing market structures similar to the existing market structure in the NEM will more accurately describe the expected result of reform in the NEM.

The introduction of LMP and FTRs in the jurisdictions we examine often coincided with changes to other market structures that were unique to the operation of the market in each of the jurisdictions. Nowhere did we find that the existing market arrangements to alleviate intra-zonal congestion were similar to that currently operated in the NEM. Therefore, we need to understand the existing flows of payments around the system in those jurisdictions to understand whether the reported transfers to consumers or generators after the reform will overstate or understate the transfers arising from the reform in the NEM.

Consequently, using the case studies that we examine to assess the distributional impact of reforms is challenging in the absence of bottom-up modelling of the market before and after the reform. Without such bottom-up analysis, one cannot accurately determine the changes to transfers that arise from the specific market structure in each jurisdiction and the transfers likely to arise from the reform in the NEM.

6.1. The Theoretical Redistribution of Payments from the Introduction of LMP in the Case Studies We Examine and the NEM

In order to assess the likely redistribution of revenue arising from the reform in each jurisdiction that we examine and the NEM, we:

- examine the current market structure and flow of payments around the market in each jurisdiction and the NEM; and
- examine the flow of payments around the market after the introduction of LMP and FTRs in each jurisdiction and the NEM.

We compare the flow of payments around the market before and after the introduction of LMP in the NEM and each jurisdiction in order to determine the changes to redistribution of revenue arising from the reform. In addition, we compare how the changes to transfers may vary between the NEM and other jurisdictions to assess whether the estimated benefits arising to consumers and generators in the jurisdictions we examine are likely to overstate or understate the impact from the reform in the NEM.

For simplicity, we focus on comparing the market structure prevailing in ERCOT and compare the distributional impact of introducing LMP in ERCOT to the distributional impact to be expected in the NEM. We focus on ERCOT because it had a similar zonal pricing market structure to the NEM before the introduction of LMP, and because ERCOT has the most evidence available on the distributional impact of reforms based on our case study review. The cost benefit analyses for ERCOT also report the distributional impact of the reforms on consumers.

We identify three main flows of payment which may change because of the introduction of LMP:

- **Changes from zonal prices to LMP:** Transfers arise from the change in prices paid by consumers and received by generators as a result of the reform. The extent to which the price setting mechanisms to determine zonal prices differ in US markets and the NEM will also explain differences in the transfers to be expected from the same reform in each market.
- **Out of merit payments (OOM payments)**: OOM payments that exist in many US markets under zonal pricing also impact the transfers arising from the introduction of LMP. After the introduction of LMP, OOM payments are no longer necessary as generators are dispatched based on LMPs. In the NEM, a form of OOM up payment is when generators are constrained on to provide energy and compensated at the 90th percentile of spot prices over the preceding twelve months.[196]
- **Efficiency gains**: The impact of the change in prices paid by consumers and received by generators and the impact of the elimination of OOM payments represent only transfers between consumers and generators. In addition to these transfers, revenue may accrue to consumers or generators (relative to the zonal world) from social improvements to the efficiency of market operation. Improvements to the efficiency of market operation represent *net social benefits* arising from the introduction of the reform, such as the benefits from more efficient dispatch (discussed in Section 4).

We explain the transfers arising from each of these sources in more detail below. However, to examine transfers using the stylised examples below we do not assume any efficiency gains from dispatch. Efficiency gains represent social benefits from moving from a zonal market to LMP. Therefore, efficiency gains may accrue to generators or consumers but do not represent transfers between generators or consumers.

6.2. Worked Example to Illustrate Transfers

In this Section, we use a worked example to illustrate the benefits accruing to consumers from the introduction of LMP. We do not explicitly consider FTRs in the worked example because FTRs may define a separate transfer of congestion revenue between consumers and generators after the reform. We discuss FTRs in more detail in Section 6.5 and in the meantime assume, for simplicity, that all congestion revenue accrues to consumers. In addition, we illustrate the benefits that are likely to accrue to consumers from the introduction of LMP in US jurisdictions and compare to the benefits that are likely to accrue to consumers in the NEM after the reform. We use this comparison in Section 6.4 to qualitatively assess whether consumer benefit estimates based on other jurisdictions are likely to overstate or understate the expected benefits in the NEM.

In our worked example below there exist two nodes: “Node A” and “Node B”, each with its own fixed generation capacity and load. There is a transmission line of fixed capacity that connects the two nodes.[197]

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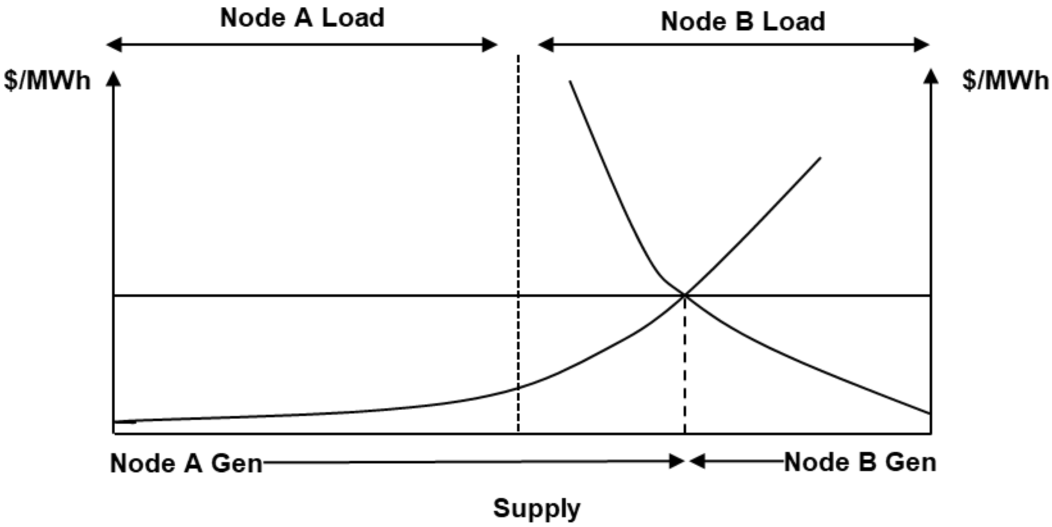
196 AEMC (14 October 2019), COGATI Proposed Access Model, p. 19.

197 We construct our worked example in this Section based on a similar example in Bernard C. Lesieutre and Joseph H. Eto (October 2003), Electricity Transmission Congestion Costs: A Review of Recent Reports.

In the absence of congestion (i.e. in the absence of a binding transmission constraint between the two nodes), the energy price in the market is determined by the lowest combination of marginal cost generation across the two nodes, as we show in Figure 6.1.

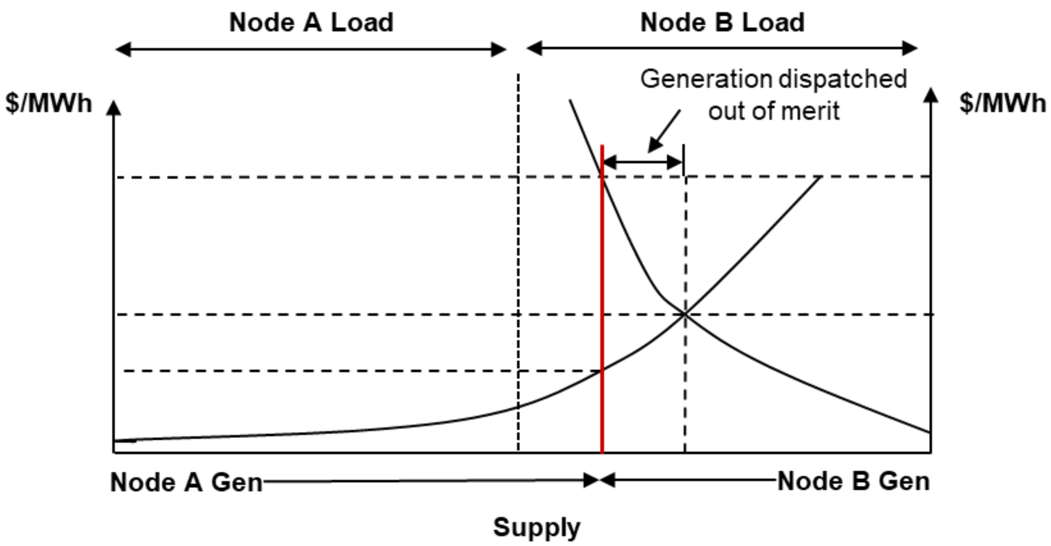
Figure 6.1: Market Outcome in the Absence of Congestion



Source: NERA Analysis.

However, if there is congestion on the transmission line (i.e. if transmission constraints bind), then some generators at Node B will need to be dispatched out of merit to alleviate intra-zonal congestion, because lower-cost generators in Node A will not be able to meet Node B load due to the binding transmission constraint between Nodes A and B. Therefore, with congestion on the transmission line from Node A to Node B, generation at Node A falls and generation at Node B rises relative to the case without congestion, as we show in Figure 6.2.

Figure 6.2: Market Outcome with Congestion



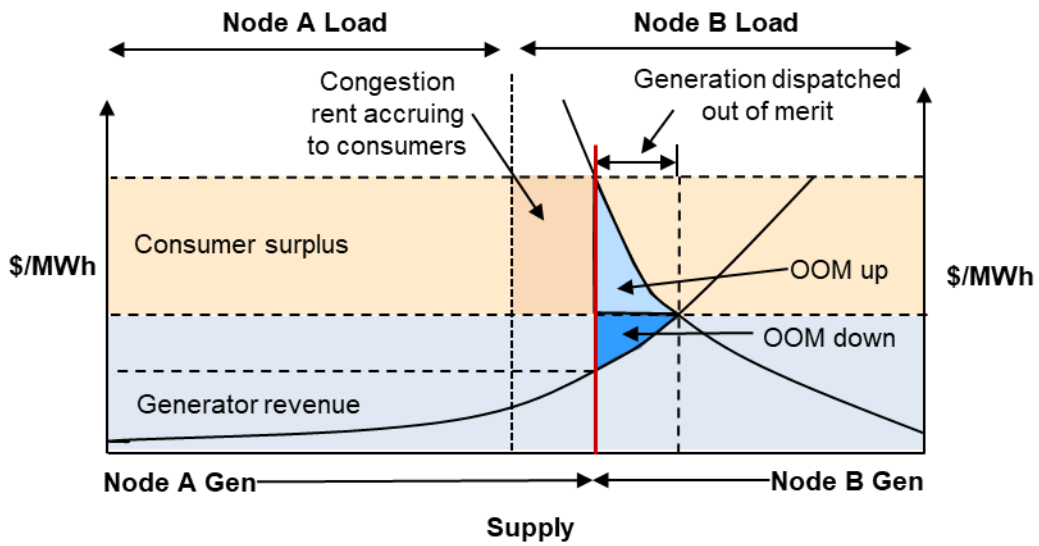
Source: NERA Analysis.

In the congested scenario, the benefits accruing to consumers and generators under zonal pricing depend crucially on the method by which the zonal price is set and whether there exist OOM payments to generators dispatched out of merit. Therefore, the transfers in benefits that occur due to the introduction of LMP also depend on how the zonal market operated prior to the reform.

6.2.1. Theoretical benefits to consumers from the introduction of LMP in ERCOT

Prior to the implementation of LMP in ERCOT, the market is initially dispatched by the system operator under zonal pricing as if intra-zonal congestion did not exist. Therefore, the zonal price is the same as the price prevailing in the market in the absence of congestion, as we show in Figure 6.3. All generators are paid the zonal price and all consumers pay the zonal price.

Figure 6.3: Market Outcome and Welfare Distribution with Zonal Pricing in ERCOT



Source: NERA Analysis.

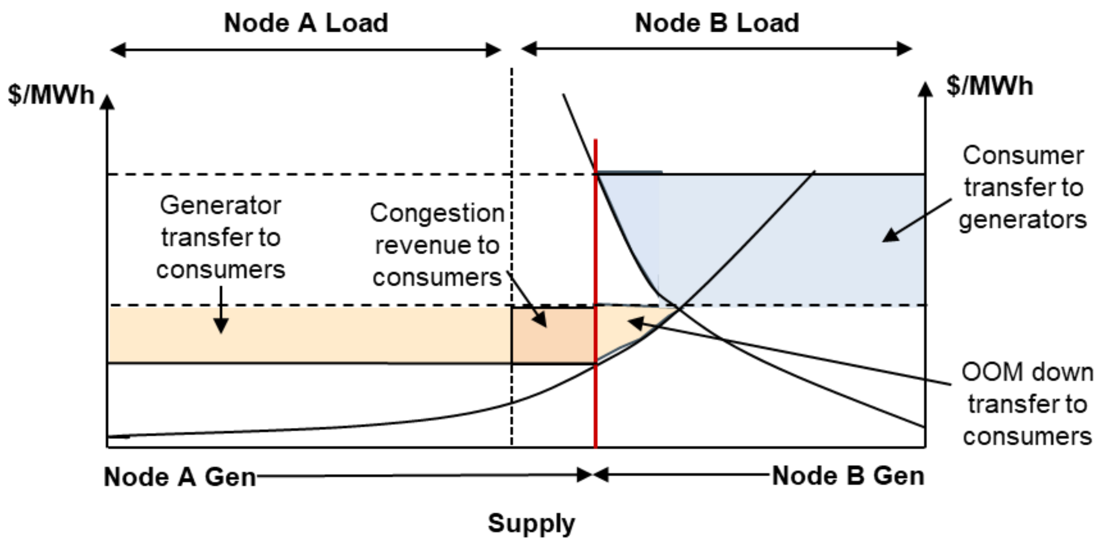
In order to alleviate intra-zonal congestion, generation is subsequently dispatched out of merit. Generators that are constrained on or off receive OOM up or down payments to compensate them for generating or reducing their output respectively to alleviate congestion. OOM payments are funded by consumers and therefore reduce consumer surplus and increase generator revenue under zonal pricing. The total transfer from consumers to generators under zonal pricing corresponds to total generator revenue from sale of power at the zonal price plus OOM up and down payments. Consumers accrue a consumer surplus because the zonal price set is below the marginal cost to provide energy in the market (the price that would prevail at the LMP at Node B). As part of the surplus that consumers accrue, they also accrue congestion rent from the fact that load at Node B can benefit from purchasing power from generation at Node A.

The introduction of generator LMP in the market results in an LMP at Node A that is lower than the LMP at Node B, see Figure 6.4. We assume for simplicity that the zonal price paid by load remains unchanged after the introduction of generator LMP and remains at the price paid by load under zonal pricing.

Consequently, generators at Node A are paid a lower price and generators at Node B are paid a higher price. The lower price paid to generators at Node A reflects a transfer from generators to consumers, part of which corresponds to the transfer of congestion revenue to consumers (through CRRs). On the other hand, the higher price paid to generators at Node B reflects a transfer from consumers to generators less the original payments by consumers to generators at Node B through OOM up payments.

Lastly, consumers no longer pay generators at Node A to compensate them for being switched off to alleviate congestion and therefore avoid the OOM down payments. The OOM down payments represent a transfer from generators to consumers arising from the reform.

Figure 6.4: Benefits Redistribution with the Introduction of LMP in ERCOT



Source: NERA Analysis.

We summarise the redistribution of benefits likely to be realised in ERCOT after the reform in Table 6.1 below.

Table 6.1: Summary of Redistribution of Benefits from the Introduction of LMP in ERCOT

	Zonal Pricing	LMP	Net Transfer
Generators	▪ Generator revenue including some congestion rent ▪ OOM up ▪ OOM down	▪ Generators at B get higher revenue and OOM up ▪ Generators at A get lower revenue	**(+/-)** Generator revenue may be lower or higher **(-)** Generators lose OOM down
Consumers	▪ Consumer surplus including some congestion rent	▪ Consumer surplus increases due to fall of generator revenue at A but falls due to increase in generator revenue at B ▪ Consumers get more congestion revenue ▪ Consumers get OOM down	**(+/-)** Consumer surplus may rise or fall **(+)** Consumers get OOM down **(+)** Consumers get higher congestion revenue

Source: NERA Analysis.

The overall redistribution of benefits will not necessarily lead to consumer benefits resulting from the introduction of LMP in ERCOT. Consumers are more likely to benefit when:

- the zonal price they were paying before the reform is higher relative to the average price across LMPs after the reform; and
- OOM down payments under zonal pricing are larger.

All the ex-post and ex-ante studies that we examine report that consumer benefits have/will increase following the introduction of LMP.

6.2.2. Theoretical benefits to consumers from the introduction of LMP in the NEM

The transfer of benefits resulting from the introduction of LMP in the NEM crucially depends on the regional reference price under the zonal pricing model. In particular, the higher the zonal price set at the regional reference node is compared to the generator's volume-weighted average of LMPs (GWAP) across the system, the larger the likely benefits accruing to consumers after the introduction of LMP. We explore the distributional impacts of the introduction of LMP under two scenarios below:

- In Section 6.2.2.1, under a scenario that assumes that the RRP under zonal pricing is higher than the GWAP; and
- In Section 6.2.2.2, under a scenario that assumes that the RRP under zonal pricing is lower than the GWAP.

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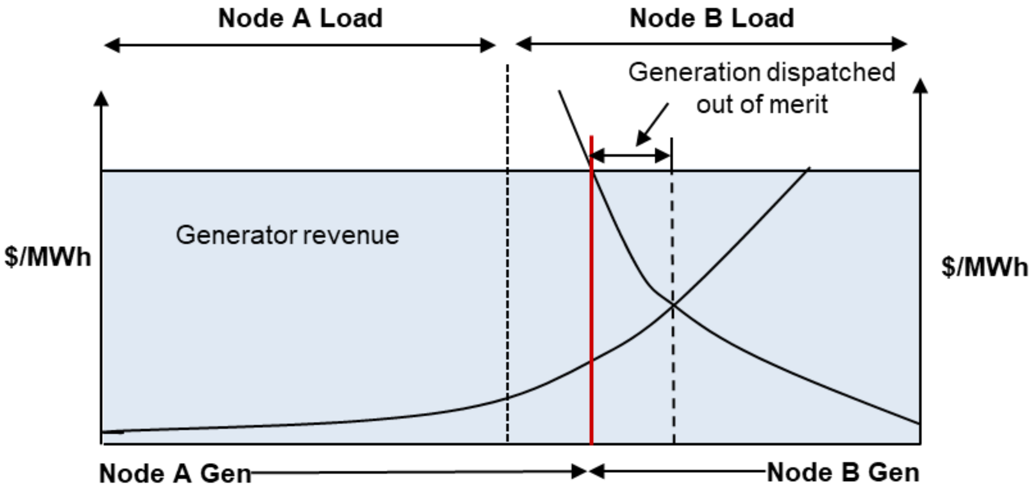
6.2.2.1. The price set by the regional reference node under zonal pricing is high relative to GWAP

In our worked example, the price would be highest under zonal pricing in the NEM if Node B was the regional reference node. If the zonal price was set at the LMP for Node B, generators in Node A and Node B would capture the revenue shown in Figure 6.5.

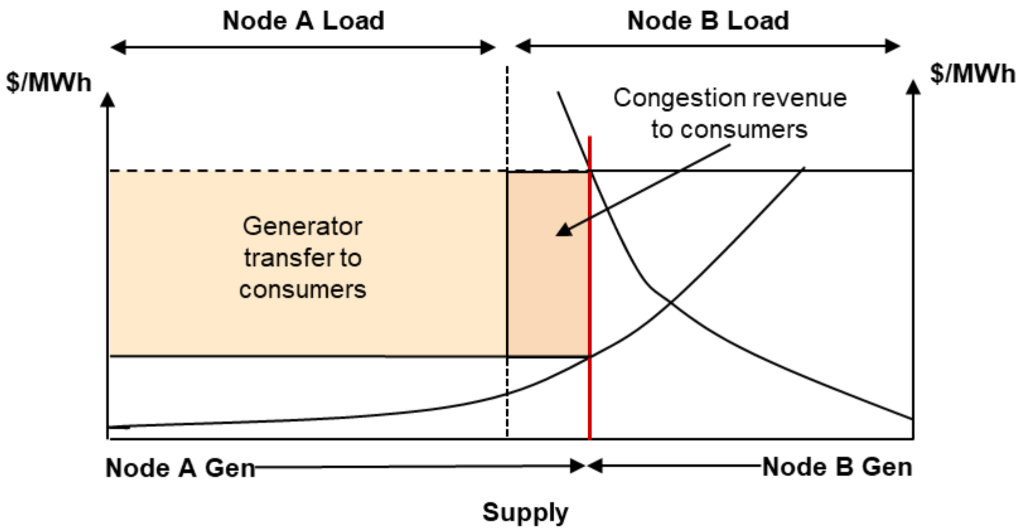
Figure 6.5: Market Outcome and Welfare Distribution with Zonal Pricing in the NEM: High Zonal Price Relative to GWAP



Source: NERA Analysis.

If one were to introduce LMP into the market, generators at Node A would be paid the lower price of the LMP at Node A instead of the LMP at Node B. The lower price paid to generators at Node A corresponds to a transfer of revenue to consumers under LMP relative to zonal pricing.

Figure 6.6: Benefits Redistribution with the Introduction of LMP in the NEM: High Zonal Price Relative to GWAP



Source: NERA Analysis.

We summarise the redistribution of benefits likely to be realised after the introduction of LMP in the NEM, when the previous zonal price was high, in Table 6.2 below.

Table 6.2: Summary of Redistribution of Benefits from the Introduction of LMP in the NEM: High Zonal Price

	Zonal Pricing	LMP	Net transfer
Generators	▪ Generators capture all revenue	▪ Generators at A receive less revenue	**(-)** Generators lose revenue
Consumers	▪ Generators capture consumer surplus	▪ Consumers get the benefit from lower prices paid to generators at A	**(+)** Consumers get transfer from lower generator revenue

Source: NERA Analysis.

Therefore, should the regional reference node that sets the zonal price under the current market structure result in a relatively high price compared to GWAP, the consumer benefits reported in the studies we examine for US jurisdictions will likely understate the benefits likely to accrue to consumers from LMP in the NEM.

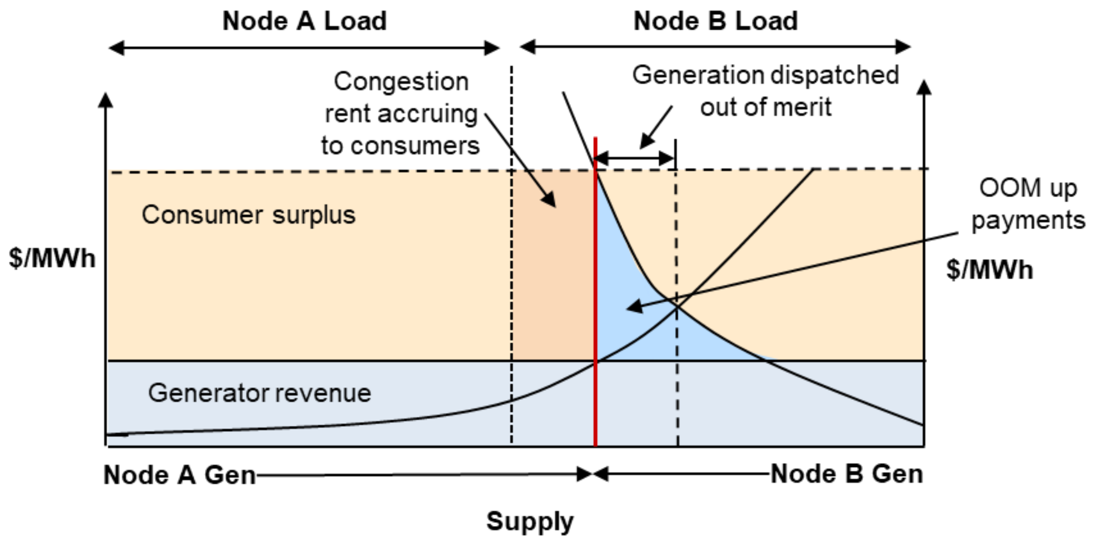
6.2.2.2. The price set by the regional reference node under zonal pricing is low relative to GWAP

In our worked example, the price would be lowest under zonal pricing in the NEM if Node A was the regional reference node. If the zonal price was set at the LMP for Node A, generators in Node A and Node B would capture less revenue than if Node B set the zonal price, see Figure 6.7. On the other hand, consumers benefit from the low zonal price set by Node A and capture higher benefits relative to the case where Node B sets the zonal price.

However, if Node A sets the zonal price, then generators at Node B would not be incentivised to bid to be dispatched to meet load at Node B because the zonal price is lower than their short run marginal costs. Consequently, generators at B would bid unavailable. To meet load, we understand that generators would be forced to switch on in dispatch and would be paid the 90th percentile of spot prices over the previous 12 months to compensate them for dispatch. The payments to switch on are equivalent to OOM up payments and are paid to generators in Node B from consumers.[198]

[198] The OOM up payment received by generators at Node B may be greater than that shown in the Figure. In particular, each generator may receive the same OOM up payment for each incremental MW of production. In this case, the area corresponding to OOM up payments would be a square in the above Figure. In either case, generators would capture the same revenue after the introduction of LMP.

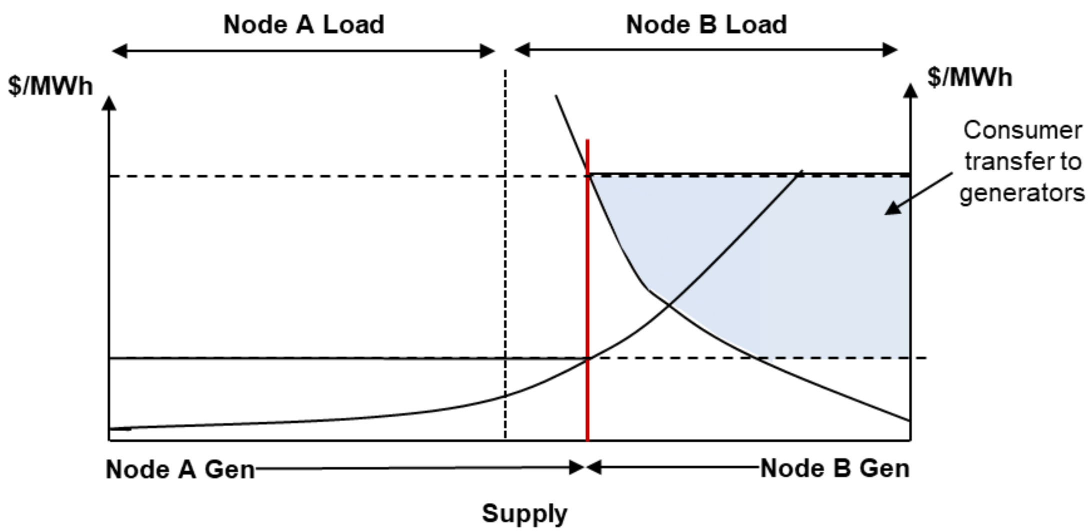
Figure 6.7: Market Outcome and Welfare Distribution with Zonal Pricing in the NEM: Low Zonal Price Relative to GWAP



Source: NERA Analysis.

The introduction of LMP when Node A sets the zonal price leads to different benefit transfers to consumers and generators than when Node B previously sets the zonal price. More specifically, consumers lose from the introduction of LMP in the case where Node A sets the zonal price. Consumers pay a higher price for power which represents a transfer in payments to generators at Node B who are compensated with a higher price (LMP at Node B) for the power they produce. The transfer from consumers to generators is equal to the difference in payments for power to generators at Node B (due to the difference in the zonal price before and after the reform), less any existing OOM up payments, see Figure 6.8.

Figure 6.8: Benefits Redistribution with the Introduction of LMP in the NEM: Low Zonal Price Relative to GWAP



Source: NERA Analysis.

In the example with low zonal market prices, consumers already capture the congestion rent in the form of lower prices. Therefore, collecting congestion revenue through sales after the introduction of LMP and redistributing to consumers through TUoS does not represent a transfer of revenue to consumers from generators.

Indeed, should consumers already capture part or all of congestion revenue (which they will if the zonal price is not the highest LMP) then total TUoS reductions do not represent the total transfer to consumers because consumers already accrued part of the congestion revenue prior to the introduction of LMP.

We summarise the redistribution of benefits likely to be realised after the introduction of LMP in the NEM, when the previous zonal price was low, in Table 6.3 below.

Table 6.3: Summary of Redistribution of Benefits from the Introduction of LMP in the NEM: High Zonal Price

	Zonal Pricing	LMP	Net transfer
Generators	▪ Generators capture revenue from selling at the low price ▪ Generators at B receive OOM up	▪ Generators at A receive the same revenue ▪ Generators at B receive more revenue ▪ Generators at B no longer receive OOM up	**(+)** Generators at B gain revenue
Consumers	▪ Consumers capture gains of paying the low zonal price ▪ Consumers receive all congestion revenue	▪ Consumers pay higher prices ▪ Consumers no longer pay OOM up	**(-)** Consumers pay higher prices

Source: NERA Analysis.

Therefore, should the regional reference node that sets the zonal price under the current market structure result in a relatively low price compared to GWAP, the consumer benefits reported in the studies we examine for US jurisdictions will likely overstate the benefits expected to accrue to consumers from the introduction of LMP in the NEM.

6.2.3. Summary

Theoretically, there are three primary drivers of benefits following the introduction of LMP in the NEM:

- **Efficiency gains**: Additional net social benefits arising from the introduction of LMP and FTRs are not captured in our illustrated example. The net social benefits may accrue to generators or consumers and therefore both generators and consumers may be made better off as a result of the reform. In other words, in our illustrated example the benefits from LMP are zero-sum, whereas if there exists net social gains from LMP (as we expect based on our discussion in Sections 4 and 5) then the reform is no longer zero-sum, and both consumers and generators can in theory benefit.

- **OOM payments**: OOM up payments do not represent a benefit that accrues to consumers as part of the introduction of LMPs. OOM up payments are exactly offset by generator revenue increases from the introduction of LMP. However, the elimination of

OOM down payments from the introduction of LMP represents a benefit to consumers in US jurisdictions. The larger the OOM down payments in US jurisdictions, the more likely that the estimates for consumer benefits from the introduction of LMPs from those jurisdictions overstate the benefits when transferred to the NEM. In ERCOT OOM down payments are significantly higher than OOM up payments and were forecast to be approximately USD 400 million per annum in the 2004 CBA.[199]

- **The zonal price relative to GWAP**: The higher the zonal price in the NEM relative to GWAP, the more benefits will accrue to consumers from the introduction of LMP. We summarise the implications for generator benefits from LMP and the treatment of estimates of consumer benefits based on experience in US jurisdictions in Table 6.4.

Table 6.4: Summary of Theoretical Benefits to Consumers from the Introduction of LMP and the Implications for Comparisons to Estimates in US Jurisdictions

Zonal Price	Consumer Benefits from LMP	Generator Benefits from LMP	US Jurisdiction Estimates Over or Under-state NEM Benefits?
Low Zonal Prices Relative to GWAP	Low	High	Over-state
High Zonal Prices Relative to GWAP	High	Low	Under-state

Source: NERA Analysis. We understand benefits to cover both benefits and disbenefits. Low benefits in the table above mean disbenefits from LMP, and high benefits mean positive benefits.

The current zonal price in the NEM is likely to be higher relative to average LMPs than it is lower:

- We understand from the AEMC that the regional reference node that sets the zonal price in the NEM is chosen to be a node with higher load, and therefore is likely to lead to a higher zonal price.
- In addition, Katzen and Leslie examine inefficient compensation under zonal pricing compared to LMP in the NEM.[200] They report that revenue to generators from selling at regional prices exceeds revenue to generators from selling at LMPs i.e. there is “net overcompensation” of generators. Net overcompensation also suggests that on average, zonal prices are above GWAP.[201]

Therefore, the consumer benefits from LMP are likely to be higher relative to the generator benefits from LMP (in the absence of net social benefits). Moreover, our estimates from the studies we examine in US jurisdictions will likely under-state the benefits in the NEM.

Despite this, in reality the zonal price is likely to be set at a node that is not highest nor lowest price node i.e. between the price set by Node A and Node B in our worked example.

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199 ERCOT, TCA and KEMA (30 November 2004), Market Restructuring Cost-Benefit Analysis, p. 3-26.

200 Matthew Katzen and Gordon Leslie (20 December 2019), Revisiting Optimal Pricing in Electrical Networks over Space and Time: Mispricing in Australia's Zonal Market

201 However, Katzen and Leslie also argue that strategic bidding results in net overcompensation. The prevalence of strategic bidding may mean that the zonal price is higher than the volume-weighted average price only because of inefficient market behavior. Therefore, one would ideally compare the zonal price without strategic bidding to the volume weighted average of LMPs to see if net overcompensation still prevails in the absence of inefficient bidding.

Based on empirical evidence, the Katzen and Leslie paper,[202] and evidence provided to us by the AEMC, the zonal price in the NEM is more likely to be closer to the highest than the lowest locational marginal price. Therefore, there will be transfers from both generators to consumers and consumers to generators arising from the introduction of LMP, and it is likely that the former transfer will be larger due to higher zonal prices. The pattern of distribution of benefits will more closely resemble the pattern arising in the worked example of ERCOT.

Consequently, using the case studies that we examine to assess the distributional impact of reforms is challenging in the absence of bottom-up modelling of the market in both the NEM and US jurisdictions before and after the reform. Without such bottom-up analysis, one cannot accurately determine whether benefit estimates in other jurisdictions are likely to understate or overstate the benefits from the reform in the NEM and the transfers likely to arise from the reform in the NEM.

6.3. Reported Impacts of the Introduction of LMP and FTRs on Consumers

Few studies across the jurisdictions we examine report an estimate of the *total* consumer benefit arising from the introduction of LMP and FTRs. Of those studies that did, only a subset reported estimates that we can use to transfer to an estimate in the NEM.

We use a benefits transfer methodology to estimate the benefits accruing to consumers from the introduction of LMPs and FTRs. We transfer estimates in other jurisdictions by assuming that the same percentage wholesale spot price reduction will apply in the NEM as estimated in the comparator jurisdictions (in the studies identified), from the introduction of LMP and FTRs. We recognise that the reform in the NEM may not pass benefits to consumers through actual wholesale spot price reductions, but may also utilise other transfer mechanisms e.g. offsetting TUoS charges. However, our use of an equivalent wholesale spot price reduction allows us to standardize the benefits transferred to consumers across the reforms in all the jurisdictions that we examine.

We apply our benefits transfer approach to estimates from ERCOT and SPP:

- In ERCOT we identify three estimates for total consumer benefits arising from the introduction of LMP and FTRs:
  - An ex-ante estimate from the CBA in 2004 finds total annual benefits accruing to consumers as a result of the reform of USD 822 million.[203] We estimate that the consumer benefits reported in the 2004 CBA are equivalent to a 5.59 per cent reduction in the average annual wholesale spot price. We describe the methodology used in the study in more detail in Appendix B;
  - An ex-ante estimate from the CBA in 2008 finds that the total annual benefits accruing to consumers as a result of the reform would be 29 per cent less than that estimated in the 2004 CBA.[204] We estimate that the consumer benefits reported in the 2008 CBA are equivalent to a 3.97 per cent reduction in average annual wholesale

[202] Matthew Katzen and Gordon Leslie (20 December 2019), Revisiting Optimal Pricing in Electrical Networks over Space and Time: Mispricing in Australia's Zonal Market

[203] ERCOT, TCA and KEMA (30 November 2004), Market Restructuring Cost-Benefit Analysis.

[204] CRA and Resero Consulting (18 December 2008), Update on the ERCOT Nodal Market Cost-Benefit Analysis.

spot prices. We describe the methodology used in the study in more detail in Appendix B; and

- An ex-post estimate from Zarnikau and Woo (an academic study) based on regression analysis finds that the introduction of LMP and FTRs in ERCOT led to a 2 per cent reduction in average annual wholesale spot prices.[205]

- In addition, the ex-ante cost benefit analysis for the introduction of LMP in SPP also reports a total expected consumer benefit from the introduction of the reform. CRA uses electricity market modelling in its 2005 CBA and reports that the introduction of LMP will lead to a 7 per cent reduction in average annual wholesale spot prices.

The two ex-ante ERCOT studies that we examine do not report an average wholesale spot price reduction as part of their analysis. For the estimate of consumer benefits from the introduction of LMP and FTRs in the 2004 CBA, we estimate the implied reduction in average wholesale spot prices by calculating the reported annual consumer benefits (USD 822 million) as a percentage of the reported total cost of serving demand. We estimate the reduction in wholesale prices implied by the 2008 CBA in ERCOT by applying a 29 per cent reduction to USD 822 million and calculating the reported annual consumer benefits (USD 583 million) as a percentage of the reported total cost of serving demand.

Across all ERCOT studies, the introduction of LMP also corresponds to the introduction of other changes such as the move from 15-minute to 5-minute dispatch intervals, as well as the introduction of the day-ahead market. Hence, estimates of changes to consumer costs from the implementation of LMP may also pick up the effects of other elements of the wider market reform.

The ex-ante SPP study that we examine reports the highest estimate for total benefits accruing to consumers from the introduction of LMP. However, SPP transitioned to LMP from a physical bilateral market rather than a zonal market and therefore the consumer benefits arising from the introduction of LMP are likely to overstate the benefits arising from the introduction of LMP and FTRs in a market with zonal pricing e.g. the NEM or ERCOT.

6.4. Benefits Transfer Approach to Estimate the Impact of the Introduction of LMP in the NEM

We adopt a benefits transfer approach to estimate the consumer impact of the introduction of LMP and FTRs in the NEM. Our methodology is similar to the methodology we use to estimate the efficiency of dispatch benefits in the NEM (see Section 4.2). More specifically, we use the studies' estimates of reductions in wholesale prices to examine the benefit to consumers in the NEM, assuming that the introduction of LMP and FTRs in the NEM will result in the same wholesale price reduction as in our comparator jurisdictions.

We estimate the cost savings in the NEM using the following method:

- We use estimates for volume-weighted spot prices in each region of the NEM for 2018/19 as reported by AEMO.

[205] Zarnikau, J.; Woo, C. K.; Baldick, R.; Journal of Regulatory Economics, April 2014, v. 45, iss. 2, pp. 194-208.

- We multiply the volume-weighted spot prices by total consumption (TWh) in each region of the NEM for 2018/19 as reported by AEMO. Therefore, we construct an estimate of annual total consumer costs of procuring wholesale energy at the spot price.
- We apply the estimates for percentage wholesale price reductions arising from the introduction of LMP in other jurisdictions to the total consumption costs as reported for the NEM, in order to estimate the total benefits accruing to consumers as a consequence of the reform.

We present our results in Table 6.5 below.

Table 6.5: Our Benefits Transfer Approach to Estimate the Annual Benefits to Consumers from the Introduction of LMP and FTRs in the NEM

			Estimated Consumer Transfer Per Annum (AUDm)					
Market	**Ex-ante or Ex-post?**	**Equivalent Reduction in Wholesale Prices**	**QLD**	**NSW**	**VIC**	**SA**	**TA**	**NEM**
ERCOT	Ex-ante	5.59%	260	369	310	89	53	**1,081**
ERCOT	Ex-ante	3.97%	185	262	220	63	38	**768**
ERCOT	**Ex-post**	**2.00%**	**93**	**132**	**111**	**32**	**19**	**387**
SPP	Ex-ante	7.00%	326	462	388	112	67	**1,354**

Source: NERA Analysis.

We estimate that the benefits accruing to consumers as a consequence of introducing LMP range from AUD 387 million to AUD 1,354 million per year. We estimate that, should the NEM achieve a benefit transfer to consumers equivalent to the average wholesale price reduction estimated across the studies we examine, the average benefit to consumers would be AUD 897 million per year.

Using our benefits transfer method and the only ex-post study we examine, we estimate that the introduction of LMP will lead to total benefits for consumers of AUD 387 million per year. We consider that this ex-post study from ERCOT provides the best evidence of the expected consumer benefits from LMP, because it is the only study that examines data of the realised price changes for consumers arising from the reform.

For clarity, the numbers reported in the above studies represent total savings to consumers from the introduction of LMP. Therefore, the above savings include and conflate both transfers from generators to consumers as a consequence of the reform as well as net social benefits arising from more efficient dispatch and accruing to consumers. In addition, the estimates from other jurisdictions capture the impact of a wide suite of reforms beyond LMP and likely conflate the impact of those reforms with the impact of introducing LMP.

However, we are unable to determine whether the wholesale price reductions reported in other studies could be realistically achieved from the introduction of LMP in the NEM without conducting electricity market modelling, which controls for the specific characteristics of the NEM and the proposed COGATI reforms.

6.5. The Impact of FTR Market Design

FTRs allow the holder access to congestion revenue and therefore protects the holder from the risk of congestion on the path covered by the right. We understand that the AEMC's current proposal is to:

- Auction FTRs to market participants to give holders the right to access payouts equivalent to congestion revenue on the contract path covered by the right (from an LMP to a regional price); and
- Pass revenue from auctions to consumers through reduced TUoS charges.

In order to analyse the distributional impact of the introduction of FTRs, we need to separate two distinct concepts:

- Insufficiency of congestion revenue (settlement residue): Insufficiency of congestion revenue means that revenue from congestion is insufficient to finance the pay-outs on outstanding FTRs. Congestion revenue inadequacy results in non-firm FTRs but is not interesting from a distributional perspective – those parties that own FTRs bear the costs of the loss of pay-out. However, non-firm FTRs may undermine the net social benefits that those rights create.
- Unfair value of auction revenue from FTRs: Unfair value of auction revenue means that the revenue from selling FTRs at auction is not sufficient to finance the pay-outs on outstanding FTRs.

Higher unfair value of auction revenue results in less congestion revenue accruing to consumers. We illustrate the impact of unfair value of auction revenue using our worked example.

If we are in the state of the world as shown in Figure 6.9 whereby the regional reference price under zonal pricing in the NEM is higher than GWAP, then if FTR auction revenues represent fair value, all congestion revenue represents a transfer from generators to consumers from the introduction of LMP. However, if auction revenue represents unfair value, generators will keep a portion of congestion revenue. Therefore, the benefits to consumers from the introduction of LMP and FTRs will be lower (and the benefits to generators higher) than if auction revenue represents fair value.

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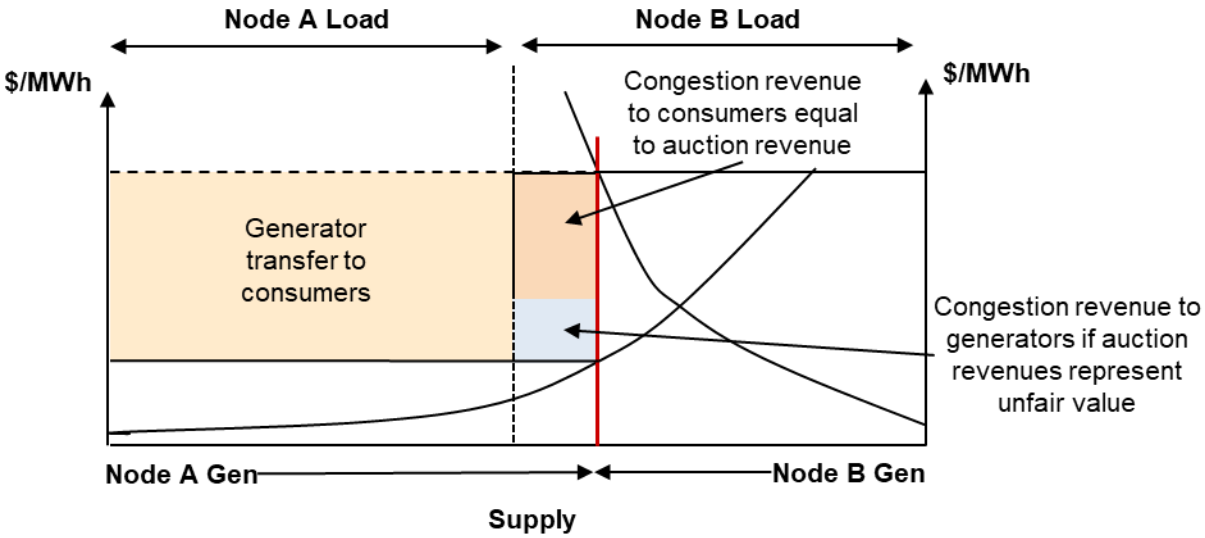
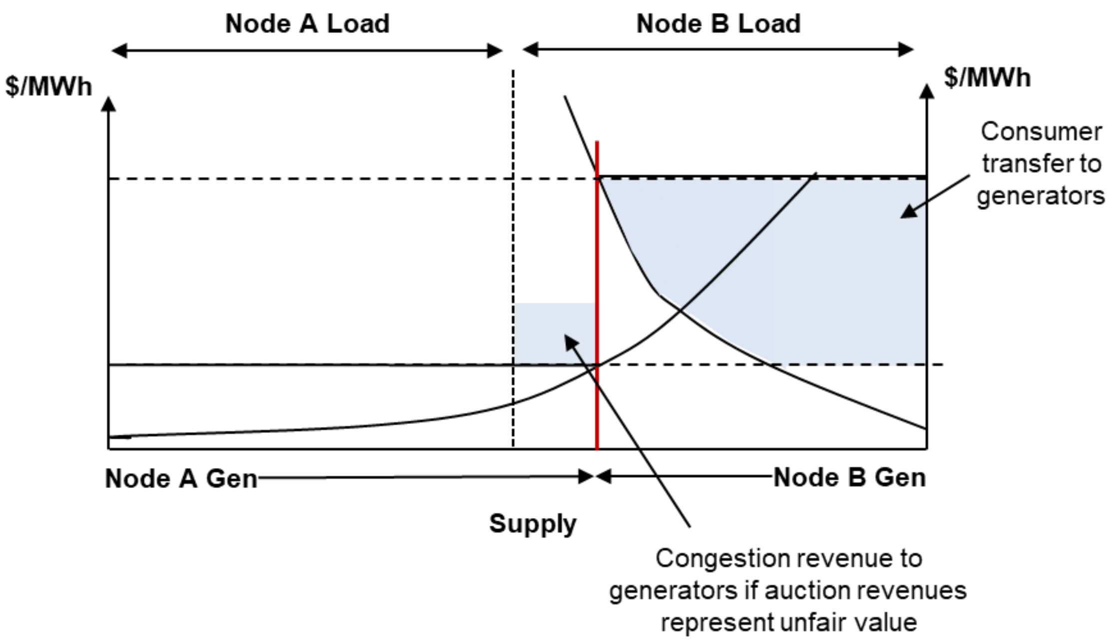
Figure 6.9: Benefits Redistribution with the Introduction of LMP in the NEM: High Zonal Price and FTR Auction Revenue that Represents Unfair Value



Source: NERA Analysis.

On the other hand, if the regional reference price under zonal pricing is relatively low, consumers are already capturing the congestion rents in the system. Consequently, if auction revenue for FTRs represents unfair value, then consumers could end up transferring congestion revenue to generators to cover the difference between auction revenue and FTR payouts, as shown in Figure 6.10. Therefore, overall consumer benefits may fall relative to zonal pricing from the introduction of LMP (and generator benefits may increase).

Figure 6.10: Benefits Redistribution with the Introduction of LMP in the NEM: Low Zonal Price and FTR Auction Revenue that Represents Unfair Value



Source: NERA Analysis.

Across the US jurisdictions that we examine, the reported prevalence of auction revenue representing unfair value is high:

- In CAISO, auction revenue from sales of FTRs was less than FTR payouts by USD 83 million to physical generators and USD 552 million to financial traders from 2009 to 2016 inclusively.[206]
- In PJM, auction revenue from sales of FTRs was less than FTR payouts by USD 1.19 billion from 2011 to September 2017 inclusively.[207]
- In NYISO, non-retail entities received FTR profits (equivalent to auction revenue from sales of FTRs less than FTR payouts plus secondary market trading profits) of USD 938 million from 1999 to 2016.[208]
- In MISO, auction revenue from sales of FTRs was less than FTR payouts by USD 207 million from 2012 to 2017 inclusively.[209]

In the jurisdictions we examine in the US, consumers are given the right to congestion revenue. Consequently, to protect consumers from the transfer of congestion revenue resulting from unfair value at auction, jurisdictions in the US are sacrificing the firmness of FTRs and forcing holders to take a write-down on pay-outs should auction revenue be less than FTR payouts. CAISO has recently introduced such a policy.[210] We understand that PJM and MISO already enforce such a policy.[211]

Therefore, experience in US jurisdictions suggests that the auction for FTRs is likely to lead to an unfair value for FTRs. Should unfair value of auction revenue not result in a write-down of FTR payouts, in other words should FTRs remain firm, then less auction revenue will be available to offset TUoS for consumers. If consumers already captured a large proportion of congestion revenue prior to the introduction of LMP (unlikely in the NEM because the price at the regional reference node is relatively high), the transfer from consumers to generators may mean that consumers accrue negative benefits from the introduction of LMPs.

In our analysis, we have abstracted from the participation of financial players in the market for FTRs. If financial players participate in the market, and auction revenues represent unfair value, then there may also be transfers from consumers and generators to those financial players as a result.

As a consequence of the unfair value paid for FTRs at auctions in the US jurisdictions we examine, the estimates for benefits accruing to consumers will likely overstate the benefits

[206] Department of Market Monitoring (27 November 2017), California ISO: Problems in the performance and design of the congestion revenue right auction, p. 12.

[207] Department of Market Monitoring (27 November 2017), California ISO: Problems in the performance and design of the congestion revenue right auction, p. 17.

[208] Department of Market Monitoring (27 November 2017), California ISO: Problems in the performance and design of the congestion revenue right auction, p. 18.

[209] Department of Market Monitoring (27 November 2017), California ISO: Problems in the performance and design of the congestion revenue right auction, p. 19.

[210] CAISO (25 May 2018), Congestion Revenue Rights Auction Efficiency: Track 1B Draft Final Proposal Addendum.

[211] CAISO (25 May 2018), Congestion Revenue Rights Auction Efficiency: Track 1B Draft Final Proposal Addendum, p. 28.

accruing to consumers from the introduction of LMPs and FTRs in the NEM, because the ex-ante studies include the allocation of all congestion revenue to consumers through FTRs (i.e. the studies assume that auction revenues are fair). On the other hand, the ex-post study for ERCOT would capture the effects of unfair auction revenues on the estimate of consumer benefits.

6.6. The Distributional Impact of Dynamic Marginal Loss Factors

In its assessment of the impact of introducing dynamic marginal loss factors, ERCOT estimates that there will be a redistribution of revenue from generators to consumers. In particular, it estimates that generator revenues from energy sales will fall by USD 212.5 million (1.8 per cent of total revenue under average loss factors).[212] For generators, ERCOT estimates redistribution of revenues from nodes with higher marginal loss factors to lower marginal loss factors. The changes in regional generator revenues are larger than the overall reduction in generator revenues, for example the North Zone would receive USD 331.9 million less under dynamic marginal loss factors. On the other hand, generators in the Houston Zone would receive USD 216.4 million more under dynamic marginal loss factors.[213]

ERCOT estimates that the reduction in annual production costs will result in a fall in annual consumer costs of USD 135 million under dynamic marginal loss factors by comparing the two scenarios.[214] Changes to total annual consumer costs differ across the zones which implies a redistribution of cost savings amongst consumers. ERCOT do not explain the reasons for the redistribution of cost savings.

6.7. Generator Benefits

The benefits accruing to generators from the introduction of FTRs and LMP will equal the net social benefits accruing to generators from the reform minus the benefit transfer to consumers arising from the reform. The studies that we examine all assume a transfer of benefits from generators to consumers resulting from the introduction of LMP. We found limited evidence in the studies we examine of the direct impact on generators from the reform.

However, unlike consumers, scheduled generators will face different prices after the reform resulting in inter-nodal redistribution of scheduled generator revenues, based on the geographical location of generators within the NEM. Scheduled generators at nodes with lower LMPs (Node A in our worked example) will be paid less for their power whilst scheduled generators at nodes with higher LMPs (Node B in our worked example) will be paid more. Without modelling the distribution of nodes, and prices across those nodes, it is difficult to quantify the degree of the redistribution between nodes.

212 ERCOT (29 June 2018), Study of the System Benefits of Including Marginal Losses in Security-Constrained Economic Dispatch, p. 3.

213 ERCOT (29 June 2018), Study of the System Benefits of Including Marginal Losses in Security-Constrained Economic Dispatch, p. 3.

214 ERCOT (29 June 2018), Study of the System Benefits of Including Marginal Losses in Security-Constrained Economic Dispatch, p. 4.

We found no evidence in the case studies that we examine of redistribution impacts across generator fuel types arising from the introduction of LMP. In particular, we found no evidence of any specific impact on renewable generation that could be used to inform the likely impact of LMP on renewable generation in the NEM. In addition, to our knowledge, unscheduled generators were also paid LMPs in all the jurisdictions that we examine.

6.8. Summary of Distributional Impacts

We identify three sources of benefits that may accrue to generators or consumers after the introduction of LMP:

- **Efficiency gains**: The net social benefits from more efficient market operation may accrue to generators or consumers and therefore both generators *and* consumers may be made better off as a result of the reform. In other words, only through net social benefits arising from the reform is a zero-sum game avoided. We discuss net social benefits in Sections 4 and 5.
- **Out of Merit payments**: The elimination of OOM up payments does not represent a benefit that accrues to consumers as part of the introduction of LMPs, as the elimination of OOM up payments is exactly offset by increases in generator revenue. However, the elimination of OOM down payments from the introduction of LMP represent benefits to consumers in US jurisdictions. The larger the OOM down payments in US jurisdictions, the more likely that the estimates for consumer benefits from the introduction of LMPs in those jurisdictions overstate the benefits when transferred to the NEM. In ERCOT, OOM down payments are significantly higher than OOM up payments and were forecast to be approximately USD 400 million per annum in the 2004 CBA.[215]
- **The zonal price relative to the generators' volume-weighted average of LMPs (GWAP)**: The higher the zonal price in the NEM relative to GWAP, the higher the benefits that will accrue to consumers from the introduction of LMP.

We use a benefits transfer methodology to estimate the benefits accruing to consumers in the NEM from the introduction of LMP and FTRs using estimates for similar reforms in US jurisdictions. However, due to differences between the US markets and the NEM before the reform, it is not clear if these estimates under- or overstate the expected consumer benefits from LMP in the NEM. A detailed modelling of the electricity market in the NEM is required to estimate expected consumer benefits more accurately.

The studies that we examine all assume a transfer of benefits from generators to consumers resulting from the introduction of LMP. We report our results in Table 6.6 below.

[215] ERCOT, TCA and KEMA (30 November 2004), Market Restructuring Cost-Benefit Analysis, p. 3-26.

Table 6.6: Benefits to Consumers in the NEM based on Case Study Evidence

Market	Ex-ante or Ex-post?	Equivalent Reduction in Wholesale Prices	Estimated Consumer Transfer Per Annum (AUDm)					
			QLD	NSW	VIC	SA	TA	NEM
ERCOT	Ex-ante	5.59%	260	369	310	89	53	**1,081**
ERCOT	Ex-ante	3.97%	185	262	220	63	38	**768**
ERCOT	**Ex-post**	**2.00%**	**93**	**132**	**111**	**32**	**19**	**387**
SPP	Ex-ante	7.00%	326	462	388	112	67	**1,354**

Source: NERA Analysis

We estimate the benefits accruing to consumers as a consequence of introducing LMP range from AUD 387 million to AUD 1,354 million per year. We estimate that, should the NEM achieve the average wholesale price reduction estimated across the studies we examine, the benefits to consumers would be AUD 897 million per year. We consider that the best available evidence on the benefits of LMP is AUD 387 million based on the ex-post ERCOT study, because this is the only study that examines data of the realised price changes for consumers arising from the reform (as opposed to estimating benefits based on an ex-ante modelling of the electricity market).

For clarity, the numbers reported in the above studies represent total savings to customers as a consequence of the introduction of LMP. Therefore, the above savings include and conflate both transfers from generators to consumers because of the reform as well as net social benefits arising from more efficient market operation and accruing to consumers. In addition, the estimates from other jurisdictions capture the impact of a wide suite of reforms beyond LMP and likely conflate the impact of those reforms with the impact of introducing LMP.

We are unable to determine whether the percentage wholesale price reductions reported in other studies are likely to overstate or understate the benefits consumers may realise from the reform in the NEM, without detailed modelling of the electricity market in the NEM and the proposed reforms.

7. Initial Evidence on the Impact on the Cost of Capital

This chapter sets out the research and analysis on the potential impact on the cost of capital of generators as a result of the COGATI reform.

7.1. The AEMC's view on the reform's impact on cost of capital

In its proposal,[216] the AEMC argues that the proposed access reform should improve investment certainty for generators, and may reduce their long-term cost of capital. The AEMC considers that the proposed access model will improve financial certainty for generators, as the market participants can better manage their dispatch risk during times of congestion using FTRs.

According to the AEMC, under the current access model, market participants are unable to manage the risks of congestion and losses effectively.[217] For example, a generator's ability to earn the regional reference price through the market is dependent on it being dispatched. Similarly, generators are unable to control their marginal loss factor once they have made an investment decision.

The AEMC argues that under the new framework, financial outcomes would be partially decoupled from physical dispatch.[218] If a generator had purchased an FTR, then it would be paid if its local price differed from the strike price in the financial transmission right. This payment would occur even if the generator was not dispatched, or subject to a dynamic loss effect than was more variable than expected. Similarly, retailers and other market participants on the demand side of the market will be able to purchase FTRs to manage any risks that accrue to them under the terms of forward contracts.

Overall, the AEMC argues that using FTRs the generators will be able to improve their risk management, which will increase investment certainty and reduce long run cost of capital, and ultimately reduce costs for consumers.[219]

7.2. Stakeholders' response to the reform's impact on cost of capital

In general, some stakeholders remain unconvinced that there would be a reduction in cost of capital for generators under the proposed access model.

Some stakeholders generally argue that the reforms would increase complexity, uncertainty and risk, which would increase the cost of capital and as a result the cost of energy.[220] For instance, Stanwell argues that FTRs may increase the cost of capital for new projects because FTR represents an additional fixed cost for the generators, and would increase the leverage and therefore risk of the firm. Stanwell also argues that FTRs would require additional equity

216 AEMC (14 October 2019), COGATI Proposed Access Model, p. 22.

217 AEMC (14 October 2019), COGATI Proposed Access Model, p. 23.

218 AEMC (14 October 2019), COGATI Proposed Access Model, p. 23.

219 AER (12 November 2019), Submission to Discussion Paper on the Proposed Access Model for the Coordination of Generation and Transmission Infrastructure, p. 11.

220 Stakeholder submissions to discussion paper, Energy Queensland. Foresight, Windlab, Powering Australian renewables fund, Bayware projects Australia, ESCO, John Laing and the CEIG, Alinta, Infigen, Total, Palisade Investment Partners.

for the project, which would increase the weighted average cost of capital, or the revenue requirement to achieve the minimum debt service coverage ratios.[221] Stanwell further argues that financiers could penalise potential projects, if there is any shortfall between FTRs and expected capacity, and if the FTRs are not always firm.[222] Origin made a similar argument, that if FTRs are not fully firm, generators would face both price and volume risk which may lead to overall higher risk and costs.[223] Snowy Hydro argues that the additional basis risk may outweigh the benefits from more efficient dispatch.[224]

In addition, stakeholders also argue that there is uncertainly around the availability and allocation of FTRs, which would not necessarily reduce the cost of capital. For example, ENGIE argues that FTRs need to be made available over the lifetime of the asset to reduce transmission risk across the project and lower the cost of capital.[225] Otherwise, incumbents may continue to face the risk of new entrants as new entrants can bid for FTRs, resulting in higher losses, congestion, competition for FTRs, and costs for the incumbent.[226]

Other generators, such as Meridian, argued that the reform itself could create uncertainty as to how the risks of price and dispatch would be allocated between generators, retailers and financiers looking to commit to new generation projects.[227]

7.3. Other commentary on the reform's impact on cost of capital

We have reviewed commentary on the proposed reform's impact on cost of capital from other agencies, such as the credit rating agencies, equity research analysts, finance literature, and various case studies discussed in Section4.1.

For credit rating agencies, we have reviewed the most recent credit rating reports and sector commentary from Moody's for any relevant comments on this issue, but we have not identified any comments on the COGATI reform.[228] We also received confirmation from Moody's that they have not considered the impact of the COGATI reform on the credit rating of the Australian power generation sector.

For the equity research, we have reviewed recent equity analyst reports for the listed generation companies, including AGL and Origin.[229] However, there is no comment on the COGATI reform so far, and the potential impact on the companies' equity risks.

221 Stanwell (13 November 2019), 2019 COGATI: Response to AEMC COGATI Discussion Papers, p. 8.

222 Stanwell (13 November 2019), 2019 COGATI: Response to AEMC COGATI Discussion Papers, p. 8.

223 Origin (8 November 2019), AEMC: Coordination of Generation and Transmission Investment Discussion Paper – Proposed Access Model, p. 6.

224 Snowy Hydro (8 November 2019), COGATI proposed access model Discussion paper, p. 1.

225 ENGIE (8 November 2019), COGATI Proposed Access Model – Discussion Paper EPR0073, p. 4.

226 Stanwell (13 November 2019), 2019 COGATI: Response to AEMC COGATI Discussion Papers, p. 8.

227 Meridian Energy Australia and Powershop Australia (8 November 2019), COGATI Proposed Access Model, p. 3.

228 There is no discussion of COGATI reform in recent Moody's sector outlook, such as Moody's Investor Service (23 July 2019), Regulated networks and unregulated utilities — Australia, Issuers will manage the transition to lower carbon and decentralized power generation.

229 We have reviewed all up-to-date equity analyst reports for AGL and Origin available to us at the time of the writing of this report. For AGL, we reviewed the following reports: JP Morgan (19 December 2019), AGL Energy (AGL AU), How much of an impact has the buyback had on the share price; JP Morgan (19 November 2019), AGL Energy, In-

There are a number of studies that focus on the costs and benefit of nodal pricing (i.e. LMP) versus zonal pricing (discussed in Section 4.1), but so far we have not identified any detailed analysis of the direct impact of nodal pricing on power companies' risks and cost of capital.

For the case studies, which we discuss in Section 4.1, we have also not identified any discussion or evidence of the impact of LMP and FTRs on power companies' risks and cost of capital.

Overall, our review of credit rating agencies' and equity research analysts' reports, the finance literature, and various case studies indicates that there is limited evidence or discussion on the impact of LMP and FTRs on companies' risks and cost of capital. The lack of discussion and evidence suggests that the credit rating agencies and equity analysts may consider it too early to publish any formal analysis on the implication of COGATI reform, or they may consider the COGATI reform to not have a significant impact on power companies' cost of capital.

7.4. NERA's assessment of the impact on generators' risk

In this section, we assess the potential impact on cost of capital by evaluating the changes in the risks faced by generators in the current model and the proposed model.

We perform our analysis using the method of decision trees, which assesses how the introduction of LMP and FTRs would affect the risks faced by a generator by constructing and evaluating its pay-offs under different scenarios. Throughout our analysis in this section, we denote the fixed forward price as "K", the regional reference price as "RRP", locational marginal price as "LMP", volume-weighted average price as "VWAP", and marginal cost as "MC". For each scenario, we compare the possible consequences in the current model and the proposed model, which allows us to determine the impact on risks. We note that our analysis is based on the AEMC's October discussion paper and December update paper, but aspects of the proposed reform may change following further consultations.

In our approach, we do not explicitly examine the partial pay-out of an FTR. Instead, our analysis models FTRs on a MW by MW basis. Partial pay-out of FTRs corresponds to the full pay-out of some MWs of FTRs and zero pay-out of others. Overall, the fraction of MWs of FTRs that pay-out correspond to the probability that FTRs are "firm". Our approach,

depth analysis of forward earnings; JP Morgan (5 November 2019), AGL Energy, Model Update; JP Morgan (30 October 2019), AGL Energy, 2019 Investor Day; JP Morgan (8 August 2019), AGL Energy, FY2020 guidance well below consensus; JP Morgan (8 August 2019), AGL Energy, With earnings now rebased, we upgrade to Neutral; JP Morgan (31 July 2019), AGL Energy, We expect sizeable market adjustments to FY2020 earnings; downgrading to Underweight; JP Morgan (16 July 2019), AGL Energy, Downgrading on valuation with risks ahead of next Federal Election; Deutsche Bank (18 June 2019), AGL Energy Ltd, VOC Bid Withdrawn – Coverage Resumed; JP Morgan (11 June 2019), AGL Energy, Conditional proposal for Vocus; Deutsche Bank (1 April 2019), AGL Energy Ltd, Labor Fleshes Out Its Energy Policy; JP Morgan (7 February 2019), AGL Energy, Strong result but no change to full year guidance; JP Morgan (7 February 2019), AGL Energy, Guidance now implies earnings will fall 10% in the June 2019 half; JP Morgan (16 January 2019), AGL Energy, Downgrading on valuation with risks ahead of next Federal Election. For Origin, we reviewed the following reports: JP Morgan (15 January 2020), Australian Energy, Quarterly commodity mark-to-market; JP Morgan (20 November 2019), Origin Energy (ORG AU), Focusing on cash generation; JP Morgan (31 October 2019), Origin Energy (ORG AU), Reasonable September quarter against our forecasts; JP Morgan (22 August 2019), Origin Energy (ORG AU), Reasonable result and outlook considering peers; JP Morgan (31 July 2019), Origin Energy (ORG AU), Mixed result with non-cash provision to see downgrades to FY2019 estimates; Deutsche Bank (3 May 2019), Origin Energy, Q3 Review; JP Morgan (30 April 2019), Origin Energy (ORG AU), Another record quarter for Integrated Gas revenue; JP Morgan (21 February 2019), Origin Energy (ORG AU), Interim results - FY2019; JP Morgan (31 January 2019), Origin Energy (ORG AU), Record Integrated Gas revenue for the quarter.

when applied to all FTRs, is equivalent to examining the partial pay-out of FTRs. Therefore, ownership (without purchase) of an FTR is still valuable even if the FTR only partially pays-out, relative to the case of not owning an FTR.

We start by considering the proposed reform's impact on the risk faced by a generator that sells its electricity in the forward market, denoted as a "hedged" generator, in Section 7.4.1. We then assess the impact on risk for the generators that do not sell forward, denoted as "unhedged" generators, in Section 7.4.2.

7.4.1. Risk assessment for hedged generators

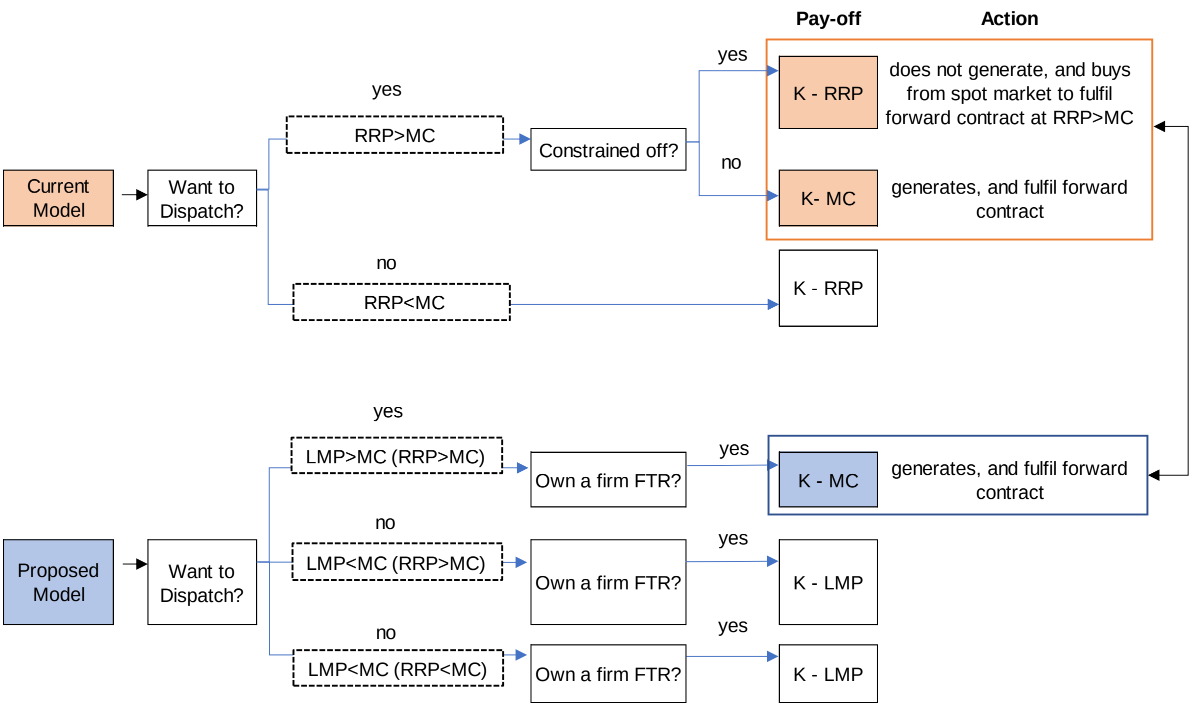
First, we consider a hedged generator, defined as generators that sells electricity in the forward market, who faces a marginal cost that is below RRP in the current model, and owns a firm FTR in the proposed model. In the current model, if the hedged generator does not face the constraint at the transmission network, then it will generate and fulfill its forward contract, with a net payoff of (K – MC).[230] However, in the current model, a hedged generator faces the risk of being constrained off, in which case it has to buy electricity from the spot market at the prevailing market price RRP to fulfill its forward contract, and receives a net payoff of (K – RRP) on the quantity of electricity that was constrained off/down.

In the proposed model, the same generator no longer faces the risk of being constrained off, and will lock in a net payoff of (K – MC) when the LMP is above marginal cost when it has a firm FTR.[231] Therefore, for a hedged generator who wants to produce when the prevailing market price is above its marginal cost, it is always better off in the proposed model if it owns a firm FTR, as illustrated in Figure 7.1.

230 In this case, the hedged generator's payoff in the forward market is K – RRP, and its payoff in the spot market is RRP – MC. The net payoff is K – RRP + RRP – MC = K – MC.

231 In this case, the hedged generator's payoff in the forward market is K – VWAP, and its payoff in the spot market is LMP – MC, and the payoff from FTR is VWAP – LMP. The net payoff is K – VWAP + LMP – MC + VWAP – LMP = K – MC.

Figure 7.1: For a hedged generator that wants to generate, having a firm FTR in the proposed model would reduce risk



Source: NERA analysis

However, since there is a trade-off between the firmness and availability of FTRs under the proposed model, there are some generators that would not have a firm FTR, and therefore would face an additional basis risk. In this case, the same generator now faces the uncertainty around whether it owns a firm FTR, either because of not being allocated one, or the FTR it has is not firm and fails to pay off. In our analysis below, we introduce an additional scenario where the generator does not own a firm FTR.[232]

As illustrated in Figure 7.2, in the proposed model, when the hedged generator does not have a firm FTR, it would face a payoff of K – MC – (VWAP – LMP), where the (VWAP – LMP) term is precisely the additional basis risk that the FTR is designed to eliminate.[233] Therefore, a hedged generator whose marginal cost is below the prevailing market price and who wants to generate faces a tradeoff between the risk of being constrained off in the current model, and the risk of not having a firm FTR, leading to additional basis risk in the proposed model. The net impact from the proposed reform would depend on which risk would dominate going forward.

232 If a generator does not own a firm FTR, but its uncertain FTR pays off, then its payoff will be the same as owning a firm FT, and would be categorized as owning a firm FTR in the schematic analysis. Since our analysis at this stage does not include an assessment of the probability of each scenario, this simplification does not affect the conclusion. We will assess the probability based on data from modelling results.

233 In this case, the generator sells forward at K, and its payoff in the forward market is K – VWAP; it generates the electricity because its marginal cost is below LMP, so its payoff in the spot market is LMP – MC; since its FTR is not firm and does not pay, the net payoff is K – VWAP – LMP – MC = K – MC – (VWAP -LMP) = K-MC – basis risk

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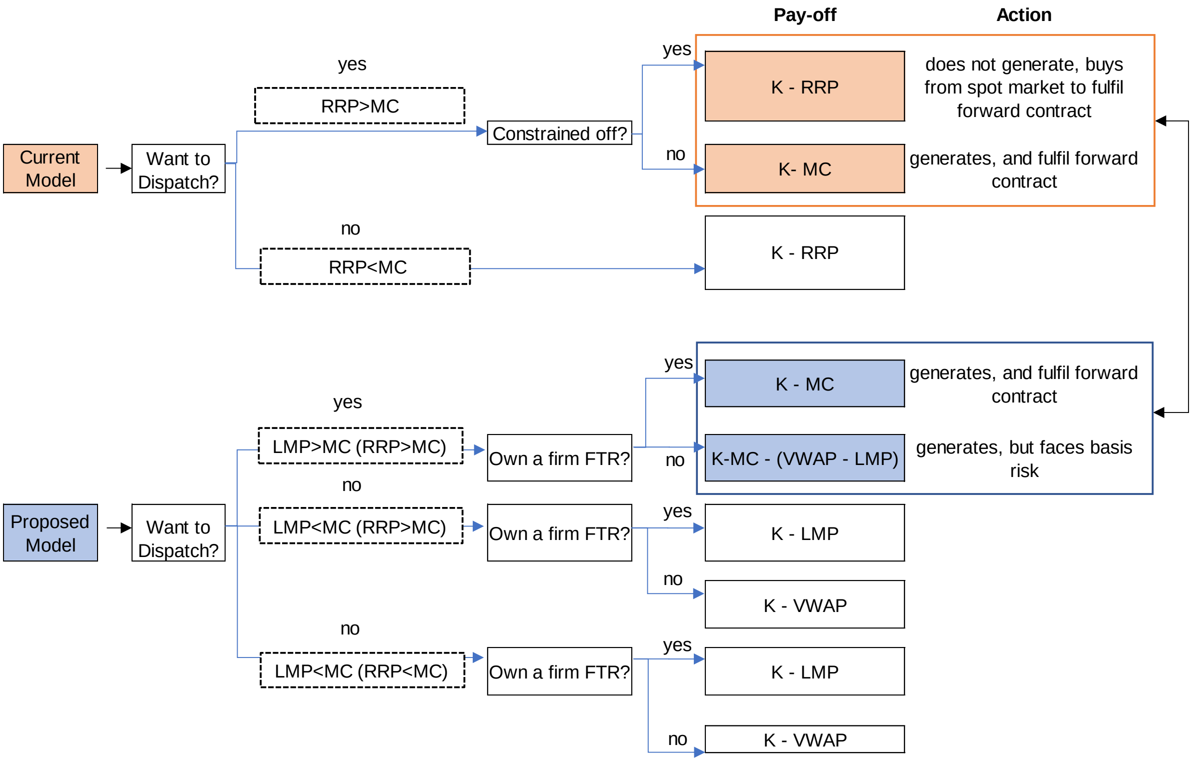
Figure 7.2: For a hedged generator that faces uncertainty of owning a firm FTR, its risk in the proposed model could be higher or lower, as it faces a trade-off between the constraint risk in the current model and basis risk in the proposed model



Source: NERA analysis

Second, we consider a hedged generator whose marginal cost is below the RRP, but its marginal cost is above the LMP in the proposed model. This means that it would want to generate electricity in the current model, but it would not want to generate in the proposed model, as illustrated in Figure 7.3.

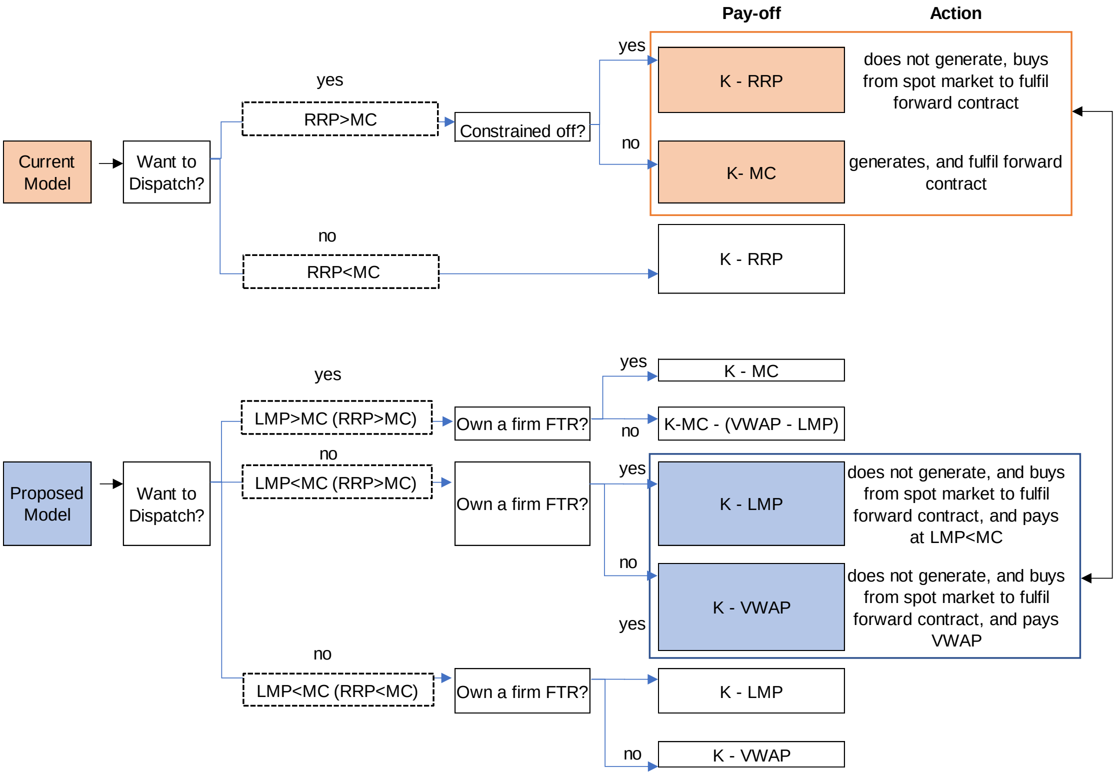
For this generator, in the current model it would face the payoff of (K – RRP) if it is constrained-off, and would face the payoff of (K – MC) if it generates. In the proposed model, its payoff would be (K – LMP) if it owns a firm FTR, [234] and (K – VWAP) if it does not own a firm FTR. [235] In this scenario, the generator would be better off under the proposed model, as this scenario assumes RRP > MC > LMP, which makes the payoff in the proposed model higher than the current model if the generator owns a firm FTR. In addition, the generator with a firm FTR would face lower downside risk in the proposed model in this scenario. This is because in this case, the LMP is constrained below MC, which makes the downside risk of the payoff K – LMP in the proposed model necessarily lower than in the current model, in which the generator faces a payoff of either K – RRP or K – MC, as illustrated in Figure 7.3. However, if the generator does not own a firm FTR, then the payoff in the proposed model would become K – VWAP, compared to either K – RRP or K – MC.

234 In this case, the hedged generator's payoff in the forward market is K – VWAP, and its payoff from the FTR is VWAP – LMP, so the net payoff is K – LMP.

235 In this case, the hedged generator's payoff in the forward market is K – VWAP, and since it does not have a firm FTR, so the net payoff is K – VWAP.

In this case, the impact on risk would depend on the relative likelihood of a generator being constrained off, the likelihood of a generator not owning a firm FTR, and the relative volatility between RRP and VWAP.

Figure 7.3: For a hedged generator whose marginal cost is below RRP but above LMP, its risk impact would depend on the likelihood of being constrained off, and the relative volatility between RRP and LMP



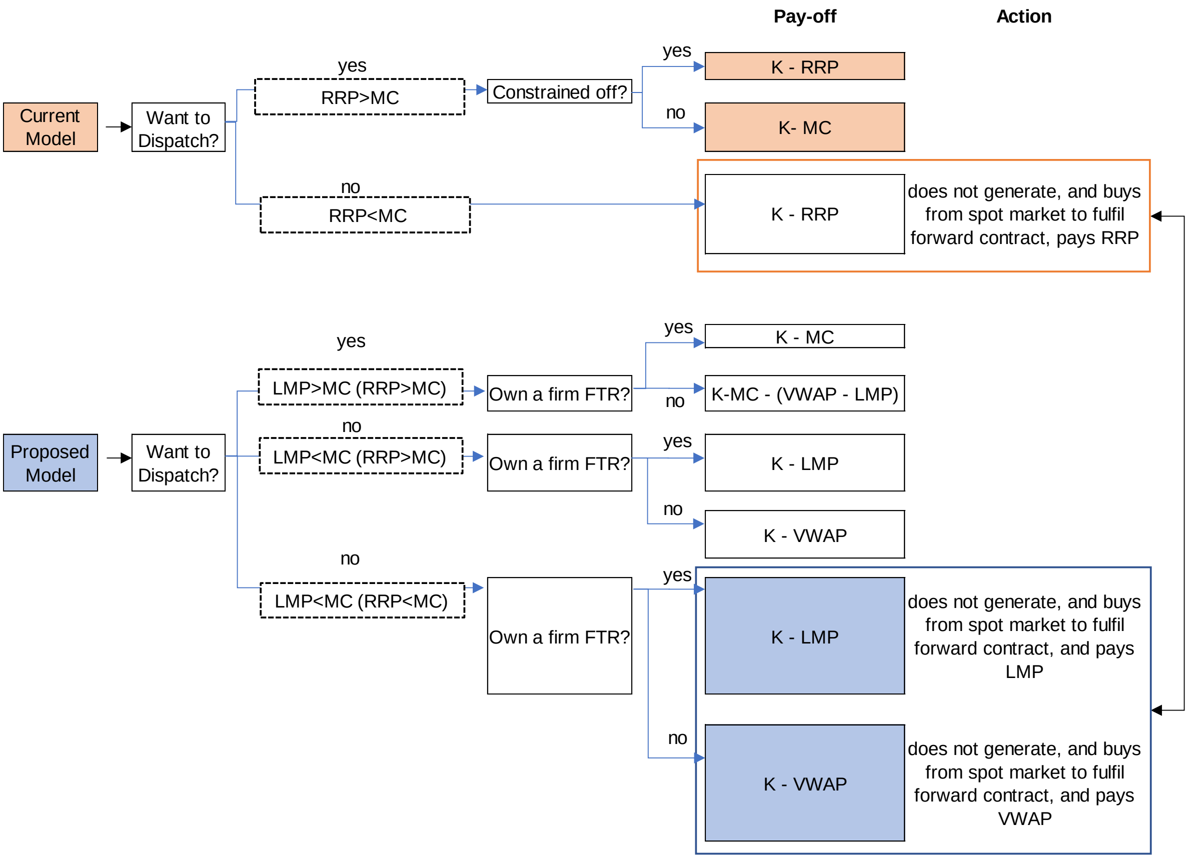
Source: NERA analysis

Finally, we consider the case where a hedged generator sells forward its electricity, but its marginal cost turns out to be above RRP and also LMP. This generator would neither generate in the current model, nor the proposed model, and would have to purchase the electricity in the spot market at the prevailing market price.

As illustrated in Figure 7.4. for this generator, in the current model its payoff is (K – RRP), and in the proposed model its payoff would be either (K – LMP) or (K – VWAP) depending on whether it owns a firm FTR.[236] Intuitively, since the generator would not generate and would purchase electricity to fulfill its forward contract, the risk impact depends on the volatilities of the prevailing market prices in the current model and the proposed model. The risk of this hedged generator could be higher or lower, depending on relative volatility between RRP, LMP and VWAP.

[236] In this case, the hedged generator's payoff in the forward market is K – VWAP, and its payoff from the FTR is VWAP – LMP, so the net payoff is K – LMP, if it owns a firm FTR. If it does not have a firm FTR, then its payoff would be K – VWAP.

Figure 7.4: For a hedged generator whose marginal cost is above price, its risk impact would depend on the relative volatility between RRP and LMP



Source: NERA analysis

In conclusion, we find that for a hedged generator who wants to generate when the prevailing market price is above its marginal cost, it is always better off in the proposed model if it owns a firm FTR, as illustrated in Figure 7.1. However, since there is a trade-off between the firmness and availability of FTRs, some generators would not have a firm FTR, and therefore would face an additional basis risk. When the hedged generator faces uncertainty around having a firm FTR, the impact on risk depends on the likelihood of a generator being constrained off, the likelihood of a generator not owning a firm FTR, and the relative volatility between RRP, LMP and VWAP. These are illustrated in Figure 7.2, Figure 7.3, and Figure 7.4.

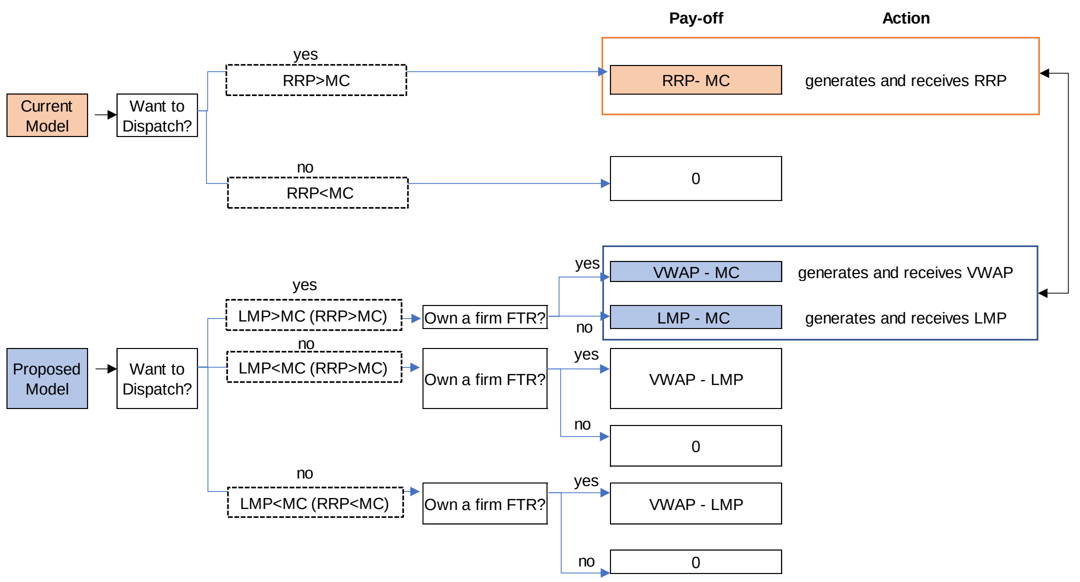
7.4.2. Risk assessment for unhedged generators

In this section, we consider the risk impact for the generators that do not sell their electricity forward, denoted as the “unhedged” generators.

For an unhedged generator whose marginal cost is below RRP in the current model, it would like to generate and dispatch, and it would face the volatility of the RRP. In the proposed model, the same generator will instead face the volatility of the prevailing market price, which is LMP.

If it owns a firm FTR, then it will receive a payoff of VWAP – MC since the FTR bridges the difference between VWAP and LMP.[237] If the unhedged generator does not have a firm FTR, then it will receive a payoff of LMP – MC. In this case, the impact on risk would depend on the likelihood of the constraint risk, the probability of owning a firm FTR, as well as the relative volatility of RRP in the current model, compared to LMP in the proposed model, as illustrated in Figure 7.5.

Figure 7.5: For an unhedged generator that faces uncertainty of owning a firm FTR, its risk in the proposed model depends on the likelihood of constraint risk, and relative volatility between VWAP and RRP



Source: NERA analysis

There are two other scenarios for the unhedged generator when it does not want to dispatch when the prevailing market price is below marginal cost, as shown in Figure 7.5. In contrast to the hedged generator, there is no basis risk introduced by the proposed model for the unhedged generator since it does not have the financial obligation to deliver the electricity. Therefore, conceptually the reform should have no material impact on the risks faced by this type of generator when it does not want to generate and dispatch.[238]

In conclusion, we find that an unhedged generator who wants to generate when the prevailing market price is above its marginal cost would be better off in the proposed model if it owns a firm FTR, since it no longer faces the constraint risk. When the hedged generator faces uncertainty around having a firm FTR, the impact on risk would depend on the likelihood of

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237 In this case, the unhedged generator receives (LMP – MC) in the spot market, and receives (VWAP – LMP) from the FTR. The total net payoff is VWAP – MC.

238 The unhedged generator will receive a payoff of VWAP – LMP if it owns a firm FTR, compared to receiving zero in the current model, but there is no impact on the downside risks.

the constraint risk, the probability of owning a firm FTR, as well as the relative volatility of RRP, VWAP and LMP.[239]

7.5. Quantification of impact on cost of capital

We draw on the weighted average cost of capital (WACC) methodology to estimate the impact on the cost of capital of generators, in line with Australian energy regulators.[240] We start by describing the methodology, and then discuss how the proposed reform would affect the parameters.

The WACC for a given firm is the weighted return on equity and debt, where the respective weights are determined by the relative proportions of debt and equity or gearing. A standard way to express this is:

$$WACC = (1-g)R^E + gR^D$$

The cost of equity is measured using the capital asset pricing model (CAPM), which assumes that the cost of equity for a firm is given by

$$R^E = RFR + \beta(TMR - RFR)$$

where R^E is the return on equity, RFR is the risk-free rate, β is the measure of the systematic risk of the company's equity with the market portfolio, and TMR is the total return on the market portfolio.

The cost of debt (R^D) can be viewed as the sum of the risk-free rate and the debt premium, which reflects the risk of debt in excess to the risk-free rate. The debt premium should reflect the credit ratings of the company.

7.5.1. Assessment of Impact on Cost of Equity under CAPM

The starting point of our analysis for the cost of equity impact is the CAPM. Under the CAPM, market participants earn a premium over the risk-free rate which depends only on correlation with the market portfolio, which is known as "systematic risks" or "beta risk". For example, if under the proposed model, a generator's expected return becomes more correlated with the market return than under the current model, then the generators would face an increase in systematic risk, and therefore command a higher required rate of return under the CAPM.

As we determine in Section 7.4, a generator would face lower risks in the proposed model if it owns a firm FTR when it wants to generate, but if the hedged generator faces uncertainty of owning a firm FTR, the impact on risk would depend on a number of variables, such as the likelihood of a generator being constrained off, the likelihood of a generator owning a firm FTR, and the volatility between RRP, LMP and VWAP. However, whether these would affect the cost of equity under the CAPM would depend on whether these risks are correlated with the market return or not.

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239 We note that aspects of the reform may change compared to the proposals set out in the AEMC's October discussion paper and December updated paper. For example, the AEMC may decide to maintain the RRP, instead of introducing VWAP. In this case, the impact on risk would no longer depend on the VWAP volatility, but the volatility between RRP and LMP only.

240 AER (December 2019), Rate of Return Annual Update

To determine the precise impact would require examination of the market correlation of the constraint risks, and basis risk, based on modelled electricity prices and historical market returns. However, in theory, we expect that the constraint risks and basis risks would not be strongly correlated with the market return. The market return is driven by macroeconomic variables such as aggregate economic growth, and reflects long-term expectation. In contrast, the constraint risk and basis risks are determined by variations in local electricity prices, which in theory would not be strongly correlated with movement in market's expected return. Therefore, while this is an empirical question, conceptually we would not expect any material impact on cost of equity as a result of access reform.

7.5.2. Assessment of Impact on Cost of Debt Using Rating Agency's Methodology

The CAPM framework assumes that the risks are only relevant if they are systematic risk, which are appropriate for the cost of equity assessment. In the context of access reform, even though the proposed model may not affect the systematic risks faced by the equity holders, the debt risk may change as a result of the proposed reform. This is because debtholders are concerned with the absolute level of risk, rather than systematic risk alone.

The impact on cost of debt could increase or decrease, depending on the relative costs and benefits of the COGATI reform. We will need to assess the change in absolute risk empirically once we have the modelling results to examine the impact of the different offsetting risk factors, such as the constraint risks, the basis risks, and the relative volatility of RRP, LMP, and VWAP. The degree to which FTRs can affect credit rating and cost of debt as a result of more contracting in the forward market depends on (i) the firmness of FTRs, (ii) the extent to which FTRs are auctioned or grandfathered, (iii) the availability of FTRs at auction, and (iv) the contract duration of FTRs that participants can purchase at auction. How the FTR will be designed and implemented would determine the likely impact on the credit rating, e.g. Moody's considers companies that have forward hedging arrangements for the longer term (e.g. 5 years) to have a higher rating.

In the absence of the modelling results, we present an illustrative scenario of maximum impact on debt risk under the assumption that the reform does reduce risk, by allowing generators to improve their hedging and also have a better market framework than the current regime as the net effect of the risk change. In this hypothetical scenario where risk is reduced under the reform, to quantify the impact on the debt risk premium, we apply the credit rating methodology published by Moody's to assess the potential change in the credit rating for the representative generator, if the access reform successfully reduces the risks.[241]

Moody's rating grid contains four broad rating factors important for ratings of generators: i) scale, ii) business profile, iii) financial policy, and iv) leverage and coverage. These broad rating factors are comprised of sub-factors that provide further detail, as shown in Figure 7.6.

Among all the sub-factors, the primary factor that we consider would likely be affected by the proposed access reform is the "Hedging and Integration Impact on Cash Flow Predictability", which accounts for 10% of rating weighting under Moody's rating methodology. In addition, the sub-factor "Market Framework & Positioning" (15% weight) could also be improved under the access reform, as this sub-factor considers the transparency and effectiveness of the

[241] Moody's Investor Service (17 May 2017), Unregulated Utilities and Unregulated Power Companies

wholesale power market in which a company operates, as well as the competitive profile and positioning of company-specific assets within the region.[242] We discuss Moody's approach to evaluating these sub-factors in Appendix E.

Figure 7.6: Moody's Rating Grid for Unregulated Power Company

Criteria	**Unregulated Power Company Sub-factor weighting**
SCALE	
Scale	10%
BUSINESS PROFILE	
Market diversification	5%
Hedging and integration impact on cash flow predictability	10%
Market framework and positioning	15%
Capital requirements and operational performance	5%
FINANCIAL POLICY	
Financial policy	15%
LEVERAGE AND COVERAGE	
(CFO Pre-W/C + Interest) / Interest Expense	10%
(CFO Pre-W/C) / Debt	20%
RCF / Debt	10%
Total	**100%**

Source: Moody's Investor Service (17 May 2017), Unregulated Utilities and Unregulated Power Companies

We apply Moody's rating methodology to a representative Australian power company using AGL Energy Ltd[243] as an example. Our starting point is the most recent Moody's credit opinion report for AGL.[244] AGL's indicated rating from the methodology grid on both a historic and forward-looking basis is Baa1, as shown in Figure 7.7.[245]

242 We do not expect other sub-factors to change as they are not closely related to the proposed reform. We consider the scale, market divarication, capital requirement and operational performance, and financial policy would be unlikely affected by the proposed introduction of zonal pricing and FTRs in the long term. There would be impacts on the financial ratios, but this section focusses on the forward looking risks, rather than the return level. The level of return is addressed in our distributional analysis.

243 AGL has the largest share of NEM capacity (21%) in January 2018. ACCC (July 2018), Retail Electricity Pricing Inquiry – Final Report, p vii. Link: https://www.accc.gov.au/system/files/Retail%20Electricity%20Pricing%20Inquiry%E2%80%94Final%20Report%20June%202018_Exec%20summary.pdf

244 Moody's Investors Service (13 August 2019), AGL Energy Ltd: Update to credit analysis following fiscal 2019 results, p.9.

245 AGL's actual rating assigned of Baa2 is one notch lower, which reflects Moody's view of AGL's increased likelihood of capital management activities and debt-funded capital expenditures in light of AGL's commitment to balance sheet strength in accordance with a Baa2 rating. Source: Moody's Investors Service (13 August 2019), AGL Energy Ltd: Update to credit analysis following fiscal 2019 results, p.9.

Figure 7.7: Moody's Grid Credit Rating Assessment of AGL Energy Ltd

Criteria	Moody's 12-18 Month Forward View as of August 2019
SCALE	
Scale (10%)	Baa
BUSINESS PROFILE	
Market diversification (5%)	Ba
Hedging and integration impact on cash flow predictability (10%)	Baa
Market framework and positioning (15%)	Baa
Capital requirements and operational performance (5%)	A
FINANCIAL POLICY	
Financial policy (15%)	Baa
LEVERAGE AND COVERAGE	
(CFO Pre-W/C + Interest) / Interest Expense (10%)	Baa
(CFO Pre-W/C) / Debt (20%)	A
RCF / Debt (10%)	A
Indicated Rating from Grid	**Baa1**

Source: Moody's credit opinion for AGL, August 2019

In assessing the credit profile of AGL, Moody's considers the energy policy and/or government intervention as a main risk factor, and commented that "AGL's rating could be upgraded if we believe there is sufficient clarity on the direction of Australian energy policy and regulation, given this will be a fundamental driver of energy prices and the company's investment priorities."[246] Therefore, if the proposed reform is successfully implemented and delivers the benefits proposed by the AEMC, then the rating scores for the "Hedging and integration impact on cash flow predictability" and "Market framework and positioning" could improve.

To assess the maximum uplift of the credit rating as a result of the proposed reform, we allow AGL to achieve the highest scores of Aaa on both the "Hedging and integration impact on cash flow predictability" and "Market framework and positioning". This would improve AGL's indicated credit rating by two notches from Baa1 to A2.[247]

246 Moody's Investors Service (13 August 2019), AGL Energy Ltd: Update to credit analysis following fiscal 2019 results, p.2.

247 Note that this is a hypothetical scenario where we assume risks are reduced as a result of the reform, and also for the maximum impact on credit rating. We will assess the change in absolute risk empirically, once we have the modelling results to examine the impact of the different offsetting risk factors.

In practice, we consider it unlikely that the sub-rating factor could achieve Aaa ratings, as the criteria are highly challenging. For a company to improve its sub-rating on "Hedging and integration impact on cash flow predictability" from Baa to Aaa, the sub-rating criteria would have to change to "Forward hedges or other contractual/ market arrangements provide a high degree of visibility on substantially all expected cash flow for the next 10 years, OR Large, high quality captive downstream customer base in non-competitive market eliminates exposure to commodity risk over the long-term", from "Forward hedges or other contractual/ market arrangements provide good visibility on 50% or more of expected cash flow for the next 3 years, OR good visibility on > 30% expected cash flow for the next 2 years, if underpinned by sizeable high quality customer base". For a company to improve its sub-rating on "Market framework and positioning" from Baa to Aaa, the sub-rating criteria would have to change to "Company operates in generation markets with clear, transparent and settled market frameworks, AND Generation mix is perfectly aligned with market

To translate the effect of improved credit rating on the cost of debt, we draw on historical yield spreads of corporate bond benchmarks between A and BBB credit ratings, controlling for maturity. Table 7.1 shows the average yield spread for one notch of credit rating between A and BBB-rated corporate benchmark indices for Australia, US, Eurozone, and UK.[248] The yield spreads for one-notch credit rating change implied from Australian, US, UK and Eurozone corporate bond benchmark indicate a range of around 15 to 25 basis points.

Table 7.1: Yield spread for one notch in credit rating between A and BBB based on corporate bond benchmark indices

	Long-term average credit spread
Australia (AUD)	0.14%
US (USD)	0.27%
UK (GBP)	0.15%
Eurozone (EUR)	0.15%

Source: NERA analysis based on Thomson Reuters United Kingdom Corporate Benchmark A and BBB 10 years, Thomson Reuters United States Corporate Benchmark A and BBB 10 years, Thomson Reuters Eurozone Corporate Benchmark A and BBB 10 years. We draw on the longest available series of Thomson Reuters (Eikon) Australian Dollar Corporate Cash Credit Curve A and BBB 5 years, since continuous time-series data for the Thomson Reuters Australia 10-year corporate benchmark index is not available.

Therefore, the generator's cost of debt could reduce by 30 to 50 basis point (two notches improvement in credit rating) in the hypothetical scenario that the proposed reform allows the generators to achieve the highest possible credit rating on the relevant sub-rating factors, and should be read as the maximum benefits on cost of debt. The impact on weighted average cost of capital would be the impact on cost of debt multiplied by the debt to asset ratio, and would be less than the range of 30 to 50 basis points.

and is expected to mirror future changes, and diversified portfolio (no fuel/technology > 50% output)" from "Company operates within generation markets whose frameworks may be undergoing some change, Generation mix is expected to remain well aligned with market average and diversified portfolio (no fuel/ technology > 50% output)."

248 We calculate the one-notch credit spread by dividing the difference between A and BBB benchmark yield by three, and averaging over the longest available period. This assumes that the constituents of the benchmarks are on average evenly distributed between A and BBB-rated benchmark indices.

7.6. Assessment of Impact on Regulatory Risk

In this section, we assess the potential impact of the introduction of the proposed reform on the regulatory risk faced by the generators, and their cost of capital.

In general, regulatory risk exists if there is a possibility of unexpected, unjustified, inconsistent, and material regulatory interventions that could have adverse effect on the business activities, such as increased business risk and/or financial risks.[249] Since regulatory uncertainty could affect the perceived risk of investing in a company, the companies that have higher regulatory risk would face higher cost of capital. The academic literature on regulatory risk and cost of capital mainly focusses on the regulated utilities, but some are relevant for the unregulated electricity companies. For example, studies show that the perceptions of unpredictability of a regulatory regime can increase volatility of returns, and asymmetric regulatory interventions can lead to expected return lower than the actual cost of capital, both of which would have negative effects on cost of capital.[250]

It is mentioned in the stakeholders' responses that the proposed reform itself could introduce uncertainty faced by generators due to its scale and complexity, which would lead to an increase in regulatory risk and cost of capital.[251] However, we do not consider there to be a material increase in regulatory risk as a result of the proposed reform. While the COGATI reform may lead to a material change to the NEM's market framework, the proposed reform is neither unexpected, nor unjustifiable, hence does not necessarily constitute an increase in regulatory risk. The AEMC has published its COGATI discussion paper in October 2019, and invited stakeholders to comment and provide feedbacks on the proposal. In response to the AEMC's discussion paper, stakeholders have raised concerns that the proposed reforms may increase their cost of capital due to an increase in regulatory risk (as discussed in Section in 7.2). However, stakeholders have not provided any quantitative analysis or evidence to support this view. Also, following the publication of the proposal, there has not been any evidence or comments from the financial market participants (i.e. credit rating agencies or equity analysts) on the increased regulatory risk as a result of the COGATI reform, which suggests that the market considers the COGATI reform not to have a material impact on risks.

In addition, the proposed reform is not necessarily an asymmetric downside risk detrimental to the generators. As shown in our analysis, the proposed reform could increase or reduce the risks faced by the generators, depending on numerous factors, and could affect the expected cash flow either positive or negatively. Also, we find that the impact on cost of capital as a result of changes in Moody's rating sub-factor "Market Framework & Positioning", which incorporates the assessment of the stability and maturity of regulatory framework, is

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[249] Pedell (2006) Regulatory risk and the cost of capital: determinants and implications for rate regulation (Vol. 3823). Springer Science & Business Media.

[250] Robinson & Taylor (1998). Regulatory uncertainty and the volatility of regional electricity company share prices: the economic consequences of Professor Littlechild. Bulletin of Economic Research, 50(1), 37-46. Pescetto (2008). Regulation and systematic risk: the case of the water industry in England and Wales. Applied Financial Economics, 18(1), 61-73. Pedell (2006) Regulatory risk and the cost of capital: determinants and implications for rate regulation (Vol. 3823). Springer Science & Business Media.

[251] For example, Meridian Energy Australia and Powershop Australia (8 November 2019), COGATI Proposed Access Model, p. 3.

relatively non-material. Therefore, we do not consider the proposed reform to materially affect the regulatory risk level, and affect the long-run cost of capital.

7.7. Conclusion: Initial Evidence on the Impact on the Cost of Capital

In its proposal, the AEMC argues that the proposed access reform should improve investment certainty for generators, and may reduce their long-term cost of capital. The AEMC argues that using FTRs the generators will be able to improve their risk management, which will increase investment certainty and reduce long run cost of capital, and ultimately reduce costs for consumers.

However, a number of stakeholder responses remain unconvinced that there would be a reduction in cost of capital for generators under the proposed access model. Some stakeholders generally argue that the reforms would increase complexity, uncertainty and risk, which would increase the cost of capital and as a result the cost of energy.

We have reviewed any commentary on the proposed reform's impact on cost of capital from other agencies, such as the credit rating agencies, equity research analysts, finance literature, and various case studies. However, there is limited evidence or discussion on impact of LMP and FTRs on power companies' risks and cost of capital. The lack of discussion suggests that analysts may consider it too early to comment, or they may not consider the COGATI reform to have a significant impact on power companies' cost of capital.

We perform our analysis using the method of decision trees, which assesses how the introduction of LMP and the FTRs would affect the risks faced by a generator by constructing and evaluating its pay-offs under different scenarios. We considered the impact on the risk faced by both "hedged" and "unhedged" generators. Overall, the impact on risk mainly depends on the magnitude of the constraint risk in the current model, and the likelihood of owning a firm FTR in the proposed model. This is because the generators face a trade-off between the constraint risk in the current model, and the uncertainty of owning a firm FTR and the resulting basis risk in the proposed model. In some cases, the impact also depends on the relative volatility between the regional reference price under the current model, and the locational marginal prices in the proposed model.

In terms of quantifying the impact on the cost of capital, we assess the effect on cost of equity under the CAPM framework, and cost of debt using rating agency Moody's rating methodology.

Conceptually we would not expect any material impact on cost of equity as a result of access reform under the CAPM. This is because we do not expect the risk factors, such as constraint risks and basis risks, to be strongly correlated with the market return. The market return is driven by macroeconomic variables such as aggregate economic growth, and reflects long-term expectation. In contrast, the constraint risk and basis risks are determined by variations in local electricity prices, which in theory would not be strongly correlated with movement in market's expected return. However, even though the proposed model may not affect the systematic risks faced by the equity holders, the debt risk premium may change as a result of the proposed reform. This is because debtholders are concerned with the absolute level of risk, rather than systematic risk alone. The impact on cost of debt could increase or decrease, depending on the relative costs and benefits of the COGATI reform. We will need to assess the change in absolute risk empirically, once we have the modelling results to examine the impact of the different offsetting risk factors, such as the constraint risks, the basis risks, and the relative volatility of RRP, LMP, and VWAP.

In the absence of the modelling results, we present an illustrative scenario of maximum impact on debt risk under the assumption that the reform does reduce risk, by allowing generators to improve its hedging and also to have a better market framework than the current regime as the net effect of the risk change. To quantify the impact on cost of debt in this scenario, we apply the credit rating methodology published by Moody's to assess the potential change in the credit rating for the representative generator, assuming that the generator could achieve highest score on the relevant sub-rating factors, which are "Hedging and Integration Impact on Cash Flow Predictability", and "Market Framework & Positioning". Our calculation indicates that the generator's cost of debt could reduce by up to 30 to 50 basis points if the proposed reform is highly successful and the generator's credit rating improves by two notches. The impact on weighted average cost of capital would be the impact on cost of debt multiplied by the debt to asset ratio.

Finally, the analysis in this section abstracts from the level of return, as we focus on the forward-looking risks. We note that the return level may be affected too, which is discussed in Section 6 . In addition, large distributional impacts that may arise in the short run could lead to longer-run effects on the cost of capital due to perceived regulatory risk.[252] The interplay between impacts on the level and risk of return is that if investors face a significant loss as the result of reform, then investors would require higher risk premium to invest in Australian power companies going forward. Grandfathering could alleviate the regulatory risks if implemented. However, since the reform is neither unexpected, nor unjustifiable, we do not consider it to be necessarily an increase in regulatory risk, and it does not warrant a material change in the cost of capital.

[252] For example, we understand that some stakeholders state that the AEMC would trigger a Market Disruption Event on ISDA-based over-the-counter contracts by changing the formulation of spot price to VWAP

8. Other Impacts

In this Section, we discuss the other potential impacts of the introduction of LMP and FTRs in the NEM. We draw on evidence across the jurisdictions we examine to discuss the likely impact of the reform on contract market liquidity and market power.

8.1. Potential Impact on Contract Market Liquidity

Assessing the impact of LMP on liquidity is difficult in practice, not least because regulators do not have a standard definition of liquidity, still less measurement across international markets. However defined or measured, changes to liquidity in the wholesale market do not necessarily lead to social benefits or social costs. By ensuring market participants access to power without moving market prices, regulators may facilitate entry and increase competition. On the other hand, low liquidity may be an efficient response to market structure, and the net social benefits of liquidity may not rise with the level of market liquidity.

The remainder of this Section is structured as follows:

- We begin by discussing the difficulties that regulators and policy makers encounter when defining and measuring liquidity in electricity markets;
- We then discuss how the existing contract market structure is an important determinant of the impact LMP and FTRs on contract market liquidity. There are substantial differences in the contract market structures in other jurisdictions that we examine (particularly in US markets) and the NEM meaning it is difficult to use evidence from other jurisdictions to draw conclusions on the likely impact of LMP and FTRs on liquidity in the NEM;
- We find little evidence of the impact of the reform on contract market liquidity in other jurisdictions. We present the best evidence we find, on liquidity from the PJM, to illustrate how the introduction of LMP and FTRs changed the pattern of liquidity in the contract market; and
- Finally, we examine the impact on liquidity from only introducing FTRs, drawing on experience in New Zealand.

8.1.1. The difficulties in measuring liquidity

Although many regulators and policymakers internationally aspire to liquid electricity markets, liquidity itself does not have a standard definition still less measurement. The definition provided by the Single Electricity Market Committee (SEM-C) in the context of considering introducing a Market Making Obligation in Ireland is a recent example of a typical definition adopted by regulators. The SEM-C described a liquid market as one in which:

1. parties can “trade ‘reasonable’ volumes without significantly moving market prices”; and
2. parties are “readily able to trade out of positions as well as to acquire those contractual positions”.[253]

[253] SEM-16-030, p. 9-10.

In practice, academics, regulators and policymakers typically focus on measures of "relative" liquidity such as:

- the level of transactions costs, often measured through bid-ask spreads;
- the amount of traded volume (or market churn); or
- other "broader" attributes such as market depth and breadth and the consequences for the "smoothness" of price changes.

The sheer number and variety of these relative measures of liquidity show that there is no agreed way to measure liquidity, even if market participants can spot a liquid market when one exists in absolute terms.

Because liquidity is so hard to measure, regulators face a greater challenge of assessing the benefits associated with a change in market liquidity. Moreover, even if a regulator had a clearly defined measure of liquidity, estimating the social benefits associated with changes in liquidity is also difficult in practice (rather than examining the transfers associated with changes to liquidity). Consequently, most regulators analyse liquidity by comparing metrics of liquidity in their market to those observed in other markets that they consider to contain a good level of liquidity.

As a result, the impact of the introduction of LMP on liquidity was rarely discussed in studies we examine and the benefits of changes to liquidity were never reported.

8.1.2. Contract market structure and the impact on liquidity

Most of the markets that we examine are in the US, and have a contract market structure that differs substantially from the current contract market structure in the NEM. For most of the US markets that we examine, retail markets are not fully competitive and often consist of regulated retailers who also own distribution networks. Only ERCOT, parts of PJM, ISO-NE and NYISO have implemented retail choice for customers in the US case studies that we examine.[254] In these jurisdictions, dominant and historically vertically-integrated retailers are often still regulated. In California, at the time of implementation of LMP, there existed three Load Serving Entities (LSEs): PG&E, SDG&E, and SCE who acted as regulated retailers as well as owning the networks. Most load was served by the incumbent LSEs with only a fraction permitted the choice of supplier.[255] In fact, the zones corresponding to VWAPs in the CAISO reform also corresponded to each of the operating areas of the LSEs.

As a consequence of regulation of LSEs and historical vertically-integrated utilities, the contract market structure in the jurisdictions that we examine is substantially different from the NEM, both before and after the introduction of LMP in those jurisdictions. For example:

- Historically in California, LSEs' purchased load from the power exchange day-ahead, hour-ahead and real time markets and were discouraged from entering into hedging contracts because the LSEs were not guaranteed full recovery of such costs. Following the California energy crisis, wholesale spot price cost-pass through was eliminated

254 Stephen Littlechild (28 February 2018), The regulation of retail competition in US residential electricity markets, p. 6.

255 Stephen Littlechild (28 February 2018), The regulation of retail competition in US residential electricity markets, p. 6.

through price caps, and LSEs instead use bilateral contracts using fixed-price long-term contracts for power.[256]

- In some states in the PJM ISO, utilities use a tranche auction process to procure energy up to three years out with Fixed Price Full Requirements (FPFR) such that the supplier bore migration and load-following risks.[257] ISO-NE have also adopted an FPFR approach with some spot price purchasing.
- In Illinois, in MISO, the Illinois Power Agency purchases power on behalf of utilities using a block and spot approach up to three years out.[258]

Of the US jurisdictions that we examine that introduced LMP, ERCOT has the most comparable degree of retail competition to the NEM. However, the contract market structure encouraged to support retail competition in the NEM is different to that in ERCOT. Whereas retailers in the NEM generally contract using standardised exchange-based products, in ERCOT, the market was "designed to rely upon and foster bilateral contracts" between suppliers and retailers.[259]

However, where liquidity has concentrated at trading hubs, that differ from the previous zones under zonal pricing, following the introduction of LMP, standardised exchange-traded products have followed, largely concentrated to day-ahead and real-time products. For example, in both ERCOT North and PJM's Western Hub, the Intercontinental Exchange offer futures contracts for peak and off-peak real-time and day-ahead products.[260] Due to the contract market structure in the states, we understand that the exchange-based products available at hubs in the US are for relatively prompt forward products (less than one-year ahead and mostly less than three months-ahead). On the other hand, in the NEM, forward products on exchanges are commonly traded on longer time horizons (greater than one-year ahead).

Therefore, the concept of liquidity in most of the markets that we examine is very different to the concept of liquidity in the exchange-based developed contracting market that currently exists in the NEM. Liquidity in US markets will tend to describe prompt forward contracts whereas in the NEM liquidity applies to forward contracts bought for power further ahead of delivery. Even if the studies we examine have ample information on the effects of the introduction of LMP on liquidity in those jurisdictions, it is not clear that the effects would be transferable to current contract market structure in the NEM.

[256] Stephen Littlechild (28 February 2018), The regulation of retail competition in US residential electricity markets, p. 6.

[257] Stephen Littlechild (28 February 2018), The regulation of retail competition in US residential electricity markets, p. 19.

[258] Stephen Littlechild (28 February 2018), The regulation of retail competition in US residential electricity markets, p. 35.

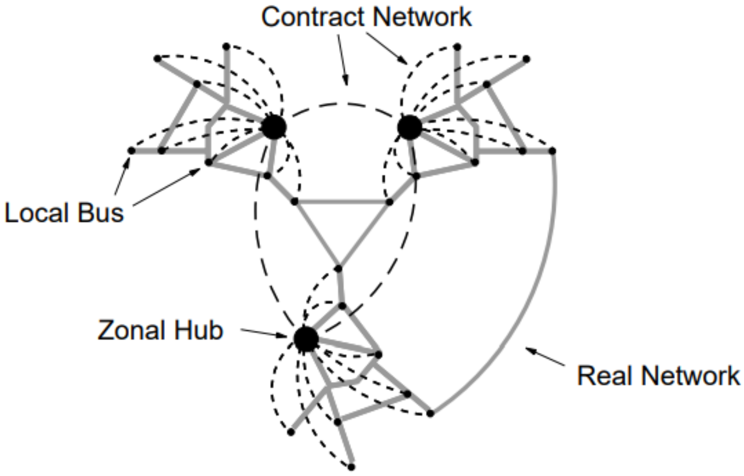
[259] Stephen Littlechild (28 February 2018), The regulation of retail competition in US residential electricity markets, p. 35.

[260] Intercontinental Exchange, Products – Futures and Options, Last accessed, 24 February 2020, Link: https://www.theice.com/products/Futures-Options/Energy/Electricity?filter=pjm

8.1.3. The pattern of liquidity following the introduction of full LMP in PJM

Under the introduction of full LMP in the PJM, liquidity has concentrated at 12 zonal hubs selected as a single location/node or a fixed portfolio of locations.[261] The concentration of contract market liquidity at hubs gives rise to a "Hub and Spoke" model, see Figure 8.1.[262]

Figure 8.1: The Hub and Spoke Contract Model



Source: William Hogan (2 April 1999), Getting the Prices Right in PJM.

According to trading activity data in the Wall Street Journal,[263] spot trading volumes fell after the introduction of FNP in April 1998. However, by mid-May 1998 traded volumes had recovered to levels observed prior to FNP.[264]

Trading volumes increased following the introduction of LMP in the PJM before falling with "the demise of energy-trading companies in late 2001", see Figure 8.2. ESAI also states that both Platt's and ICE indicate a reduction in PJM bid-ask spreads from over USD 5 per MWh in 1998-99 to USD 4 per MWh in 2000 and then below USD 2 per MWh from 2001, however it is unclear what products the bid-ask spreads reported by ESAI pertain to.[265]

In particular, liquidity concentrated at the western trading hub of the PJM. To capitalise on liquidity at the western hub, the New York Mercantile Exchange launched a new futures

261 William Hogan (2 April 1999), Getting the Prices Right in PJM: Analysis and Summary: April 1998 through March 1999 The First Anniversary of Full Locational Pricing, p. 21.

262 William Hogan (2 April 1999), Getting the Prices Right in PJM: Analysis and Summary: April 1998 through March 1999 The First Anniversary of Full Locational Pricing, p. 21.

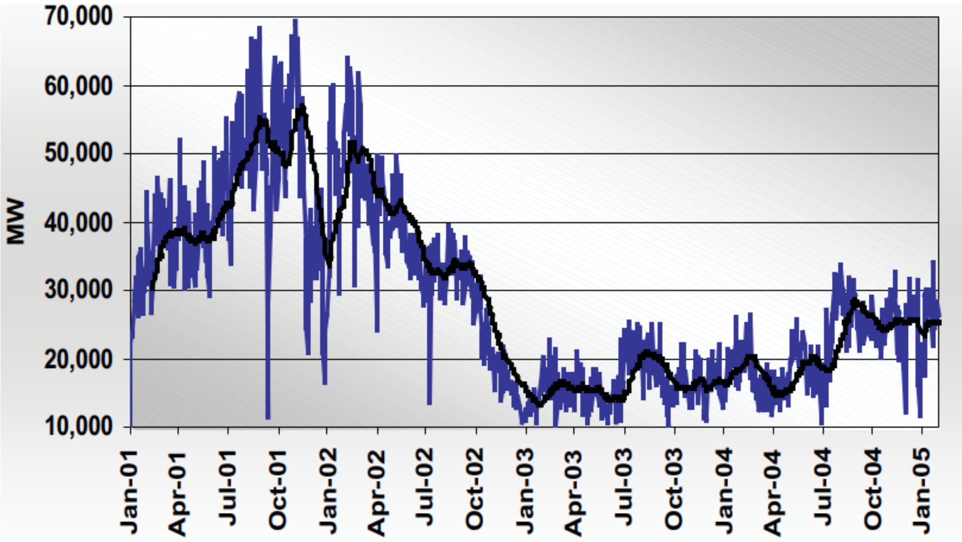
263 Secondary Source from William Hogan (2 April 1999), Getting the Prices Right in PJM: Analysis and Summary: April 1998 through March 1999 The First Anniversary of Full Locational Pricing, p. 21. Primary Source: "DJ Electricity Price Indexes," Wall Street Journal, June 3, 1998, p. C19.

264 William Hogan (2 April 1999), Getting the Prices Right in PJM: Analysis and Summary: April 1998 through March 1999 The First Anniversary of Full Locational Pricing, p. 6.

265 ESAI analysis of Platts Data. Source: Edward Krapels and Paul Flemming (November 2005), Impacts of PJM RTO Expansion, p. 26.

contract at the hub.[266] The OTC market was reported to be so liquid that standardised futures contracts may not have been able to compete.[267]

Figure 8.2: "North American" Next-Day On-Peak Trading Volumes



Source: ESAI analysis of Platts Data, ESAI, Impacts of PJM RTO Expansion, p. 24.

8.1.4. The impact of the introduction of FTRs on contract market liquidity in New Zealand

Of the non-US jurisdictions that we examine, New Zealand has a similar contract market structure to the NEM and introduced FTRs in 2013. Full LMP has existed since the market was liberalised in 1996.[268] At the time of the introduction of FTRs the Electricity Commission stated that it expects FTRs will result in, amongst other benefits:

- A reduction of hedge market costs because participants would be able to access more liquid prices at other trading hubs.[269] The EC states that the introduction of an inter-island FTR market would reduce spreads between bids and offers in the hedge market by 7 to 11 per cent (NZD 0.41-0.64) relative to the case of no introduction.[270] The EC states that the present value of the reduction in hedge market costs would be NZD 33.2 to 69.5 million over 10 years.[271]

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266 William Hogan (2 April 1999), Getting the Prices Right in PJM: Analysis and Summary: April 1998 through March 1999 The First Anniversary of Full Locational Pricing, p. 6-7.

267 From: William Hogan (2 April 1999), Getting the Prices Right in PJM: Analysis and Summary: April 1998 through March 1999 The First Anniversary of Full Locational Pricing, p. 7. "The New York Mercantile Exchange will launch an electricity futures contract March 19 at the PJM western hub, one of the most liquid markets in the Eastern grid. ... The PJM hub already features an active and growing over-the-counter forwards market. A liquid hub can have a downside [for the futures contract] given that players are content trading in the OTC, said one Northeast broker." Power Markets Week, February 8, 1999, p. 14.

268 NZIER (February 2007), The Markets for Electricity in New Zealand, prepared for the Electricity Commission, p. 36.

269 Electricity Commission (2010), Consultation Paper – Managing Locational Price Risk Proposal, p. 78.

270 Electricity Commission (2010), Consultation Paper – Managing Locational Price Risk Proposal, par.3.4.23.

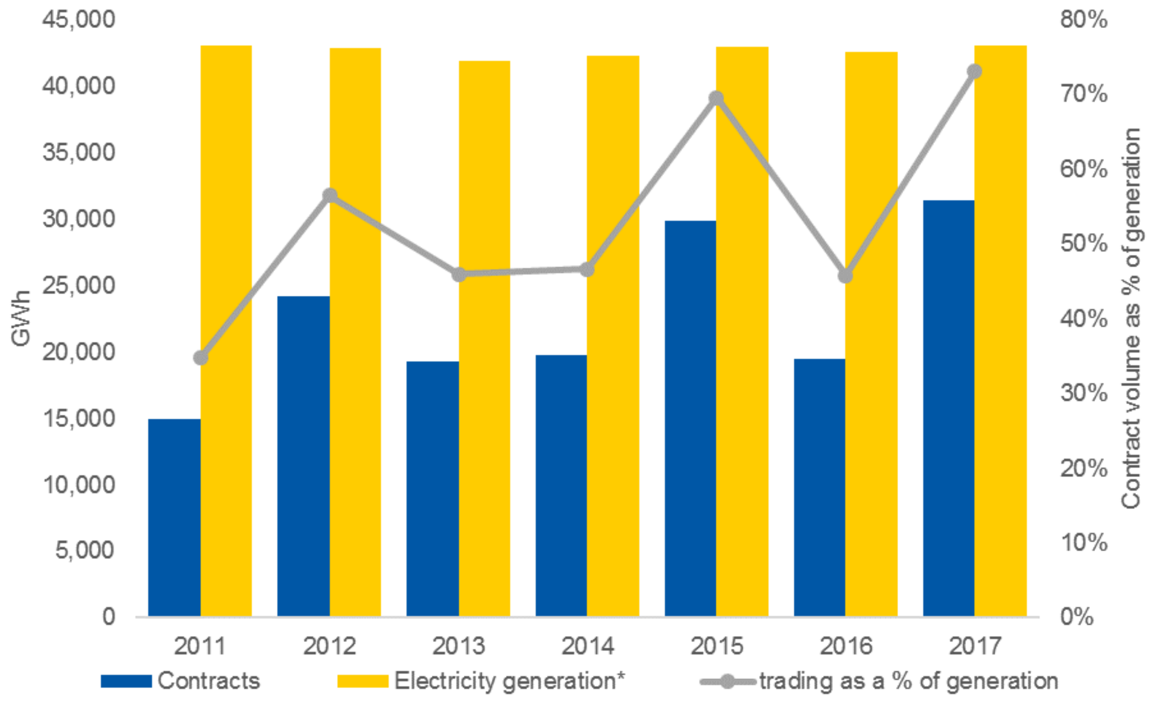
271 Electricity Commission (2010), Consultation Paper – Managing Locational Price Risk Proposal, par.6.2.15.

- A mechanism by which participants can effectively manage price risk between the North and South Island hubs. The EC states that it expects the present-value cost savings from "enhance locational price risk management" due to the introduction of a locational hedge (the inter-island FTR) as NZD 21.6 to 28.8 million over 10 years.[272]

From the EC's description of its methodology, it is unclear to us how it estimates the benefits listed above. Moreover, we understand that the EC does not distinguish between transactions costs savings and net social benefits arising from its estimated improvements to liquidity, and includes both in its total estimate of benefits arising from the introduction of FTRs.

Figure 8.3 takes data from the New Zealand Electricity Hedge Disclosure System and measured grid injections to measure contract churn over time. The EA also operates a voluntary MMO (since 2010) to support contract market liquidity.[273]

Figure 8.3: New Zealand Contract Volumes Before and After the Introduction of FTRs in 2013



Source: NERA analysis, Electricity Hedge Disclosure System, EA EMI data on grid injections.

Whilst it is difficult to establish what liquidity, and contract volumes, would have been in the NZ market without the introduction of FTRs, the evidence suggests that the introduction of FTRs have not led to a significant rise or fall in overall market liquidity. To our knowledge, the EA has not reported on the realised benefits from the implementation of FTRs, even in its 2017 discussion paper surrounding changes to the FTR market.

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272 Electricity Commission (2010), Consultation Paper – Managing Locational Price Risk Proposal, Table 8.

273 As described in Electricity Authority (1 May 2015), Hedge Market Development: Enhancing Trading of Hedge Products - Consultation Paper, Electricity Authority. (Available at https://www.ea.govt.nz/dmsdocument/19441)

On the other hand, the extension of the range of FTR products offered to those including Haywards, Islington and Invercargill Hubs at the end of 2014 may suggest market demand for such products.[274] As of 2017, there were 40 different FTR products varying in location, direction and type (option or obligation).[275]

8.1.5. Summary of potential impacts on contract market liquidity

The impact of the introduction of LMP on liquidity was rarely discussed in the cost benefit analyses or monitoring reports across the markets that we examine. The structure of the contract market that existed at the time of introduction of LMP varies across the jurisdictions we examine, and in most cases is substantially different relative to the structure of the contract market in the NEM. As a result, even when impacts on liquidity are discussed in the case studies, inferring key lessons on the likely impacts of LMP on liquidity in the NEM from other jurisdictions is difficult.

In general, across the case studies we examine, liquidity was not reported to substantially improve nor decline as a result of the introduction of LMP. For instance, in PJM, spot trading volumes fell after the introduction of full LMP in April 1998. However, by mid-May 1998 traded volumes had recovered to levels observed prior to full LMP.[276]

In most cases, for example in PJM and ERCOT, the *distribution* of liquidity in the market changed after the introduction of full LMP, with the formation of trading hubs at nodes throughout the system and relatively stronger liquidity at those hubs compared to the rest of the market (for example the Western Trading Hub in PJM and North Hub in ERCOT). A hub and spoke contract market model resulted whereby suppliers and LSEs at local nodes to the hub contract at the hub, and between hubs, and purchase FTRs to manage physical congestion risks to the hub. When liquidity concentrated at these hubs, standardised exchange-based or OTC contracts were introduced by exchanges to facilitate trading between contract hubs.[277] However, we understand that the products traded at these hubs are relatively short term compared to those contracts traded in the NEM.

The existing structure of the contract market across the jurisdictions that we examine also informed the design of the FTR market, when implemented alongside LMP. The design of the FTR market, and more precisely, the choice to allocate and method of allocation of FTRs to market participants is also an important determinant of the impact of contract market liquidity resulting from the reform. In many of the US jurisdictions that we examine, for example PJM, FTRs are allocated to LSEs on the basis of historical bilateral contracts between suppliers and LSEs.[278] Consequently, because LSEs are grandfathered an FTR to manage congestion risk, LSEs can contract at the nodal price faced by the supplier (or the nearest trading hub). Under these situations, dispersion of liquidity (i.e. a lack of liquidity outside of the hubs) is not necessarily a problem for LSEs because they are endowed with a

[274] Electricity Authority (9 March 2017), FTR Development Issues and Opinions Paper, para.3.18.

[275] Electricity Authority (28 March 2017), Financial Transmission Rights development, para.3.14.

[276] William Hogan (2 April 1999), Getting the Prices Right in PJM: Analysis and Summary: April 1998 through March 1999 The First Anniversary of Full Locational Pricing, p. 6.

[277] Intercontinental Exchange, Products – Futures and Options, Last accessed, 24 February 2020, Link: https://www.theice.com/products/Futures-Options/Energy/Electricity?filter=pjm

[278] Monitoring Analytics (14 November 2019), State of the Market Report for PJM, January through September 2019, p. 648.

financial instrument to manage the resulting congestion risk between their node and the hub. In other words, assuming FTRs are firm, holding an FTR between one's node and the hub, and trading liquid forward contracts at the hub is a close substitute for being able to trade liquid forward contracts at one's node.

Despite the relative lack of discussion of the impact on liquidity in the case studies we examine, we can draw the following key lessons on the impact of liquidity of the implementation of LMP and FTRs:

- Most CBAs that we examine that explicitly comment on liquidity suggest that the introduction of LMP will not lead to a deterioration of contract market liquidity. Ex-ante studies for ERCOT suggest that liquidity, as measured through the volume of transactions, will increase after the reform.[279]
- New Zealand has the most comparable contract market to the NEM across the jurisdictions we examine. The EC states that introducing FTRs would encourage market participants to buy hedge contracts at central nodes because locational risk is mitigated. Consequently, at the time of the reform, the EC states that it expects transactions costs will fall by 7-11 per cent[280] and the present value of cost savings from "enhanced locational price risk management" would be NZD 21.6 to 28.8 million over 10 years.[281] To our knowledge, the EC does not explain the methodology it uses to estimate the benefits listed above.
- In the PJM and ERCOT liquidity concentrated at trading hubs after the introduction of LMP (the Western Hub in the PJM and the Northern Hub in ERCOT) resulting in a hub and spoke model for contract market liquidity. Liquidity was reported to be strong at these hubs although the benefits associated with such liquidity were not reported in the studies we examine.[282]

One may also infer that, with the exception of the studies we discuss above, the relative lack of analysis on the impact of contract market liquidity in the ex-ante and ex-post assessments would suggest that liquidity in the contract market does not substantially change with the introduction of LMP and FTRs.

8.2. Market Power Impact of Reforms

The physical constraints of an electricity network can result in congestion and pockets of local market power. In most US markets that we examine, in order to be dispatched, suppliers often submit a market-based bid or price-based bid in addition to a regulated cost-based bid to the system operator in each settlement period. In the absence of market power, the system operator expects these two bids to the same. However, if a supplier has local

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279 ERCOT, TCA and KEMA (30 November 2004), Market Restructuring Cost-Benefit Analysis, p. 6-19.

280 Electricity Commission (2010), Consultation Paper – Managing Locational Price Risk Proposal, par.3.4.23.

281 Electricity Commission (2010), Consultation Paper – Managing Locational Price Risk Proposal, par.6.2.15.

282 From: William Hogan (2 April 1999), Getting the Prices Right in PJM: Analysis and Summary: April 1998 through March 1999 The First Anniversary of Full Locational Pricing, p. 7. "The New York Mercantile Exchange will launch an electricity futures contract March 19 at the PJM western hub, one of the most liquid markets in the Eastern grid. ... The PJM hub already features an active and growing over-the-counter forwards market. A liquid hub can have a downside [for the futures contract] given that players are content trading in the OTC, said one Northeast broker." Power Markets Week, February 8, 1999, p. 14.

market power, it can exercise its market power in the absence of Market Power Mitigation policies (MPM), in two main ways:

- Economic withholding occurs when a supplier raises its market-based bid above competitive levels i.e. its regulated cost-based bid; and
- Physical withholding occurs when the supplier physically withholds power, for example by declaring an outage, when it would not have done so in a competitive market.

In theory, the introduction of LMP will not exacerbate, or introduce new sources of market power, providing the underlying physical constraints of the system remain unchanged.[283] Therefore, unless the physical constraints of the system are reformed alongside the introduction of LMP, then the same pockets of local market power will exist under both zonal and LMP market systems.

LMP highlights market power, because exercised market power at a given node will be observable through the local marginal price at the node. Under zonal pricing, the same market power would be exercised at the node, but the effects would be obscured by the settlement of a zonal price.[284] Consequently, LMP provides a clearer signal over when local market power is created and exercised, and where MPM should be targeted.

The remainder of this Section is structured as follows:

- We first explain the tests used by system operators to identify the potential for market power at dispatch;
- We then discuss how system operators commonly mitigate the offers of market participants when it is deemed that those participants are exercising market power;
- We then examine the evidence for the existence and prevalence of local market power across the jurisdictions that we examine;
- We provide an overview of evidence for market power exercised in hours of high demand in the PJM. The phased introduction of market-based bidding in the PJM allows us to examine the difference in the prevalence of market power compared to when market participants could not choose their bid (under cost-based bidding); and
- Finally, we summarise evidence that participants are strategically bidding in response to the tests imposed by system operators in PJM and ERCOT.

8.2.1. Tests used by system operators to identify the potential for local market power

MPM takes the form of two steps:

1. Identification of market power through a test or defined threshold.
2. Actions to mitigate the exercise of market power, often in the form of bid capping or mitigation.

283 Scott Harvey and William Hogan (20 December 2001), Market Power and Withholding.

284 Matthew Katzen and Gordon Leslie (20 December 2019), Revisiting Optimal Pricing in Electrical Networks over Space and Time: Mispricing in Australia's Zonal Market, p. 35.

Across the case studies that we examine, the tests used by system operators to identify when local market power is exercised are relatively similar. The commonality is unsurprising, given numerous nodal markets that we examine are in the US and subject to common regulation by FERC. We summarise the currently employed tests for market power in Table 8.1, and note whether the tests are applied before or after market dispatch.

Table 8.1: Summary of MPM Across the Jurisdictions we Examined

Market	Test for Market Power	Offer cap	Test Applied Before or After Dispatch
PJM	✓	✓	Before
NYISO	✓	✓	Before
ISO-NE	✓	✓	Before
CAISO	✓	✓	Before
SPP	✓	✓	Before
MISO	✓	✓	Before
ERCOT	✓	✓	Before
Ontario - IESO (Zonal Pricing)	✓	✓	After
New Zealand	✓	×	After

Source: NERA Analysis.

Across all the LMP markets in the US that we examine, both offer caps and tests for market power are imposed before system dispatch in any given settlement period. The two most common types of tests for market power used in these jurisdictions, which when triggered may result in offer mitigation or capping, are:

- **Tests for supplier market concentration at a given node:** System operators analyse market concentration using a test or metric and compare to pre-determined criteria. The tests used in our surveyed jurisdictions include:
  - *The Three Pivotal Supplier Test (TPS): Used in: PJM, CAISO.* The TPS measures the degree to which the supply from the tested supplier is required in order to meet load, given transmission constraints, in the relevant market after the supply from the largest two other suppliers is removed.[285] If at least four suppliers pass the three-pivotal supplier test, then the node is deemed competitive. Constraints that do not pass the three-pivotal supplier test are deemed non-competitive.[286]
  - *The Residual Supply/Demand Index (RSI): Used in ISO-NE.* The RSI measures the percentage of load that cannot be served without the resources of the largest supplier at a given node, assuming that the market could call upon the quick-start capacity from all other suppliers. In ISO-NE, if the RSI is below 100, a portion of the largest supplier's generation is required to meet load and that supplier is deemed pivotal.[287]

285 Monitoring Analytics (22 July 2015), Overview of Three Pivotal Supplier Test, p. 3.

286 CAISO (2009), Annual report on market issues and performance, p. 4.2

287 ISO-NE Internal Market Monitor (17 May 2018), 2017 Annual Markets Report, p. 100.

– *The Herfindahl-Hirschmann Index – (HHI): Used in ERCOT.* The HHI is a measure of market concentration. The index is calculated by summing the squares of supplier generation share at each node. In ERCOT, if the HHI is less than 2,000 on the import side of the constraint, the network constraint is deemed to be uncompetitive.

- **Thresholds defined relative to cost-based bid or conduct threshold:** *Used in NYISO, MISO, SPP.* Other system operators define market power on the basis of how far market price bids by suppliers deviate from pre-determined thresholds. For example, in NYISO, economic withholding is identified based on increases in market-price bids relative to relevant average accepted bids over the previous 90 days.[288] In SPP, market power is measured when the supplier's market bid deviates from a threshold based on the regulated cost-based bid or "mitigated offer bid" of the supplier.[289]

Only two of the jurisdictions we examine test and correct for identified local market power after dispatch. Of these two jurisdictions, only New Zealand implements LMP. In New Zealand, the Electricity Authority (EA) may declare an "undesirable trading situation" (UTS) in response to situations that "threaten confidence in, or the integrity of, the wholesale market" and "cannot satisfactorily be resolved by any other mechanism available".[290] UTS gives the EA discretion to intervene ex-post and administer retrospective pricing. We understand that until recently, the UTS is rarely used, and that the EA has prescribed test criteria that suppliers can use to ensure a UTS is avoided.[291] The criteria are similar to the test criteria used in markets with LMP in the US. However, we understand that the UTS criteria are currently being reviewed by the EA.[292]

Ontario (IESO) currently has zonal pricing and adjusts Out of Market Payments to correct for market power identified by IESO after dispatch.[293] It acknowledges that its current market power mitigation strategy would not be possible under LMP because congestion will instead enter generator compensation through LMPs, which cannot be adjusted ex-post without disrupting settlements.

8.2.2. Offer-capping in cases of identified local market power

If a node or supplier's bid is deemed to be uncompetitive, the system operator can mitigate or cap suppliers' market-based bids. In markets with complex bidding, the system operator can mitigate or cap all aspects of the supplier's bid e.g. for energy, operating reserves, no-load, start-up etc. The system operator can also mitigate bids in either or both of the real-time and day-ahead markets. In most of our studied jurisdictions that impose MPM prior to dispatch,

288 NYISO, 23.3 MST Att H Criteria for Imposing Mitigation Measures, 23.3.1.4. Link: https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9TariffSections/2505.htm

289 SPP Market Monitoring Unit (15 May 2019), State of the Market 2018, p. 219.

290 Electricity Authority (20 June 2016), Guidelines for Participants on Undesirable Trading Situations, p. 7.

291 Electricity Authority (4 June 2014), Improving the efficiency of prices in pivotal supplier situations, p. 2-3

292 Electricity Authority, MDAG briefing on trading conduct review, Link: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/review-of-spot-market-trading-conduct-provisions/development/mdag-briefing-on-trading-conduct-review/

293 IESO (August 2019), Single Schedule Market: High-Level Design, p.57.

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the system operator caps bids by choosing to dispatch the supplier on the basis of its cost-based bid and not its market-based bid:

- In some jurisdictions, e.g. PJM, the supplier is dispatched on its exact cost-based bid or market-based bid, whichever is lower.
- In other jurisdictions, e.g. SPP and ERCOT, the supplier is dispatched on a bid defined relative to, but not necessarily exactly to its cost-based bid. The market dispatch software calculates a reference price to form a mitigated offer curve upon which the supplier is dispatched if it is cheaper than its market-based bid.
- In CAISO, suppliers select one of three options for their default energy bid used if their actual bid is subject to bid mitigation:[294]
  - *Cost-based:* Default energy bid is based on unit's incremental heat rate, spot market gas price and variable O&M costs, with a 10 per cent uplift to cover additional costs.
  - *Negotiated bid:* A "customised calculation of a unit's marginal or opportunity costs" implemented by a third party.
  - *LMP based:* The default energy bid is calculated based on LMPs during periods when the unit was dispatched over the prior 90 days.

We understand that all the US markets that we examine except ERCOT are subject to a FERC-mandated offer cap on bids:[295]

- "Market participants can only submit incremental energy offers up to 1,000 US$/MWh without review
- Offers above 1,000 US$/MWh need to be verified on a cost basis before they are allowed to set price
- Offers above 2,000 US$/MWh must also be verified on a cost basis, but they are exempt from setting price"

We understand that ERCOT imposes its own caps on wholesale market prices.[296]

In other words, these markets are subject to an offer cap in the absence of market power. Each market may impose additional caps on offers in the absence of market power. For example, CAISO implemented stricter offer caps during the first three years of LMP which it introduced in 2009.[297] On a system level basis, CAISO introduced a USD 500 per MW energy bid cap in 2009, which increased to USD 750 per MW and USD 1,000 per MW in the second and third years respectively of the new market design. Until April 2010, CAISO also implemented a USD 2,500 per MW cap on overall market prices

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294 CAISO (2009), Annual report on market issues and performance, p. 4.3.

295 Anthony Giacomoni (15 May 2019), U.S. ISO/RTO Wholesale Market Caps, p. 14.

296 J. Zarnikau and C.K. Woo (22 January 2014), Did the introduction of a nodal market structure impact wholesale electricity prices in the Texas (ERCOT) market?, p. 198

297 CAISO (2009), Annual report on market issues and performance, p. 4.2

8.2.3. Existence of local market power

IMMs across the markets we examine report that the potential for local market power is relatively high in 2018 and that MPM remains critical for a competitive market:

- In MISO, the IMM reports that HHI indicates low concentration across the entire market (HHI of 591) but high concentration in local areas, such as the WUMS Area (2708) and the South Region (3673).[298] The IMM also uses pivotal supplier analysis to show that a supplier was pivotal in at least 87 per cent of constrained areas.[299]
- The IMM for ERCOT uses an RSI to identify that a pivotal supplier existed in 30 per cent of all hours in 2018.[300] When loads exceeded 65 GW, a pivotal supplier existed in 95 per cent of all settlement periods. Similar to the case of PJM described in Section 8.2.5, in hours of higher load a particular supplier's generation is more likely to be required, and therefore pivotal, to meet load.
- In SPP, the IMM finds significant geographic variation in the prevalence of a pivotal supplier, driven by congestion. It finds that in the New Mexico and West Texas regions, a pivotal supplier exists 98 to 100 per cent of hours whereas in other regions, no pivotal supplier exists.[301] However, examining the HHI across the entire market in 2018, it finds hourly HHI indicates competitiveness and varies from 502 to 1,283, an increase on 2017 driven in part by a merger of suppliers mid-year.[302]
- The IMM in CAISO assessed that overall prices were competitive despite indication that "prices may have been significantly in excess of competitive levels in some peak summer hours".[303]

8.2.4. Prevalence of local market power

However, IMMs also conclude that generally, the prevalence of offer capping was low in 2018, and therefore MPM are working:

- The IMM for MISO reports that energy offer mitigation did not occur in the day-ahead market and in fewer than one per cent of hours in the real-time market.[304]
- In SPP, the system operator mitigated bids in day-ahead market occurred at levels of 0.05 per cent for operating reserves, 0.16 per cent for no-load, less than 0.01 per cent for incremental energy, and approximately 2.4 per cent of start-up offers.[305] The IMM for SPP also found that most market-based bids imposed negative mark-ups relative to mitigated bids, which it argues implies a competitive market.[306]

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298 Potomac Economics (June 2019), 2018 State of the Market Report for the MISO Electricity Markets, p. 87.

299 Potomac Economics (June 2019), 2018 State of the Market Report for the MISO Electricity Markets, p. 87.

300 Potomac Economics (June 2019), 2018 State of the Market Report for the ERCOT Electricity Markets, p. xxi.

301 SPP Market Monitoring Unit (15 May 2019), State of the Market 2018, p. 216.

302 SPP Market Monitoring Unit (15 May 2019), State of the Market 2018, p. 213.

303 CAISO (May 2019), 2018 Annual Report on Market Issues and Performance, p. 151.

304 Potomac Economics (June 2019), 2018 State of the Market Report for the MISO Electricity Markets, p. 89.

305 SPP Market Monitoring Unit (15 May 2019), State of the Market 2018, p .221.

306 SPP Market Monitoring Unit (15 May 2019), State of the Market 2018, p. 218.

- In ERCOT, the IMM evaluates that the "potential economic withholding levels were extremely low".[307]
- The IMM for CAISO states that in "the day-ahead and real-time markets, the frequency and impact of automated bid mitigation increased significantly in 2018 compared to 2017" but "the overall impact of this mitigation remained low".[308] The number of units with mitigated bids averaged 1.6 per hour in 2017 in the 15 minute market and 3.6 per hour in the 5 minute market. On the other hand, the IMM reports that "Local market power mitigation of exceptional dispatches for energy played a significant role in limiting above-market costs in 2018, reducing above-market costs by about $18 million in 2018 compared to $33,000 in 2017".[309]

Low prevalence of market power through failed tests is unsurprising given that suppliers understand the market conditions and congestion at their local node and also understand the MPM that the system operator in their jurisdiction is using to mitigate their bids. Consequently, to avoid offer capping, suppliers will bid such that they expect to not fail the MPM tests.

8.2.5. Evidence of market power in the PJM during hours of high demand

The staggered introduction of market-based bidding in PJM after the introduction of LMP allows us to examine whether market power may have led to distorted market-based bidding relative to cost-based bidding.

LMP was initially implemented in the PJM alongside cost-based bidding in 1998 which significantly reduced the potential for exercising market power in the market, with a potential cost to market efficiency.[310] Consequently, during the first year of LMP in the PJM, generators outside of the PJM exporting to the market without cost-based bidding restrictions often set market-clearing location prices.[311]

In 1999, the PJM replaced cost-based bidding with market-based bidding whereby generators can submit offers anywhere up to the FERC mandated USD 1000 per MW cap. However, beyond the mandated offer cap, the PJM did not operate an ex-ante nor ex-post test for exercised local market power.

The IMM for PJM presents evidence that market power was exercised under market-based bidding in hours of high demand in 1999. From 1 April 1999 to 31 March 2000 prices were higher under market-based bidding than in the previous 12 months with cost-based bidding.[312] After controlling for changes in fuel costs, 84 per cent of the increase in prices was driven by 15 high demand days in summer.

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[307] Potomac Economics (June 2019), 2018 State of the Market Report for the ERCOT Electricity Markets, p. 143.

[308] CAISO (May 2019), 2018 Annual Report on Market Issues and Performance, p. 151.

[309] CAISO (May 2019), 2018 Annual Report on Market Issues and Performance, p. 151.

[310] Francisco Munoz et al. (2018), Economic Inefficiencies of Cost-based Electricity Market Designs, The Energy Journal, Vol 39, No. 4.

[311] William Hogan (2 April 1999), Getting the Prices Right in PJM: Analysis and Summary: April 1998 through March 1999 The First Anniversary of Full Locational Pricing, p. 7.

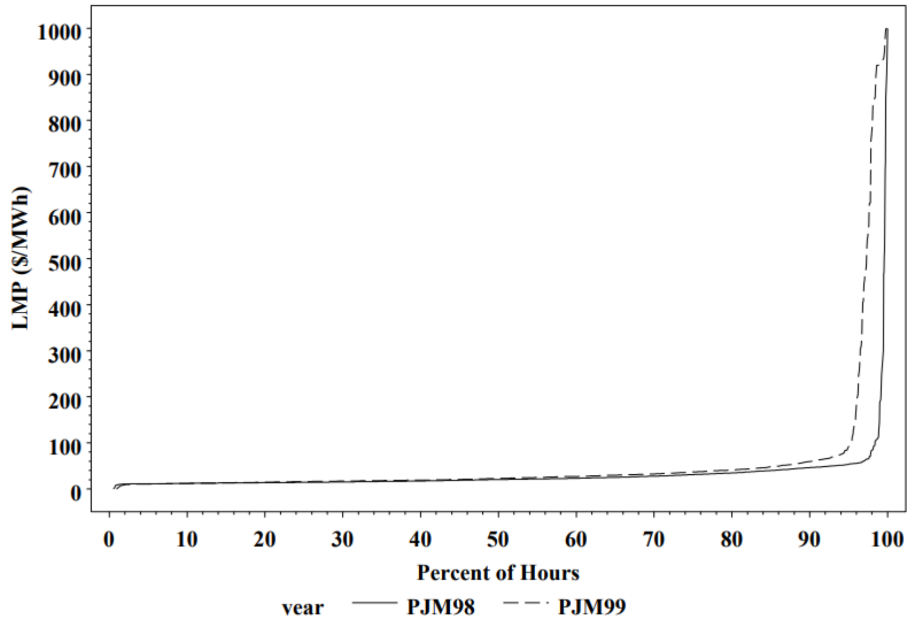
[312] Market Monitoring Unit (June 2000), PJM Interconnection State of the Market Report 1999, p. 9.

During hours of highest demand in the summer of 1999, there was a "marked difference" in the distribution of system-wide LMPs under cost-based bidding rather than market-based bidding, see Figure 8.4.[313] The IMM states "constrained LMPs during the summer of 1998 never exceeded about $55/MWh, while constrained LMPs during the summer of 1999 reached a level of about $950/MWh".[314]

The IMM states that had "the supply curves been cost-based, prices would not have increased above the $130 level during the summer of 1999".[315] However, it also suggests that some prices above USD 130 would have been required to attract imports.

Nevertheless, the IMM concludes that "scarcity was responsible for some of the price increase, but market power also played a part, although the relative proportions of the two factors are unclear".[316] It argues that on high demand days, generators know that PJM would have to take most of its offered energy on a day-ahead basis and will therefore offer higher prices.[317]

Figure 8.4: Price Duration Curves in Summer of 1998 and Summer of 1999



Source: Market Monitoring Unit (June 2000), PJM Interconnection State of the Market Report 1999.

Similar effects to that observed in PJM were reported in other markets that we examine. For example in 2018, the IMM for CAISO also argues that "prices may have been significantly in excess of competitive levels in some peak summer hours".[318]

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313 Market Monitoring Unit (June 2000), PJM Interconnection State of the Market Report 1999, p. 13.

314 Market Monitoring Unit (June 2000), PJM Interconnection State of the Market Report 1999, p. 13.

315 Market Monitoring Unit (June 2000), PJM Interconnection State of the Market Report 1999, p. 18.

316 Market Monitoring Unit (June 2000), PJM Interconnection State of the Market Report 1999, p. 18.

317 Market Monitoring Unit (June 2000), PJM Interconnection State of the Market Report 1999, p. 23.

318 CAISO (May 2019), 2018 Annual Report on Market Issues and Performance, p. 151.

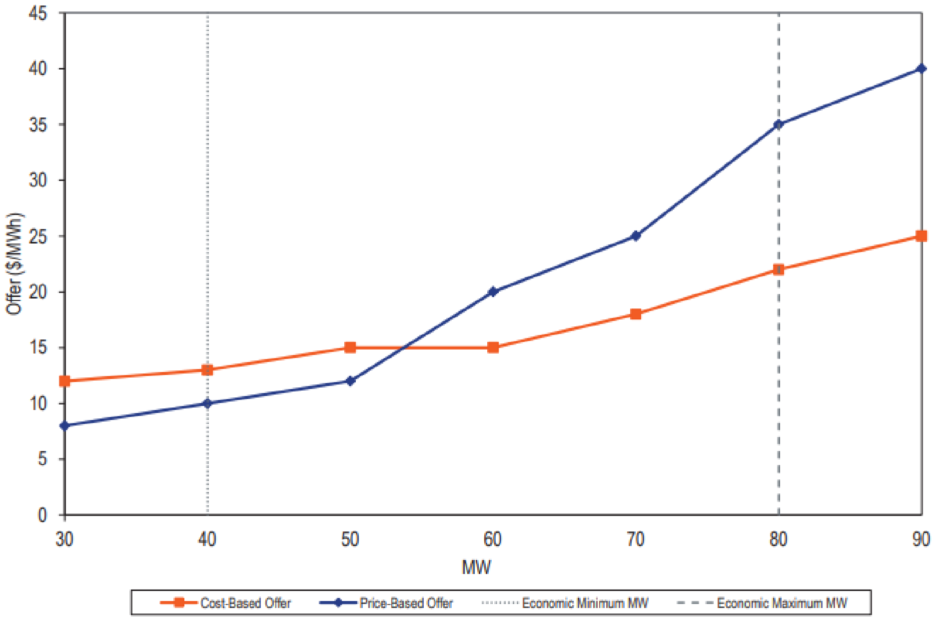
8.2.6. Strategic bidding in response to MPM tests

In the PJM, the IMM identifies instances where offer capping can be evaded by participants.[319] One such instance is when a participant can adapt its market-based bids to offer a low mark-up on cost-based bid at low volumes and a higher mark-up at higher volumes, see Figure 8.5. In the PJM, the unit is committed on the lower of its market-based or cost-based bids should its offer be mitigated.

Consequently, in the example in Figure 8.5, should a unit fail the test for market power it would be committed on its market-based offer (which is lower to start) that has lower dispatch cost despite achieving a higher payoff relative to cost-based bids at higher volumes.[320] Units may also offer different minimum run times or start up times to evade mitigation. For example, a higher minimum run time on a cost-based bid may result in the system operator selecting to run the unit on the basis of its price-based bid.[321]

It is difficult to determine the prevalence of strategic bidding ex-post with respect to MPM in the PJM because if the supplier is dispatched on the basis of its market-based bid, it is not considered offer-capped.

Figure 8.5: Offers with Varying Mark-ups to Avoid Capping



Source: Monitoring Analytics (14 November 2019), State of the Market Report for PJM, January through September 2019.

In ERCOT, a supplier's offer is mitigated using a reference price to construct a mitigated offer curve. The IMM identifies that if a supplier has significant market power it may

[319] Monitoring Analytics (14 November 2019), State of the Market Report for PJM, January through September 2019, p. 205.

[320] Monitoring Analytics (14 November 2019), State of the Market Report for PJM, January through September 2019, p. 205.

[321] Monitoring Analytics (14 November 2019), State of the Market Report for PJM, January through September 2019, p. 206.

influence the reference price using its market-based bid. In other words, it can use a higher market-based bid to increase its reference price received when and if its offer is then mitigated.[322] Hence, even if it looks like the market power has been successfully mitigated, the supplier has still influenced the market price.

The IMM for ERCOT uses the output gap as an indicative measure to examine the prevalence of market power used to influence the reference price in 2018. The output gap is measured as the difference between the capacity level on a generators market-based offer curve and its cost curve, at the first-step reference price (calculated by only examining competitive nodes). It finds that only 8 per cent of hours in 2018 had an output gap, and those had “very small quantities of capacity”. It therefore concludes that the market was competitive.[323]

8.2.7. Summary of potential market power impacts

Across all regimes that we examine, system operators have introduced MPM alongside the introduction of LMP. MPM introduced by system operators, especially in the US markets that we examined, have converged in design. Most jurisdictions we examine impose an offer cap on bidding in any given settlement period. In addition, most jurisdictions now impose MPM that involve the automatic testing of nodes for the prevalence of local market power in any given settlement period *before* dispatch, followed by the capping of offers by the system operator if market power is deemed to exist.

Market participants understand the restrictions placed on their bidding behaviour by the system operator’s MPM and will change their behaviour to respond to those policies. Therefore, an absence of exercised market power that is identified under the system operator’s MPM does not necessarily mean that market power would not be exercised should MPM not exist in the market.

Consequently, the reported prevalence of local market power, as measured by the prevalence of offer capping by the system operator, is relatively low across the case studies we examine. We find reported evidence of local market power in hours of high demand in the PJM and CAISO. Hours of high demand tend to correspond to times when participants can forecast that they will likely be dispatched by the system operator to meet load.

However, the Independent Market Monitor (IMM) for PJM and ERCOT identifies the potential for strategic bidding to manipulate the outcome of MPM, which suggests that supplier bidding behaviour may continue to remain inefficient under LMP.

Despite the potential for strategic behaviour, the frequency with which market power tests indicate that market power is being exercised in a local area tends to exceed the subsequent frequency of offer capping by the system operator. IMMs recognise that the process by which MPM policies are eventually enforced remains to the discretion of the system operator. As stated by the IMM for the PJM, the “process used to determine the final set of units

[322] Potomac Economics (June 2019), 2018 State of the Market Report for the ERCOT Electricity Markets, p. 142.

[323] Potomac Economics (June 2019), 2018 State of the Market Report for the ERCOT Electricity Markets, p. 143.

subject to offer capping in the day-ahead market is not transparent and is not documented in the PJM manuals”.[324]

[324] Monitoring Analytics (14 November 2019), State of the Market Report for PJM, January through September 2019, p. 200.

9. Methodology for Quantification of Benefits

Chapters 4 to 8 above have set out the existing evidence on the likely impact of access reforms with reference to international evidence on the impact of similar reforms in international markets. Evidence from international markets may not reflect the market impacts of access reform in the NEM for at least two reasons. Firstly, the international evidence is not comprehensive and provides little information on some potentially-important categories of benefit for the NEM, such as any reduction in the cost of new investment over time. Secondly, the international evidence consists of top-down comparisons which do not control for differences between the market structure of the international benchmarks and the NEM.

We would need to conduct bottom-up modelling to assess the likely impacts of access reform including the peculiarities of the specific changes proposed in the NEM. Bottom-up modelling is outside the scope of this report. However, this chapter sets out our views on how we might conduct that modelling. In particular:

- Section 9.1 describes the modelling platform that we would plan to use to analyse the market impacts of access reform;
- Section 9.2 provides a high-level overview of how we could use that platform to assess the benefits of access reform;
- Section 9.3 briefly describes our proposed assumptions on generation capacity and demand; and
- Section 9.4 sets our proposed assumptions on transmission network capacities and expansion.

9.1. We Would Plan to Use PLEXOS to Model the Benefits of Access Reform

In principle, one could attempt to model the impact of access reform on the NEM through:

- Analysis of historical data and attempting to draw lessons from bidding behaviour that has previously been observed in the NEM;
- Reliance on a recognised modelling platform, such as PLEXOS (described in Figure 9.1, below). Off the shelf electricity market models typically operate under a cost-minimisation logic. Accordingly, they seek to mimic the behaviour of a competitive electricity market over the long term; or
- Construction of a bespoke model from scratch or reliance on an existing proprietary models. A bespoke model could either aim to deliver a least-cost dispatch and expansion or seek to mimic strategic behaviour by bidders, but typically both is computationally challenging for real-world networks.

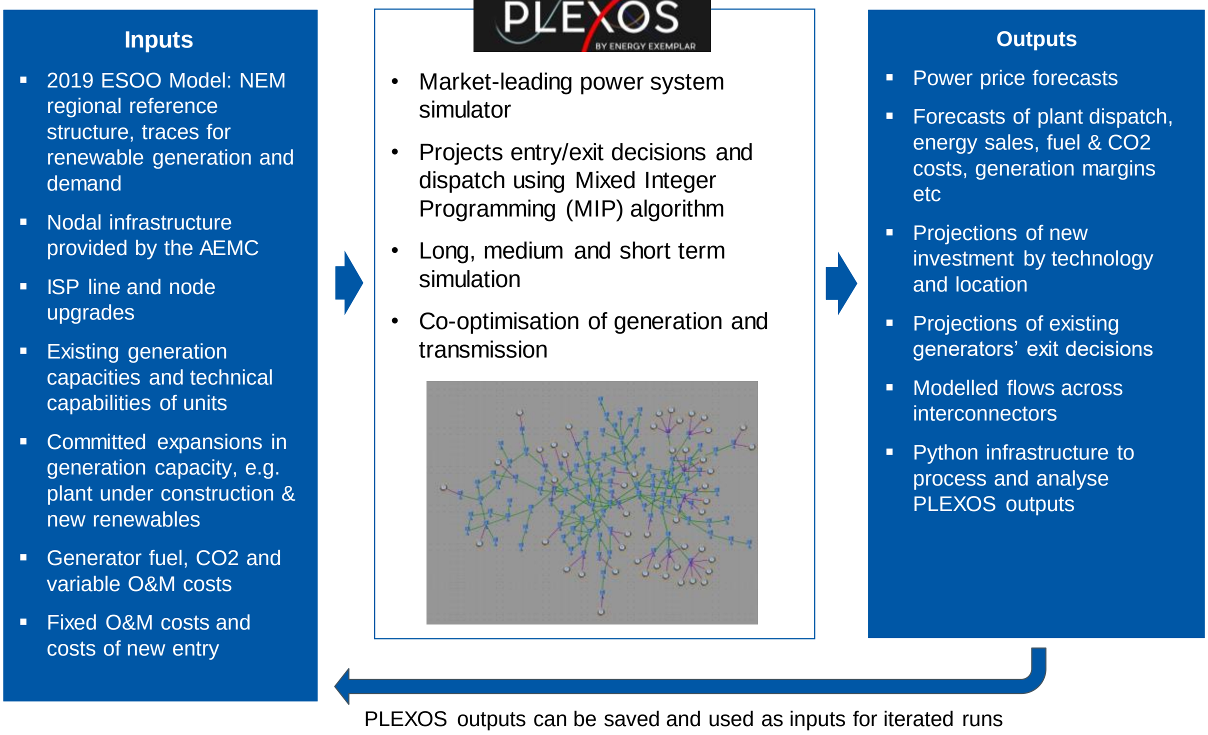
We would envisage modelling the benefits of implementing the access reform using specialist energy modelling software, such as PLEXOS. Modelling the market using PLEXOS has a number of key advantages for quantifying the benefits of access reform:

- PLEXOS is an industry-leading platform for modelling electricity markets for which we and market participants already have access to a published (but not nodal) version for the

NEM (the Electricity Statement of Opportunities or "ESOO" model is published by AEMO as part of its regular reviews of system security and reliability in the NEM);

- Unlike reliance on purely historical data, the model will be able to optimize the long-term least cost expansion planning of generation (and where applicable transmission capacity). Accordingly, a single modelling engine can be used to estimate both the short term and dynamic benefits;
- Use of an electricity market model to estimate the impact of access reform improves materially on the use of historical data not just for the long term but in the historical period as well: We have access to one version of the past and therefore the current, counterfactual, situation in which market participants earn regional average prices may be established with reference to existing data. However, we have no version of the past in which the access reform prevailed. Some cost benefit analyses proceed by comparing an optimised (e.g. by PLEXOS) counterfactual with the factual (i.e. status quo). Doing so may materially exaggerate the estimated benefits of reform because the cost benefit analysis identifies calibration error as benefits from the access reform. As a result, we propose to compare *modelled* versions of current conditions using the same modelling engine for both states of the world as the primary method for identifying the benefits of access reform. We may also compare our counterfactual prices with historical data as a cross-check on our findings.
- As a publicly-recognised modelling platform, market participants have much greater clarity and understanding of our results than if we were to use a bespoke, proprietary algorithm. (At NERA we have our own proprietary modelling tools, however reliance on PLEXOS is much more transparent and therefore appropriate for an important market reform such as the proposed access reform); and
- Reliance on a standardised modelling logic reduces the need for checking and auditing all of the inputs and operation of the model relative to programming the model from the bottom-up.

Figure 9.1: Schematic Overview of the Proposed PLEXOS Model



9.2. Using a PLEXOS Model to Estimate the Benefits of Reforms

Our principal method of quantifying benefits will be to run the PLEXOS model twice for two different sets of assumptions:

- A "factual" world which represents the implementation of the COGATI reforms; and
- A "counterfactual" world, representing the NEM under the status quo.

Our quantification will proceed by analysing the differences between those two worlds, including the differences between the two worlds in total system costs (i.e. economic efficiency) and prices (i.e. distributional impacts between buyers and sellers of electricity). The use of our PLEXOS model would differ between impacts of the access reform.

We may distinguish between three groups of impacts:

- The first group of potential impacts from the access reform may in principle be modelled in PLEXOS itself. Improvements to the efficiency of dispatch from Locational Marginal Pricing and Dynamic Loss Factors could belong to this group. Running a PLEXOS model would allow us to analyse the total costs of the system and the impact on prices of different assumptions about bidding behaviour in the short term, e.g. competitive cost-based bidding in the factual world and potentially distorted bids under the status quo. PLEXOS also allows for endogenous construction of generation, storage and transmission when run in long-term expansion mode. In principle it could therefore be used to examine the cost savings that result from building generation closer to load and at less congested nodes over the long term. In practice, endogenous construction of transmission networks, particularly at a nodal level is likely to be challenging due to the lack of data on the costs of individual links between each node on the network. Nonetheless, we could use a PLEXOS model to measure the total system costs under alternative transmission expansion plans to analyse which plans were optimal in the factual and counterfactual worlds and which reduced costs overall.

- The second group of potential impacts from the access reform would not be outputs from PLEXOS but be informed by our PLEXOS runs. These impacts may include effects on the cost of capital, market power, the relative benefits of Settlement Residues and Financial Transmission Rights and any impacts on liquidity. For instance, although PLEXOS will not calculate the impact on the cost of capital of the reform formulaically, PLEXOS runs would enable us to quantify the risks faced by market participants (such as the dispersion of prices) with and without the reform. In turn, understanding the level of that risk will inform any qualitative judgement about impacts on the cost of capital. Running PLEXOS in long-term expansion mode with an alternative cost of capital assumption will allow us to calculate a change in overall system costs and prices from investment delayed or brought forward by market participants. Similarly, our PLEXOS model will allow us to calculate measures of concentration at nodes on the system relevant to the consideration of market power; the dispersion of prices will inform conclusions on the likely pay-out of FTRs.

- The third group of potential impacts from the access reform would be largely or entirely unrelated to any modelling conducted in PLEXOS. These impacts include the implementation costs of the reform, any ongoing costs of trading operations and costs of running and designing FTR auctions.

9.3. We Will Base Our Model on the Publicly-Available ESOO Model of the NEM

The base of our PLEXOS model will be the publicly available model of the NEM, produced by AEMO as part of its annual Electricity Statement of Opportunities (ESOO). The ESOO provides a ten-year outlook on the evolution of the network – supply and demand balance, outage patterns, expected levels of unserved energy – to help stakeholders plan future operations and investments.[325]

The ESOO model provides a list of properties for each fuel type, region and generator – existing and "committed", that is, a planned project set to enter the network within the ten-year outlook period. This includes capacity, heat rate, VO&M charge, as well as technical constraints such as minimum stable levels. The model allows a combination of scenarios for demand forecasts, outages and ratings; we adopt the default 'baseline' outlook, which represents the following assumptions on future developments:

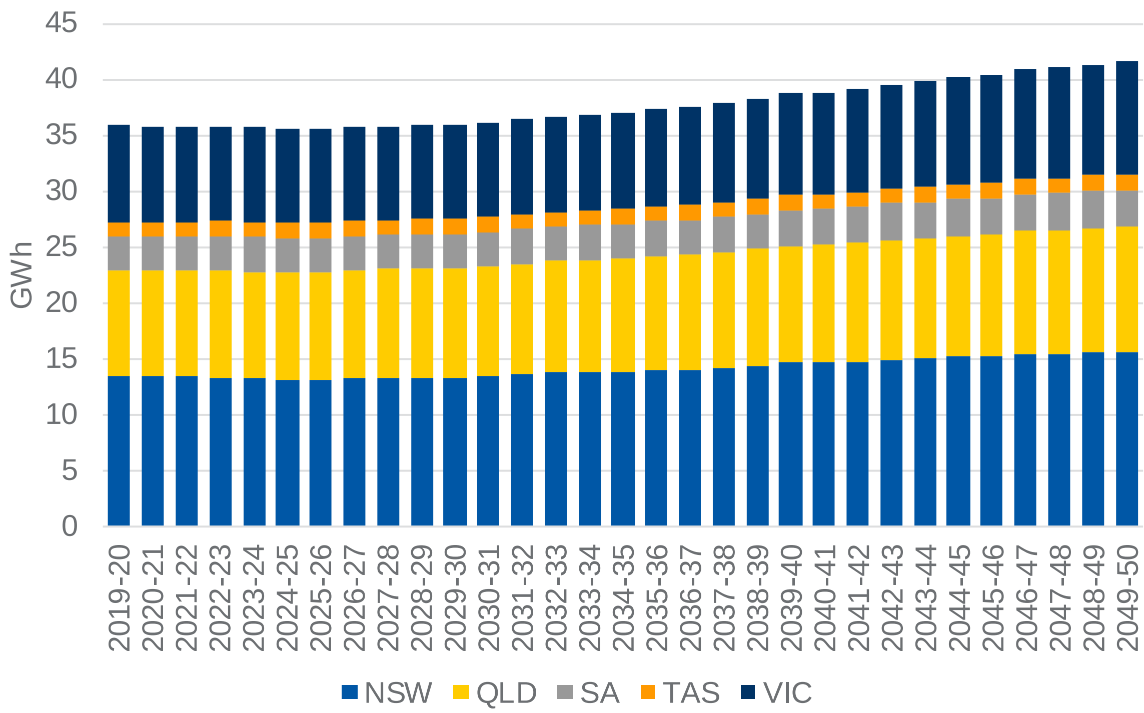
- **"Central" demand scenario:** this scenario forecasts future growth and evolution of demand assuming the system will transition to decentralised, low-carbon technologies at "moderate" speed (as opposed to the "fast change" and "slow change" alternatives). It sets medium-level build costs for renewable projects, "neutral" outlooks at fossil fuel prices, "moderate" uptake of rooftop PV and electric vehicles, "moderate economic and

[325] AEMO (August 2019). ESOO Methodology Document: 2019 Electricity Statement of Opportunities, para 1.1.

population growth, and an average temperature rise of 3 to 4.5 °C by 2050.[326] Peak demand evolution by region is depicted in Figure 9.2.

- **50% Probability of Exceedance (POE):** there is a 50% probability of demand forecasts being exceeded (as opposed to 10%).
- **2017-2018 reference year:** demand traces are modelled based on the state of the system as of fiscal year 2017-18.
- **Outages "All average":** the ESOO can model forced outage rates for generators by technology type. The "all average" option represents the average outage rate by type, aggregated across historical years 2015-16, 2016-17, 2017-18, and 2018-19.[327]

Figure 9.2: Peak Summer Demand in the 'Central' Scenario, with 50% POE, Increases Smoothly Until 2050



Source: AEMO September 2019 Input and Assumptions Book

We draw further from AEMO's inputs and assumptions for network planning and forecasting to form assumptions on build costs, heat rates and fuel prices for potential new entrant plants by technology type, as part of our long-term modelling.

326 AEMO (September 2019). Input and Assumptions Book.

327 AEMO (August 2019). 2019 ESOO Input Data Package and Model Instruction, para 1.2.

9.4. We Will Develop a Nodal Structure for the Model and Assume Future Transmission Investment Based on the ISP

The original ESOO Model is regional rather than nodal. This means that only the Regional Reference Nodes and a set of major lines and interconnectors are defined in PLEXOS. To build a nodal model requires additional assumptions on:

- The nodal constraints on the network;
- Assignment of generators to nodes;
- The node of new investment;

We will work with the AEMC and AEMO to integrate all existing and planned nodes and lines. We may constrain the nodes of new investment based on technical advice provided by AEMO.

Our analyses of the short-term effects of the Access Reform will assume a static transmission network. Over the long term, we will need to assess the impact given the potential changing scope of the transmission network (and indeed, assess whether the Access Reform would affect the scope of future expansion).

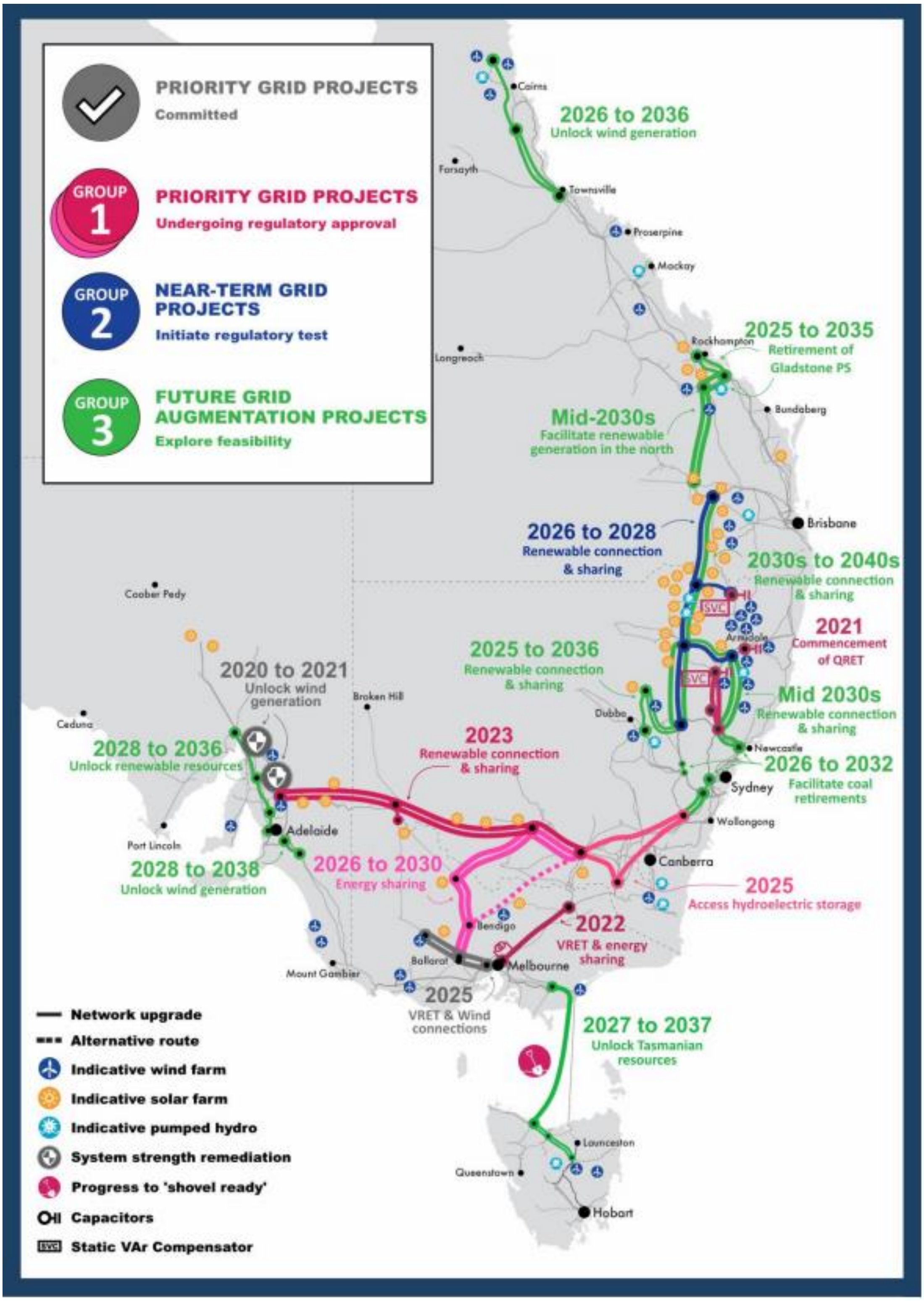
We plan to augment the transmission network in our model based on AEMO's draft 2020 Integrated System Plan (ISP), which details AEMO's strategy for optimal future investments for enhanced reliability and emission reduction. The draft ISP distinguishes five investment programmes which are committed or scheduled over the next seven years: [328]

- The augmentation of the transmission network in Western Victoria (Western Victoria Transmission Network Project) already committed;
- The Queensland to NSW Interconnector (QNI) and Victoria to NSW Interconnector (VNI) minor upgrades planned for 2020-21 and 2022-23, respectively;
- Project EnergyConnect, a new interconnector between NSW and South Australia to be delivered in 2023-24;
- HumeLink, an augmentation to the current node and line structure in South NSW to accommodate the Snowy Hydro storage project, scheduled for 2024-25;
- VNI West, a new interconnector between Victoria and NSW to be delivered in 2026-27.

These projects are considered "Priority grid projects" – represented as part of Group 1 in Figure 9.3, below.

[328] AEMO (2019). Draft 2020 Integrated System Plan, Executive Summary, para D.2.

Figure 9.3: The ISP Upgrades Included in Our PLEXOS Model are High Priority



Source: AEMO Draft 2020 ISP[329]

329 AEMO (2019). Draft 2020 Integrated System Plan, Executive Summary, para D.4.

Appendix A. Jurisdictions Not Included in Benefits Assessment

As explained in Section 4, five out of the ten jurisdictions included in our case study review did not have any useful, transferable evidence on the social benefits of the introduction of LMP. This appendix explains what evidence on benefits, if any, was available from these jurisdictions, and why this was not useful for the NEM:

1. The New Zealand electricity market began trading in 1996 with full nodal pricing. We have not found any estimates of the benefits of this reform.[330] New Zealand introduced FTRs in 2013 and there are ex ante studies available that estimate the costs and benefits of this reform.[331] However, the social benefits resulting from increased efficiency in dispatch arise due to the move to nodal pricing, and not from the introduction of FTRs. FTRs primarily have a distributional impact and may have longer-term pro-competitive effects;

2. The State of New York introduced generator nodal pricing as part of a wide-ranging restructuring of the electricity industry in 1999 that included the creation of the competitive wholesale market in NY (NYISO).[332] We have not identified any studies that estimate the social benefits of these reforms such that those benefits include the benefits from the adoption of nodal pricing.[333] However, we have identified an estimate of the capital cost savings from a more efficient development pathway for generation and transmission investment in NYISO. We discuss this estimate, and its relevance to the expected benefits from the introduction of LMP in the NEM, separately in Section 5.1;

3. The New England electricity market began operating with generator nodal pricing in 2003.[334] We have found no studies that estimate the social benefits of the reform;

4. Singapore implemented nodal pricing as part of the introduction of the National Electricity Market of Singapore (NEMS) in 2003, the culmination of a twenty-year reform process that included the privatization and liberalization of electricity markets in Singapore.[335] A 2006 PWC report conducted a CBA of the move from the Singapore Energy Pool to the NEMS. However, this study is not publicly available;

5. The Pennsylvania-New Jersey-Maryland marketplace introduced full nodal pricing in 1998 (as part of a wider suite of reforms that also introduced the PJM Interconnector as

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330 Frontier Economics, *Generator Nodal Pricing – a review of theory and practical application*, April 2008, p. 65.

331 Energy Market Services (2018), *FTR Allocation Plan 2018*, 2018, p.A6.

332 Frontier (April 2008), Generator Nodal Pricing – a review of theory and practical application, p 42., FERC (2010) 2010 ISO RTO Metrics Report Appendix G, p 197.

333 A 2007 CBA by analysis group estimates the benefits of the restructuring of the NY electricity market, but assumes zonal pricing in its modelling of the NY electricity market both in the reform and the counterfactual scenarios.

334 Frontier (April 2008), Generator Nodal Pricing, p 52

335 Frontier (April 2008), Generator Nodal Pricing, p 61., EMC (2003), Wholesale Electricity Market Report 2003, p 2.

the Independent System Operator (ISO)). We have not been able to locate any studies that estimated the social benefits of this reform.[336]

[336] Benefits estimates are available for the geographical expansion of the PJM market in 2004. However, these estimates are not useful because we cannot separate the benefits that accrue from the reform to the areas that newly joined PJM and to the existing PJM markets.

Appendix B. Summary of Studies Relied Upon for Estimating Expected Efficiency Benefits in the NEM

Table B.1 summarises the studies we have relied upon to estimate the expected benefits from efficient dispatch (due to the introduction of LMP) in the NEM.

Table B.1: Key Studies Relied Upon to Estimate Benefits in Australia

Jurisdiction and Study	Summary of Methods
ERCOT, 2004 CBA (TCA and KEMA, Market Restructuring CBA) **and 2008 CBA** (CRA and Resero, Update on the ERCOT Nodal Pricing CBA)	The 2004 CBA estimates the social benefits from nodal pricing reform as the variable production cost savings (savings in fuel, variable O&M and environmental costs) that arise from increased dispatch efficiency and more efficient generation siting under the nodal market design. The authors (TCA and KEMA) model the electricity market under two scenarios: first, using the original market configuration, and second, assuming that nodal pricing reform is implemented as planned. Benefits from more efficient dispatch accrue because under the nodal model, intrazonal constraints are recognised based on a marginal cost basis (due to locational marginal pricing), whereas under the zonal approach, ERCOT operators control the system using average shift factors (through the use of transmission line operational limits), and must therefore be more conservative. The 2004 CBA estimates total social benefits of USD 587 million in NPV terms (in 2013 prices), which represents a fall in variable production costs of 1.05%. The 2008 CBA is an update of the 2004 CBA. It only estimates the benefits from more efficient dispatch (through a reduction in production costs)[337], and assumes a level of benefits from efficient generation siting based on the findings of the 2004 CBA (i.e. based on the share of siting benefits in total benefits). The estimate of social benefits is equal to USD 520 million in NPV terms (in 2008 prices), equivalent to a fall in variable production costs of 0.6%. The changes in the results are driven by the changes that took place in the four years between the two CBAs, including: (1) significant investment in transmission infrastructure in ERCOT (this reduces benefits from nodal pricing as it reduces congestion); (2) addition of new thermal generation capacity; (3) resulting changes to bottlenecks in the ERCOT transmission network; (4) significantly higher natural gas prices; (5) lower demand expectations. The 2004 and 2008 ERCOT CBAs are the only studies we have found that attempt to capture the generator siting benefit of nodal pricing reform.
CAISO, Wolak, 2011	The Wolak paper estimates the benefits of the introduction of nodal pricing in California using actual data from before and after the reform (from 1 January 2008 to 30 June 2010 – the reform was implemented 1 April 2009). Wolak focuses exclusively on the costs of gas fired generators in California, arguing that other technologies (which have substantially lower variable costs of production) would be expected to run if they are available under both nodal and zonal designs. Hence, he argues that the benefits of nodal pricing reform will be realised primarily by gas plants. Wolak estimates the conditional mean of the variable costs of gas-fired plants in CAISO before and after the reform (controlling e.g. for differences in the price of natural gas), and finds that variable costs fall by 2.1% as a result of the reform. He estimates annual variable production cost reductions associated

337 In the 2008 CBA, production costs include fuel costs, variable O&M costs, environmental costs and start-up costs (and the balance of import costs and export revenues).

with nodal pricing reform of about USD105 million (2010 prices), which is equal to the estimated economic benefit (social benefit) of the reform.

We consider that the Wolak paper likely does not capture the benefits from more efficient generator siting, given that the study period ends 15 months after the introduction of nodal pricing reform in California.

MISO, Brattle, 2009

The 2009 Brattle study uses regression analysis to estimate system-wide production and cost functions for all large power units in MISO operating throughout the sample period from December 1999 to November 2007. The study estimates the impact of MISO's April 2005 market reform on the variable costs (fuel and environmental costs) of generators in MISO. This market reform involved the introduction of a centralised market-driven unit commitment and dispatch process for all plants in MISO, the establishment of regional power exchanges, and the introduction of day-ahead and same-day energy markets and an ancillary services market, in addition to the introduction of generator nodal pricing.

Brattle finds that on average, generators' variable costs (fuel and environmental costs) fall by 2.61% as a result of the market reform (controlling for changes in fuel prices over time). This is equal to cost savings of USD 172 million per annum (in 2007 prices).

As Brattle's analysis considers the impact of the market reform on the variable costs of a group of existing generators, it does not capture the benefits that arise from the more efficient siting of generators over time, as a result of the reform. The authors also note that some of estimated benefits may be due to ongoing productivity improvement, and not due to the impacts of the market reform.

SPP, CRA, 2005

CRA's 2005 CBA estimates the benefits from implementing a real-time Energy Imbalance Service (EIS) market in SPP, which involves the introduction of generator nodal pricing, by conducting electricity market modelling (using the GE-MAPS software), and comparing outcomes under a 'base case' (i.e. no reform) and an 'EIS case' scenario.

Benefits arise from the modelling for two reasons. First, CRA enforces inefficient congestion management in the model in the 'base case', by decreasing transfer limits on all flowgates by 10% (to reflect the estimated inefficiency of congestion management under the original system's Transmission Line Relief process). Second, CRA assumes optimal (least-cost dispatch) in the EIS case but sub-optimal dispatch in the base case. This reflects the fact that under the SPP's market model before the reform, generators designated as network resources had priority access to the transmission system in times of scarcity, thus introducing inefficiency in the dispatch process. CRA estimates that total variable generation costs (i.e. fuel costs, variable O&M costs, start-up costs and emissions costs) will fall by 2% due to the EIS reforms.

IESO Brattle, 2017

The 2017 Brattle study estimates the expected benefits of the proposed market reform in IESO (which included LMP for generation, as well as the introduction of a financially binding day-ahead market), based on a benefits transfer approach. Specifically, Brattle uses ex post benefit estimates (i.e. savings in total production costs) from similar reforms in CAISO, MISO and SPP, normalises these estimates per unit of energy delivered, and calculates the average of benefits realised in MISO, CAISO and half the benefits realised in SPP (exercising its judgement that benefits in SPP from the wider 2014 reform are likely to be higher than benefits in Ontario). It then estimates expected benefits in Ontario by adjusting for the size of the Ontario market in 2021 (when the reform was expected to be introduced at the time Brattle study), estimating benefits of CAD 84 million per year from the reform.

Brattle then revises the CAD 84 million per year figure to account for the fact that some generators are locked into existing contracts, and hence do not respond to market price signals. Specifically, Brattle finds that marginal units are exposed to market incentives (i.e. not locked into long term contracts) in 66% of all hours. Brattle therefore assumes that benefits in Ontario will amount to 66% of its estimate based on the benefits realised in comparator jurisdictions.

Sources: (1) ERCOT, TCA and KEMA (30 November 2014), Market Restructuring Cost-Benefit Analysis; (2) CRA and Resero Consulting (18 December 2008), Update on the ERCOT Nodal Market Cost-Benefit Analysis; (3) Frank Wolak (2011), Measuring the Benefits of Greater Spatial Granularity in Short-Term Pricing in Wholesale Electricity Markets; (4) Brattle (1 October 2009), Generation Cost Savings from Day 1 and Day 2 RTO Market Designs; (5) CRA (April 2005), Southwest Power Pool Cost-Benefit Analysis; and (6) Brattle (20 April 2017), A benefits case assessment of the Market Renewal Project.

Appendix C. Estimating the Total Variable Costs of Generation in the NEM

This appendix sets out our detailed approach to the "benefits transfer" analysis, i.e. our approach to estimate the expected benefits from more efficient generation dispatch in the NEM from the introduction of LMP, based on the estimated benefits of similar reforms in other jurisdictions (as discussed at a high level in Section 4.2).

Our approach to estimating the cost savings from more efficient dispatch is to apply the estimated percentage efficiency saving from the studies we surveyed (see Section 4.2) to our estimate of annual variable production costs in the NEM in 2018/19. We estimate the cost savings in the NEM using the following method:

- We use assumptions for fuel prices and variable operating and maintenance (O&M) costs across the generation mix from the 2019 AEMO ESOO model in PLEXOS;[338]
- We take the modelled annual average fuel costs (including transportation costs) and variable O&M costs per MWh for each generation fuel type the NEM from a PLEXOS model run over a year (2019/20, see Section 8.2.7 for details of the model). We construct an annual weighted average fuel cost and variable O&M cost per MWh for the NEM by scaling our cost estimates for each generation fuel type by generation by that fuel type in 2018/19 as reported by the AER. [339] We report our estimates for the annual weighted fuel cost and variable O&M cost per MWh for the NEM in Table C.1;

Table C.1: Our Estimates for the Annual Weighted Fuel Cost and Variable O&M Cost (AUD per MWh)

	Thermal Only	Across the NEM
Fuel Cost (AUD per MWh)	27.12	21.34
Variable O&M Cost (AUD per MWh)	4.39	4.30

Source: NERA Analysis.

- We multiply our annual average fuel prices and variable O&M costs by total annual consumption in 2018/19 in each region of the NEM, as reported by the AER, to estimate the annual variable costs of generation in 2018/19 in each region of the NEM.[340] We use data on consumption (as opposed to generation of power) as this data was readily available;
- We apply the percentage efficiency gain estimate (i.e the estimate of the percentage reduction in generation costs) reported by each study to our estimate of variable production costs to estimate the generation cost savings arising from more efficient dispatch.

338 AEMO ESOO 2019 Modelling Assumptions, Version Number 1.2.

339 https://www.aer.gov.au/wholesale-markets/wholesale-statistics/generation-capacity-and-output-by-fuel-source-nem AER (1 January 2020), Generation capacity and output by fuel source – NEM, Link: https://www.aer.gov.au/wholesale-markets/wholesale-statistics/generation-capacity-and-output-by-fuel-source-nem

340 AER (1 January 2020), Annual electricity consumption – NEM, Link: https://www.aer.gov.au/wholesale-markets/wholesale-statistics/annual-electricity-consumption-nem

The fuel costs and variable O&M costs that we use in PLEXOS will likely understate actual fuel and variable O&M costs. In particular, the PLEXOS model does not include ramping constraints and therefore understates generation by marginal fuel types i.e. gas, and overstates generation by baseload fuel types e.g. coal. Therefore, the fuel costs reported by PLEXOS for gas will be lower than actual fuel costs (because actual gas generation is higher, and the fuel costs for the additional plants are higher).

In addition, we adapt our methodology for two of the source studies to account for methodological differences across the estimates we survey:

- For CAISO, Wolak only estimates the reduction in annual average variable cost savings for gas generation. Gas generation comprised 60 per cent of total thermal generation in 2011 in CAISO.[341] Consequently, we only apply the estimated efficiency benefit from Wolak's study to thermal generation in the NEM and only estimate the annual costs of production related to thermal units in the NEM.

  Hence, for the estimate of efficiency benefits based on the Wolak study, we follow a similar methodology to above, but estimate annual average fuel costs and variable O&M costs for thermal units (as opposed to all units). We then estimate the total variable production costs of thermal units by multiplying the average variable costs by the total generation of thermal units in 2018/19, which we find by multiplying total consumption in 2018/19 by the percentage of output from thermal fuel source as reported by AER.[342]

- For MISO, Brattle Group's estimated efficiency benefits only pertain to fuel cost savings and not variable O&M costs. Therefore, we only apply the efficiency savings from the MISO study to our estimate of total annual fuel costs.

In Table C.2, we report our estimates for the benefits from more efficient dispatch after the introduction of LMP and FTRs in the NEM.

Table C.2: Estimated Benefits from More Efficient Dispatch in the NEM

Market Study	Percentage Efficiency Benefit	Estimated Benefits per Annum (AUDm)					
		QLD	NSW	VIC	SA	TA	NEM
CAISO	2.10%	29.21	37.34	23.28	6.51	5.62	**101.96**
MISO	2.61%	31.25	39.94	24.90	6.96	6.02	**109.06**
SPP	2.00%	28.77	36.77	22.92	6.41	5.54	**100.40**
ERCOT	1.05%	15.10	19.30	12.03	3.37	2.91	**52.71**
ERCOT	0.60%	8.63	11.03	6.88	1.92	1.66	**30.12**

Source: NERA Analysis

341 Frank Wolak (2011), Measuring the Benefits of Greater Spatial Granularity in Short-Term Pricing in Wholesale Electricity Markets, p. 247.

342 AER (1 January 2020), Generation capacity and output by fuel source – NEM, Link: https://www.aer.gov.au/wholesale-markets/wholesale-statistics/generation-capacity-and-output-by-fuel-source-nem

Appendix D. Case Study Table – Benefits from Efficient Dispatch

Market	Market before the reform	Reforms introduced	Aspects of reform included in benefits estimate
ERCOT	ERCOT applies a zonal approach to congestion management, with 5 zones in place, and manages intra-zonal congestion through the re-dispatch of individual generators. ERCOT manages congestion based on the estimated impact of generation and load schedules on Commercially Significant Constraints (CSCs) using average shift factors. Generators receive out-of-merit (OOM) payments if they are constrained on / off the network. These payments are paid by customers.	▪ Generator nodal pricing ▪ Zonal VWAPs for load ▪ Resource-specific bidding (vs. portfolio-bidding under previous regime) ▪ Use of actual shift factors (vs. average shift factors previously) ▪ 5-minute dispatch intervals (vs. 15-minutes dispatch intervals) ▪ Implementation of the day-ahead market (for energy) – previously DAM only for ancillary services ▪ Congestion Revenue Rights (also intra-zonal), vs. previous inter-zonal Transmission Congestion Rights	▪ Ex ante studies of benefits (2004 CBA and 2008 CBA) considers two sources: (1) more efficient dispatch; and (2) more efficient generator siting ▪ The benefits from more efficient dispatch accrue from the more efficient utilisation of generators under the nodal market, due to the use of actual and not average shift factors: ▪ Under average shift factors, all generators in a zone are treated as if their output has an equal effect on flows on zonal boundaries (the CSCs). Hence, ERCOT must manage the system more conservatively than under the nodal approach (through the use of transmission line operational limits).
CAISO	▪ Bilateral day-ahead scheduling ▪ Real-time imbalance market ▪ Out-of-merit payments if generators are constrained on or off ▪ Strategic bidding behaviour experienced in California before the reforms (“DEC game”) ▪ OOM payments were changed to pay out based on regulated prices to	▪ Generator nodal pricing ▪ Zonal VWAPs for load ▪ Integrated day-ahead forward market and real-time imbalance market ▪ Intra-zonal FTRs (CRRs) implemented alongside nodal pricing	▪ Ex ante study (Wolak, 2011), so all benefits of reform included (except benefits from more efficient generator siting, because study is based on data from shortly the reform)

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	manage intrazonal congestion, in response to strategic bidding ▪ Generators can submit complex bids in the nodal market (e.g. energy bid + start-up costs), vs. energy only bids in zonal markets		
MISO	▪ MISO's 2005 footprint was served by over 35 control areas, each with its own local dispatch ▪ Bilateral market dominated by vertically integrated local utilities ▪ MISO managed congestion by requesting local re-dispatch from local balancing authorities and through non-market mechanisms such as transmission curtailment.	▪ Region-wide day-ahead and real-time electricity markets ▪ Generator nodal pricing ▪ High-granularity zonal VWAPs for load ▪ Obligation-style FTRs allocated by auction	▪ Brattle's (2009) ex post estimate includes the benefits of all aspects of the reforms Estimates reduction in generation costs from more efficient use and coordination of the existing set of generators, but does not include benefits from more efficient generator siting
SPP	▪ Bilateral market ▪ Congestion managed primarily using transmission loading relief (TLRs).	▪ Generator nodal pricing ▪ Zonal pricing for load ▪ Move to uniform transmission charges ▪ FTRs not implemented at this time	▪ Ex ante study (CRA, 2005) considered benefits from two sources: (1) increased dispatch efficiency, (2) sub-optimal congestion management (differences in the "effective flowgate capacity" assumed in the two scenarios)

Source: NERA analysis

Appendix E. Moody's Assessment Sub-Rating Factors

This Appendix sets out Moody's approach to assess the relevant sub-rating factors that could be affected by the COGATI reform, and results into a change in cost of debt.

E.1. Moody's Assessment of "Hedging and Integration Impact on Cash Flow Predictability"

Moody's evaluates this factor by considering the effectiveness of company's hedging strategy, the contribution from other contractual or market arrangements (such as PPAs or capacity payments) and the extent to which a high-quality customer supply base can help dampen overall cash flow volatility.[343] Specifically, Moody's key determinants for this factor are tenor and form of hedging arrangements in place, and company's policy regarding how hedged its cashflows will remain in future years. For example, Moody's considers that most power companies would have contractual arrangements that hedge one to five years ahead, would award higher rating for the companies that can achieve a high degree of earning visibility over an extended period of time (e.g. next ten years).[344] Moody's also assesses the consistency of the companies' hedging policy and practices, and the extent to which other contractual or market arrangements can enhance the predictability of earnings, such as power purchase agreements (PPAs) with dependable counterparties, capacity payments under a stable market framework or output from renewable energy sources (RES) operating under an established and stable incentive framework.[345]

Table E.1 shows Moody's rating guidance for the sub-factor rating for "Hedging and integration impact on cash flow predictability". Moody's considers that companies whose contracts or hedges provide sound visibility on a majority of expected future cash flows over the next three year period are often scored Baa or higher, whereas unhedged companies tend to score lower in this sub-factor as their cash flow tend to be volatile.[346] For a company to achieve "Aaa" rating in this category, the forward hedging arrangements need to provide a high degree of visibility on substantially all expected cash flow for the next 10 years.

In addition to hedging arrangement and policy, Moody's also takes into account the size and quality of downstream customer base, which could reduce cashflow volatility. However, it is unclear whether the customer base would be affected directly by the proposed access reform.

[343] Moody's Investor Service (17 May 2017), Unregulated Utilities and Unregulated Power Companies, p.8.

[344] Moody's Investor Service (17 May 2017), Unregulated Utilities and Unregulated Power Companies, p.9.

[345] Moody's Investor Service (17 May 2017), Unregulated Utilities and Unregulated Power Companies, p.9.

[346] This guidance recognises that aside from customized bilateral contractual arrangements, it is generally difficult and expensive to hedge effectively beyond five years and that market liquidity is often limited to three years. Moody's Investor Service (17 May 2017), Unregulated Utilities and Unregulated Power Companies, p.9.

Table E.1: Moody's rating assessment for hedging and integration impact on cash flow predictability

Sub-Factor Rating	Hedging and Integration Impact on Cash Flow Predictability
Aaa	Forward hedges or other contractual/ market arrangements provide a high degree of visibility on substantially all expected cash flow for the next 10 years, OR Large, high quality captive downstream customer base in non-competitive market eliminates exposure to commodity risk over the long-term
Aa	Forward hedges or other contractual/ market arrangements provide good visibility on 75% or more of expected cash flow for the next 7 years, OR good visibility on > 50% expected cash flow for the next 5 years, if underpinned by sizeable high quality customer base
A	Forward hedges or other contractual/market arrangements provide good visibility on 50% or more of expected cash flow for the next 5 years, OR good visibility on > 50% expected cash flow for the next 3 years, if underpinned by sizeable high quality customer base
Baa	Forward hedges or other contractual/ market arrangements provide good visibility on 50% or more of expected cash flow for the next 3 years, OR good visibility on > 30% expected cash flow for the next 2 years, if underpinned by sizeable high quality customer base
Ba	Forward hedges or other contractual/ market arrangements provide good visibility on 30% or more of expected cash flow for at least the next 2 years, OR good visibility on > 30% expected cash flow for at least the next year, if underpinned by sizeable high quality customer base
B	Minimal reliable cash flow visibility, OR Limited ability to hedge, OR Portfolio of contracts/hedges very short term, OR Substantial short generation position versus customer base
Caa	No reliable cash flow visibility, OR Hedging strategy is ineffective, OR Most assets in underdeveloped markets characterised by little transparency, poor liquidity and limited potential to hedge

Source: Moody's Investor Service

E.2. Moody's Assessment of "Market Framework & Positioning"

The rating sub-factor "Market Framework & Positioning" assesses the predictability and supportiveness of the company's generation market, and the company's positioning within that market.[347] Moody's assessment of the generation market takes account of how developed and settled the energy market framework is, the width of the reserve margin, and the market's susceptibility to political interference and intervention.

In the discussion paper, the AEMC argues that the access reform would improve the effectiveness of the market framework via increasing contract market liquidity and providing

347 Moody's Investor Service (17 May 2017), Unregulated Utilities and Unregulated Power Companies, p.11.

more efficient pricing signal.[348] Therefore, if the access reform is successfully implemented, it could provide clarity on the direction of Australian energy policy and regulation, and increase market liquidity, leading to a higher rating score for the market framework sub-factor.[349] In terms of Moody's rating guidance, it indicates that a company would score Baa or better if it operates predominantly in well-designed competitive market, and the competitive profile of its assets must be at least above average, as show in Table E.2.

Table E.2: Moody's rating assessment for Market Framework & Positioning

Sub-Factor Rating	Market Framework & Positioning
Aaa	Company operates in generation markets with clear, transparent and settled market frameworks, AND Generation mix is perfectly aligned with market and is expected to mirror future changes, and diversified portfolio (no fuel/technology > 50% output)
Aa	Company operates in generation markets with settled and supportive market frameworks, AND Generation mix is expected to remain very well aligned with market average and diversified portfolio (no fuel/ technology > 50% output)
A	Company operates in generation markets with frameworks that are supportive but may be evolving, good visibility on > 50% expected cash flow for the next 3 years, if underpinned by sizeable high quality customer base, AND Generation mix is expected to remain very well aligned with market average and some fuel/ technology concentration (single technology > 50% output) may be present
Baa	Company operates within generation markets whose frameworks may be undergoing some change, Generation mix is expected to remain well aligned with market average and diversified portfolio (no fuel/ technology > 50% output)
Ba	Company operates within generation markets whose frameworks are undergoing change, Generation mix is expected to remain well aligned with market average and some fuel/technology concentration (single technology > 50% output) OR Generation mix is not well aligned with market average, and is expected to remain so for the foreseeable future and diversified portfolio (no fuel/ technology > 50% output)
B	Company operates the majority of its fleet in a relatively new and untested markets with high risk of adverse political interference, OR Generation mix is expected to remain mis-aligned with market average for the foreseeable future and Fuel/ technology concentration (single technology > 50% output)

[348] AEMC (14 October 2019), COGATI Proposed Access Model, p. 17.

[349] Moody's assessment of the effectiveness of a market framework include liquidity, pricing transparency, prevailing reserve margins and market demand, prospects for new generation, the length of time that the framework has been in place, the degree to which it has been tested (including in the courts) and expectations for material modifications. Moody's Investor Service (17 May 2017), Unregulated Utilities and Unregulated Power Companies, p.11.

Sub-Factor Rating	Market Framework & Positioning
Caa	Company operates within undeveloped market frameworks, which are unfavourable to generators, OR Generation mix is expected to remain mis-aligned with market average for the foreseeable future and single generation technology

Source: Moody's Investor Service

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