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Costs and Benefits of Additional Market Making in the NEM

Australian Energy Market Commission

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Contents

List of Tables

List of Figures

Executive Summary

Background

The Australian Competition and Consumer Commission's (ACCC) Retail Electricity Price Inquiry (REPI) found that the futures market was "not working sufficiently well for small and standalone retailers to effectively manage their wholesale risk". The ACCC specifically recommended that a mandatory market making obligation be imposed in South Australia, due to low liquidity in the hedge market that region.

Three schemes which may promote liquidity have been announced since the inquiry:

- The Energy Security Board (ESB) announced its intention to impose a "Market Liquidity Obligation" (MLO) that comes into force when a regional reliability falls below a threshold.
- The Australian Securities Exchange (ASX), which provides the platform for trading forward contracts, is also in the process of implementing a voluntary market making scheme for exchange-traded electricity futures contracts.
- In addition, ENGIE has initiated a rule change request to introduce a tender for incentivised market making in the NEM.

In its public consultation, the AEMC lists the following potential designs as options for reform:[1]

1. Do nothing: Instead rely on the introduction of the ASX MMO plus MLO.
2. Incentivised MMO: Market makers identified through a centralised tender process. This is the MMO design suggested by ENGIE.
3. Trigger driven MMO: Similar to the mandatory MMO discussed below but would only apply when the trigger condition is met. This suggested trigger is when churn falls below 1.5. Additional triggers may include, but are not limited to, specified average or maximum bid ask spread levels. Liquidity triggers such as these may justify the need for greater liquidity and greater price discovery. The trigger driven MMO could be implemented as either an incentivised MMO or a mandatory MMO.
4. Mandatory MMO: An obligation placed on market makers, who are identified by the AEMC, to make hedge contracts available "during time periods when a shortage of contracts is identified".[2]

Internationally, regulators Have Implemented MMOs to Promote Liquidity, Often Without a Firm Basis for Intervention

Academics, regulators and market participants internationally have not reached a consensus about how they should define liquidity, how much is enough or how they should measure it. Whilst a liquid market for forward contracts facilitates competition in electricity markets, it is also the outcome of a competitive market. Intervening in forward markets may impose costly

[1] AEMC (December 2018), National Electricity Amendment (Market Making Arrangements in the NEM) Rule 2019 Consultation Paper, p. 21.

[2] AEMC (December 2018), National Electricity Amendment (Market Making Arrangements in the NEM) Rule 2019 Consultation Paper, p. 21.

trading risks on market participants whilst not addressing the underlying features of the market which lead to the (perceived) lack of liquidity in the first place. Nonetheless regulators internationally have sought to promote liquidity, including in Great Britain, Singapore and New Zealand. (The Irish regulator recently abandoned plans to introduce an MMO for practical reasons).

In part due to problems with measuring the benefits accurately and the challenge of constructing a robust counterfactual, the benefits of MMOs internationally have been largely elusive. Whilst MMOs have tended to improve liquidity in the contract market to some extent, this improvement has not been the "step-change" in liquidity that the regulator often desired.

The costs of MMOs are similar across the international case studies we reviewed. These costs largely comprise the costs of collateral and taking suboptimal risk positions from the perspective of the trading firm. These costs are higher when price discovery is harder (i.e. during periods of high volatility) and when the obligation places tighter constraints on market makers (MMs). Designing MMOs requires a trade-off between ensuring that market-making services are provided during periods of high volatility (because the benefits of price signals are largest in these periods), whilst ensuring that MMs do not bear disproportionate costs of providing market-making services.

The (Social) Costs of the Proposed Market-Making Schemes are Likely to be Broadly Similar across Options

Whilst differing MMO designs involve different costs of regulation and incentives, the key driver of the cost of an MMO is the trading requirements placed on MMs. We understand that the trading provisions under the ASX MM scheme and the AEMC's other potential reforms have largely converged on the parameters that will be used in the MLO. Therefore, across the proposed MMO designs, we estimate that the social cost (i.e. the costs to generators, retailers and consumers combined) of market-making is broadly similar. In each case, we have adjusted international benchmarks for the cost of market-making to account for the higher volatility of the price of electricity contracts in Australia.

Nonetheless, the costs of the MMO schemes are likely to differ somewhat in practice because:

1. The ASX MMO is voluntary. Therefore, MMs may suspend market-making during periods of volatility, which will reduce the variable costs of market making;

2. The Centralised Tender Process may have lower costs because the most efficient market makers are appointed. However, the Singapore experience highlights that an inefficient tender design could also result in high costs. In part these costs may comprise a transfer (i.e. overcompensation) to market makers rather than represent the social costs of market making.

3. The Trigger Driven Obligation may have lower costs than the compulsory market making scheme because it is mandatory only when triggered; and

4. The Mandatory Market-Making Scheme may have higher costs if it results in less efficient market makers being selected. It may also distort competition across the market

over the long term by increasing regulatory risk and discouraging investment by those who may fall subject to the scheme.

The *distribution* of costs may also differ between the schemes at least in the short term. For instance, the Centralised Tender Process explicitly passes costs onto consumers or non-MMs; the compulsory scheme imposes costs on MMs (albeit that they may pass these costs through over the long term).

MMOs May Benefit Society when Liquidity is Inefficiently Low

Benefits of an MMO stem from the presumption that a market failure is resulting in insufficient liquidity. Absent such a market failure, an MMO will only impose the costs of additional trading without knock-on benefits that exceed those costs. The additional volume traded as a result of the MMO will be limited to trades mandated or incentivised through the MMO (i.e. there will be no additional trades in the wider market). An MMO in such circumstances is at best a transfer from market-makers to their trading counterparties.

Where the MMO is responding to a market failure, introducing the MMO may have a knock-on effect on liquidity in the market as a whole. As the AEMC has previously identified, MMOs in the presence of such market failures may theoretically:

- improve signals for efficient investment in generation;
- enhance wholesale and retail market competition; and
- enhance transparency and predictability of forward prices.

These three categories of benefit manifest themselves in costs and risks for market participants. We measure these potential benefits collectively with reference to the reduction in these costs and risks for market participants.

Electricity markets generally, and the NEM in particular, experience volatile market prices. Market participants face a trade-off between hedging in forward markets and exposing themselves to additional price risk in the spot market. The precise trade-off that they make will depend on:

- the transactions costs they face embodied in the bid-ask spreads prevailing in the market; and
- their cost of attracting capital into the business measured by a return on the risk capital that they need to remain solvent.

We quantify the benefits of an MMO by considering the impact it has on the costs of financing and trading for competing generators and retailers. Our estimated benefits are equal to the reduction in costs that generators and retailers would need to recover in equilibrium. Provided that the threat of entry acts a constraint on market prices, existing generators and retailers would pass through these benefits to customers.

We Quantify the Benefits of MMOs by Simulating the Impact of Lower Transactions Costs on the Optimal Hedging Strategy

We construct a simplified balance sheet for a representative supplier. We then run Monte Carlo simulations to examine the impact of the evolution of electricity prices and customer churn on suppliers' balance sheets. We assume that MMOs will result in the availability of forward markets at narrower bid-ask spreads and model the impact of those narrower spreads on the optimal hedging strategy. We find that suppliers tend to hedge more, when hedges are available at more cost-effective transactions costs.

Our modelling identifies the two categories of benefit resulting from lower transactions costs imposed by the MMO:

- A direct financial benefit to competing generators and retailers on the volume that they trade; and
- Allowing generators and retailers to hold fewer assets on their balance sheets to insure themselves against insolvency. Holding fewer assets offers a benefit to market participants equal to the cost of capital or required return on those assets.

Our modelling is necessarily an abstraction from reality. Example simplifications include modelling:

- the balances of *representative* suppliers rather than each market participant and assuming that generators are the counterparty to supplier trades. In practice, this may understate the benefits of an MMO if generators trade frequently to reflect their expectations of when they will be in merit or suppliers trade between themselves;
- hedging of quarterly flat swaps, rather than the wider range of contracts which may exist currently or in future and may therefore understate the benefits of the MMO. We model quarterly flat swaps for tractability and because reliable data does not yet exist for contracts which are only rarely traded; and
- the impact of reducing *market* bid-ask spreads and assuming that market participants could hedge their entire volumes at the reduced spreads. This assumption implies a knock-on effect of the MMO on liquidity in the market as a whole and may over or understate the benefits of the MMO depending on how market spreads respond to its introduction. In the worst case, the MMO could reduce spreads for the relevant products to the mandated levels only for the mandated or incentivised volumes which form part of the scheme or merely concentrate liquidity in the mandated windows.

We set out our key assumptions and the directional impact of these assumptions on our conclusions in more detail in Chapter 5 of this report.

We Estimate High and Low Cases across Two Scenarios for the Net Benefits of MMOs

We present results in Table 1. We base the cost estimates in the Table on international benchmarks adjusted for NEM conditions. We base our benefits estimates on our modelling of representative market participants in the NEM as described above. We have assumed that the costs and benefits are correlated as presented in the Table , because volatility and trade drive both costs and benefits. In principle however, costs may be higher in low benefit scenarios if the volumes traded under the MMO are high and the MMO does not promote liquidity in the wider market.

Table 1: Estimated net benefits of the proposed MMO designs

	Scenario	[1] ASX MMO + MLO		[2] ENGIE's Incentivised MMO		[3] Trigger Driven MMO - SA Only		[4] Mandatory MMO	
		Low	*High*	*Low*	*High*	*Low*	*High*	*Low*	*High*
Benefits	MMO	10.3	26.3	10.3	26.3	5.2	12.6	10.3	26.3
	MMO+Liq.	22.4	56.0	22.4	56.0	12.2	28.6	22.4	56.0
Costs		13.7	18.6	17.3	19.6	5.9	6.3	17.1	19.2
Net Benefits	**MMO**	**-3.4**	**7.7**	**-7.1**	**6.7**	**-0.7**	**6.3**	**-6.8**	**7.2**
	MMO+Liq.	**8.7**	**37.3**	**5.0**	**36.4**	**6.4**	**22.3**	**5.3**	**36.8**

Source: NERA Analysis

The Table sets out benefits for two scenarios for the impact of the MMO on liquidity in the market:

- "MMO" assumes that market spreads for forward contracts are capped at the mandated levels of 5 per cent (New South Wales, Queensland, Victoria) and 7 per cent (South Australia). In practice, average bid-ask spreads are typically below these caps under current conditions and only exceed them on a few days. Accordingly, in this scenario average bid-ask spreads fall only slightly (c. 0.1 percentage points) from current conditions except in South Australia (where they fall by 1.6 percentage points);

- "MMO plus Liquidity" estimates the benefits for a case in which the MMO reduces spreads by more than the "MMO" scenario. For NSW, QLD and VIC, we double the reduction in bid-ask spreads that we estimate in our MMO scenario (c. 0.2 percentage points). For SA, doubling the reduction in bid-ask spreads would reduce transactions costs by over 3 percentage points from existing levels and would dwarf the benefits seen in other jurisdictions. Accordingly, we relied on estimates produced by the Electricity Authority in New Zealand of the impact of market makers on market bid-ask spreads.[3] This method results in a further reduction of market bid-ask spreads by a further 1.04 percentage points.

These two scenarios do not capture the full potential range of net benefits from the MMO. For instance, the costs of ENGIE's incentivised MMO set out in the Table do not take account of the risks of overcompensation to market-makers or lower costs from selecting more efficient market-makers.

For each scenario we estimate a high and low case for the benefits of the MMO by making different assumptions about the volume to which they apply:

- In the low case, we calculate the overlap for each market participant based on the total annual volumes that they generate and retail. We then assume that these overlap volumes

[3] The Electricity Authority in New Zealand estimated that three market makers would reduce market bid-ask spreads to around 60 per cent of the mandated spread. SA would have three market makers under the MMO proposals and a mandated spread of 7 per cent. We therefore estimate a bid-ask spread of 4.06 per cent.

are perfectly internally hedged and market participants receive no benefit on these volumes from a reduction in transactions costs.

- In the high case, we assume that market participants receive the benefit of reduced transactions costs over the total volume of electricity generated in the market.

The method we employ in our low case is likely to understate the benefits of the MMO and the method in our high case is likely to overstate them.

Our Results Suggest that the ASX MMO May Deliver Similar Benefits to the Other Designs and be Lower Cost

Whether an MMO is likely to generate net benefits for society depends more crucially on the extent to which it increases liquidity than the costs of the obligation. If the volume of trades under the MMO's terms are a small proportion of a wider step-change in liquidity arising from it, the benefits of the MMO are likely to exceed the costs.

In the "MMO" scenario the net benefits of the introduction of any of the proposed MMO designs are not positive in the low case. In particular, all of the designs would have negative net benefits, as low as *minus* \$7.1 million. All of the designs have positive net benefits in the high case for the "MMO" scenario and in the "MMO plus liquidity" scenario.

The benefits set out in the Table are best seen as the benefits if all market makers market make to the same degree under each design. The designs (1)-(4) set out in the table mandate the same bid-ask spreads and our modelling assumes that they therefore have the same impact on the market. As a result, our model suggests that the net benefit of each design is similar, and our comparative results between designs depend crucially on that assumption.

In practice, the different designs may be more or less effective in delivering narrower bid-ask spreads in the wholesale market. Market participants have the option of withdrawing from the ASX scheme periodically over time. Therefore, in principle, the liquidity benefits of this scheme could be lower than the other schemes. However, if the ASX scheme results in a similar market outcome to the other designs, we would expect the net benefits of the ASX scheme to be greater because it presents cost savings relative to the other designs.

1. Introduction

The AEMC has commissioned NERA Economic Consulting to advise on, analyse and estimate the costs and benefits associated with the proposed designs of a Market Making Obligation (MMO) in the National Electricity Market (NEM).

This report proceeds as follows:

- Chapter 2 sets out the background to the economic concept of liquidity and plans for an MMO in Australia;
- Chapter 3 provides an overview of international markets which have implemented MMOs and the costs and benefits of those interventions;
- Chapter 4 provides a high-level assessment of the costs of MMOs in Australia, based on adjustments to those of the international case studies for Australian conditions; and
- Chapter 5 provides a high-level overview of the benefits of the MMO, including the results of bottom-up modelling which aims to quantify the benefits that an MMO would have by reducing the transactions costs paid by market participants and risks that they face.

2. Background

This chapter sets out the background behind liquidity interventions and the proposed MMO in Australia. It proceeds as follows:

- Section 2.1 describes the economics of liquidity and provides general observations on interventions to support liquidity;
- Section 2.2 describes the economics of forward trading and why it is important in electricity markets;
- Section 2.3 explains methods for forward trading in the National Electricity Market (NEM); and
- Section 2.4 describes the background behind the current MMOs under consideration in Australia.

2.1. The Economics of Liquidity and Interventions to Support it

Although many regulators and policymakers internationally aspire to liquid electricity volumes, 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 (MMO) 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”.[4]

As should be clear from above, this definition, in common with many others that regulators and policymakers have historically proffered, does not describe a unique market outcome. It does not define the “reasonable”-ness of traded volumes, the significance of resulting changes in prices or the ease of trading out of positions.

In practice, academics, regulators and policymakers typically focus on measures of “relative” liquidity such as the level of transactions costs, traded volumes or “smooth” price changes, or other “broader” attributes such as market depth and breadth. The sheer number and variety of these relative measures of liquidity show that there is no agreed way to measure liquidity, even if traders can spot a liquid market when one exists in absolute terms.

However defined, liquidity in the wholesale market is not a goal that regulators necessarily pursue in and of itself. By ensuring market participants to access power without moving market prices, regulators may facilitate entry and increase competition. However, lack of liquidity is itself a *symptom* as well as a cause of the structure of the wholesale market and efficiencies of related markets (see discussion in Section 5.1 below). The ultimate rationale for intervention relies on market failures that culminate in insufficient liquidity in the first

[4] SEM-16-030, p. 9-10.

place as well as concluding that intervention is likely to increase liquidity towards the efficient level.

Accordingly, regulators face at least the material challenge of assessing whether an intervention to support liquidity is likely to be effective:

- identifying whether their market is sufficiently liquid and identifying the efficient level of liquidity;
- measuring any improvement in liquidity that the regulator can affect by intervening; and
- ensuring that any intervention to treat the symptom, i.e. lack of liquidity, is more efficient than measures aimed at treating the fundamental cause of that deficiency (or leaving the problem unresolved).

2.2. Economics of Forward Trading and the Need to Trade

In wholesale electricity markets, particularly in the context of a Gross Pool such as the NEM all market participants have access to power at a price determined by the system operator through the spot market. All market participants who wish to sell power must sell it through the gross pool and therefore the market is liquid by any reasonable standard. In electricity, and particularly in the NEM, concerns about lack of liquidity relate to forward contracts for power traded ahead of delivery.

In principle, given the ability of market participants to arbitrage between forward and spot markets, a liquid spot market could be sufficient for market participants to trade effectively, at least in the idealised markets of classical economic theory. In practice, participants in the energy market may find need to trade forward products to compete effectively in both generation and retail, for at least the following reasons:

1. **Offsetting risks:** Generators and retailers face offsetting risks in the wholesale market. A generator faces the risk that at the time of dispatch, the price of power in the wholesale market is below the costs of generation. On the other hand, retailers that commit to supplying customers at a given price in the future face the risk that when they come to buy that power, the price is higher than the tariffs they are collecting from customers. Therefore, it is efficient for these two parties to trade power forward, compensating the other party for realised differences in the spot price and the contract price at the time of delivery.
2. **Different risk appetites:** If two retailers have different attitudes towards the risk of adverse wholesale price movements in the future, then there may be an efficient trade between them in the forward market such that each party is better off. In other words, if one retailer wishes to pay a large risk premium for a forward product, another retailer with higher appetite for risk (or what economists term lower risk aversion) may wish to trade and take on that risk in return for the large premium.
3. **Different views of the future:** If two agents have different views of the future then a trade between them in the forward market may be efficient. For example, if one retailer believes that the future wholesale price will be lower than the wholesale price today and another retailer believes that the future wholesale price will be higher than today, then the first retailer could sell wholesale power forward to the other retailer. Then, if that first retailer's expectations are realised, they can buy the power from the wholesale market to

deliver the forward power and make the difference. Changes in these views over time results in opportunities for trade and thus increased liquidity.

4. **Capital market imperfections:** Asymmetry of information between the capital market and the physical market requires that retailers must hedge the wholesale spot price of power in the forward market. If the capital market has perfect information and is risk neutral then retailers could just purchase power on the wholesale market with the expectation that they would break even.[5] However, capital markets add a risk premium to financing. Here, the downside risk (that wholesale market spot prices are higher than tariffs from customers at the point of dispatch) is weighted more than the upside potential (that wholesale market spot prices are lower than tariffs from consumers at the point of dispatch). Hence, retailers are required to hedge. This increases the capital requirements to enter the market.

There are two main types of risk that participants in the wholesale market may need to hedge against:

1. **Volume Risk:** Related to the quantity of electricity supplied or dispatched.
2. **Price Risk:** Related to the wholesale price of electricity at the point of supply or dispatch.

There are four main hedge contracts and strategies to hedge against these risks in the National Electricity Market (NEM), these are:[6]

1. **A Swap Contract:** When both parties agree a price and volume for a period of time and settle the difference between the agreed price and spot price. Typically, when a party holds a swap contract for delivery in the future and the price of the underlying asset moves against that party, then it is required to post collateral.
2. **A Cap Contract:** Used to hedge sudden spikes in demand and price. These risks are especially important in the NEM because of the high Value of Lost Load (VoLL) and high wholesale market price cap.[7]
3. **An "All-in-one" Contract or Load-following hedge:** "the price the buyer pays for each unit of electricity is fixed but the volume of electricity contracted under the hedge is allowed to vary with the buyer's needs. This differs from a typical hedge, where the volume of electricity is also fixed."[8]
4. **Vertical-Integration:** Generators and retailers face opposing risks. In other words, whilst a retailer faces the risk of additional costs when the wholesale price is higher than it expected, a generator faces the opposing risk of lower revenues when the wholesale price is lower than it expected. Therefore, there are benefits of a single company owning both a generator and retailer: this is vertical integration (VI). VI provides a company with an internal hedge against wholesale price movements without the need to purchase

5 "Risk neutral" in this context implies that the capital market cares only about the expected return relative to its cost of capital rather than the distribution of returns around that expected return.

6 Other contract types are available: for example option contracts and PPAs; as well as variations of the products listed here: for example baseload or peak contracts and varying contract durations. Source of four main hedge contracts: ACCC (July 2018), Retail Electricity Pricing Inquiry – Final Report, p. 108.

7 Currently AUD 14,500 per megawatt hour.

8 ACCC (July 2018), Retail Electricity Pricing Inquiry – Final Report, p. 108.

contracts in the contract market. That is not to say the VI firms have no need to trade forward contracts. For example. no firm is perfectly vertically integrated,[9] firms have different fuel mixes and thus are exposed to different risks and vertical integration does not eliminate the incentive to arbitrage contract prices where its expectations differ from other market participants.

The reasons that liquidity does not emerge naturally in electricity markets are still poorly understood. It is often contended that vertical integration is a *cause* of low liquidity in electricity contract market.[10] Indeed, while low liquidity is often attributed to vertical integration, vertical integration can be a response to underlying market conditions which make forward contracting difficult rather than being the *cause* of low liquidity. Moreover, there is no consensus on a sufficient level of liquidity in the forward market.

That is to say high levels of vertical integration and low contract market liquidity may be an efficient outcome. Intervening to provide liquidity when this is the case may be inefficient. However, the costs of intervening and reducing the benefits of VI in the wholesale market may be offset by consequent increased competition in the retail market, reducing consumer tariffs.

2.3. Liquidity and the NEM

The National Electricity Market (NEM) is a regional gross pool across five states: New South Wales (NSW), South Australia (SA), Tasmania (TAS), Victoria (VIC) and Queensland (QLD). The gross pool market settles contracts through exchange-based trading, thus removing counterparty risk for the spot market.

The spot price for electricity is set in each region at 30-minute intervals. However, a dispatch price is determined every five minutes within that 30-minute interval.[11] 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.[12] The price of the final offer required to meet demand sets the dispatch price for that five minutes. The 30-minute spot price is the average of the six dispatch prices in that period.[13] The generators receive the spot price for the period and not the dispatch price, regardless their initial offers. The spot price has a price cap, or VoLL, of AUD 14,500/MWh and a price floor of AUD -1,000/MWh.[14]

9 The forecast pattern of a firm's generation output rarely matches the forecast pattern of its retail sales. I.e. even if the total volumes are the same, their forecast timing, value and location will differ. That is to say, a 'gentailer' that generates 100 GWh of electricity and sells 100 GWh of electricity over a year, may still have the need to hedge as its generation and retail sales are unlikely to match at any given point int time.

10 E.g. ACCC (July 2018), Retail Electricity Pricing Inquiry – Final Report, p. 104, which notes: *"there is a trend towards vertical integration, which has reduced liquidity and lessened the ability of participants to effectively manage their risk*

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

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

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

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

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.[15] Though we note that the AEMC is currently considering reforms in this area as part of the coordination of generation and transmission investment (CoGaTI) review.[16]

Residential consumer tariffs have increased by an estimated 56 per cent from 2007-08 to 2017-18 to an estimated average of 30.3 c/kWh.[17] The predominant reasons for this are increasing network costs, responsible for 38 per cent of this change, and wholesale electricity costs, responsible for 27 per cent of this change.[18] There are regional variations in this relationship: for example, in SA, wholesale costs are responsible for 42 per cent of the increase in consumer bills.[19]

As the ACCC found in its Retail Electricity Pricing Inquiry: "[commercial and industrial] C&I customers in the NEM pay almost half the price for electricity that residential customers pay. This reflects economies of scale in supply as well as much lower retail costs and margins."[20] The estimated average tariff for C&I customers in 2017-18 is 15.7 c/kWh, an increase of 58 per cent since 2007-08.[21]

Like many electricity markets globally, the NEM is in the middle of transition towards renewables. An increase in renewables capacity, particularly intermittent wind generation and the withdrawal of large amounts of coal generation capacity (4154 MW between 2012 and 2018[22]) has resulted in a compositional shift in the generation mix in the NEM away from coal and towards gas and wind, as shown by Figure 2.1. This graph also excludes rooftop solar which accounted for 3.44 per cent of output and 11.07 per cent of installed capacity in 2018.[23]

At the same time as this change in the generation mix has occurred, there has also been a structural shift towards vertical integration between generation and retail, as shown in Figure 2.2. As discussed in Section 2.2, vertical integration may be an efficient response to market structure that results in low liquidity, rather than being the *cause* of that low liquidity.

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

16 See, e.g. https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and.

17 ACCC (July 2018), Retail Electricity Pricing Inquiry – Final Report, p. 7.

18 ACCC (July 2018), Retail Electricity Pricing Inquiry – Final Report, p. 7.

19 ACCC (July 2018), Retail Electricity Pricing Inquiry – Final Report, p. 17.

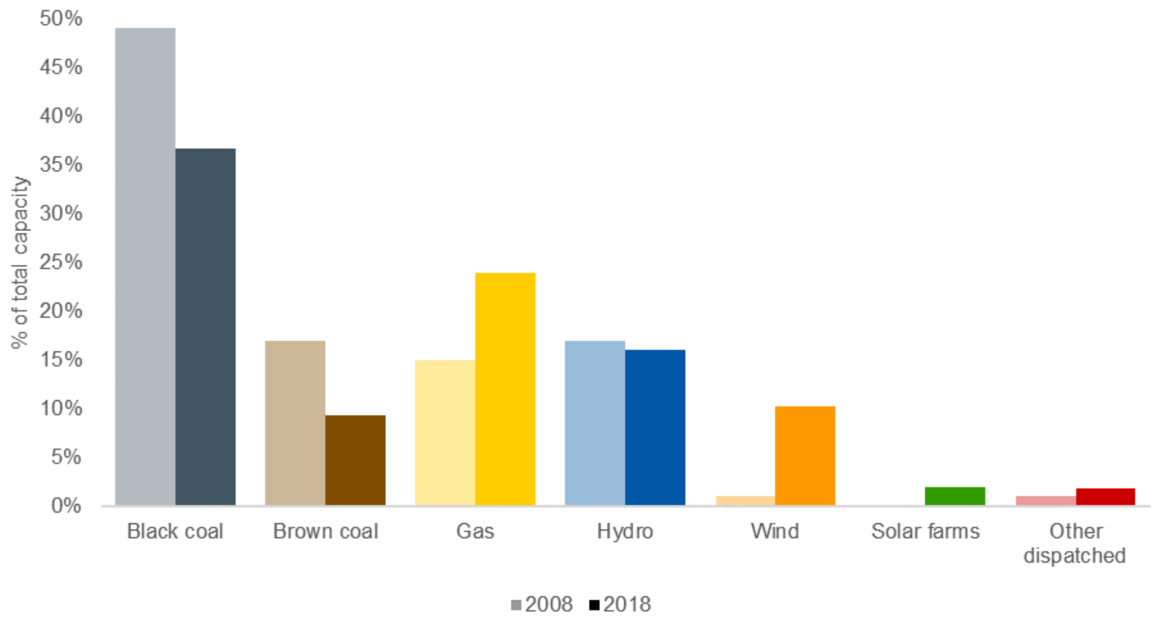
20 Square brackets added. Source: ACCC (July 2018), Retail Electricity Pricing Inquiry – Final Report, p. 31.

21 ACCC (July 2018), Retail Electricity Pricing Inquiry – Final Report, p. 32.

22 AER 2018 State of the Energy Market.

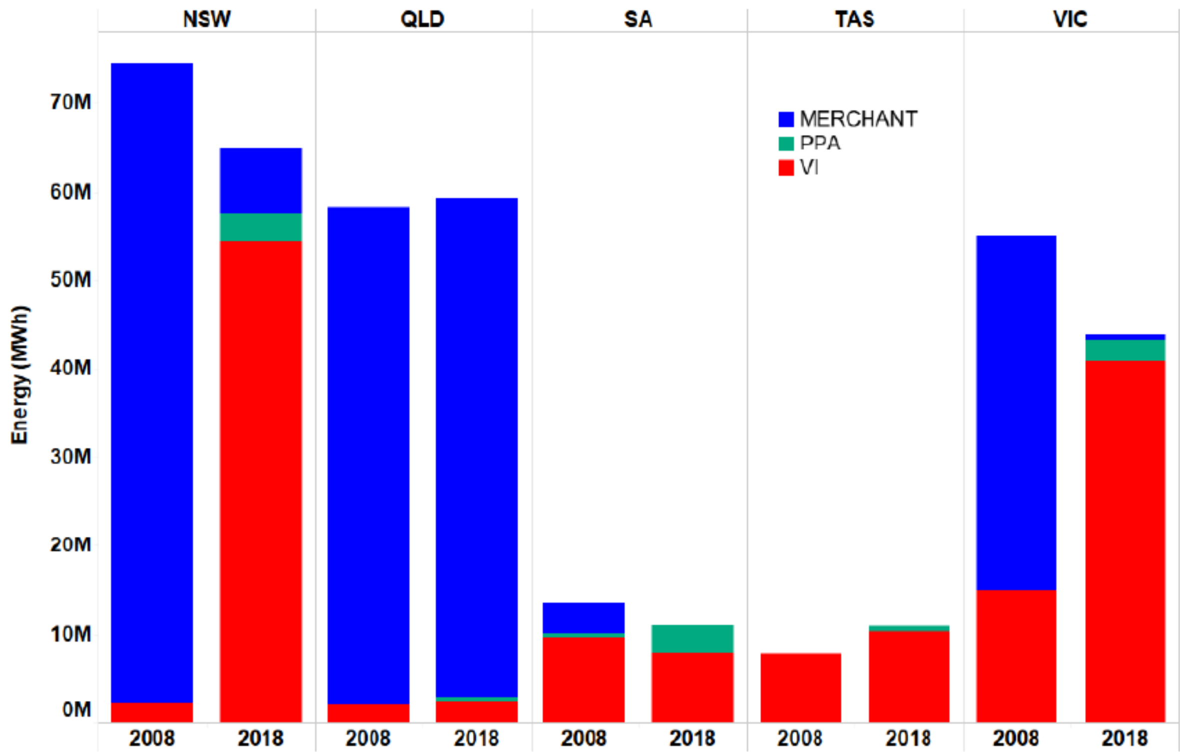
23 AER 2018 State of the Energy Market.

Figure 2.1: Scheduled generation capacity in the NEM by fuel source



Source: AER 2008 and 2018 State of the Energy Market reports. Note: Rooftop solar excluded from 2018 figures to give comparable numbers to 2008 figures which are for scheduled generation.

Figure 2.2: Output ownership by state



Source: AEMC (11 April 2019), National electricity amendment (short term forward market) rule 2019: Consultation paper.

While there is no precise definition of liquidity, contract market churn is a common proxy. In Australia, contract churn varies across states and is materially lower in South Australia than New South Wales, Victoria and Queensland, as shown in Figure 2.3. Similarly, observed spreads are much higher in South Australia than the other NEM regions, as shown in Figure 2.4.

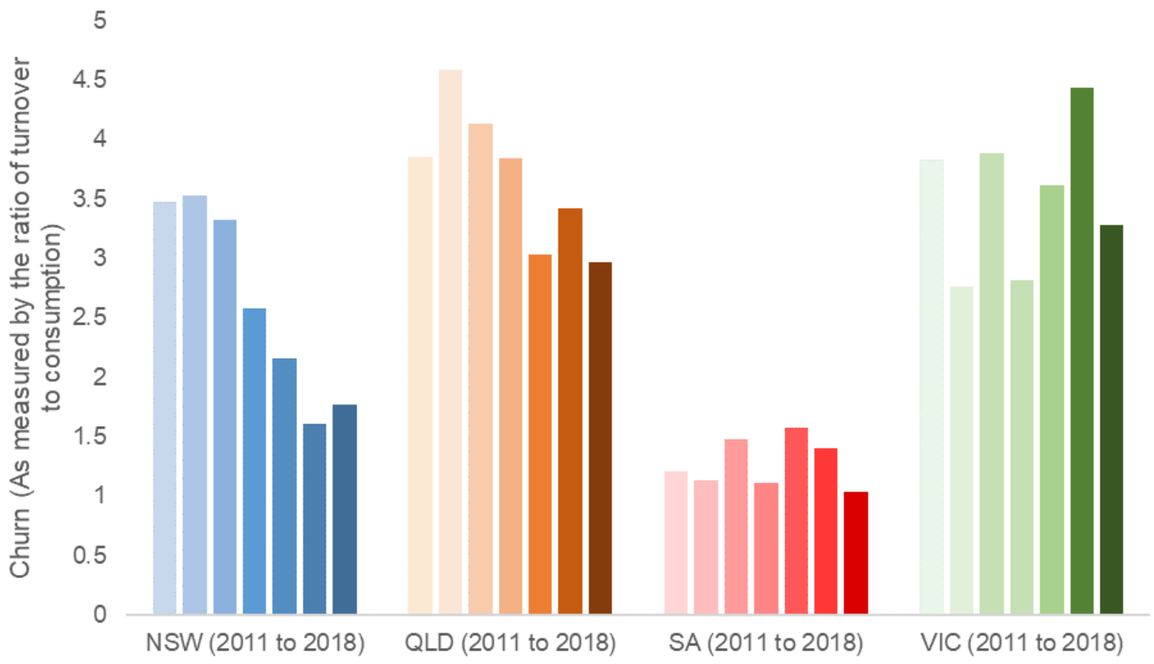
We understand that the AEMC is considering liquidity in the NEM as part of this process and do not consider this issue extensively. However, we note:

- Victoria and New South Wales both have extensive vertical integration yet also have much higher liquidity than South Australia; and
- Vertical integration can be an efficient response to underlying market conditions which are not conducive to a liquid contract market.

Regarding the second point, the fuel mix also differs substantially across the different NEM states. Figure 2.5 demonstrates the unique position (in Australia) of South Australia and Tasmania relative to the other NEM states – neither state has any coal fired generation and the majority of capacity is renewables (wind for South Australia and hydro for Tasmania). A lack of dispatchable capacity in South Australia may therefore be a key driver of low liquidity in South Australia, and vertical integration may be an efficient response to these conditions.

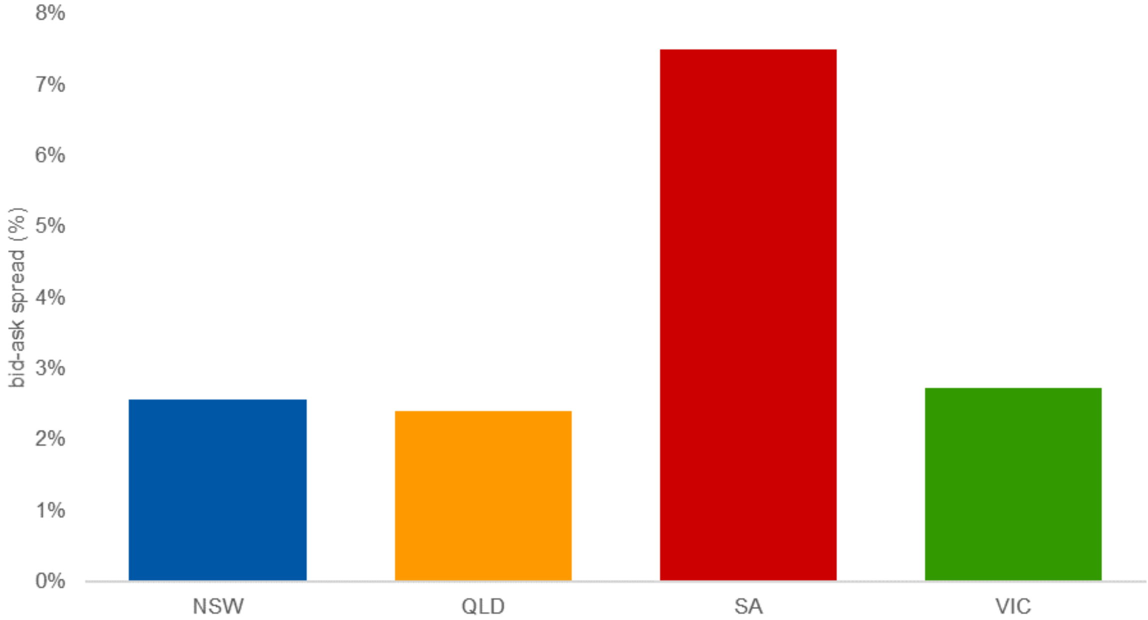
However, churn in SA is not particularly low by international standards. Whilst churn in Great Britain is significantly higher at the time of the introduction of the MMO, churn in Ireland was lower (when Ireland was considering introducing an MMO) and churn in Singapore was much lower because the futures exchange had not launched at the time of the introduction of the first MMO.

Figure 2.3: Liquidity, proxied by contract churn, annually by state



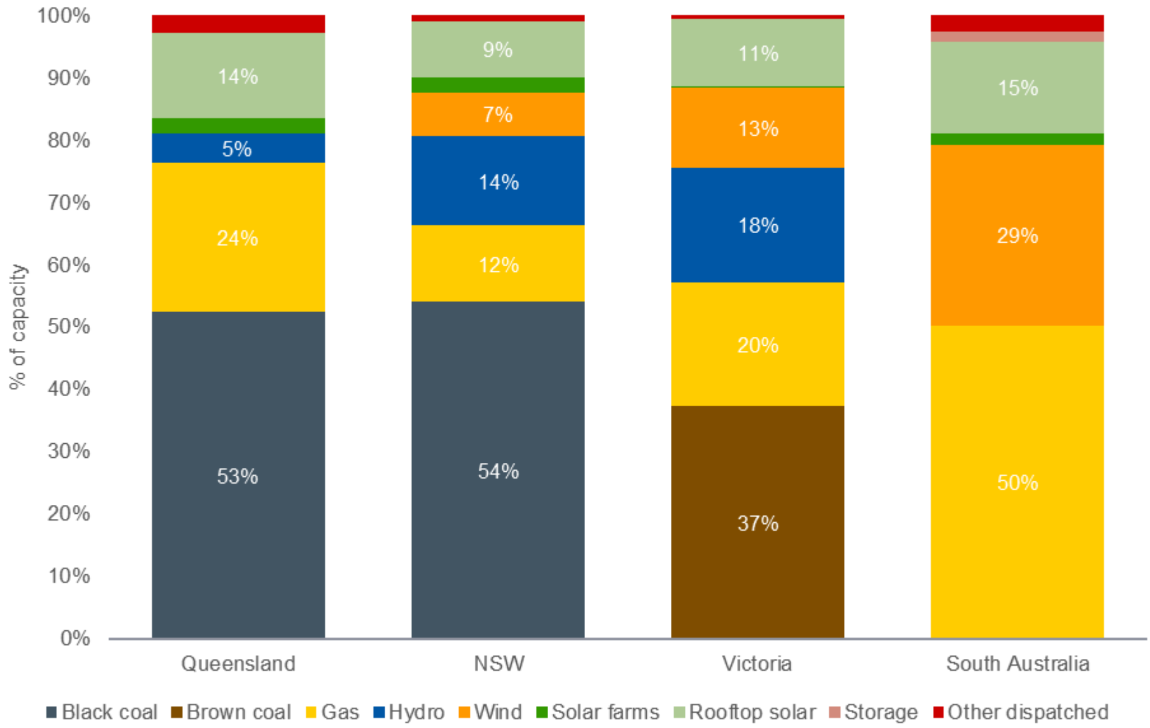
Source: AEMC analysis of 2018 AFMA survey.

Figure 2.4: Average quarterly baseload swap bid-ask spreads by state based on historical data from 2014 to 2018 inclusively



Source: AEMC analysis of ASX data.

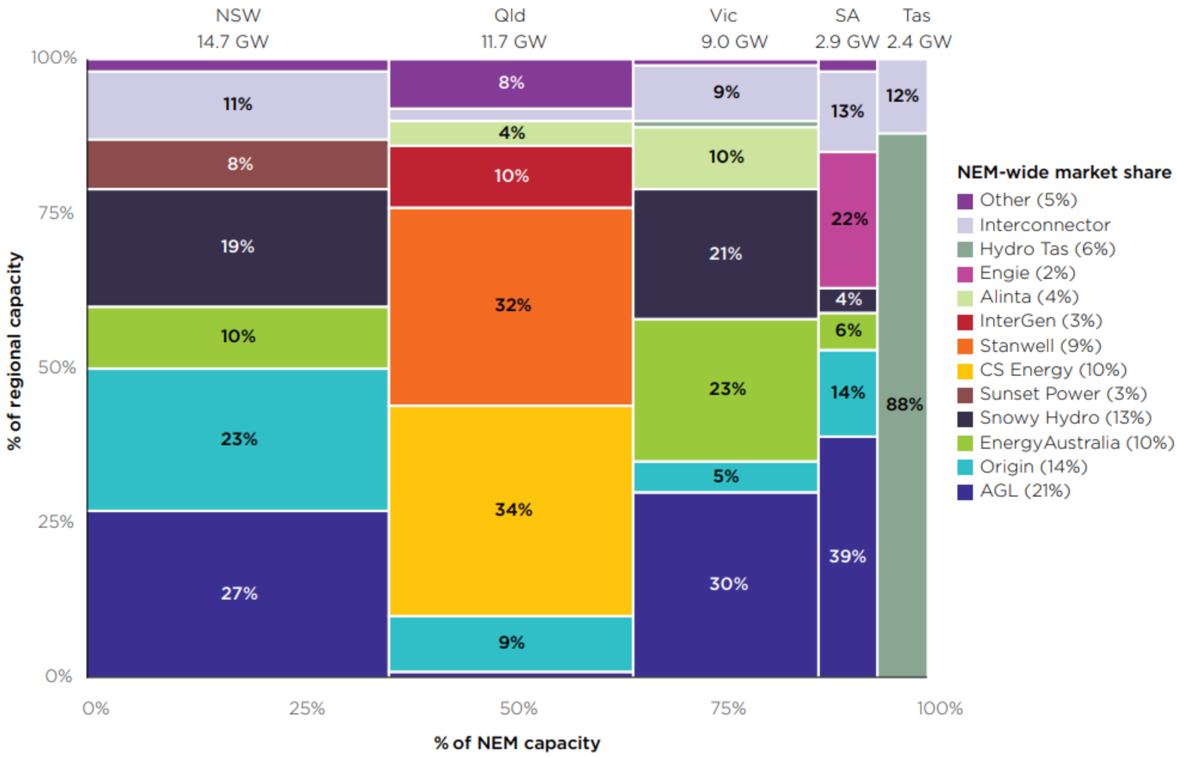
Figure 2.5: Generation capacity mix by state



Source: AER 2018 State of the Energy Market.

As a final point we note that the generation market is relatively concentrated across the different states in the NEM. In each state of the NEM, generation is dominated by approximately three generators (with the exception of Tasmania), see Figure 2.6. The three largest generators accounted for 69, 76, 74 and 75 per cent of total regional variation in NSQ, QLD, VIC and SA respectively. The majority of, but not all of, these largest generators are vertically integrated 'gentailers'.

Figure 2.6: Generation capacity market shares across the NEM (January 2018)



Source: ACCC (July 2018), Retail Electricity Pricing Inquiry – Final Report, p vii.

2.4. History of the MMO Intervention in the NEM

The Australian wholesale market has undergone significant change in recent years leading to higher and more volatile wholesale prices and, as a consequence, higher retail prices for customers. In response to this, the Australian Competition and Consumer Commission (ACCC) launched a Retail Electricity Pricing Inquiry which was published in July 2018.

As part of this Inquiry, the ACCC found that contract markets, in particular the futures market, was "not working sufficiently well for small and standalone retailers to effectively manage their wholesale risk"[24]. It found that larger, vertically-integrated retailers could access cheaper wholesale electricity compared to smaller retailers. In addition, the ACCC argued that the market trend towards vertical integration has exacerbated this problem,

24 ACCC (July 2018), Retail Electricity Pricing Inquiry – Final Report, p. 104.

reducing liquidity and “lessened the ability of participants to effectively manage their risk”[25]. Meanwhile, the “opacity” of the over-the-counter contract market also “contributes to concerns about price discrimination against smaller retailers”.[26]

As a result, the ACCC made a number of recommendations to improve the functioning of wholesale (and retail) electricity markets. One of these recommendations, Recommendation 7, was the introduction of a market making obligation (MMO) in the South Australian (SA).[27]

The MMO aims to “enhance contract market liquidity and reduce risk management costs for non-obligated participants”[28]. The ACCC assess that “improving retailers’ access to risk management products would likely improve competition in the retail market”[29]. It recommended that the MMO only be introduced in SA because “the level of trading activity in Victoria, NSW, and Queensland is high enough that market making obligations may not noticeably improve the level of market activity”[30]. This is because SA is relatively small and has high wholesale and retail market concentration and has a very high penetration of intermittent wind generation (see Section 2.3).

The ACCC recommended that the design of the MMO should consider the size and generation portfolio in the SA market, the concentration of generation ownership, the beneficial effects of the MMO on market efficiency and liquidity, the costs of the MMO borne by MMs and “any impact on the incentives of intermittent generators to invest in firming technology”[31].

Concurrently, the Energy Security Board (ESB) proposed a Market Liquidity Obligation (MLO) as part of the Retailer Reliability Obligation (RRO) under the National Energy Guarantee. The RO, to be implemented by July 2019, “intends to support a reliable energy system by requiring companies to hold contracts or invest directly in dispatchable energy to meet demand”[32]. The MLO addresses the risk of lack of liquidity when forcing retailers to hedge should the RO be triggered. The ACCC notes in its proposed introduction of an MMO in SA that it “should be designed in such a way as to ensure that the two mechanisms can work together”[33].

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25 ACCC (July 2018), Retail Electricity Pricing Inquiry – Final Report, p. 104.

26 ACCC (July 2018), Retail Electricity Pricing Inquiry – Final Report, p. 104.

27 ACCC (July 2018), Retail Electricity Pricing Inquiry – Final Report, p. 130.

28 ACCC (July 2018), Retail Electricity Pricing Inquiry – Final Report, p. 130.

29 ACCC (July 2018), Retail Electricity Pricing Inquiry – Final Report, p. 130.

30 ACCC (July 2018), Retail Electricity Pricing Inquiry – Final Report, p. 130.

31 ACCC (July 2018), Retail Electricity Pricing Inquiry – Final Report, p. 130.

32 AER (March 2019), AER releases a timetable for the publication of guidelines for the Retailer Reliability Obligation, Last Accessed: 29/4/19, Link: https://www.aer.gov.au/communication/aer-releases-a-timetable-for-the-publication-of-guidelines-for-the-retailer-reliability-obligation.

33 ACCC (July 2018), Retail Electricity Pricing Inquiry – Final Report, p. 130.

In addition, the Australian Securities Exchange (ASX) commenced a process to introduce voluntary market making which it aimed to implement in April 2019.[34] In return for market making, the market maker (MM) would receive rebates "based on a proportion of fees received by the ASX on each contract"[35]. As of December 2018, two MMs had entered into voluntary agreements for SA and five MMs had done so for New South Wales, Victoria and Queensland. The ASX arrangement stipulates that MMs must continuously quote two lots in SA and five lots in other states, at a maximum bid-ask spread of AUD 4-6/MWh and for a minimum of 25 minutes during each daily market making trading window.[36]

In response to the proposed MMO for SA and the ESB's proposed MLO, ENGIE submitted a proposal to the AEMC to initiate a National Electricity Rule (NER) change process to assess the benefit of market making in the NEM.[37] As the AEMC notes, ENGIE disputed the "value of compulsory market making as the solution for South Australian market conditions" and "does not believe the case has been well made that vertical integration is the primary, or even a significant contributor to the challenges faced by market participants on both sides of the market in South Australia"[38]. The challenges being high prices and low liquidity in the contract market.[39] ENGIE made an alternative proposal: a tender run by the AER for an incentivised voluntary market making scheme covering the entire NEM.

ENGIE argues that the tender to provide market making services should be conducted every three to five years and should cover all states in the NEM.[40] It argued that the cost of this tender should be recovered from customers. ENGIE proposed that the MMO should specify lot sizes, cumulative exposure, required spreads and minimum trading requirements. In addition, ENGIE states that the MMO should replace the MLO proposed by the NEG.[41]

The AEMC launched a public consultation on the rule change and ENGIE's request. The AEMC consultation covered a range of market making mechanisms including voluntary market making as proposed by ENGIE, a trigger driven obligation, which includes an incentive fee for market making during specific periods, or a mandatory MMO.[42] When examining each of the possible market making solutions, the AEMC will evaluate whether

34 AEMC (March 2019), Update on stakeholder feedback on market making arrangements in the national electricity market, Last Accessed: 29/4/19, Link: https://www.aemc.gov.au/news-centre/media-releases/update-stakeholder-feedback-market-making-arrangements-national.

35 AEMC (December 2018), National Electricity Amendment (Market Making Arrangements in the NEM) Rule 2019 Consultation Paper, p. 28.

36 AEMC (December 2018), National Electricity Amendment (Market Making Arrangements in the NEM) Rule 2019 Consultation Paper, p. 28.

37 ENGIE (October 2018), ESB Consultation Paper: Market making requirements in the NEM and Notification of intention to lodge a proposal to amend the National Electricity Rules.

38 AEMC (December 2018), National Electricity Amendment (Market Making Arrangements in the NEM) Rule 2019 Consultation Paper, p. 1.

39 AEMC (December 2018), National Electricity Amendment (Market Making Arrangements in the NEM) Rule 2019 Consultation Paper, p. 1.

40 AEMC (December 2018), National Electricity Amendment (Market Making Arrangements in the NEM) Rule 2019 Consultation Paper, p. 14.

41 AEMC (December 2018), National Electricity Amendment (Market Making Arrangements in the NEM) Rule 2019 Consultation Paper, p. 14.

42 AEMC (December 2018), National Electricity Amendment (Market Making Arrangements in the NEM) Rule 2019 Consultation Paper, p. 21.

"the rule will, or is likely to, contribute to the achievement of the national electricity objective (NEO)"[43]. It evaluates the mechanism based on whether it will enhance transparency and efficient operation of the NEM, enhance wholesale and retail market competition, improve the efficiency of investment in and retirement of generation capacity and demand response and whether the administrative costs of each scheme justify the expected benefits.

43 AEMC (December 2018), National Electricity Amendment (Market Making Arrangements in the NEM) Rule 2019 Consultation Paper, p. 17.

3. International Experience with Market Making Obligations

In this chapter, we summarise international experience with Market Making Obligations (MMOs) and draw on this experience to highlight some learned lessons for future design and implementation of MMOs. In Section 3.1 we provide an overview of the case studies and a high-level summary of our learnings. In Section 3.2 we discuss the specific learnings in more detail.

3.1. Overview of Case Study Regimes and Summary of Learnings

We summarise the market context, design of the MMO and performance of the MMO in Great Britain, New Zealand, Singapore and Ireland in Table 3.1. The full case studies can be found in Appendix B.

From this comparison, we draw the following conclusions and lessons from international experience with MMOs.

- The market concentration at the time of the introduction of MMOs is similar across case studies. Whilst generation fuel mix and demand vary across case studies, this does not seem to relate to differences in the design of MMOs.
- The objective of each MMO is similar across case studies. The MMO is introduced to improve competition and lower market concentration in the retail market.
- Whilst MMOs have tended to improve liquidity in the market, this improvement has not been the "step-change" in liquidity that the regulator desired.
- The introduction and operation of MMOs has coincided with an increase in new entrant suppliers. However, it is unclear whether this can be attributed to the introduction of MMOs.
- The costs of MMOs are similar across case studies and are higher when price discovery is harder and obligations bind more tightly.
- The design of incentives in incentivised MMOs can lead to large windfalls for participants and large costs for consumers.
- The choice of market makers (MMs) that least distorts competition and incentives depends on industry concentration and extent of vertical integration.
- The information available to regulators to assess the costs and benefits of an MMO, prior to introducing the MMO, is poor. Whilst ex-post cost data is generally better, the ex-post benefits remain hard to quantify.

Table 3.1: Summary of international case studies

	Great Britain	Singapore	New Zealand	Ireland
Market Context				
Market trends and context	▪ Government liberalised the electricity market between 1996 and 1998. ▪ Customers, historically supplied by a local incumbent, could choose energy supplier. ▪ By 2002, Ofgem, the energy regulator, concluded that competition was sufficiently vigorous that it could remove price controls. ▪ By 2008, 6 vertically-integrated suppliers had emerged, supplying 99% of customers. ▪ Ofgem launched an investigation into the competitiveness of Britain's electricity wholesale and retail markets. ▪ Following the investigation, Ofgem concluded that it needed to intervene in the wholesale market to improve liquidity. ▪ Self-dispatch wholesale market.	▪ Historically, state-owned vertically-integrated monopoly. ▪ Market deregulated in 1998 to allow trading between generators and retailers (both government-owned). ▪ Review in 1999 and concluded that further deregulation would lead to benefits from competition. ▪ National market introduced in 2003. ▪ Retail competition gradually introduced. ▪ All customers contestable in 2019. ▪ Gross pool wholesale market. ▪ Futures exchange introduced in 2015: - To provide options to hedge risk, and - To reduce retail barriers to entry.	▪ Historically, state-owned vertically-integrated monopoly (ECNZ). ▪ ECNZ was split up into a number of firms, including what are now The Big Four 'gentailers'. ▪ The Big Four 'gentailers' are now privatised (Contact) or partially privatised (Meridian, Mercury and Genesis). ▪ Full retail competition introduced in 1999 allowing customers to choose their electricity retailer. ▪ NZEM is a gross pool with nodal pricing. ▪ Rising prices have led to various government reviews and reforms over time. ▪ VI a common topic in these reviews.	▪ Single electricity market (SEM) for the island or Ireland. ▪ Introduced in 2007. ▪ Dominated by a state-owned incumbent, ESB (roughly half generation and supply market). ▪ ESB subject to regulation: - The regulator imposes a Directed Contracts (DCs) obligation on ESB to offer power to smaller suppliers. ▪ Replaced by I-SEM in 2018 to meet targets of EU integrated model including development of futures markets. ▪ Ex-post pool wholesale market.
Generation	▪ Mix of fuels, natural gas growing: 21% fuel mix in Q1 2014. ▪ Solar/wind growth: 12% fuel mix in Q1 2014. ▪ 69% by The Big Six in 2014.	▪ Relies on natural gas: 95% of the fuel mix in 2015. ▪ Renewable penetration marginal. ▪ 91% by biggest 6 generators in 2015.	▪ Mostly renewable sources, 74% of generation in 2010 (of which 76% hydro). ▪ 92% by largest 5 generators in 2012.	▪ Mix of fuels, mostly gas: 48% fuel mix in 2016. ▪ Wind: 20% electricity generated in 2016. ▪ 76% by biggest 4 generators in 2016.
Demand	▪ Seasonal demand: fluctuations of ~30% for residential customers. ▪ ~ 304 TWh consumption in 2014.	▪ Flat daily load shape which leads to low volume risk. ▪ ~ 46 TWh consumption in 2015.	▪ Seasonal demand higher in winter than in summer. ▪ ~ 41 TWh consumption in 2010.	▪ Seasonal demand. ▪ ~ 26 TWh consumption in 2016.
Vertical integration (VI)	▪ Prevalent: The Big Six are vertically-integrated entities supplying 94% of customers in Q1 2014. Four out of The Big Six generate at least half of their supply.	▪ Prevalent: the 7 largest generators were the only 7 retailers in 2014. ▪ Market shares of retailers mirror their annual generation market shares.	▪ Prevalent: The five largest vertically-integrated firms had a combined retail market share of 97% in March 2019.	▪ Prevalent: Largest 4 suppliers served 82% of consumption whilst generating 75% of electricity in 2016. ▪ Some ringfencing enforced.
Hedging	▪ CMA found product availability allowed entrants to match VI firm hedging strategies.	▪ Occurred predominantly through vertically-integrated arms.	▪ Occurred via bilateral, non-anonymous contracts on a platform that precluded entrant retailers from participating.	▪ SEM-C: 71.5% market hedged against spot. VI natural hedge provides 26.5%.
Liquidity	▪ Ofgem argued low: churn of 3 in 2014.	▪ Low/None. No futures market prior to MMO introduction.	▪ Low: ASX contracts only began trading in 2009 with MMOs commencing in 2010.	▪ SEM-C: argues low liquidity.

	Great Britain	Singapore	New Zealand	Ireland
Design of the Market Making Obligation				
Introduced	▪ **Mandatory MMO:** 31st March 2014.	▪ **Incentivised MMO:** 1st April 2015.	▪ **"Voluntary" MMO: June 2010**	▪ **Mandatory MMO:** not introduced.
Purpose	▪ To improve wholesale market liquidity. ▪ To mandate The Big Six trade and provide forward products with/to entrant suppliers.	▪ To provide liquidity in new futures market.	▪ To obligate incumbent generators to "establish a liquid hedge market". ▪ To improve liquidity and access to hedge products for independent retailers.	▪ To provide "forward hedging instruments" and liquidity in these instruments. ▪ To address market power concerns.
Design of the MMO	▪ MM must market make for 7 Baseload and 6 Peak products up to four seasons ahead. ▪ MM must post lots at 5MW and 10MW lot sizes. ▪ Maximum bid-ask spread: 0.5% for Baseload and 0.7% for Peakload. ▪ For products further ahead (three and four seasons) spread is limited to 0.6% for Baseload and 1% for Peakload. ▪ Spread 0.2 percentage points larger for first 3 months. ▪ MM must market make in two hour-long trading windows each day.	▪ MM receives Forward Sales Contract (FSC) as compensation. ▪ Volume of FSCs received depends on volume commitment to market make. ▪ Total FSCs available is 6 per cent of the forecasted total annual electricity sales from 2014 to 2016. ▪ MM must market make for 9 quarterly baseload contracts (2 years ahead). ▪ MM must post 6 lots of 0.5MW lot size. ▪ Maximum bid-ask spread: S$3/MWh (changed to 10% in re-launch). ▪ No fewer than one reload per window (60 secs to repost). ▪ Must make in 50% windows each day, 80% cumulative windows in a month. ▪ 7 monthly contracts (6 months ahead) added in April 2017 with maximum spread of S$4/MWh.	▪ The Big Four 'gentailers' entered into voluntary market making agreements with the ASX. ▪ MM must market make for 4 Baseload quarterly contracts (1 year ahead) and 6 Baseload monthly contracts (6 months ahead). ▪ MM must market make for 30 mins each trading day. ▪ Maximum bid-ask spread: 5% of bid price if bid price > $30, 10% if bid price <$30. ▪ MM must post lots of 0.1MW lot size. ▪ Liquefy requirement of 20 lots per side for monthly contracts and 30 lots per side for quarterly contracts. ▪ MMs receive a small rebate in exchange fees for market making.	▪ MM must post lots on monthly and quarterly baseload, mid-merit and peak contracts for up to a year ahead. ▪ MM must post at 3MW lot size for Baseload, 2MW for Mid-merit and 1MW for Peakload. ▪ Maximum bid-ask spread: 5% of bid price. ▪ MM must make in one hour-long trading window each day.
Suspension of obligations	▪ Fast market rule: MM can suspend trading in particular product and window if price changes more than 4% in a given direction. ▪ Volume cap rule: MM can suspend trading in particular product and window if MM accumulates net position of 30MW.	▪ None specifically related to the MMO. ▪ Determined by exchange rules governing every-day trading. ▪ Revenue floor and cap imposed on FSC in re-launch.	▪ Maximum bid-ask spread requirement can be suspended if firms experience "portfolio stress". ▪ Portfolio stress not defined and no disclosure obligations on parties to let market know they have suspended.	▪ Fast market rule: MM can suspend trading if traded price moves more than 4% in a given window. ▪ Volume cap rule: Calendar year and daily window net exposure caps that allow the MM to suspend trading.
Participants	▪ The Big Six 'gentailers'.	▪ Six voluntary MMs: One 'gentailer' and five stand-alone retailers.	▪ The Big Four 'gentailers'.	▪ When generation and supply market share is greater than 4% (4 companies).
Cost recovery	▪ No explicit cost recovery mechanism, obligated firms therefore bear the costs.	▪ Passed on in retail tariffs.	▪ No explicit cost recovery mechanism, obligated firms therefore bear the costs.	▪ No explicit cost recovery mechanism, obligated firms therefore bear the costs.

	Great Britain	Singapore	New Zealand	Ireland
Performance of the Market Making Obligation				
Performance	▪ 17 percent increase in traded volume from 2013 to 2017. ▪ Increased trade of Peakload contracts. ▪ 2.5 times the number of suppliers in the market (as of August 2018). ▪ Bid-ask spreads narrowed. ▪ CMA found financial players not attracted. Without these players, no “step-change” in market liquidity	▪ Initial generators failed to take-up the FSC citing that it imposed off-setting cost on retail arms. ▪ Re-launch MMO open to new retail entrants with altered obligations. ▪ Wolak estimates 7-22% and 8-26% savings in wholesale and retail prices respectively. ▪ The number of electricity retailers increased from 7 to 25 (August 2017).	▪ The government’s objective of open interest of 3,000 GWh was not reached until late 2013. ▪ Trading is concentrated in the products for which market making applies with limited trading in other products. ▪ Despite increase in contract volumes, churn (measured as contract volumes as a % of physical generation) is still less than 1.	▪ Not implemented. ▪ Concerns from consultation on the impact of risk on the cost of capital and disproportionate impact across firms. ▪ Deferred decision and continued to monitor GB MMO.
Objective achieved?	▪ Churn rose with market volatility in 2016 but in 2017 comparable to starting levels. ▪ Increase in liquidity in windows at expense of the rest of the day.	▪ Liquidity increased but transaction volume only 5% of underlying physical consumption annually.	▪ Unmatched open interest reached desired level 3 years post introduction.	▪ Not implemented.
Reported cost	▪ £0.5m fixed costs, £0.3-0.7m variable costs. ▪ Variable costs increased to £3-8m in 2016 due to market volatility.	▪ FSC caused windfall due to falling underlying spot prices. ▪ EMA took out S$204m loan to pay.	▪ ‘Gentailers’ have reported their annual costs as ranging from NZ$1-5m.	▪ Not implemented.
Future of the MMO	▪ Wholesale market structure changed substantially since introduction of MMO: ▪ In September 2016, E.ON SE divested its fossil fuel generation, reducing generation market share from 6% to 1%. ▪ It applied to have Ofgem remove the MMO from its licence, approved in November 2016. ▪ In December 2017, Centrica applied to remove the MMO after divesting generation. ▪ Ofgem approved in August 2018. ▪ Scottish Power sold its generation assets to a non-VI generator, Drax, in December 2018 and had its MMO removed in January 2019. ▪ This decreasing VI leaves 3 MMs and puts the future of the MMO into question. Ofgem is currently assessing the MMO to this end.	▪ New **Incentivised MMO** in 2018. ▪ Tender cost: S$218,000 per month passed to consumers. 6 participants. ▪ MMs must market make for 9 quarterly baseload contracts (2 years ahead) and 6 monthly contracts (6 months ahead) in 80% of cumulative monthly windows. ▪ MMs must post six 0.5MW lots for first year ahead and four 0.5MW lots thereafter for quarterly products. Six 0.5MW lots for monthly products. ▪ Maximum bid-ask spread: $1/MWh or 2% of the bid price, whichever lower, for quarterly. For monthly: Quarterly spread plus $1/MWh. ▪ MMs must respond to request for quote (when not posting) with max. bid-ask spread of 1.5 times prevailing spread.	▪ Concerns over the “fragility” of the MMO during times of tight supply have led the current Electricity Pricing Review (EPR) to consider mandatory scheme. ▪ The EPR recognises an incentivised scheme would likely be more efficient. However, concerns over the time taken to implement and refine the incentivised scheme in Singapore have led it to conclude a mandatory scheme would be quicker to implement. ▪ At the same time, the ASX and the current market makers have considered the design of an incentivised scheme. ▪ Therefore, future of market making in flux.	▪ Not implemented.

Source: NERA Analysis.

3.2. Detailed Discussion of Case Study Learnings

In this section, we discuss the key observations from international experience with MMOs.

3.2.1. Markets with MMOs have similar concentration but supply and demand conditions have not greatly influenced their design

The degree of market concentration and number of participants is similar across case study markets at the time of the proposed introduction of MMOs: each market was concentrated with a small number (four to seven) of vertically-integrated ‘gentailers’ generating and supplying a large percentage of electricity (70 to 90 per cent).

The size, daily-shape and seasonality of demand differs amongst countries. However, the implementation and design of MMOs does not seem to relate to these differences. Singapore has a relatively small market, of approximately 46 TWh annual consumption, with little seasonal variation and a high proportion of industrial demand leading to a flat daily load shape.[44] Therefore, volume risk is relatively low. On the other hand, Great Britain has a substantially greater market size, of approximately 304 TWh annual consumption, with a high degree of seasonal variation (approximately 30 per cent of demand for residential consumers), leading to relatively higher volume risk.[45] New Zealand has similar annual consumption to Singapore, but like Great Britain experiences a very seasonal demand profile.[46]

The generation fuel mix also substantially differs across countries. Singapore is characterised by almost only relying on natural gas (95 per cent of generation in 2015) with low penetration of renewables.[47] Great Britain, had some penetration of renewables, around 12 per cent of the fuel mix.[48] On the other hand, New Zealand has relatively high penetration of renewables (74 per cent of generation in 2010, 76 per cent of which is hydropower).[49] New Zealand’s high hydro share (56 per cent in 2010, 60 per cent in 2018)[50] and limited storage, this results in an additional risk to be managed, between year or “dry year” risk, and leads to further benefits of vertical integration.[51]

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44 EMA (June 2015), Singapore Energy Statistics 2015, p. 5.

45 Department for Business, Energy and Industrial Strategy (March 2019), Energy trends: Electricity, Link: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/789362/Electricity_March_2019.pdf, p. 41. Department for Energy and Climate Change (March 2015), UK Energy Statistics, 2014 and Q4 2014, p. 2.

46 Electricity Authority (November 2018), Electricity in New Zealand, p. 9.

47 EMA (June 2016), Singapore Energy Statistics 2016, p. 23.

48 Ofgem (April 2019), Electricity generation mix by quarter and fuel source (GB), Last Accessed: 29/4/19, Link: https://www.ofgem.gov.uk/data-portal/electricity-generation-mix-quarter-and-fuel-source-gb.

49 Ministry of Business, Innovation and Employment (April 2019), MBIE Electricity Statistics, Last Accessed: 29/4/19, Link: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/electricity-statistics/.

50 Ministry of Business, Innovation and Employment (April 2019), MBIE Electricity Statistics, Last Accessed: 29/4/19, Link: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/electricity-statistics/.

51 See the 83-year average storage level on page 4 of the report: Meridian (July 2017), Monthly operating report for July 2017, p. 4.

3.2.2. Regulators introduced MMOs for the common objective of improving competition in the retail market

In all case studies, regulators considered the MMO as part of a broader number of interventions to improve competition and lower market concentration in the retail market. This was in response to concerns that the high degree of concentration found in each market, due to the small number of large ‘gentailers’, resulted in high barriers to entry for entrant suppliers. As a result, consumers were perceived to face higher tariffs due to reduced retail market competition.

Vertical integration may provide a natural hedge to spot price movements. Regulators perceived that the vertically-integrated ‘gentailers’ were hedging internally, and this prevented new entrant suppliers from accessing forward products from generators to hedge their future expected supply commitments. Regulators argued that the internal hedging manifested itself in low liquidity in the wholesale market.

In each case, the regulator proposed to introduce an MMO to improve liquidity in the wholesale market. More specifically, the regulator argued that the proposed MMO would ensure that vertically-integrated incumbents provided the forward hedging instruments that new supplier entrants required. It argued that this would lower the barrier to entry into the retail market.

In the case of Singapore, no futures exchange market existed prior to the introduction of the MMO. Therefore, the regulator also introduced the MMO to facilitate liquidity in forward products on the new exchange. This was part of a broader reform to introduce competition into the retail market. Therefore, whilst the Singaporean case appears different to other market contexts, the broad objective of the MMO was similar.

3.2.3. MMOs may have had some positive impact on liquidity but not the “step-change” that regulators desired

In all case studies, introducing MMOs improved market liquidity. Unsurprisingly, the MMO also reduced bid-ask spreads. However, this improvement was marginal and did not result in the “step-change”[52] in liquidity that regulators was generally aiming to achieve.[53] In Great Britain, churn rose with market volatility in 2016 but, in 2017, fell back to a similar level to the start of the MMO (of around 3).[54] In New Zealand, despite an increase in contracted volumes, churn remains less than 1.[55]

MMOs in Great Britain and New Zealand, required that market makers (MMs) trade mandatory products within a particular market making window. Liquidity in those windows and specified products increased.[56] However this improvement in liquidity in the windows may have been at the cost of liquidity at other parts of the trading day. In Great Britain, the Competition and Markets Authority (CMA) found that whilst traded volumes had risen since

[52] CMA (June 2016), Energy Market Investigation Final Report: Liquidity Appendix, p. A7.1-27, 92.

[53] The introduction of the MMO in Singapore could be argued to have resulted in a step change in liquidity because it facilitated and accompanied the launch of a futures exchange market: previously no exchange had existed.

[54] Ofgem (October 2018), State of the Energy Market Report 2018, p.58, Figure 2.35.

[55] Electricity Hedge Disclosure System, EA EMI data on grid injections.

[56] Ofgem (July 2017), S&P Review: Consultations, p.13, Figure 11.

the introduction of the MMO, they had fallen outside of the two trading windows specified by the obligation.[57] The CMA examined data outside the windows and found that "product availability had become worse since the introduction of S&P"[58] arguing that "these results paint a picture of relative, rather than absolute, availability".[59]

There is also evidence that there are indirect costs of MMOs for financial players in the market.[60] The movement of liquidity to market windows at the expense of other times during the day means speculative trading is likely to be dissuaded.[61] The CMA argued that without the introduction of financial players, and the liquidity throughout the day to support them, that there would not be the "step-change" in the level of liquidity that Ofgem was targeting.[62]

3.2.4. It is unclear whether MMOs have facilitated increased entry

In all case studies, the number of entrant suppliers has increased concurrently with the operation of MMOs. This entry has also reduced the supply market share of the vertically-integrated incumbents. For example, the number of retail participants increased 2.5 and 3.5 times in Great Britain and Singapore respectively.[63] In New Zealand, the number of retail participants increased 3.6 times from 10 in 2009 to 36 in 2019, and the market share of the largest four vertically integrated 'gentailers' fell from 86 per cent to 75 per cent.[64] However, it remains difficult to assess the relationship between relatively small increases in wholesale market liquidity, facilitated by MMOs, and the effect on market access for new entrants. This is made more difficult as the introduction of MMOs often coincided with other regulatory interventions aimed at increasing supplier market access. In other words, the introduction of MMOs itself reflects a regulatory determination to increase access to wholesale markets and promote competition. Any increase in competition may reflect that regulatory determination (and associated policies) rather than the MMO itself.

3.2.5. The costs of MMOs are similar across case studies but are higher when price discovery is harder and obligations are tighter

The reported costs of fulfilling MMOs are similar across case studies. In Great Britain, MMs reported approximate annual average costs of fulfilling the MMO of AUD 1.3m to AUD 2.2m per MM.[65] In New Zealand, MMs reported approximate annual average costs of fulfilling the MMO of AUD 1m to AUD 3.8m per MM.[66] In Singapore, the tender for market

57 Ofgem (July 2017), S&P Review: Consultations, p.13, Figure 11.

58 CMA (June 2016), Energy Market Investigation Final Report: Liquidity Appendix, p. A7.1-20, 62.

59 CMA (June 2016), Energy Market Investigation Final Report: Liquidity Appendix, p. A7.1-20, 63.

60 Ofgem (July 2017), S&P Review: Consultations, p.26, 3.14.

61 CMA (June 2016), Energy Market Investigation Final Report: Liquidity Appendix, p. A7.1-20, 65.

62 CMA (June 2016), Energy Market Investigation Final Report: Liquidity Appendix, p. A7.1-27, 92.

63 Ofgem (August 2018), Centrica Special Condition AA Decision Letter: Request for modification of special condition AA of electricity generation licences held by Centrica group, p.4. EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.2.

64 EMA, Market Share Trends, Last Accessed: 29/4/19, Link: www.emi.ea.govt.nz/r/5o4z1.

65 Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition, p.16, 2.7.

66 Meridian (March 2019), Electricity Price Review Options Consultation: Meridian and Powershop submission, p. 10.

making services, from the recent launch of the Future Incentive Scheme, totalled AUD 3.6m per MM per year.[67]

Price discovery describes the process by which a MM determines the price of a contract in the market by trading with other market participants. There may be costs associated with price discovery: MMs may be obligated to post bid-ask spreads for products in the market and therefore, due to informational asymmetries, may be taken on bid-ask spreads which are not reflective of the aggregate market sentiment. Through an iterative process of re-posting bid-ask spreads for products, the MM may be able to ascertain this market sentiment. The costs that the MM incurs in this process are increasing in the informational asymmetries between the MM and other market players. These are higher when prices are volatile or when other price signals in the market are sparse (for example at the start of trading windows, for non-mandated products and when there are fewer other MMs).

Costs of market making were reported to be higher when price discovery is harder. In Great Britain, variable costs in 2016 were 6 to 18 times greater than those in 2015. This is attributed to the volatility experienced in Q3 and Q4 of 2016.[68] In particular, MMs stated costs arose from the start of the trading windows, when price discovery was harder and yet the maximum bid-offer spreads for mandatory products were small.[69]

MMOs which include a mandatory trading window and maximum bid-ask spreads rely more heavily on regulatory safeguards to ensure that obligated parties do not face high costs when price discovery is harder. Whilst Great Britain did have safeguards relating to a net exposure cap or fast market rule, MMs argued that the volume cap was set too high which resulted in the above-mentioned increase in costs.[70] In response, Ofgem considered adopting a soft-landing period of ten minutes at the start of each market making window, where bid-offer spreads would be wider (1 per cent for all products) to allow for less risky price discovery.[71]

On the other hand, in the incentivised MMO in Singapore, MMs must only post obligations for 80 per cent of the cumulative windows in a month and may therefore withdraw when price discovering is harder.[72] MMs in New Zealand may suspend market making if the firms experience “portfolio stress”[73] which is left undefined in the MM agreements. Therefore, during periods of high volatility MMs continued to trade but with higher bid-ask spreads which reduced the costs of price discovery borne by the MMs.[74]

The problem for the regulator is to ensure adequate safeguards exist such that obligated parties do not bear higher costs of market making when price discovery is more difficult. At

67 Trustpower (March 2019), Trustpower Submission: Electricity Price Review’s Options Paper, The Lantau Group: Market Making Requirements in New Zealand, p. 19.

68 Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition, p.16, 2.8.

69 Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition, p.16, 2.8.

70 Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition, p.4.

71 Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition, p.14, 3.2.

72 In the Forward Incentive Scheme in Singapore, MMs are still obligated to respond to a request for quote when not posting prices in the market. However, the maximum bid-ask spread for this quote is 1.5 times the prevailing market spread.

73 New Zealand Government (February 2019), Electricity Price Review – Options Paper, p. 19.

74 Meridian (October 2018), Electricity Price Review: First Report for Discussion – Meridian submission, p. 47.

the same time, market making services are arguably at their most valuable when price discovery is hard.[75] When limited trading in futures products exist at the introduction of the MMO, for example in the case of Singapore (with no exchange) and New Zealand (exchange established in the year prior to the introduction of the MMO), the risks of market making are higher and therefore the safeguards should be stronger. Indeed, Ofgem justifies not expanding the MMO to additional products because little current trading in those products exists upon which to base prices and this would result in high risks for MMs.[76]

3.2.6. The design of incentives in incentivised MMOs can lead to windfalls for participants and larger costs for consumers

Depending on the choice of incentive in an incentivised MMO, the risks of market movements may be socialised and borne by the regulator or consumers. In the first incentivised MMO in Singapore, MMs were compensated for market making through the issuance of a Forward Sales Contract (FSC), a contract for difference between generators and retailers. After the issuance of the contract, over-supply led to a falling pool price and turned the FSC into a large windfall. In response, the regulator postponed the arrangement and re-launched with caps on the risks and revenues that may be accrued by the MMs. The cost of the FSC to the regulator was a minimum of AUD 212m, which was passed on in tariffs to consumers.[77] In the newest MMO in Singapore, the Future Incentive Scheme, services were instead based on a tender process which placed the risks of market making on the MMs, whilst remaining an incentivised scheme.

This suggests that the design of an incentivised scheme is difficult to ascertain ex-ante and may lead to large unexpected costs. The New Zealand Government's 2018/19 Electricity Price Review discussed the relative benefits of moving to a mandatory or incentivised MMO. The EPR recommends a mandatory scheme because it could be introduced "relatively quickly" whereas "Singapore's experience suggests an incentive-based scheme would take several years to develop".[78] However, as discussed above, the design of the safeguards in a mandatory scheme is complex, so it may not necessarily be quick. In addition, to the extent that others can learn from the Singapore experience, an incentivised scheme may no longer take too long to design. Indeed, in New Zealand the ASX and the MMs have been progressing the design of an incentivised scheme and have argued to the EPR that such a scheme could be implemented quite quickly.[79]

3.2.7. The choice of market makers that least distorts competition and incentives depends on market structure

The choice and number of MMs may lead to disproportionate costs of market making for each MM. This depends on the market concentration, firm structure and may theoretically depend on the relative degrees of dispatchable generation between participants.

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75 AEMC (December 2018), National Electricity Amendment (Market Making Arrangements in the NEM) Rule 2019 Consultation Paper, p. 21.

76 CMA (June 2016), Energy Market Investigation Final Report: Liquidity Appendix, p. A7.1-27, 94.

77 Trustpower (March 2019), Trustpower Submission: Electricity Price Review's Options Paper, The Lantau Group: Market Making Requirements in New Zealand, p. 18.

78 New Zealand Government (February 2019), Electricity Price Review – Options Paper, p. 20.

79 See, e.g. ASX (15 March 2019), ASX submission: Electricity Price Review - Options paper, p. 9.

Regulators should choose MMs based on:

- any informational advantage that the MM may have on prices, or
- the ability of MMs to bear the costs of market making; or
- instead allow the market for market making to select those participants in an incentivised or voluntary scheme.

In most case studies, regulators have placed the MMO on vertically-integrated generation and supply companies. Placing the obligation on vertically-integrated companies may reflect a regulatory suspicion that vertically-integrated companies are withholding access to hedging products from smaller rivals. To the extent that regulators have had an underlying economic rationale, they have argued that vertically-integrated companies are best placed to assess market prices and bear the costs of buying and selling because they are already present on *both* sides of the market. Placing an obligation on those parties most able to bear it will reduce the costs of market making services, and particularly the costs associated with price discovery. The only case where the MMs were not all 'gentailers' was Singapore. This was because the vertically-integrated companies argued that the proposed incentive, the FSC, provided a zero-sum benefit: the cost to their retail arm offset the benefit of the FSC to the generation arm. Therefore, due to no initial uptake, the regulator opened market making up to new entrants.[80]

Regulators should also avoid distorting competition when designing market-making schemes such that they do not adversely affect certain MMs relative to others. For instance, a firm with a smaller proportion of dispatchable generation, for example due to a relatively higher ownership of wind generation, is less strongly placed to provide market making services than a company with only dispatchable generation.

In the case of Ireland, the lack of suitable MMs was an important reason for not introducing the MMO. The industry in Ireland is dominated by a single state-owned company, ESB (which comprises roughly half the generation and supply market). Meanwhile, the three other generators qualifying for the proposed MMO had a proportionally higher ownership of wind generation. The regulator was concerned that this may lead to a disproportional impact of risk on the cost of capital across firms.[81]

Regulators have not reached a consensus on the minimum number of MMs required to ensure that each MM does not face costs of market making that are considered too high. At the time of introduction of each MMO, four to six companies were chosen to provide market making services. In the case of Great Britain, due to changing wholesale market structure, only three companies of the original six continue to act as MMs. Ofgem was concerned that:

> "the remaining obligated parties will face disproportionate costs and risks in continuing to meet the licence condition, and whether on balance there is a case for suspending the MMO"[82].

80 Trustpower (March 2019), Trustpower Submission: Electricity Price Review's Options Paper, The Lantau Group: Market Making Requirements in New Zealand, p. 18.

81 SEM Committee (March 2016), Measures to promote liquidity in the I-SEM forward market: Decision Paper, p. 21.

82 Ofgem (August 2018), Open letter: S&P Update, p.2.

3.2.8. Regulators have typically failed to quantify costs accurately ex-ante and the benefits either ex-ante or ex-post

The information available to regulators to perform an ex-ante assessment of the costs and benefits of an MMO is poor. Whereas cost data reported by MMs can be used to examine the financial costs of the MMO ex-post, the ex-post benefits remain hard to ascertain.

The reasons for this are at least twofold:

1. There is not an agreed measure of liquidity nor agreed level which represents sufficient liquidity in the wholesale market. This explains why each regulator assessed that there was insufficient liquidity in its own wholesale market despite significant variation in the level of liquidity across those wholesale markets.
2. Whilst improving liquidity might encourage the entrance of new suppliers, the entry of suppliers will necessarily improve liquidity. Therefore, beyond any initial change associated with the introduction of an MMO, it is hard to disentangle the effects of the MMO from effects associated with the increased number of market entrants. Regulators have frequently introduced MMOs alongside broader packages of regulatory measures encouraging new entrants to the wholesale market, for example the Secure and Promote licence condition in Great Britain.

The challenge of establishing a clear case for intervention or the benefits of doing so has contributed to the relatively similar designs of MMOs internationally. Regulators have frequently relied on precedent rather than provided a detailed bottom-up estimate of the benefits or an optimised design. For instance:

- In the re-launch of Singapore's MMO, the regulator abandoned its proposed maximum bid-ask spread and instead directly adopted the spread used in New Zealand's MMO.[83]
- In Ireland, the decision to not implement the MMO was partly based on the advantage of continuing to observe the performance of Great Britain's MMO.[84]

In other words, the lack of differences between international MM schemes does not establish the lack of need to tailor designs to specific circumstances.

[83] Trustpower (March 2019), Trustpower Submission: Electricity Price Review's Options Paper, The Lantau Group: Market Making Requirements in New Zealand, p. 18.

[84] SEM Committee (March 2016), Measures to promote liquidity in the I-SEM forward market: Decision Paper, p. 37.

4. Costs

In this chapter, we discuss the estimated and reported costs of MMOs from international case studies. We use this to qualitatively identify the main cost drivers of MMOs and discuss how these may differ, in magnitude and importance, with the design of the MMO. Based on this qualitative evidence, we construct quantitative estimates of the costs across proposed schemes by using reported cost data from international case studies, calibrated to the NEM.

4.1. Estimated Costs of International MMOs

We begin by examining estimated costs arising from international MMOs.

4.1.1. Great Britain

In preparation for the introduction of the MMO, Ofgem estimated the costs and benefits of the obligation. Ofgem examined “set-up costs” and “ongoing costs”.[85] “Set-up costs” included development of IT systems to provide information on the MMs’ trading position and credit exposure, as well as legal costs when establishing agreements with a trading platform. “Ongoing costs” include transaction fees on trades (which would otherwise be avoided), additional staff costs, costs relating to open positions and costs from managing credit exposures. For clarity, “ongoing costs” included both the fixed and variable costs borne by the MM from annually providing market making services.

After a request for information from potential MMs, Ofgem concluded that expected set-up costs would average £200,000 with high and low estimates detailed in Table 4.1.

Table 4.1: Ex-ante estimated set-up costs for market makers

	Low	Best	High
Total set-up cost per S&P licensee	£100,000	£200,000	£400,000

Source: Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition - Impact Assessment.

In response to the Impact Assessment, Scottish Power, a member of The Big Six, argued that the set-up costs estimated by Ofgem were too low relative to its estimates (greater than £400,000 but unreported). Scottish Power cited IT costs as the primary difference in estimates.[86]

The estimated range for total annual operating costs, “ongoing costs”, of the MMO was £969,000 to £4,844,000 with a best estimate of £2,488,000 for each licensee, see Table 4.2.[87] These costs are not net of income from traded positions. Ofgem based its estimates of staff costs on potential MMs’ responses which it used to estimate FTE requirements. It then used wage data for similar job codes to calculate the estimated costs. Ofgem estimated costs from

[85] Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition - Impact Assessment, p.29.

[86] Scottish Power (December 2013), WPML: statutory consultation on the 'S&P' licence condition Response, p.5.

[87] Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition - Impact Assessment, p.30.

open positions and traded volumes from strong assumptions which related to the design of the MMO, in particular the volume cap rules.

Table 4.2: Ex-ante estimated ongoing costs for market makers

	Low	Best	High
Staff costs	£80,000	£220,000	£220,000
Transaction fees	£50,000	£550,000	£1,100,000
Cost of open positions	£750,000	£750,000	£1,500,000
Costs from managing credit exposures	£89,000	£928,000	£2,024,000
Total annual cost per S&P licensee	£80,000	£2,448,000	£4,844,000

Source: Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition - Impact Assessment.

In 2017, four years after the introduction of the MMO, four of the MMs reported their estimated costs directly arising from the MMO, see Table 4.3.[88]

Table 4.3: Reported fixed and variable costs for market makers in GB

Units: GBPm	2014	2015	2016	H1 2017
Fixed costs	~ 0.5	~ 0.5	~ 0.5	~ 0.5
Variable costs	0.2 - 0.7	~ 0.5	3.0 – 8.0	0.3 – 0.7

Source: Licensee submission to Ofgem. Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition.

Costs in 2014 and 2015 fell below the ex-ante estimates that Ofgem made prior to the implementation of the MMO, although reported staff costs were double the estimate. However, variable costs in 2016 were two to four times ex-ante estimates. This is because of the volatility experienced in Q3 and Q4 of 2016.[89] In particular, licensees stated costs arose from the start of the trading windows, when price discovery was harder and yet the bid-offer spreads for mandatory products were small.[90]

4.1.2. New Zealand

The Electricity Authority (EA) prepared a cost-benefit analysis of MMOs in 2011 to advise on the additional costs of moving from the voluntary ASX scheme to a mandatory MMO.[91] The EA argued that because potential MMs were already trading in hedged products, the set-up costs associated with the MMO (for example the development of IT and legal costs when

88 Ofgem (December 2017), Secure and Promote review: Consultation on changes to the special licence condition, p.16, 2.7.

89 Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition, p.16, 2.8.

90 Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition, p.16, 2.8.

91 Electricity Authority (November 2011), Cost Benefit Analysis – Market-Making Obligations.

establishing agreements with a trading platform) would mean “no incremental direct costs would arise”.[92] Despite this, the EA estimated both the set-up and ongoing incremental costs of the mandatory MMO (relative to the voluntary MMO) for each MM, see Table 4.4. However, the EA did not provide further reasoning behind these numbers and the mandatory MMO was not adopted.[93]

Table 4.4: EA estimated incremental cost of moving from a voluntary to mandatory MMO for each MM

Units: NZDm	**Low**	**Best**	**High**
Set-up costs	0	0.5	6
Annual ongoing costs	0	0.2	2

Source: Electricity Authority (November 2011), Cost Benefit Analysis – Market-Making Obligations.

MMs under the voluntary MMO reported their annual costs of providing market making services. Meridian estimates that it has incurred costs of NZ$1m to NZ$2m per annum on average due to its voluntary market making agreement.[94] In the last year however, this cost has been much higher, with Meridian estimating the market marking agreement has resulted in a cost of NZ$5m for YTD 2019. Contact and Genesis estimate that for the FY18 their making costs have been NZ$2m[95] and NZ$4m[96] respectively.

4.1.3. Singapore

To our knowledge, the EMA did not make an ex-ante estimate of the costs of the MMO publicly available. In part, this is because the MMO is incentivised and therefore licensees were compensated through the issuance of the Forward Sales Contract (FSC). The reported cost of the FSC to the regulator was high: a minimum of AUD 212m, which was passed on in tariffs to consumers.[97] This was largely due to the failed launch of the MMO, with no cap on the realised benefit or cost from the FSC. The FSC became a large windfall as the margin between pool and vesting price grew substantially due to overgeneration.[98]

In the newest MMO in Singapore, the Future Incentive Scheme launched in 2018, market maker incentives were determined through a tender process. The EMA found six MMs

[92] Electricity Authority (November 2011), Cost Benefit Analysis – Market-Making Obligations, p. 18.

[93] In part this was because a key benefit the EA was calculating related to reducing the maximum bid ask spread from 10% to 5%. At the time this was occurring, the ASX MMs amended their market making agreements to reduce the maximum spread to 5%.y

[94] Meridian (March 2019), Electricity Price Review Options Consultation: Meridian and Powershop submission, p. 10.

[95] Contact (August 2018), 2018 Full Year Results Presentation, p. 26.

[96] Genesis (February 2019), HY19 Result Presentation, p. 9.

[97] Trustpower (March 2019), Trustpower Submission: Electricity Price Review’s Options Paper, The Lantau Group: Market Making Requirements in New Zealand, p. 18.

[98] Trustpower (March 2019), Trustpower Submission: Electricity Price Review’s Options Paper, The Lantau Group: Market Making Requirements in New Zealand, p. 18.

through the tender process for the FIS.[99] The tender price was set at S$218,000 per month per MM.[100] This can be interpreted as the ex-ante estimated cost of providing market making services by each licensee in the market.

4.1.4. Summary

The reported and estimated costs for MMs fulfilling MMOs are similar across international case studies, see Table 4.5. In Great Britain, MMs reported approximate annual average costs of fulfilling the MMO of AUD 1.3m to AUD 2.2m per MM.[101] In New Zealand, MMs reported approximate annual average costs of fulfilling the MMO of AUD 1m to AUD 3.8m per MM.[102] In Singapore, the tender for market making services, from the recent launch of the Future Incentive Scheme, totalled AUD 3.6m per MM per year.[103]

Table 4.5: Summary of total annual reported costs of fulfilling the MMO

Units: AUDm/MM	Great Britain	New Zealand	Singapore
Number of MMs	6	4	6
Total cost	1.3 – 2.2	1 – 3.8	3.6*

**Cost indicated by tender process.*
Source: Summary of sources in section.

The largest proportion of these costs relate to the variable costs of providing market making services. More specifically, the largest costs relate to managing open positions and credit exposures (approximately 30 per cent and 40 per cent of the total annual ex-ante estimated costs in Great Britain respectively). These are reported to be particularly large when volatility in the market is high. However, the data on these reported costs is poor, with little granularity on the costs arising from specific components of market making.

4.2. Qualitative Assessment of Costs of MMOs

In this section, we use the reported and estimated costs of MMOs in other international contexts to identify key cost drivers for MMOs. For context, we summarise the main differences in market making requirements across international case studies and the proposed MMO designs in the NEM in Table 4.6.

99 The MMs are DRW Singapore Pte Ltd; ENGIE Global Markets, Singapore Branch; Epoch Energy Solutions Pty Ltd; Fenix One Asia Pte Ltd; Liquid Capital Australia Pty Ltd and RCMA Pte Ltd.

100 Trustpower (March 2019), Trustpower Submission: Electricity Price Review's Options Paper, The Lantau Group: Market Making Requirements in New Zealand, p. 19.

101 Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition, p.16, 2.7.

102 Meridian (March 2019), Electricity Price Review Options Consultation: Meridian and Powershop submission, p. 10.

103 Trustpower (March 2019), Trustpower Submission: Electricity Price Review's Options Paper, The Lantau Group: Market Making Requirements in New Zealand, p. 19.

Table 4.6: Summary of MMO designs across countries and the proposed design in the NEM

	Great Britain	Singapore	New Zealand	Australia MMO (MLO design)
Market wholesale price volatility	▪ Daily spot annualised volatility of 148%, 133% since MMO introduction. ▪ Annual spot volatility during MMO ranging from 87% in 2014 to 231% in 2016. ▪ Quarterly contract annualised volatility of 7.78% during the MMO.	▪ Daily spot annualised volatility of 62%, 74% since MMO introduction. ▪ Quarterly contract annualised volatility of 7.35% during the MMO.	▪ Daily spot annualised volatility of 229-593% since MMO introduction (in Otahuhu and Benmore hubs respectively). ▪ Quarterly contract annualised volatility of 13.33-17.58% during MMO (in Otahuhu and Benmore hubs respectively).	▪ Daily spot annualised volatility ranging from 148% in NSW to 784% in SA. ▪ Quarterly contract annualised volatility of 12.57% in NSW to 19.42% in SA.
Mandated bid-ask spread	▪ 0.5% for Baseload and 0.7% for Peakload products except: ▪ For 3rd and 4th season ahead products, maximum spread is 0.6% for Baseload and 1% for Peakload.	▪ Lowest of S$1/MWh or 2% for quarterly products. ▪ Prevailing quarterly spread + S$1/MWh for monthly products ▪ MMs must respond to a request for quote when not actively trading in windows with maximum spread of 1.5 times the prevailing market spread.	▪ 5% if bid price greater than NZ$30. ▪ 10% if bid price less than NZ$30.	▪ Greater of AUD 1 or 5% for flat Baseload or Peakload contracts in NSW, VIC, QLD. ▪ Greater of AUD 1 or 7% for flat Baseload or Peakload contracts in SA. ▪ Greater of AUD 1 or 10% for cap contracts in all states.
Maximum exposure	▪ Lots of 5 MW and 10 MW. ▪ Continuous posting (max 5min reload). ▪ Fast market rule: MM can suspend trading in particular product and window if price changes more than 4% in a given direction. ▪ Volume cap rule: MM can suspend trading in particular product and window if MM accumulates net position of 30 MW.	▪ 6 lots of 0.5 MW for quarterly contracts up to a year ahead. ▪ 4 lots of 0.5 MW for quarterly contracts for the following year ahead. ▪ 6 lots of 0.5 MW for monthly contracts. ▪ Must post in >80% of the cumulative trading window time in the month. ▪ MMs must respond to a request for quote when not trading in windows.	▪ 0.1 MW lots. ▪ 20 lots per side for monthly contracts. ▪ 30 lots per side for quarterly contracts. ▪ May widen bid-ask spreads if MM experiences “portfolio stress”.	▪ 1 MW lots. ▪ 5 lots in NSW, QLD, VIC and 2 in SA. ▪ Window net sales limit: 5 MWs in NSW, QLD, VIC and 2 MWs in SA. ▪ Quarterly net sales limit: 1.25% of aggregate MMs generation capacity. ▪ Total net sales limit: 10% of aggregate MMs generation capacity, over the period of the MLO.
Duration of windows	▪ Two hour-long trading windows each day.	▪ One hour-long window each day.	▪ Must market-make for 30 mins each day.	▪ 30 minutes in each of the two half-hour windows each day. ▪ “Grace period” of 10 sessions per month where MM do not have to market make.
Number of products	▪ 7 Baseload and 6 Peak products. ▪ Front 2 monthly products, Front 1 quarterly product, and Front 4 seasonal products (4th season ahead only for Baseload).	▪ Front 9 quarterly Baseload products. ▪ Front 4-6 monthly Baseload contracts (only available upon expiry of nearest quarter).	▪ Front 4 Baseload quarterly contracts. ▪ Front 6 Baseload monthly contracts.	▪ Baseload and Peakload futures (monthly or quarterly) or Cap futures. ▪ MM chooses combination of products.

Source: NERA Analysis.

4.2.1. The number of obligated parties

Regulators should choose the number of MMs in conjunction with the choice of maximum bid-ask spread in the MMO design. This is because the costs of price discovery for each MM falls with the total number of MMs in the market: more MMs means that more information exists in the market upon which to base prices and also more bids and offers are posted which allow an individual MM to unwind its open position. On the other hand, in cases where a single MM exists, the costs associated with price discovery are greater because there is less information upon which to base prices and no guarantee that other bids and offers will be posted to allow the MM to unwind its position. This is enacted in existing MMOs. For example, in Western Australia, the single MM (Synergy) faces a maximum bid-ask spread of 20 per cent of the bid price whereas, in Great Britain, the MMs face a maximum bid-ask spread of 0.5 to 1 per cent of the bid price.

This concern is of particular importance in volatile markets and when the design of the MMO stipulates that the MM must market make for mandatory trading windows with a maximum bid-ask spread. The use of net-volume cap, soft-landing or fast market rules may mitigate this risk. However, these have proven difficult to estimate ex-ante (see the Great Britain case study). In addition, setting these safeguards or maximum bid-ask spread that bind too tightly will result in MMs exiting the market during periods of volatility. This is when market making may be the most useful for other market participants.

4.2.2. Staff costs

In Great Britain, Ofgem estimated that staff costs are a low proportion of each MM's total annual costs of meeting an MMO (approximately 9 per cent of the total annual ex-ante estimated costs). This corresponded to an estimated 0.5 to 1 trader FTE and 0.5 to 2 other staff FTEs.[104] Whilst MMs reported realised staff costs that were roughly double Ofgem's estimates, the proportion of staff costs remains low in the context of total costs from the MMO.

Given this low proportion of total costs, we do not expect staff costs to form a significant cost that MMs will bear because of the adoption of an MMO. The EA in New Zealand notes that, given MMs are already active in the contract market, the MMs will already have staff dedicated to trading, and therefore the incremental cost of moving to an MMO will likely be low.[105] However, MMO designs that obligate the MM to trade higher volumes may increase its staff costs to manage these traded volumes.

4.2.3. Transactions costs

Ofgem estimated that MM' costs related to the volume of electricity traded under the MMO forms the largest proportion of its annual costs. More specifically, the largest costs relate to managing open positions and credit exposures (approximately 30 per cent and 40 per cent of

[104] Ofgem (November 2013), Wholesale power market liquidity: statutory consultation on the 'Secure and Promote' licence condition - Impact Assessment, p.56.

[105] Electricity Authority (November 2011), Cost Benefit Analysis – Market-Making Obligations, p. 18.

the total annual ex-ante estimated costs in Great Britain respectively). A number of factors may increase the cost of managing open position and credit exposures:

- **Obligations to trade a certain lot size/total amount:** MMOs which place an obligation on MMs to trade larger total amounts or larger lot sizes may increase the volume of transactions and the volume traded. In the design of a mandatory MMO, MMs should be obligated to trade a sufficient volume to provide the liquidity and products demanded in the market, whilst ensuring that MMs do not face risks they cannot efficiently manage. In an incentivised MMO, where the incentive is determined by a tender process, the regulator can delegate the assessment of risk to potential MMs (who, in their bid to provide market making services, include the estimated cost of bearing this). However, this cost may still be socialised.
- **Obligations to trade for a particular time period:** MMOs which stipulate that the MMs must trade during particular trading windows may increase transactions costs, particularly in periods of volatility or at the start of the stipulated trading window when price discovery is harder. An MMO without an obligation to trade for a particular time period, such as New Zealand's voluntary MMO, delegates the responsibility of assessing risk to MMs, who may withdraw from providing market making services when the costs of price discovery are too high.
- **Net volume cap rules:** Net volume cap rules, as used in the Great Britain MMO, protect the MM from incurring too much net volume exposure on a particular product. These rules provide important safeguards for MMs in volatile markets, when the MMO otherwise stipulates that MMs must trade for a particular time period.
- **Maximum bid-ask spreads:** When markets are volatile, maximum bid-ask spreads ensure that MMs continue to provide price signals. In MMOs where maximum bid-ask spreads may be avoided in periods of high volatility, for example New Zealand, MMs have been observed to increase their posted bid-ask spreads to reflect market uncertainty. This reduces the volume of transactions in these periods, diminishing the benefit of the MMO to other market participants.

  In MMOs with maximum bid-ask spreads, the regulator should ensure that adequate safeguards (for example, fast market caps) exist to protect MMs when price discovery is harder (when the market is more volatile). This has proven difficult in practice. For example, MM costs increased in Great Britain in 2016 due to market volatility. MMs argued that the fast market cap was set too high which resulted in costs arising from the obligation to market make in the volatile market.[106] As a result, Ofgem considered allowing a wider bid-offer spread (1 per cent for all products) beyond a 1 per cent threshold for market price movement.[107]
- **Cost of collateral:** The amount of collateral that each MM is required to post to fulfil the MMO depends on the maximum volume exposure it faces. The opportunity cost of the collateral, as dictated by the forgone rate of return, will vary proportionally with the collateral requirement.

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106 Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition, p.4.

107 Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition, p.16, 3.12.

- **Exchange fees:** The MM will face two types of exchange fees. The first relates to setting up a legal agreement with the exchange. The EA argues that because most MMs already trade hedges on the exchange, these incremental costs are likely to be low.[108] The MM also faces an exchange fee on each transaction. This relates to the total volume of transactions that the MM undertakes. In the case of the ASX MMO (and the case of New Zealand) a rebate is given to MMs by the exchange to compensate for these fees.

The transactions costs for MMs fulfilling MMOs rises with market volatility (see Great Britain and New Zealand case studies). The trade-off, for regulators designing MMOs, becomes ensuring that market making services are provided during periods of high volatility (because the benefits of price signals are largest in these periods) whilst also ensuring that MMs do not bear disproportionate costs of providing market making services in these periods.

4.2.4. Costs of compensation in incentivised MMOs

A significant cost of an incentivised MMO is the cost of providing the incentive. This may be borne by the regulator or socialised through consumer tariffs. A well-designed incentivised MMO should not lead to additional social costs compared to a mandatory MMO: the costs will just be borne by different market participants. However, if the incentive is poorly designed, an incentivised MMO may overcompensate MMs for market making services leading to additional costs, in the form of a transfer from consumers or the regulator to the MMs.

If the incentive is designed through regulator estimates, rather than an auction or tender process, the regulator should balance providing sufficient incentives to attract MMs whilst also capping the incentives to ensure that it will not face costs that exceed the benefits of the MMO. The experience of Singapore should act as both a warning and a lesson for future incentivised MMO design.

Alternatively, the determination of incentives through a tender process delegates the process of determining the level of incentives in an MMO to MMs. MMs may be more able to accurately estimate the costs of providing market making services. However, the tender process should be designed so that potential MMs are not able to manipulate outcomes. This may be more difficult in markets with fewer potential MMs. The tender process should also require potential MMs to submit multiple bids depending on the number of MMs finally selected to fulfil the obligation. As we discussed above, this is because the costs of fulfilling the MMO may vary with the number of MMs. This concern was raised by market participants during the design of the tender process in Singapore.[109]

4.2.5. Monitoring, reporting and regulatory costs

A disadvantage of implementing mandatory MMOs relative to voluntary or some incentivised MMOs is the relative increase in monitoring and reporting costs. In New

[108] Electricity Authority (November 2011), Cost Benefit Analysis – Market-Making Obligations, p. 18.

[109] EMA (March 2018), Request for Proposal (RFP) for the 1st Futures Incentive Scheme (FIS) to Provide Market Making Services for the Period 1 August 2018 to 31 January 2020, p.27.

Zealand, the EPR also recognised that an incentivised scheme may be more efficient on this basis:

> "A mandatory market-making obligation could be replaced later by an incentive-based scheme whereby companies best placed to act as market makers could be paid to take on that responsibility. A levy on vertically integrated companies above a minimum size could help recover market-maker fees. This could be more efficient than a mandatory obligation, and compliance monitoring and enforcement costs could be lower."[110]

Ofgem estimated that the total annual reporting costs for each MM related to the Secure and Promote licence in Great Britain would be £60,000.[111]

Regulators may also bear a cost of monitoring MMs during an MMO: these costs are increasing in the strictness of obligations placed on MMs. The regulator may also incur costs related to assessing the benefits of the MMO or monitoring a set of market measures in the case of a trigger driven MMO. In the case of an incentivised MMO, the regulator also bears the cost of designing and operating the tender process. Whilst more frequently tenders may reduce the annual cost that MMs bid to provide market making services, due to smaller time periods and less uncertainty for MMs, it may increase regulator costs by increasing the number of tenders.

4.3. Qualitative Assessment of Costs of the Proposed MMOs

The cost drivers may vary in magnitude and importance with the potential design of the Australian MMO. In its public consultation, the AEMC lists the following potential designs:[112]

1. Do nothing: Instead rely on the ASX MMO plus MLO.
2. Incentivised MMO: Market makers identified through a centralised tender process. This is the MMO design suggested by ENGIE.
3. Trigger driven MMO: Similar to the mandatory MMO discussed below but would only apply when the trigger condition is met. This suggested trigger is when churn falls below 1.5. Additional triggers could include specified average or maximum bid ask spread levels. The AEMC argue that either trigger may justify the need for greater liquidity and greater price discovery. The trigger driven MMO could be implemented as either an incentivised MMO or a mandatory MMO.

[110] New Zealand Government (February 2019), Electricity Price Review – Options Paper, p. 20.

[111] Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition - Impact Assessment, p.33.

[112] AEMC (December 2018), National Electricity Amendment (Market Making Arrangements in the NEM) Rule 2019 Consultation Paper, p. 21.

4. Mandatory MMO: An obligation placed on market makers, who are identified by the AEMC, to make hedge contracts available "during time periods when a shortage of contracts is identified".[113]

Whilst these four designs stipulate differing mechanisms to select MMs, and compensate them for providing market making services, the actual obligation placed on market makers is similar. The design of the mandatory, incentivised and trigger driven obligations are based on the design of the Market Liquidity Obligation (MLO) as part of the Retailer Reliability Obligation (RRO). We summarise this design in Table 4.6. Whilst the design of the ASX MMO has also converged to that of the MLO, it differs in four main ways:

1. The MLO specifies that market makers should trade monthly products, whereas the ASX MMO does not.
2. Under the ASX MMO, the MM should market make for a minimum of 25 minutes in each 30-minute trading window whereas in the MLO design the MM must market make for the entire window.
3. The MM is permitted to suspend trading under the ASX MMO for "unusual price volatility (as determined by the MM)"[114], whereas under the MLO design it may not.
4. The MM is permitted to suspend trading when it experiences an "unscheduled generation outage"[115], whereas under the MLO design it may not.

We now discuss how the cost drivers differ across proposed MMO designs and affect the total social cost of each MMO design. A summary of our discussion can be found in Table 4.7. The social cost is defined as the total cost of facilitating the obligation across all agents: in other words; aggregating across regulators, consumers and MMs. This does not stipulate how the social costs should be distributed amongst those agents.

- **Staff costs and set-up costs:** We estimate that staff and set-up costs are likely to be similar across the proposed MMO designs. This is because the types of products, technology systems to trade and quantity of trading are similar under each of the MMO designs. In addition, we follow the analysis of the EA and estimate that the incremental staff and set-up costs from an MMO are likely to be low because the MMs already trade the forward products.[116]
- **Transactions costs:** We estimate that, whilst transactions costs will vary across proposed MMO designs, the level of these transactions costs will be relatively similar. This is because the lot sizes, maximum bid-ask spreads, trading windows for market making, collateral costs and exchange fees from the quantity of trading are all similar across the proposed designs and follow the design of the MLO. The remainder of

113 AEMC (December 2018), National Electricity Amendment (Market Making Arrangements in the NEM) Rule 2019 Consultation Paper, p. 21.

114 Latest reported design of AMX MMO and MLO sourced from the AEMC.

115 Latest reported design of AMX MMO and MLO sourced from the AEMC.

116 Electricity Authority (November 2011), Cost Benefit Analysis – Market-Making Obligations, p. 18.

differences in transactions costs across the proposed designs are driven by the relative efficiency of MMs and the costs of exit.

These transactions costs are the lowest for the ASX MMO because MMs have lower costs of exit. More specifically, MMs may withdraw from market making when there is "unusual price volatility" and "unscheduled generation outages". Under other designs, exit by the MM under these circumstances is not permitted. Therefore, MMs can avoid additional transactions costs of market making during volatile periods.

Under the mandatory MMO, trigger driven MMO and incentivised MMO, the obligation faced by MMs is identical. However, we estimate that the trigger driven obligation will have the lowest transactions costs of these three because it will only be applied when during trigger periods, currently this would only be in South Australia. In addition, we estimate that the incentivised MMO will result in similar transactions costs to the mandatory MMO. However, these may be lower if the design of the tender process facilitates the selection of the most efficient MMs.

- **Costs of tender process:** The additional cost of designing and running the tender process applies to only the incentivised MMO proposed by ENGIE. The costs of the tender process increase with the frequency of the tender process. Therefore, to minimise costs accruing to the regulator, the tender should be infrequent. However, as the tender process becomes more infrequent, the risks associated with estimating the cost of market making increases for potential MMs. As a result, the potential MMs may build in larger risk premiums to their bids, increasing the social cost of the obligation through the risk of overcompensation. The frequency of the tender process should therefore balance these two opposing cost mechanisms.
- **Costs of compensation for MMs:** Whereas efficient compensation for participating in an incentivised MMO is a transfer of costs between parties and does not contribute to the social cost of the mechanism, overcompensation may lead to additional social costs.[117] The risk of overcompensation applies to the ASX MMO and the incentivised MMO proposed by ENGIE. The risk of overcompensation in the ASX MMO is low because the exchange rebates offered are low relative to the cost of market making. In addition, the rebates vary with the quantity of market making that the MM facilitates. The risk of overcompensation in a tender process is higher. This overcompensation occurs when the risks surrounding market making are large enough such that MM's bid with large risk premiums. Alternatively, overcompensation can occur when the design of the tender process leads to uncompetitive outcomes.
- **Monitoring, reporting and regulatory costs:** We estimate that the monitoring, reporting and regulatory costs are the lowest with the ASX MMO design. This is because the ASX administers the MMO and, through the exchange, may collect the relevant monitoring data already at low cost. Given this information, the reporting requirements and costs borne by MMs may be low. We estimate that the mandatory MMO will have higher monitoring, reporting and regulatory costs because MMs will be required to report to the regulator who, in turn, will incur monitoring costs to ensure the MMs are compliant

117 Under-compensation will simply lead to a less than 100 per cent transfer between parties. Therefore, in the case of under-compensation, more costs are borne by the MMs than the regulator.

with the obligation. We estimate the incentivised MMO and the trigger driven MMO will incur the highest monitoring, reporting and regulatory costs. This is because of similar monitoring costs as well as the added costs of designing and calibrating incentives or monitoring of the relevant market indicators, for example churn, that determine when the trigger driven obligation is triggered.

Table 4.7: Expected cost drivers of market making across proposed MMO designs

<table>
<tr><th></th><th>(1) ASX MMO</th><th>(2) ENGIE’s Incentivised MMO</th><th>(3) Trigger Driven MMO</th><th>(4) Mandatory MMO</th></tr>
<tr><td>Set-up costs</td><td colspan="4">▪ Similar across schemes: we expect the cost of IT development and legal fees are unlikely to vary across MMOs but will depend on the number of market makers (e.g may be avoided by non-participation in non-mandatory MMOs).</td></tr>
<tr><td>MM staff costs</td><td colspan="4">▪ Similar across schemes: Additional staff may be required to market make. Given MMs already trade these contracts, incremental costs are low and will be similar across MMO designs.</td></tr>
<tr><td>Transactions costs</td><td>▪ Lowest: MMs have more flexibility to withdraw from the market, forfeiting only the forgone exchange fee rebate.</td><td>▪ Second Highest: Largely the same as the Mandatory MMO but tender process selects most efficient MMs.</td><td>▪ Second Lowest: Forced to market make only in trigger periods. Tender process may select most efficient MMs.</td><td>▪ Highest Cost: (joint) largest obligation and selection of MMs by regulator may not select lowest-cost providers.</td></tr>
<tr><td>Costs of Tender Process</td><td>▪ None</td><td>▪ Costs of tender process: tender costs increase with frequency but costs of participating (per occasion) likely to fall with frequency.</td><td colspan="2">▪ None</td></tr>
<tr><td>Costs of compensation for MMs</td><td>▪ Low risk of overcompensation: ASX must set MM fee at correct level. Exchange fee rebate proportional to market making services provided. Borne by ASX who may recover from other exchange fees on market participants.</td><td>▪ Medium risk of overcompensation: May be higher if the tender process is less frequent/MMO covers a longer time frame as uncertainty for MMs increase. Borne by regulator who may recover through consumer tariffs, exchange fees or levy on market participants.
▪ Unclear whether overcompensation is larger under (2) or (3) because:
– Regulatory instrument is more complicated for bidders to assess under (3);
– Less compensation likely required under (2) because the obligation is contingent.</td><td colspan="2">▪ No compensation: MMs bear cost.</td></tr>
<tr><td>Reporting costs for MMs</td><td>▪ Likely to be low: ASX would collect data which would constitute both the monitoring and reporting requirements for MMs.</td><td colspan="3">▪ Higher than (1): Will depend on the stringency of obligations in MMO design.</td></tr>
<tr><td>Regulatory costs</td><td>▪ Likely to be low: Largely administered by ASX, exchange data collected anyway.</td><td colspan="3">▪ Higher than (1): Costs of monitoring the obligation in each case.</td></tr>
</table>

Source: NERA Analysis.

4.4. Quantitative Assessment of Costs of Proposed MMOs

Using this comparison of cost drivers across the proposed MMO designs, we estimate the total social cost of each proposed MMO design, see Table 4.8. The total social cost is the total net cost to society of introducing the MMO, irrespective of who bears those costs. We use the same cost categories as those reported by MMs to Ofgem, because these reported costs are the data we use to quantify our own estimates.

To estimate this total cost, we used the MM's reported costs to Ofgem of fulfilling the MMO between 2014 and 2017. These are listed in Table 4.3. Using these costs, we calculate the variable cost of market making per percentage point of volatility. We then scale this cost by the difference in volatility between GB and the NEM.[118] This difference in volatility is based on differences in the historical annualised volatility in the spot and one-quarter ahead prices. We use the difference in quarterly annualised volatility to generate a low-end scaled estimate and an average of the quarterly and the spot annualised volatility to generate a high-end scaled estimate.

To ensure we do not also scale fixed costs, these are deducted and then re-added to the final estimate after the volatility scaling. The fixed costs are taken from the GB MM's reported data.

Once we have this scaled volatility cost, we adjust the cost by half of the difference in the maximum bid-ask spread between the proposed MMO design and the GB design. This is because a larger bid-ask spread reduces the volume of transactions that a MM undertakes. In other words, we assume that half of the transactions that a MM would have been forced to trade under the GB scheme are now within the bid-ask spread and therefore the MM no longer needs to trade on these transactions, saving those costs.

In addition, we assume that incentives and tender processes are designed to ensure that no overcompensation is given to MMs. However, we estimate the cost of the incentivised MMO using data from Singapore, where evidence suggests overcompensation occurred in the tender process (see case study), to provide a high-end cost of the proposed incentivised MMO.

We assume that it will take two full-time equivalent employees three months to design and implement the tender process. This forms a low case estimate. For the high case we assume it takes the two FTEs six months. We use Ofgem's estimates for FTE staff costs for consistency.

Our assumptions for estimates of regulatory costs are derived from the Ofgem ex-ante estimates of incremental costs borne by a MM from staff and monitoring requirements of the MMO. These are £220,000 and £60,000 per year respectively, see Table 4.2. We assume that a symmetric monitoring and staff cost accrues to the regulator when the proposed MMO design requires monitoring and these staff.

118 For the NEM, we take an average of these volatilities across NSW, VIC, QLD and SA. In addition, we performed a currency conversion to move from GBP to AUD. The exchange rate assumed was GBP 1 to AUD 1.86

To construct the stand-alone cost estimate for each MMO design, we use the following methods and assumptions:

1. **ASX MMO plus MLO:** For the ASX MMO plus MLO, we assume no regulatory costs are incurred because the ASX already collects data which could be used to monitor compliance with the scheme at no incremental cost. Whilst we assume that the MLO is included in this case, we do not assume that it is triggered. We estimate three variable cost ranges for the ASX MMO plus MLO which differ in underlying method and assumptions:

    A. **No market making in SA:** The first method assumes that MMs withdraw from market making in SA. This case represents a "walk away" case where MMs do not provide market making services when the market is volatile. We characterise this as no market making in SA because this is where price volatility and the cost of market making is the highest. We use cost per unit volatility estimates from GB, but only for years 2014, 2015 and 2017. We omit 2016 because this is when higher costs were experienced because of higher market volatility. This means our cost per unit volatility estimates are lower. In addition, we scale up the volatile by average volatility in QLD, VIC and NSW but not SA. This results in a lower range of estimated variable costs per market maker.[119]

    B. **Market make in all periods:** The second method assumes that MMs market make in all periods. Given the proposed design of the ASX MMO plus MLO is similar to the mandatory MMO, we assume that the variable costs are similar in this case (see method under mandatory MMO). We recognise that there are differences between the mandatory MMO and ASX MMO plus MLO designs in the mandated number of trading windows in each month (that the MM must provide market making services**)**. This may lead to differences in costs between the two proposed designs. However, we assess that this difference will not be large: If some MMs do not provide services for two or three consecutive trading windows, it is unlikely to result in large costs. Instead, costs are more likely incurred when no trading occurs for consecutive weeks, for example due to a plant outage.

    C. **Estimate using the NZ MMO as a benchmark:** In the last case, we use the baseline reported cost of the NZ MMO which is also a voluntary MMO with built in exchange fee rebate. More specifically, we use Meridian's reported cost of NZD 1m to NZD 2m per year.[120] From this baseline cost, we calculate the cost per unit volatility in NZ and then scale up using volatility in the NEM to estimate the variable costs of the design in the NEM. The maximum bid-ask spreads are similar between these two schemes and therefore no adjustment is made for transactions costs.

[119] On first examination of Table 4.8, it may be surprising that the variable cost per market maker are relatively similar between the mandatory and ASX MMO plus MLO cases. However, this is because we are reporting the variable costs per average market maker across the NEM. In reality, the variable cost of market making in SA is considerably greater for the three operating market makers, but this difference is average across all seven market makers in the NEM.

[120] Meridian (March 2019), Electricity Price Review Options Consultation: Meridian and Powershop submission, p. 10.

2. **ENGIE's Incentivised MMO:** The proposed incentivised MMO includes both staff and monitoring regulatory costs as well as the cost of the tender process. In addition, we construct two estimated ranges of variable costs:
   A. **Estimate using the GB MMO as a benchmark:** Given the obligation faced by market makers in the incentivised MMO is similar to the mandatory MMO, the variable cost using GB cost per unit of volatility data is the same as the mandatory MMO case (see method under mandatory MMO).
   B. **Estimate using the Singapore MMO as a benchmark:** In addition, we construct an estimate based on a cost per unit volatility estimate from the incentivised MMO, the Future Incentive Scheme, in Singapore. The cost used is the annualised tender price to provide market making services per MM, determined in the tender process at the start of the MMO. Once again, we scale this estimate for the relative differences in volatility and bid-ask spreads between Singapore and Australia.
3. **Trigger driven MMO:** The trigger driven MMO is assumed to only apply in SA. The cost estimate is derived from the cost per unit volatility numbers in GB and scaled for volatility in SA. In addition, the wider maximum bid-ask spreads under the MMO design in SA result in a different transactions costs saving relative to the other schemes. Lastly, the estimate is scaled downwards to reflect the fact that fewer products need to be made available in SA, and the corresponding net-sales caps are therefore tighter.
4. **Mandatory MMO:** The mandatory MMO cost estimate simply uses the general method described above: We estimate the cost per unit of volatility in the GB MMO and scale the volatility by the difference in volatility between GB and Australia. We also adjust for the difference in maximum bid-ask spreads between the MMOs.

Across all cost estimates for the proposed MMO designs, we do not account for the impact on variable costs from changing the number of market makers. In reality, we may expect the costs of market making to fall with an increase in the number of market makers (as discussed in Section 4.2). This is because the more other MMs, the more opportunities that a single MM can trade out of their position. In addition, the less the costs of price discovery in trading windows.

We summarise our estimates in Table 4.8.

Table 4.8: Estimated differences in total annual costs across proposed MMO designs

All costs in AUDm/yr/MM	(1) ASX MMO plus MLO			(2) ENGIE's Incentivised MMO		(3) Trigger Driven MMO - Applies only to SA	(4) Mandatory MMO
	(1A) No market making in SA	(1B) Market make in all periods	(1C) Estimate using NZ MMO benchmark	(2A) Estimate using GB MMO benchmark	(2B) Estimate using Singapore MMO benchmark		
Variable costs	1.34 to 1.61	1.44 to 1.73	1.43 to 1.44	1.44 to 1.73	3.63 to 6.17	0.85 to 0.99	1.44 to 1.73
Fixed costs	0.93	0.93	0.93	0.93	0.93	0.93	0.93
Number of MMs	6	7	7	7	7	3	7
Regulatory costs	0	0	0	0.526	0.526	0.526	0.526
Tender process costs	0	0	0	0.22 to 0.45	0.22 to 45	0	0
Total cost	**13.65 to 15.25**	**16.60 to 18.63**	**16.54 to 16.57**	**17.34 to 19.60**	**32.70 to 50.65**	**5.85 to 6.29**	**17.12 to 19.15**
	13.65 to 18.63			**17.34 to 50.65**			

Source: NERA Analysis.

If each proposed MMO was implemented in *all* the states, the ASX MMO imposes the lowest social cost. This is because the ASX MMO has no regulatory costs and the lowest variable costs for each MM. The lower variable costs are because MMs may withdraw from market making when market volatility increases. In the scenarios here, this corresponds to when no MMs provide market making services in SA. Estimates based on both a cost per volatility number in GB in non-volatile years and estimates from the NZ scheme, where market makers were observed to widen bid-ask spreads during volatility, give lower variable cost estimates than the mandatory MMO. Moreover, if MMs did not drop out, then the scheme places a similar obligation on MMs as the mandatory MMO: this represents a cap on the variable costs of the ASX.

Meanwhile, our estimate for the costs of the mandatory MMO imply costs per MM similar to, but slightly greater than, the costs reported by MMs in GB. The higher costs reflect the additional volatility in the NEM.

The wide range of estimates on the incentivised MMO reflect the risks of designing a tender process. The GB estimate presents a low case where the tender is well designed and therefore the costs of the obligation are the same as the mandatory MMO (because the design of the MMO is the same). Therefore, the tender process in this case simply represents a transfer in who bears the cost of market making. On the other hand, the estimated costs based on the Singapore process highlight the risk of overcompensation for participants when the tender process is poorly designed, leading to a larger social cost.

In these estimates, we have simplified the assumptions around the effects of using a tender process and therefore, we may have overstated the costs of the incentivised MMO. This is because the tender process, if implemented, would likely not lead to overcompensation and may instead select those MMs who can most efficiently provide market making services. It is possible that this could lower costs relative to the mandatory MMO. Moreover, the use of a tender process to incentivise participation (rather than the selection of MMs by the regulator) may attract financial players to provide market making services. These players may be more efficient at providing market making services than the ‘gentailers’ in the market. These factors may lead to lower fixed and variable costs.

Overall, we find that the trigger driven obligation imposes the lowest total social cost. This is a misleading result because we assume that the trigger driven MMO is only implemented in SA whereas all other MMO designs would be implemented across the NEM. Therefore, we consider the incremental cost of imposing the trigger driven obligation in SA in Section 5.3.6.

A key difference between the expected annual costs of the proposed MMOs is the distribution of the costs of market making. In the proposed ASX MMO, the cost of incentivising market making is borne by ASX who may socialise the cost across market participants through exchange fees. In the proposed incentivised MMOs (both ENGIE’s proposal and the trigger driven obligation), a tender process delegates the estimation of the total costs to potential MMs. This cost is then borne by the regulator who may choose to socialise the cost through exchange fees, levies on market participants or consumer tariffs. In the proposed mandatory MMO (or trigger driven obligation with mandatory MMO) the costs are born by the MMs.

Therefore, the expected annual costs for the regulator differ significantly across proposed MMO designs. In the ASX MMO, the regulator has minimal participation in the scheme and therefore bears low/zero costs. In the incentivised MMOs, the regulator incurs monitoring costs, staff costs and the one-off cost of designing and running the tender process. In the mandatory MMO, the regulator incurs monitoring and staff costs, but avoids the cost of the tender process. The trigger driven obligation may be closer to either category, depending on whether a tender process is adopted under an incentivised trigger driven MMO. In addition, the regulator incurs a monitoring cost under the trigger driven MMO which arises from monitoring market indicators related to the trigger and determining when the obligation is triggered.

Other than costs related to the design of incentives or number of market participants, the cost of market making to each MM is relatively common across proposed designs. There are three exceptions:

1. The ASX MMO when participants have low costs of exit during periods of volatility. This reduces the variable cost of market making.
2. The incentivised MMO using Singapore estimates. These estimates include the potential overcompensation in the tender process.
3. The trigger driven obligation. These estimates are lower because MMs only need to market make in SA, as opposed to across all states.

Therefore, whilst differing MMO designs involve different costs of regulation and incentive provision, the key drivers of the cost of an MMO are the requirements placed on MMs after they enter into market-making arrangements.

5. Benefits

In this section, we discuss the benefits of MMOs qualitatively through their potential impact on market liquidity. We then model the benefits of lower transactions costs arising from the implementation of an MMO to quantitatively estimate the benefits of an MMO in each state.

5.1. The Benefits of an MMO and Market Failure

The benefits from intervening through an MMO are generated by improving liquidity in the forward power market. An increase in liquidity is not necessarily a positive outcome for society in and of itself. However, if liquidity is inefficiently low, an MMO may increase social welfare.

Liquidity may be inefficiently low because of failures in the market for wholesale electricity products or in related markets:

1. **Liquidity as a public good:** The social marginal benefit of trading in the forward market and improving liquidity exceeds the private marginal benefit. This is because price discovery is costly and therefore the absence of liquidity increases the costs of generating liquidity. In other words, when the market is liquid, a participant has price references to allow it to form clearer expectations of future market prices. Therefore, it can more accurately assess the prevailing market price and trade accordingly. When the market is illiquid, this is not possible and the resulting higher risk premium of trading may discourage further market participation, reducing liquidity further. It may be that coordination between market participants is required to generate a step change in liquidity.
2. **Protection of market power:** There is a natural hedge between generators and retailers, as we discussed in Section 2.1, which party explains why vertical integration is common across energy markets. Consequently, it is possible that vertically-integrated ‘gentailers’ with sufficient market power and a very close correlation between the needs of their generation and retail businesses could maintain barriers to entry in the retail market by withholding forward products from the wholesale market. Instead, such ‘gentailers’ can choose to manage risk internally, either with explicit contracts or implicitly by leaving both unhedged. In other words, a vertically integrated generator that was long on generation could strategically refuse to enter into forward contracts for its *net* generation position. Doing so would leave the remainder of the market short of forward contracts and prevent independent retailers from obtaining the hedging contracts they need. This could in principle result in low liquidity in the futures market. Maintaining market power and raising consumer tariffs because of this market power may lead to inefficiencies in the supply market. However, whilst this may be possible for a perfectly vertically integrated ‘gentailer’ in principle. In practice ‘gentailers’ are not perfectly vertically integrated and therefore still strong incentives to trade in the forward market.
3. **Asymmetric information between market participants:** This can also lead to a degree of asymmetric information between market participants. Those with a large volume of generation and supply may be able to better assess future prices and conditions relative to those smaller, independent retailers without generation capacity. This problem may manifest itself in higher barriers to entry to the retail market, but also low liquidity in the futures market reflecting uncertainty by the small, independent retailers.

4. **Asymmetric information between the physical and capital markets:** Asymmetric information between the capital market and the physical market requires that retailers must hedge the wholesale spot price of power in the forward market. If the capital market has perfect information then retailers could just purchase power on the wholesale spot market with the expectation that they would break even, and still obtain financing. However, capital markets add a risk premium to financing. Here, the downside risk (that wholesale market spot prices are higher than tariffs from customers at the point of dispatch) is weighted more than the upside potential (that wholesale market spot prices are lower than tariffs from consumers at the point of dispatch). Hence, retailers are required to hedge. This increases the capital requirements to enter the market, absent a liquid wholesale market in which they may trade.

5.2. Qualitative Assessment of the Benefits Identified by the AEMC

The AEMC has identified three potential benefits that introducing an MMO could have on liquidity.[121] Sections 5.2.1 to 5.2.3 discuss each of these in turn.

5.2.1. Efficiency of investment in and retirement of generation capacity

An MMO that improves transparency in pricing, particularly for products further along the forward curve, can lead to clearer investment signals and therefore, dynamic efficiency gains. A lack of liquidity in the wholesale market may lead to uncertainty over future investment in generation, particularly when this investment requires a degree of forward sale of the power to attract financing. Similarly, illiquidity may lead to the earlier retirement of generation capacity when future demand is not clearly communicated through transparent pricing. An MMO can improve these signals by mandating that MMs post prices on products further along the forward curve at maximum bid-ask spreads.

5.2.2. Enhance wholesale and retail market competition

If vertically-integrated incumbents have market power and are strategically withholding forward products to construct barriers to entry, then mandating those incumbents to provide the products may improve wholesale and retail competition. In addition, if vertical integration is simply an efficient way to manage the risks between power generation and supply but leads to informational asymmetries on the future price of power, then an MMO can improve price signals to prospective entrants to the market.

The benefits from the implementation of MMO designs in other energy markets are hard to assess and rarely reported on. A key problem has been the concurrent implementation of the MMO alongside other reforms to improve retail market competition. For example, ex-post assessments which estimate that the number of independent retailers has increased since the introduction of the MMO are unable to determine whether this is due to the MMO or other interventions (see the Great Britain and New Zealand case studies).

5.2.3. Enhance transparency and predictability

An MMO mandates that MMs post prices for certain products over specified periods of time, which are typically trading windows. This not only gives retailers confidence that they have the opportunity to purchase these products in those trading windows but also improves the

[121] AEMC (December 2018), National Electricity Amendment (Market Making Arrangements in the NEM) Rule 2019 Consultation Paper, p. 15.

price signals for those retailers. Moreover, MMOs which mandate maximum bid-ask spreads for products may lead to a more accurate determination of the true market price by retailers, who are provided with a more transparent set of prices.

Transparency has further importance as a signal to new supplier entrants as well as to consumer groups who can better hold those suppliers to account for the cost of the service they provide. Transparency in pricing also works to reduce information asymmetries, particularly between the capital market and the physical market. This may lower the cost of entry for new suppliers who face lower risks if faced with clearer price signals, and more information about expected future prices.

As we discussed in Section 3, the design of an MMO should balance obligations which ensure that MMs provide market making services when prices are volatile and price discovery is harder with the costs imposed on MMs of the obligation. This is because the benefits of market making are greatest when the market is the most volatile and price discovery is hardest, in other words when liquidity is low.

All four of the proposed MMO designs set limits to ensure that the MMs post prices for a certain number of trading windows throughout the year. The ASX MMO is the least strict of the designs with a lower number of trading windows in addition to allowing MMs to withdraw from the market when they experience "unusual price volatility". As we discussed, this reduces the costs of the ASX MMO relative to the other designs but also significantly reduces the potential benefits if MMs can avoid price discovery during volatile periods.

The use of trading windows to enforce market making for a specified period of time each day is common across international designs of MMOs. Whilst including a trading window gives small retailers certainty as to when they can purchase forward products each day, it may also reduce the impact on overall market liquidity. This is because the focus of trading in the mandated trading windows may come at the expense of liquidity at other parts of the day.

In Great Britain, the CMA found that whilst traded volumes had risen since the introduction of the MMO, they had fallen outside of the two trading windows specified by the MMO over the period.[122] The CMA examined data outside the windows and found that "product availability had become worse" [123] since the introduction of the MMO arguing that "these results paint a picture of relative, rather than absolute, availability"[124].

In addition, the concentration of trading in two trading windows each day can have implications for financial player participation and entry into the market. The movement of liquidity to market windows at the expense of other times during the day means speculative trading is likely to be dissuaded.[125] The CMA argued that without the introduction of financial players, and the liquidity throughout the day to support them, that there would not be the "step-change" in the level of liquidity that Ofgem was targeting.[126]

This "step-change" in liquidity refers to the coordination problem discussed above. In other words, for an MMO to have a marked impact on liquidity, it needs to generate a large enough

[122] Ofgem (July 2017), S&P Review: Consultations, p.13, Figure 11.

[123] CMA (June 2016), Energy Market Investigation Final Report: Liquidity Appendix, p. A7.1-20, 62.

[124] CMA (June 2016), Energy Market Investigation Final Report: Liquidity Appendix, p. A7.1-20, 63.

[125] CMA (June 2016), Energy Market Investigation Final Report: Liquidity Appendix, p. A7.1-20, 65.

[126] CMA (June 2016), Energy Market Investigation Final Report: Liquidity Appendix, p. A7.1-27, 92.

increase in trading that is sufficient to lead to further participation in the market and further improvements in liquidity beyond the MMO. The MMO therefore acts as a short-term coordination mechanism to lead to a market outcome where liquidity is sufficient to encourage further participation, even if the MMO is then removed. The problem remains identifying this sufficient level of liquidity.

5.3. Quantitative Assessment of the Benefits of Proposed MMOs

Estimating the benefits of MMOs quantitatively is a challenging exercise. So much so that none of the international case studies we reviewed had made a material effort to estimate the benefits of an MMO quantitatively. For instance, Ofgem simply relied on the assertion that the estimated costs were small and therefore that even small benefits would justify the intervention. In New Zealand, simplified metrics such as a percentage of industry costs were used.

Sections 5.3.1 to 5.3.7 set out our approach to quantifying the benefits of the proposed MMO in Australia. The AEMC's three identified benefits all stem from the understanding that an increased ability to hedge reduces the costs and risks faced by generators and suppliers. Our modelling examines the benefits of increased forward market liquidity (i.e. lower transactions costs) to a representative supplier attempting to hedge its anticipated load and the counterparty generator. These benefits consist of increased hedging and reduction in risks and a reduction in transactions costs for the hedges entered into.

5.3.1. The trade-off between hedging and risk capital

Theoretically, a retailer faces a trade-off between hedging and holding risk capital. A retailer has an obligation to supply its customers with power in the future. Many of its customers are on tariffs which may agree a fixed price for this power. Therefore, the retailer faces a risk: that the wholesale cost of power at the point of delivery for its customers is above the price agreed with its customers.

There are two main ways a retailer can mitigate this risk:

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

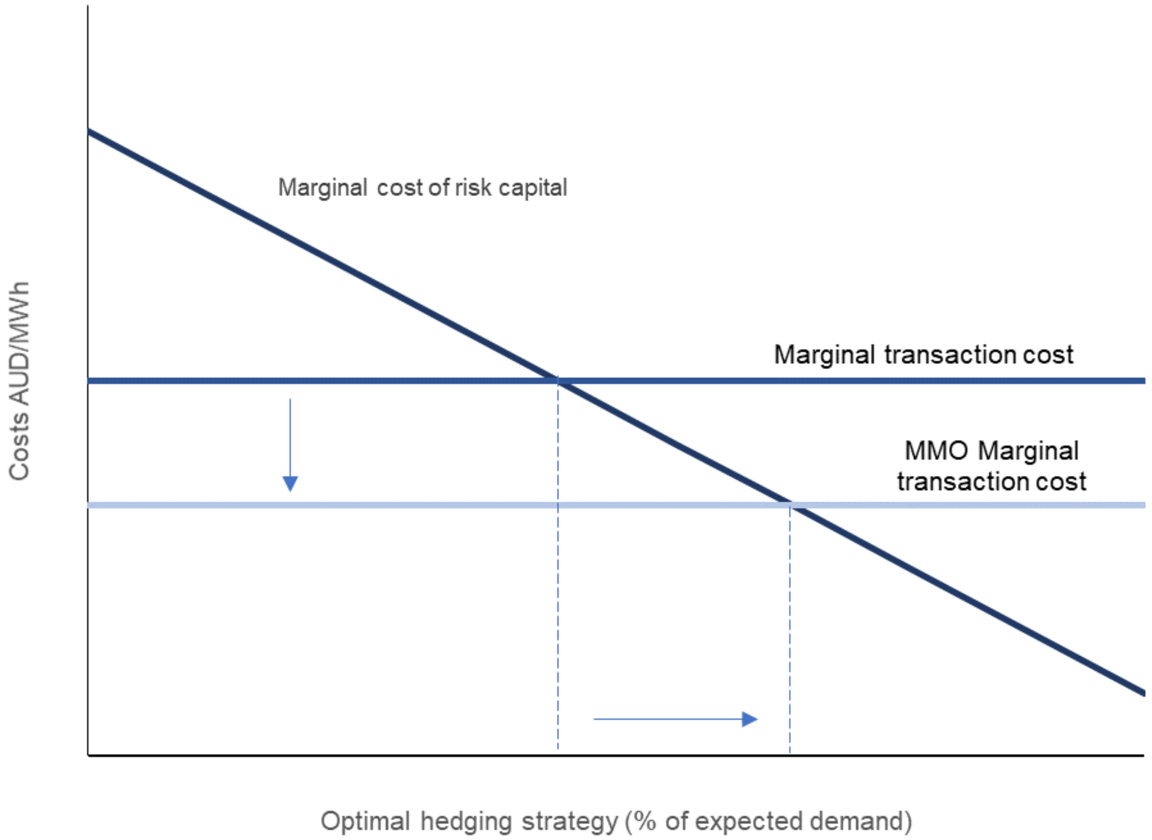
   The transactions cost includes the exchange fees of the trade but is also related to the prevailing bid-ask spread of the product in the market. The wider the bid-ask spread, the more that it costs the retailer to make the trade relative to the true market price (assuming that the bid-ask spread is centred around the true market price).

   The cost of marking to market is the cost of the capital used as collateral when the updated price of the contract falls below the strike price. In these cases, the retailer is providing assurance through posting collateral that it can make the transfer to the counter-party. Therefore, the retailer must hold capital to use in the case that the power price falls below the strike price while the retailer holds the contract. The cost of holding this capital is determined by the opportunity cost of the capital, in other words, the forgone rate of return on that capital. Therefore, the more the retailer hedges, the more transaction and collateral costs that it incurs.

2. **Holding risk capital:** Alternatively, the retailer can hold capital to pay the difference between the wholesale cost of electricity and the tariff agreed with its customers. This is in effect a form of self-insurance. The cost of holding this capital is determined by the weighted average cost of capital.

The optimal hedging strategy balances these two methods to minimise costs. If the retailer increases the degree to which it is hedged against wholesale price movements, it reduces the risk capital requirements to protect against these movements and the costs associated with holding this capital. On the other hand, the more the retailer hedges, the more transactions costs and the higher costs of posting collateral it incurs.

Figure 5.1: Illustration of the trade-off between transactions costs and risk capital



Source: NERA Analysis.

We model this trade-off for a representative retailer operating in the wholesale market in the NEM. A potential benefit of the implementation of an MMO is to ensure that forward products are available for trade at mandated maximum bid-ask spreads that are lower than levels prevailing today. This reduces the transactions costs of hedging forward by a given amount, making it relatively more attractive for retailers to hedge rather than hold risk capital. Therefore, this potential benefit can be quantified as the savings associated with the change in risk capital. More specifically, these savings are quantified by examining the rate of return, the weighted average cost of capital, on this change in risk capital.

5.3.2. Summary of model method

In order to quantify this benefit across MMO designs, we simulate the monthly cashflows of a single representative retail supplier in each state in the NEM. We summarise our model method in this section, see Appendix A for the full details of the model.

5.3.2.1. Modelling power prices

To model the costs of procuring electricity in the futures market, we assume that retail suppliers hedge their requirements using quarterly baseload contracts, up to eight quarters ahead. To keep the number of possible hedging strategies limited, we do not simulate prices for peak or cap contracts. Limited liquidity of monthly contracts means we are unable to analyse and simulate the volatility of those contracts.[127]

We simulate quarterly prices according to the volatility and co-movement of prices of different quarterly contracts traded on the same day. In particular, we use price data for futures contracts traded on each day between 2016 and 2018, inclusive, with separate data for each NEM region. We estimate the extent to which the different forward product price series co-vary, using Principal Component Analysis (PCA).

We assume that prices for each product are fixed at the beginning of our modelling period, based on the average price for each product over the duration of Q4 2018. Then, based on the estimated volatilities and PCA, we simulate daily shocks for each contract, using a Geometric Brownian Motion process, which assumes that that day’s price for a particular product is equal to the previous day’s price for that same product, multiplied by some random shock.[128] The PCA ensures that these shocks are consistent with both the volatility and the co-movement of prices observed in the historical data.

We simulate the daily-average power price, based on an error-correcting process relative to the previous day’s daily-average price and the price of the active quarterly baseload contract (i.e. the balance-of-quarter or zero-quarters-ahead contract). In addition, the actual daily-average price of electricity experiences occasional large price shocks. In order to simulate these days, we calculate the observed frequency, size and standard deviation of such events in each state between 2016 and 2018. We assume that these estimated parameters effectively represent the probability and likely impact of such events. We allow the model to randomly insert such large daily price spikes based on these estimated parameters. This creates price risk for the retailers.

5.3.2.2. Retailer cashflows and risk capital

We simulate the monthly cashflows of a single representative retail supplier in each of the four states. We simulate cashflows over the course of 12 months. The following items are assumed to drive a supplier’s cashflows:

- **Revenues from tariffs:** driven by the average retail tariff structure, the number of customers served by the retailer, and the amount of electricity it sells to those customers.

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127 In the three years of historical data we analyse, from 2016 to 2018, inclusive, traders only conducted around 200 trades across all monthly contracts, according to ASX trading data.

128 The precise formula is: $P_t = P_{t-1} * e^{(\text{Shock(t)} - 0.5*\text{Standard Deviation(P)})}$.

We use annual average customer switching rates to simulate customer numbers across the 12 months. This is so that the retailer faces a volume risk when hedging.

- **The costs of procuring electricity in wholesale markets:** including (i) spot market procurement, (ii) forward market procurement and (iii) any collateral payments required to cover differences between the strike price agreed upon and the updated market view of the price for a particular contract.
- **Transactions costs:** for procuring contracts in the wholesale market. We assume the transactions cost of the contract is half of the bid-ask spread. Crucially, these bid-ask spreads, and therefore transactions costs, are assumed to vary across the proposed MMO designs in each state.
- **Other costs not related to the purchase and sale of energy:** such as network charges, the costs of environmental subsidies, and overhead costs associated with retail electricity companies.

In each month of our 12-month cashflow period, we simulate the revenues and costs to identify (i) the cash balance in each month; (ii) the level of transactions costs paid; and (iii) the average energy revenues received by generators for each hedging strategy.

We use this cashflow to calculate the risk capital that the representative retailer needs to hold to remain solvent in 98 per cent of the annual simulations. We adopt this rate on advice from the AEMC. The cost of holding this risk capital is determined by the weighted average cost of capital. The total cost of risk capital is falling in the degree of hedging.

5.3.2.3. Calibrating MMO designs

We assume that the effect of an MMO in this model is to reduce the bid-ask spreads on forward contracts. We examine the proportion of contracts which currently trade outside of the maximum bid-ask spread stipulated by each MMO design. This is the proportion of contracts upon which the MMO design "binds". We use this proportion to estimate the reduction in market-wide bid-ask spreads arising from the implementation of each MMO design. We calculate this reduction for each state, see Table 5.1.[129]

We also consider the externality of liquidity as described in Section 5.1. Therefore, we consider a scenario where the introduction of the MMO leads to a "step-change" in liquidity. In other words, in this scenario the MMO has not merely the benefit of capping bid ask spreads at particularly volatile times but reducing bid-ask spreads across the market even when the MMO does not formally bind. We call this scenario "MMO plus liquidity".

We calculate a different set of bid-ask spreads representing our "MMO plus liquidity" case. For QLD, NSW and VIC we use double the reduction in bid-ask spreads estimated above. This is equivalent to an additional 5-10 per cent reduction in transactions costs. For SA, where the MMO is most binding, we recognise that doubling the reduction may lead to an implausibly low bid-ask spread, even with a "step-change" in liquidity. Accordingly, we relied on estimates produced by the Electricity Authority in New Zealand of the impact of market makers on market bid-ask spreads[130] We assume three market makers and scale the

[129] More specifically, we examine the historical average bid-ask spreads of quarterly baseload products, from one quarter ahead to eight quarters ahead, from 2016 to 2018 inclusively, weighted by our assumed hedging profile for the retailer.

[130] Electricity Authority (21 November 2011), "Cost Benefit Analysis – Market-Making Obligations", p.14.

EA's estimate for the 7 per cent maximum bid-ask spread in SA. This gives us an estimated spread of 4.06 per cent.

Table 5.1: Calculated historical and estimated bid-ask spreads arising from the MMO based on historical data for quarterly baseload swaps from 2016 to 2018 inclusively

Units % of bid price	**MMO Cap**	**Historical average**	**"MMO" (historical average capped at MMO cap)**	**"MMO + Liquidity"**
VIC	5.0	1.9	1.8	1.7
SA	7.0	6.7	5.1	4.06
QLD	5.0	1.9	1.8	1.7
NSW	5.0	2.0	1.9	1.8

Source: NERA Analysis.

Therefore, each MMO design reduces transactions costs by a different amount in each state. In our model, the reduction in transactions costs across MMO designs varies only if the stipulated maximum bid-ask spread varies across designs.

The size of this reduction in transactions costs depends on the assumed retailer hedging strategy. We calculate the retailer cashflows which include these transactions costs for the following hedging strategies: 60, 70, 80, 90 and 100 per cent of expected demand.

We recognise that most retailers in the NEM hedge more than 60 per cent of their expected demand. However, in our model we only consider hedging through flat swaps. Therefore, we can think of the optimal hedging strategy as the optimal amount of expected demand that the retailer should hedge through flat swaps. In reality, the retailer may hedge a larger proportion of its expected demand using other products.

5.3.2.4. Estimating the benefits

We simulate the model for each combination of the calibrated bid-ask spreads and hedging strategies. Several of the input parameters are inherently volatile (e.g. power prices). Therefore, we simulate the model approximately 4,000 times for each combination to capture the distribution around each of the output parameters, reporting the average result.

We then identify the optimal hedging strategy based on the simulations in our model. This strategy balances the risk capital savings and transactions costs from hedging as described in Section 5.3.1. We compare the net benefit of the hedging strategies across proposed MMO designs to estimate the benefits per MWh of each MMO design. We then multiply by the total unhedged volume of electricity generated and supplied in each state to get the total benefit of the MMO in that state.

Our implicit assumption is that generators are the counter-party to the retailers hedging strategy and therefore also gain through hedging future power prices. We measure the benefit to generators by examining the minimum price generators receive for their power across a 12-month period. The lower this price, the more risk capital the generator must hold. The degree of hedging increases the minimum price, because the generator is less exposed to adverse wholesale price movements at the point of dispatch.

5.3.3. Model results

We report our results for each state in Table 5.2. Three matrices are shown for each state. Along the columns of each matrix is the hedging strategy for the retailer. Each row corresponds to the modelled bid-ask spread. As discussed above, we examine three bid-ask spreads: historical spreads, estimated spreads after the introduction of an MMO and estimated spreads after the introduction of an MMO which leads to a “step-change” in liquidity: we call this “MMO plus liquidity”. These differ across states and are detailed in Table 5.1.

Our estimated results are reported relative to the 60 per cent hedging strategy baseline. As discussed in Section 5.3.2.3, our hedging products are flat swaps. Therefore, this baseline can be interpreted as the percentage of expected demand that the retailer hedges using flat swaps. Moreover, we define the benefits of the MMO relative to this baseline. Therefore, the extent of hedging in the baseline is not as important as the difference in hedging strategy under each of the proposed MMOs.

The first matrix details the risk capital saving per MWh from moving across hedging strategies. This saving is increasing towards the top right of the matrix. This is because the risk capital saving increases as the retailer hedges more. It also increases slightly as transactions costs fall. This is because transactions costs appear in the cashflow statement for the representative retailer. The higher the transactions costs, the lower the average cashflow balance for the retailer for a given hedging strategy, and the more risk capital that the retailer is required to hold. These risk capital savings are reported relative to the 60 per cent hedging strategy for each of the evaluated bid-ask spreads.

The second matrix details transactions costs for the representative retailer. These are increasing to the bottom right of the matrix. This is because transactions costs increase with the amount of hedging that the retailer undertakes, as the retailer buys more forward products. Transactions costs also increase with bid-ask spreads, as the transactions cost is defined as half of the bid-ask spread. These costs are reported relative to the 60 per cent hedging strategy for each of the evaluated bid-ask spreads.

The last matrix defines the optimal strategy for the retailer by differencing the previous two tables. In other words, this optimal strategy balances the marginal savings to risk capital of increasing hedging with the marginal cost of transactions costs. The optimal hedging strategy for each bid-ask spread is highlighted with a black box.

Table 5.2: Optimal hedging strategies (Units in $/MWh)

	New South Wales – Hedging Strategy					Victoria – Hedging Strategy				
Bid-ask Spread	60%	70%	80%	90%	100%	60%	70%	80%	90%	100%
Risk Capital Savings (AUD/MWh)										
MMO + Liquidity	0.02	0.38	0.64	0.97	1.24	-0.21	0.35	0.75	1.28	1.55
MMO	0.01	0.37	0.63	0.96	1.23	-0.10	0.38	0.75	1.20	1.54
Historical	0.00	0.36	0.62	0.95	1.22	0.00	0.41	0.75	1.12	1.53
Transaction Costs (AUD/MWh)										
MMO + Liquidity	-0.11	-0.01	0.10	0.20	0.31	-0.05	0.02	0.10	0.18	0.26
MMO	-0.06	0.04	0.15	0.25	0.36	-0.03	0.05	0.14	0.22	0.30
Historical	0.00	0.10	0.21	0.31	0.42	0.00	0.09	0.17	0.26	0.35
Optimal Strategy (Risk Capital Savings - Transaction Costs)										
MMO + Liquidity	0.13	0.39	0.54	0.77	**0.93**	-0.15	0.32	0.65	1.10	**1.30**
MMO	0.06	0.32	0.47	0.70	**0.86**	-0.08	0.32	0.61	0.98	**1.24**
Historical	0.00	0.26	0.41	0.64	**0.80**	0.00	0.32	0.57	0.86	**1.19**

	South Australia – Hedging Strategy					Queensland – Hedging Strategy				
Bid-ask Spread	60%	70%	80%	90%	100%	60%	70%	80%	90%	100%
Risk Capital Savings (AUD/MWh)										
MMO + Liquidity	0.11	0.55	0.86	1.12	1.29	-0.04	0.42	0.89	1.44	1.83
MMO	0.06	0.51	0.80	1.09	1.26	-0.02	0.42	0.89	1.43	1.82
Historical	0.00	0.48	0.75	0.99	1.23	0.00	0.43	0.88	1.43	1.81
Transaction Costs (AUD/MWh)										
MMO + Liquidity	-0.89	-0.66	-0.42	-0.19	0.04	-0.05	0.02	0.10	0.17	0.25
MMO	-0.53	-0.24	0.05	0.34	0.64	-0.03	0.05	0.13	0.21	0.29
Historical	0.00	0.38	0.76	1.14	1.52	0.00	0.08	0.17	0.25	0.34
Optimal Strategy (Risk Capital Savings minus Transaction Costs)										
MMO + Liquidity	1.00	1.21	1.28	**1.31**	1.25	0.01	0.40	0.80	1.26	**1.58**
MMO	0.60	0.75	0.75	**0.75**	0.63	0.01	0.37	0.75	1.22	**1.53**
Historical	0.00	**0.10**	-0.01	-0.15	-0.30	0.00	0.35	0.71	1.17	**1.47**

Source: NERA Analysis. Note: Green denotes highest profit scenario and red denotes lowest profit scenario.

The optimal hedging strategy is found by comparing the trade-off between risk capital savings, in the first matrix, to incurring transaction costs, in the second matrix, relative to a 60 per cent hedging strategy at the "Historical" transactions costs. Where this difference is maximised determines the optimal hedging strategy for the representative retailer.

The benefits of introducing an MMO and achieving the reductions in transactions costs shown consist of differences between the black-squared boxes. For instance, the benefit for a retailer of moving from the "Historical" market spreads to the "MMO" scenario in South Australia is $0.66/MWh consisting of:

- A reduction in risk capital of $0.62/MWh ("MMO" risk capital of 1.09 at optimal 90 per cent hedging minus "Historical" risk capital of 0.48 at 70 per cent hedging strategy); and
- A reduction in transaction costs of $0.04/MWh ("MMO" transactions cost of 0.34 at optimal 90 per cent hedging minus "Historical" transactions costs of 0.38 at 70 per cent hedging strategy).

These benefits are summarised in Table 5.3.

Table 5.3: Model results for optimal hedging strategies ($/MWh)

Units: AUD/MWh		NSW	QLD	SA	Vic	NEM
Retailer						
Risk Capital Benefits	MMO	0.01	0.01	0.62	0.01	**0.64**
	MMO + Liquidity	0.02	0.01	0.64	0.02	**0.69**
Transactions Costs Benefits	MMO	0.06	0.04	0.04	0.05	**0.19**
	MMO + Liquidity	0.11	0.09	0.57	0.09	**0.86**
Total	**MMO**	**0.06**	**0.05**	**0.66**	**0.05**	**0.83**
	MMO + Liquidity	**0.13**	**0.10**	**1.21**	**0.11**	**1.55**
Generator						
Risk Capital Benefits	MMO	0.01	0.003	0.26	0.003	**0.28**
	MMO + Liquidity	0.03	0.01	0.30	0.01	**0.34**
Transactions Costs Benefits	MMO	0.06	0.04	0.04	0.05	**0.19**
	MMO + Liquidity	0.11	0.09	0.57	0.09	**0.86**
Total	**MMO**	**0.07**	**0.05**	**0.30**	**0.05**	**0.47**
	MMO + Liquidity	**0.14**	**0.10**	**0.87**	**0.10**	**1.20**

Source: NERA Analysis.

In New South Wales, market spreads are already relatively low compared to other states. This means that hedging is beneficial because transactions costs are lower relative to the risk capital savings. Therefore, in our model, retailers hedge 100 per cent of their expected demand at historical bid-ask spreads. Moreover, the maximum bid-ask spread as stipulated by the MMO does not bind tightly, because existing spreads are below this threshold. Therefore, the absolute difference in transactions costs from moving from the historical spread to the estimated market spread with an MMO is relatively small. As such, we do not estimate a large benefit from the introduction of the MMO in NSW. However, this benefit is increased when we consider the MMO plus liquidity bid-ask spread. In all cases, the retailer’s optimal strategy in the model is to hedge 100 per cent of expected demand.

A similar case is observed for Queensland and Victoria which also have relatively low historical bid-ask spreads. Therefore, the introduction of an MMO has a low estimated impact on spreads because the obligation does not bind tightly. Here, like NSW, our model suggests that retailers would already find it optimal to hedge 100 per cent of expected demand in all three scenarios.

In South Australia, the historical bid-ask spreads are significantly higher than the other three states. Moreover, the maximum bid-ask spread as stipulated by the MMO binds most tightly in SA, giving rise to the largest absolute difference in transactions costs between historical and MMO spreads. As a result, the introduction of the MMO makes hedging more attractive to retailers in our model. We model that they increase their hedging strategy from 70 per cent of expected demand to 90 per cent of expected demand after the introduction of the MMO. If we assume the additional liquidity benefit, which reduces transactions costs further, then retailers further maintain their hedging strategy of 90 per cent of expected demand but realise further benefits. This is because the marginal benefit of holding less risk capital exceeds the marginal transactions costs when transactions cost fall substantially.

5.3.4. Benefits across states in the NEM

We calculate the total benefit in each state by multiplying by the total MWh supplied. We follow two methods:

1. The first multiplies by total MWh supplied in the state. This assumes that all traded volumes in the state are subject to the transactions cost benefits of the MMO and forms our high case estimate.

2. The second multiplies by the total estimated "unhedged" volume in the state. This is the total of the volume supplied by independent generators and the "unhedged volume" of VI 'gentailers'. The VI "unhedged volume" is estimated by comparing the shares of generation and supply that vertically-integrated entities hold in each state. We assume that the overlap in generation and supply is fully hedged due to vertical integration and therefore only the difference is unhedged for generators and retailers. As such, this forms a low case estimate, because in reality it is likely that even a fully vertically integrated entity would trade forward because its own generation is unlikely to be the lowest cost method of meeting its customers' load in real time.

These total benefits from unhedged and total volumes are reported in Table 5.4 and Table 5.5 respectively. The actual benefits may fall between the two estimates.

Based on our model estimates, the benefits of the introduction of the MMO will be greatest in SA, despite the relatively smaller market size. This is because the MMO's stipulated maximum bid-ask spread binds more tightly in SA giving rise to the largest transactions cost savings for retailers. As a result, these retailers increase the amount of hedging they undertake, resulting in higher benefits from the reduced risk capital.

Other than SA, the introduction of the MMO has relatively minor benefits in other states (as estimated by our model). In part this is because the MMO does not change the market bid-ask spreads substantially: it is binding on a smaller proportion of transactions than in SA, and therefore the transactions cost benefit of the MMO is smaller. Consequently, we estimate that the optimal retailer hedging strategy does not change substantially after the introduction of the MMO.

Table 5.4: Total estimated modelled benefits (using unhedged volume estimates) relative to historical bid-ask spreads

Units: AUDm		NSW	QLD	SA	Vic	NEM
Retailer						
Risk Capital Benefits	MMO	0.11	0.15	3.88	0.08	**4.22**
	MMO + Liquidity	0.22	0.29	4.03	0.16	**4.70**
Transactions Costs Benefits	MMO	0.83	0.96	0.23	0.38	**2.41**
	MMO + Liquidity	1.67	1.92	3.59	0.77	**7.94**
Total	**MMO**	**0.95**	**1.11**	**4.12**	**0.46**	**6.63**
	MMO + Liquidity	**1.89**	**2.21**	**7.62**	**0.92**	**12.65**
Generator						
Risk Capital Benefits	MMO	0.24	0.03	0.85	0.13	**1.25**
	MMO + Liquidity	0.48	0.06	1.00	0.25	**1.79**
Transactions Costs Benefits	MMO	0.83	0.96	0.23	0.38	**2.41**
	MMO + Liquidity	1.67	1.92	3.59	0.77	**7.94**
Total	**MMO**	**1.07**	**0.99**	**1.09**	**0.51**	**3.66**
	MMO + Liquidity	**2.14**	**1.98**	**4.59**	**1.02**	**9.73**

Source: NERA Analysis.

Table 5.5: Total estimated modelled benefits (using total volume estimates) relative to historical bid-ask spreads

Units: AUDm		NSW	QLD	SA	Vic	NEM
Retailer						
Risk Capital Benefits	MMO	0.47	0.17	8.72	0.26	**9.62**
	MMO + Liquidity	0.93	0.35	9.05	0.52	**10.85**
Transactions Costs Benefits	MMO	3.46	1.14	0.52	1.27	**6.40**
	MMO + Liquidity	6.92	2.28	8.07	2.55	**19.81**
Total	**MMO**	**3.92**	**1.31**	**9.25**	**1.53**	**16.02**
	MMO + Liquidity	**7.85**	**2.63**	**17.12**	**3.07**	**30.67**
Generator						
Risk Capital Benefits	MMO	0.83	0.04	2.87	0.20	**3.93**
	MMO + Liquidity	1.65	0.09	3.37	0.39	**5.49**
Transactions Costs Benefits	MMO	3.46	1.14	0.52	1.27	**6.40**
	MMO + Liquidity	6.92	2.28	8.07	2.55	**19.81**
Total	**MMO**	**4.28**	**1.18**	**3.39**	**1.47**	**10.33**
	MMO + Liquidity	**8.57**	**2.36**	**11.44**	**2.94**	**25.31**

Source: NERA Analysis.

For generators, the benefits to risk capital mirror the pattern observed across states for retailers. These benefits are higher in SA relative to other states because of the greater impact of the MMO. This symmetry in results is because generators are modelled as the counter-party to retail hedging, which consequently determines the benefits accruing to generators.

5.3.5. Net benefits of the MMO

We aggregate across reported benefits and compare to our cost estimates to estimate the total net benefit of introducing the MMO across the NEM. We set out our estimated net benefits in Table 5.6. The benefit ranges are drawn from the total retailer and generator benefits set out in Table 5.4 and Table 5.5 above. The cost ranges are those shown in Table 4.8.

In the case of the incentivized MMO, we choose not to report the costs associated with the Singapore MMO. Therefore, the cost range reported is that estimated from the GB cost per volatility numbers plus an adjustment for the cost of the tender process. In doing so, we do not include the costs associated with the risk of overcompensation in a tender process, which the Singapore cost estimates may include. Therefore, we may overstate the total net benefit of the incentivized MMO. On the other hand, we also do not adjust our cost estimates to reflect the fact that the tender process may select more efficient MMs, including financial players. If this occurred without overcompensation, our net benefit estimates would understate the total net benefits associated with the incentivized scheme.

To provide a range of estimate net benefit, we subtract the high case cost from the high case benefit under both MMO and "MMO plus Liquidity" cases. This is because we note that benefits and costs are may increase with volatility in the market. Therefore, the high case benefit correlates to the high case cost because of the relationship through this market volatility.

Table 5.6: Estimated net benefits of the proposed MMO designs

		[1] ASX MMO + MLO		[2] ENGIE's Incentivised MMO		[3] Trigger Driven MMO - SA Only		[4] Mandatory MMO	
	Scenario	*Low*	*High*	*Low*	*High*	*Low*	*High*	*Low*	*High*
Benefits	MMO	10.3	26.3	10.3	26.3	5.2	12.6	10.3	26.3
	MMO+Liq.	22.4	56.0	22.4	56.0	12.2	28.6	22.4	56.0
Costs		13.7	18.6	17.3	19.6	5.9	6.3	17.1	19.2
Net Benefits	**MMO**	**-3.4**	**7.7**	**-7.1**	**6.7**	**-0.7**	**6.3**	**-6.8**	**7.2**
	MMO+Liq.	**8.7**	**37.3**	**5.0**	**36.4**	**6.4**	**22.3**	**5.3**	**36.8**

Source: NERA Analysis.

In the "MMO" scenario, which assumes that the MMO only has an effect when market spreads are above the mandated spread, the net benefits of the introduction of an MMO are unclear. In particular, all of the designs would have negative net benefits if the costs transpired to be at the upper end of our estimated ranges and the benefits transpired to be at the bottom of our estimated ranges. If the benefits were to be at the top of our estimated ranges and costs at the bottom, any of the schemes would have positive net benefits. This result is predominantly driven by net benefits in South Australia where we estimate that the transactions costs are reduced most by the MMO.

All of the designs have positive net benefits in the "MMO plus liquidity" scenario, which assumes a "step-change" on liquidity in the wholesale market as a whole. In this case, transactions costs are significantly reduced by the MMO, particularly for SA. As a result the risk capital savings are large enough such that we estimate that at, even at the low end of the estimated range, the introduction of each proposed MMO design will lead to a net benefit. However, as we discussed in Section 3.2.3, this “step-change” in liquidity has not been realised in international experience with MMOs.

Our model is an abstraction from reality; it assumes that market participants trade quarterly products in a given profile to meet demand. In our model, the only benefit of an MMO is through its impact on bid-ask spreads and corresponding transactions costs. The designs set out in the table mandate the same bid-ask spreads. As a result, our model suggests that the net benefit of each design is similar and our comparative results depend crucially on that assumption.

In practice, the different designs may be more or less effective in delivering narrower bid-ask spreads in the wholesale market. Market participants have the option of withdrawing from the ASX scheme periodically over time. In particular, MMs may walk away when the market is volatile and costs of market making are higher. This may reduce the liquidity benefits of the ASX scheme relative to our estimates here. In addition, this may reduce the availability of hedging products to retailers who may no longer be able to follow their hedging strategies.

Whilst we abstract from this possibility in our modelling, we acknowledge that our estimated benefits for the ASX scheme may overstate the benefits that will be delivered by the scheme. In other words, whilst we present a cost range which corresponds to varying degrees of participation in the ASX scheme (from not market making in SA to full participation) our benefits range corresponds to full participation in the ASX.

Therefore, in principle, the net benefits of this scheme may be lower than we estimate. However, if the ASX scheme were to result in a similar market outcome to the other designs, we would expect the net benefits of the ASX scheme to be greater because it presents cost savings relative to the other designs.

5.3.6. Incremental net benefits of each proposed MMO design

Given that the ASX MMO and MLO are likely to be implemented, we consider the incremental net benefit of introducing an additional MMO to this baseline. We estimate that the planned introduction of the ASX MMO and MLO may lead to benefits relative to the current market position in the NEM. However, the degree to which the ASX MMO and MLO are effective, and therefore the degree to which a further introduction of MMO is justified depends on the take-up of the ASX incentivized scheme. We therefore consider, the incremental net benefit of introducing an additional MMO to baselines where the ASX MMO and MLO is in operation but take-up by MMs varies. Whilst we assume that the MLO is included in this case, we do not assume that it is triggered.

More specifically, we consider two baseline cases:

(i) **“ASX MMO plus MLO - No dropping out”:** In this first scenario we assume that MMs always participate in and fulfil the requirements of the ASX MMO or MLO design in all states. In this case, we assume that the benefits of the MMO are the same as those under incentivized or mandatory MMOs because the design of the scheme is similar. As discussed in Section 4.3, we recognize that the number of trading windows that each MM is required to trade in differs under the proposed design of these obligations. However, we do not believe this will significantly alter the benefits from each scheme.

(ii) **"ASX MMO plus MLO - No market making in SA":** In this second scenario, we assume that six MMs provide market making services under the ASX MMO plus MLO arrangements in all regions apart from SA. We estimate the costs of market making in this scenario by using our cost per volatility percentage point estimates scaled up for volatility in NSW, QLD and VIC (but not SA). Our model benefits are aggregated across regions (with no assumed benefit in SA).

Our estimated incremental net benefits of moving from the first baseline case (no dropping out) are shown in Table 5.7, whilst our estimated incremental net benefits of moving from the second baseline case (no market making in SA) are shown in Table 5.8.

Table 5.7: Incremental net benefits from ASX MMO plus MLO – No dropping out

		[1] ASX MMO + MLO – No dropping out		[2] ENGIE's Incentivised MMO		[3] Trigger Driven MMO - SA only		[4] Mandatory MMO	
	Scenario	*Low*	*High*	*Low*	*High*	*Low*	*High*	*Low*	*High*
Benefits	MMO	0	0	0	0	0	0	0	0
	MMO+Liq.	0	0	0	0	0	0	0	0
Costs		0	0	0.7	1.0	0.5	0.5	0.5	0.5
Net Benefits	**MMO**	**0.0**	**0.0**	**-0.7**	**-1.0**	**-0.5**	**-0.5**	**-0.5**	**-0.5**
	MMO+Liq.	**0.0**	**0.0**	**-0.7**	**-1.0**	**-0.5**	**-0.5**	**-0.5**	**-0.5**

Source: NERA Analysis.

Table 5.7 shows the incremental costs and benefits from moving from the baseline defined in (i) to each alternative proposed MMO design. In this case, there are no additional benefits from market making when moving to one of the alternative designs, because market makers are already fulfilling the obligation. Therefore, the incremental net benefit is negative and reflects the increase in regulatory and monitoring costs from moving to the other schemes. In the case of the incentivized MMO, there is an additional cost of the tender process. As we described in Section 5.3.5, there is also a risk of overcompensation of MMs or chance of more efficient MMs in the incentivized scheme which we do not show here.

Table 5.8: Incremental net benefits from ASX MMO plus MLO – No market making in SA

		[1] ASX MMO + MLO – No market making in SA		[2] ENGIE's Incentivised MMO		[3] Trigger Driven MMO - SA only		[4] Mandatory MMO	
	Scenario	*Low*	*High*	*Low*	*High*	*Low*	*High*	*Low*	*High*
Benefits	MMO	0	0	5.2	12.6	5.2	12.6	5.2	12.6
	MMO+Liq.	0	0	12.2	28.6	12.2	28.6	12.2	28.6
Costs		0	0	3.7	4.4	3.5	3.9	3.5	3.9
Net Benefits	**MMO**	**0.0**	**0.0**	**1.5**	**8.3**	**1.7**	**8.7**	**1.7**	**8.7**
	MMO+Liq.	**0.0**	**0.0**	**8.5**	**24.2**	**8.7**	**24.7**	**8.7**	**24.7**

Source: NERA Analysis.

Table 5.8 shows the incremental costs and benefits from moving from the baseline defined in (ii). In this baseline, market makers fulfil the ASX MMO plus MLO obligations in all regions except SA where they do not market make. This represents the net benefits of further intervention if one expects that no or limited market making will occur in SA under the ASX MMO plus MLO or if one adopts a "wait and see" approach and then discovers subsequently that no or limited market making occurs in SA under the ASX MMO plus MLO.

Hence, the incremental movement from the baseline, to a mandatory obligation or trigger driven obligation that only binds in SA, is equivalent. Moreover, the incremental movement to the incentivized scheme, assuming over compensation does not occur and MMs are equally efficient, is the same as the mandatory obligation plus the cost of the tender process.

From the baseline of no market making in SA, other model suggests that there will be an incremental net benefit of introducing an alternative MMO design. This is because the effect of introducing an alternative MMO is to mandate market making in SA. In SA, the introduction of an MMO leads to the largest reduction in transactions costs and therefore, the largest risk capital savings for retailers and generators. As a result, the net benefits of introducing an MMO in SA are the highest across the states in the NEM. Moreover, the incremental costs of introducing an alternative MMO are lower, because two of the additional three MMs in SA have already incurred fixed costs of market making in other states.

We also considered a baseline case where market makers did not provide market making services in SA but also dropped during periods of price volatility in QLD and VIC. We do not report the results for brevity. Unsurprisingly, we found slightly greater incremental benefits relative to the baseline case (ii) above. However, we also found that the incremental increase in costs roughly offset those benefits. This suggests that the majority of the incremental net benefit is because an additional intervention obligates market making in SA.

This is consistent with our previous findings and is intuitive given the modelling method we use to estimate the benefits of the proposed MMO designs: In SA the introduction of the MMO is most "binding", in other words, we estimate it reduces the transactions costs associated with bid-ask spreads by more. Therefore, the incremental benefits to retailers and generators from risk capital savings and these lower transactions costs may be the greatest.

In other states, the MMO does not bind tightly. Therefore, without a step-change in liquidity from the introduction of the MMO, it is unclear whether the benefits realized from reducing transactions costs offset the costs of forcing MMs from trading and managing open positions in the market.

5.3.7. Overview of key simplifications in our modelling framework

Our quantitative model does not capture all the potential effects of the introduction of an MMO. In particular:

- Our model understates the value of hedging (and the intervention) because it only includes quarterly products. It therefore ignores any benefits of new products becoming liquid, for example monthly, peak or cap products. Moreover, because we do not model these products, the hedging strategy used by retailers in our model may be a simplification of the actual hedging strategy used in the NEM.
- Our model does not account for any movement of liquidity to the mandated trading windows under each of the proposed MMOs. In addition, our model does not account for any loss of liquidity in non-mandated products. Both of these effects were observed in the GB MMO (see GB case study). Therefore, our model may overstate the benefits of the MMO. Moreover, in the GB MMO the CMA noted that movement of liquidity to trading windows may discourage financial players from entering the market.[131]
- In our model, the weighted average cost of capital (WACC) is used to calculate the benefits associated with holding less risk capital. We assume a constant WACC which is independent of hedging strategy. In practice, the WACC may reflect the hedging strategy followed by the retailer. For example, at very low hedging levels the WACC may be higher because of the asymmetric information between physical and capital market described in Section 5.1.
- We do not consider product availability in our model. At each hedging level, the retailer can go to the market and buy as much of each forward product as it would like at the specified bid-ask spread. It may be that we overstate the benefits of hedging because of this. This is because the MMO mandates market making up to a daily certain net sales limit. Once this level is achieved, no further lots of that product are obligated to become available.

  On the other hand, we do not consider the benefit for retailers of having certainty of product availability during specific times of the day. The MMO ensures that products are made available daily in trading windows, subject to the exemptions of each design. This certainty of liquidity may be beneficial to retailers. However, in our model, product availability is not a concern.
- Our model overstates risk capital benefits for generators, because we ignore fuel and cost correlation with market prices. In other words, when generators receive higher wholesale prices in our model, this is assumed to be beneficial to the bottom line of their cashflow. In reality, these higher prices may occur when fuel costs are higher, increasing the costs of generators and negating this benefit to the cashflow balance.
- Our model understates the benefits of transactions cost reductions because power is only traded once. In reality, churn in most state markets in the NEM is greater than one, see

131 CMA (June 2016), Energy Market Investigation Final Report: Liquidity Appendix, p. A7.1-25, 81.

Figure 2.3. This means that power is traded more times than it is consumed. This increases the benefits from the reduction in transactions costs. Our model understates this benefit because we implicitly assume a churn of one. Furthermore, any benefits to generators in finding their place in the merit order or responding to changing fuel conditions are not included in our model.

- Our model does not count the benefits of potential changes in the hedging strategy due to falling transactions costs. In other words, we assume that retailers hedge following an exponential path as described by the AEMC. If product availability improved or transactions costs fell, this strategy may change which may result in further benefits to the retailer. We do not allow this strategy to change with the transactions costs in the market and therefore may understate the benefits of these falling costs.
- We do not take account of the wider distortions to market structure or impacts on competition. The introduction of the MMO may improve the availability of forward products and encourage the entry of small, independent retailers. The entry of new suppliers may change the degree of competition in retail markets and reduce consumer tariffs. This may change the market equilibrium. It may also have repercussions for the retailer's cashflows which are not considered here.

  Alternatively, if the introduction of the MMO increases the entrance of small independent suppliers, it may result in strategic behaviour by market incumbents to increase barriers to entry or change pricing patterns to entrench their market position.

  In addition, the introduction of a mandatory MMO may lead to distortions to competition over the longer term. This is particularly true for retailers and generators who are at the margin which the regulator uses to dictate selection as a MM. Moreover, if participants change their position at this margin so that they are not selected as MMs, then this may require the regulator to redefine the margin to ensure enough MMs provide market making services. This can lead to further distortions to the market structure.
- Lastly, we report our results with an implicit but uncalculated confidence interval around each estimate. In other words, each of our low and high case estimated benefits and costs are subject to change as the number of simulations changes. This is particularly pertinent to this model because we calculate our benefits using 2 per cent of the observed distribution. That is to say that, because we use the case where 2 per cent of the retailers declare insolvency as our baseline for risk capital, we are using a baseline level of risk capital that is estimated from 2 per cent of the total simulations.

  We have used a large number of simulations, around 4000, to compensate for this but understand that our model, and estimated net benefits, are less effective at distinguishing granular differences in net benefits. Using very small differences between the modelled benefits to advise policy is also unwise because, as discussed above, the benefits we model are only a subset of the potential benefits arising from the introduction of an MMO. Simply put, whilst our model indicates the potential differences in net benefits across the proposed designs, small differences would not provide a firm basis for selecting one MMO design over another. For example, a difference in estimated net benefits of 0.1m AUD would be unlikely to be statistically significant.

Appendix A. Description of Modelling Approach

In this appendix, we describe our approach to quantifying the benefits of each proposed MMO by modelling the trade-off between holding risk capital and hedging faced by retailers and generators.

A.1. General Modelling Approach

In order to identify the benefits associated with each proposed MMO design, we simulate the monthly cashflows of a single representative retail supplier in each of the four states. We simulate cashflows over the course of 12 months but, due to the longer-term hedging strategies employed by retail suppliers and generators, we simulate power prices for up to five years. In our model, the representative retailer's cashflows are driven by:

- **Revenues from tariffs**: driven by the average retail tariff structure, the number of customers served by the retailer and the amount of electricity the retailer sells to those customers.
- **The costs of procuring electricity in wholesale markets**: including (i) spot market procurement; (ii) forward market procurement; and (iii) any collateral payments required to cover differences between the agreed strike price and the updated market price for a particular contract.
- **Transactions costs for procuring contracts in the wholesale market**: based on half of the bid-ask spread of purchasing the contract. Therefore, underlying transactions costs, for a given bid-ask spread, are a percentage of the value of the contract.
- **Other costs not related to the purchase and sale of energy**: such as network charges, the costs of environmental subsidies and overhead costs associated with retail electricity companies.

In each month of our 12-month cashflow period, we simulate the revenues and costs to identify:

(i) The cash balance in each month;

(ii) The transactions costs paid; and

(iii) The average energy revenues received by generators.

Each output parameter has a distribution because several of the input parameters are inherently volatile (e.g. power prices). Therefore, we iterate the model approximately 4,000 times to capture each of these distributions. In each iteration, we estimate a representative retailer's cashflow for a range of scenarios, based on different bid-ask spreads and hedging strategies.

As described in Section A.3 below, we use (i) and (iii) to estimate risk capital requirements for retailers and generators respectively, while we use (ii) to estimate the transactions costs associated with each proposed MMO design. We compare the risk capital requirements and transactions costs across proposed MMO designs to estimate the benefits per MWh of each MMO scheme. We multiply these benefits by the total volume of electricity generated and supplied in each state and the volume of *unhedged* electricity generated and supplied in each state to generate a range of total benefits from each design.

In the subsequent sections of this appendix, we describe our approach to estimating and simulating each of the components of the model.

A.2. Mechanics of Cashflow Items

A.2.1. Demand and Revenues

Our representative electricity retailer generates revenue through the recovery of tariffs from customers. In our simulation, tariff revenue in a given month and state is determined by our simulation of customer numbers, monthly demand quantities and an assumption of the annual median tariff.

To simulate monthly customer numbers, we assume that each representative retailer initially serves 100,000 customers. We subsequently simulate monthly customer churn which determines the numbers of customers that the retailer serves across the 12-month period. We use observed average customer switching rates in each state from 2014 to 2017 to estimate these monthly churn rates.[132] More specifically, we assume that the historical switching rate determines the probability that, in each month, a customer leaves the retailer. Symmetrically, we also assume that the historical switching rate determines the probability that, in each month, a customer joins the retailer. Using these probabilities, we perform 1000 simulations of the net monthly change in customer base that the representative retailer serves. We calculate the standard deviation of this resulting distribution to estimate monthly customer churn. We use this estimate of monthly customer churn as the standard deviation of a mean-zero, normally distributed random variable to simulate the monthly change in the customer base that our representative retailer serves across the 12-month period.

We estimate monthly consumption using annual average consumption figures in each state and half-hourly data on electricity demand shape on a network-region level for 2017. We aggregate the shape data to obtain monthly demand shapes. We then apply this shape to the annual consumption data to calculate monthly consumption for each state.

To simulate revenues, we multiply our simulated customers number and consumption figures by the median weighted tariff in each state.[133] These tariff figures are a weighted measure of the tariffs for customers on standing and market offers.

A.2.2. Power Price Simulation

The representative retailer's cashflows depend on the prices of futures contracts and spot market electricity. The hedging strategy followed by the retailer determines the relative importance of each of these prices for the retailer's cashflow (see Section A.2.3). We simulate each of these prices using different approaches.

A.2.2.1. Futures price simulation

To model the costs of procuring electricity in the futures market, we assume that retail suppliers hedge their requirements using quarterly baseload contracts, up to eight quarters ahead. To keep the number of possible hedging strategies limited, we do not simulate prices

[132] Customer switching data are sourced from the AEMC.

[133] Tariff data are sourced from the AEMC.

for peak or cap contracts. Limited liquidity of monthly contracts makes it difficult to accurately analyse and simulate the volatility of those contracts.[134]

We simulate quarterly prices according to the volatility and co-movement of prices of different quarterly contracts traded on the same day. In particular, we use price data for futures contracts traded on each day from 2016 to 2018 inclusively. We calculate separate volatilities and co-movements for each of the quarterly baseload contracts, from zero to eight quarters ahead, in each state. Table A.1 below gives an illustrative example of this data.

Table A.1: Illustrative historical futures prices

	Maturity	**Q0**	**Q1**	**…**	**Q8**
Trade Date	(Delivery Period)	Q2 2017	Q3 2017	…	Q2 2019
2/4/2017		\$50.6	\$55.1	…	\$47.1
3/4/2017		\$55.8	\$56.2	…	\$46.9
4/4/2017		\$53.2	\$55.5	…	\$47.0

Source: NERA Analysis.

Using a code written in MATLAB, we estimate the volatility of each price series, or the extent to which the prices for that series changes from one trading day to the next. For this part of our analysis, the price series we analyse represents maturity relative to the trading date. In other words, we have a single series representing one-quarter-ahead contracts, even though the maturity of this series jumps by a quarter each time the trade date enters a new quarter. Therefore, our volatility analysis excludes natural price jumps (or drops) as the quarter rolls over.

We also estimate, using the MATLAB code, the extent to which the different price series co-vary, using Principal Component Analysis (PCA). PCA estimates the common factors which drive prices across different products. For example, if electricity prices are driven partially by gas prices, and gas is imported from one particular country, a weakening of the AUD with respect to that country's currency would cause all electricity products to become more expensive. However, products which are more exposed to today's exchange rate will be more affected by this currency change. PCA estimates the impact of this exchange rate shock on all products, ensuring that those most affected are impacted more. In the case of other random shocks, some product prices will rise whilst others may fall.

However, these principal components are mathematical in nature, and do not necessarily relate to any one intuitive source. Rather, the components are mathematically selected from historical data up to the point where a fraction of the total past variation in the price series is explained by shocks to those components. Based on a matrix of daily prices for futures contracts up to eight quarters ahead, MATLAB estimates the "Eigenvalues" and "Eigenvectors" which define the importance of each of the principal components in explaining total variation and the extent to which each principal component drives changes to each price series.

[134] In the three years of historical data we analyse, from 2016 to 2018, inclusive, traders only conducted around 200 trades across all monthly contracts, according to ASX trading data.

We assume that prices for each product are fixed at the beginning of our modelling period. This fixed price is the average price for each product over the duration of Q4 2018. We use these prices to represent the "starting point" prices applicable at the beginning of 2017. At the beginning of 2017, we assume that retailers would begin to hedge to deliver electricity in 2019. We did not use data from Q4 2016 as our starting point because during this period spot prices were somewhat elevated compared to later time periods. This period preceded the direction given by the Queensland government in June 2017 to the state owned generators.

Then, based on the estimated volatilities and principal components, we simulate daily shocks for each contract, using a Geometric Brownian Motion (GBM) process, which assumes that that the price for a particular product on a given day is equal to the previous day's price for that same product multiplied by a random shock.[135] The eigenvectors and eigenvalues derived from the PCA ensures that these shocks are consistent with both the volatility and the co-movement of prices observed in the historical data.

Additionally, whilst we model the volatility for contracts based on their maturity relative the current trading date (e.g. one-quarter-ahead volatility, regardless of the trading quarter), we ensure that the relevant previous day's price corresponds to the same price. For example, on 1 April, our simulated price for the one-quarter-ahead contract (for delivery in Q3 of that year) will be equal to the *two*-quarter-ahead price from 31 March, which is still in Q1, scaled by a random shock.

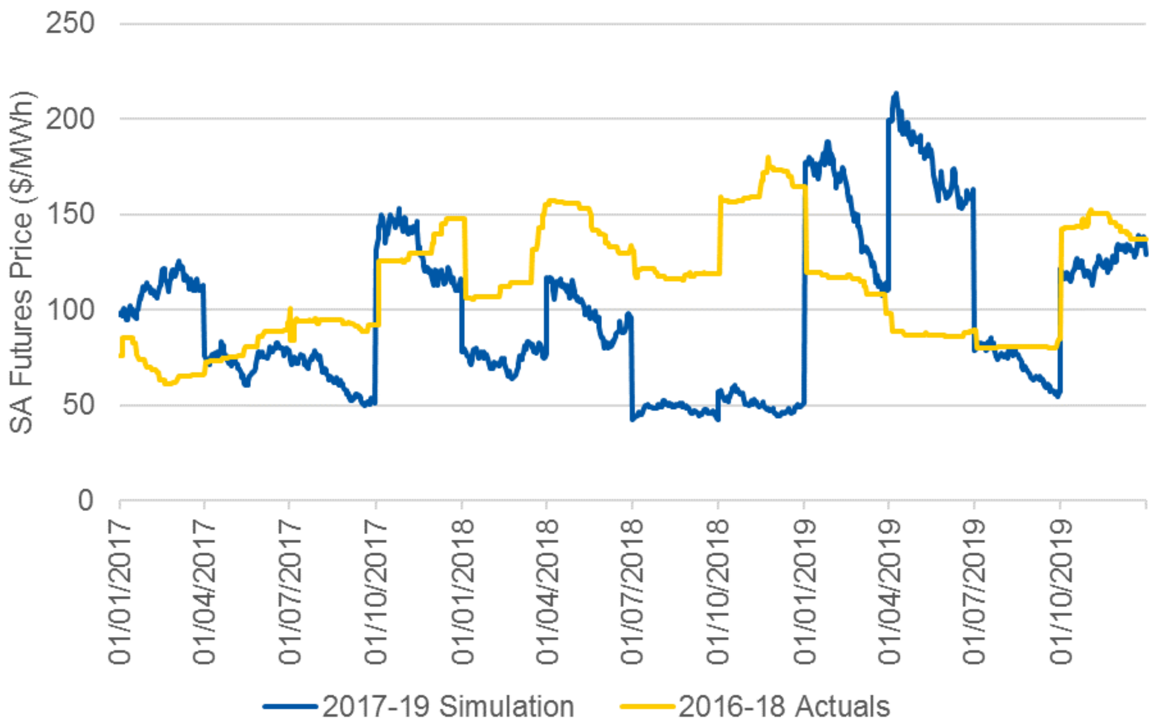
Assuming fixed, known prices as of the beginning of 2017, we simulate the futures prices for each day to the end of 2019 (the end of our cashflow year). Because cashflows in a given period are partially dependent on the procurement of futures contracts for delivery in subsequent periods, we continue to simulate prices for contracts up to eight quarters ahead throughout 2019 (e.g. up to Q4 2021), even though the maturity periods of these contracts fall beyond the end of the period of our cashflow analysis.

In Figure A.1, we show our simulated price for a one-quarter-ahead contract in SA between 2017 and 2019 and compare this simulated price against the actual data for that contract from 2016 to 2018.[136]

135 The precise formula is: $P_t = P_{t-1} * e^{(\text{Shock}(t) - 0.5*\text{Standard Deviation}(P))}$.

136 Note that our simulation uses Q4 2018 prices as its starting point and treats these as fixed prices on 31 December 2016.

Figure A.1: Futures price simulation



Source: NERA Analysis.

A.2.2.2. Spot price simulation

The retailer's procurement costs are heavily dependent on the half-hourly spot price, which it pays to meet demand in each half-hour. Costs associated with the spot price only relate electricity as it is delivered. Therefore, we only simulate prices for the 2019 cashflow period, which contains 17,520 half-hourly settlement periods.

Firstly, we simulate the daily-average power price, based on an error-correcting process relative to the previous day's daily-average price and the price of the active quarterly baseload contract (i.e. the balance-of-quarter or zero-quarters-ahead contract). In particular, using data between 2016 and 2018, we estimate an econometric equation for each state which estimates the extent to which the daily-average price relates to (i) the previous day's power price, (ii) the active quarterly baseload contract and (iii) random unexplained shocks.[137]

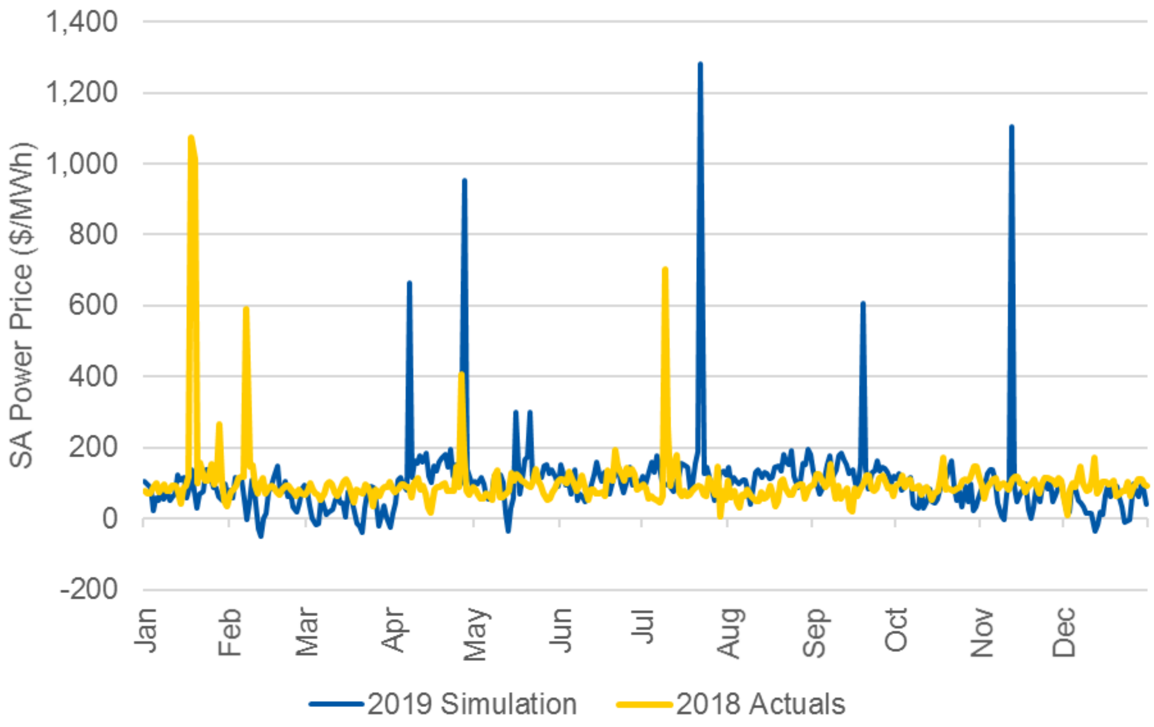
Intuitively, if the daily price is far from the price of the active balance-of-quarter contract, the deviation should be reduced quickly as market participants arbitrage between the contracts. The introduction of daily, independent shocks (defined by the standard deviation of the residual error term of each econometric equation) ensures that daily prices remain volatile while still being consistent with the prices of the balance-of-quarter contract.

137 The precise equation is $P_t = Q_t + \alpha * (P_{t-1} - Q_t)$ + shock, where P_t represents the daily price in period *t* and Q_t represents the price of the active quarter contract traded in period *t*. We can rearrange this equation such that the daily price is a weighted average of the previous day's price and the active quarter price, plus the shock: $P_t = \alpha * P_{t-1} + (1 - \alpha) * Q_t$ + shock.

Secondly, the historically observed daily-average price of electricity also experiences occasional large price shocks. This can happen as a result of a random forced outage for a pivotal plant. To simulate these days, we calculate the observed frequency, size and standard deviation of these "large daily price spike" events in each state between 2016 and 2018. We assume that these estimated parameters represent the probability and likely impact of such events. We randomly generate these "large daily price spikes" in our price simulation based on these estimated parameters.

Figure A.2 provides one particular simulation of power prices in South Australia. On most days the daily average price tracks the balance-of-quarter price, with some volatility around it. Occasionally, due to some random shortage event, a "large daily price spike" occurs and the price jumps to $300 and above. For comparison, we also show the actual daily average power price in 2018.

Figure A.2: Daily price illustration



Source: NERA Analysis.

Finally, we multiply our simulated daily prices by the observed 2017 ratio of each half-hour's price to that day's average. For example, assume that the daily-average price of power on 4 July 2017 in Victoria was $100/MWh, and that the price between 14:00 and 14:30 that day was $150/MWh (or 1.5 times the daily average). If our simulation estimates a daily price for 4 July 2019 of $80/MWh, we would calculate the 14:00-14:30 price as $120/MWh (1.5 times the daily average).

A.2.3. Hedging Strategies and Costs

Retailer's wholesale procurement costs are defined by the prices of future contracts and by the spot price. Moreover, the relative importance of each of these prices depends on the supplier's hedging strategy. For example, if a retailer hedges all of its demand with futures contracts, then it will be primarily exposed to prices of futures contracts, with very little exposure to spot market volatility. In this section, we describe our approach to modelling different hedging strategies, and discuss the resulting cashflows.

Firstly, we determine the total share of demand a supplier wishes to hedge before delivery. As discussed in Section A.1, we consider a range of different degrees of hedging, each of which could be optimal under different proposed MMO designs and associated bid-ask spreads.

Secondly, we calculate the total level of demand that a retailer expects to deliver in a given period, irrespective of whether it hedges this demand. We rely on our demand simulations as described in Section A.2.1. However, to reflect the volume uncertainty that a supplier must consider when hedging, we assume that the supplier does not know exactly what its demand requirements will be. Rather, for any given trading day, the retailer assumes that it will continue to serve its current number of customers for the duration of the modelling period. As random customer churn causes the supplier's customer base to vary in size, the supplier updates its view of expected demand for a delivery period. Given quarterly contracts are based on a fixed number of MW in each period of the quarter, we assume that the supplier would target a certain percentage of its *average* demand over a quarter. We therefore assume that the retailer would accept that it could be under-hedged in periods of high demand and over-hedged in periods of low demand.

Lastly, we determine the "shape" of hedging. This describes proportion of the target level of hedging that the supplier wishes to procure in each month in advance of delivery. The AEMC has provided us with representative "exponential" hedging strategies. This strategy assumes that, for a given delivery period, a supplier procures more electricity per month in the forward market as the delivery period approaches. The AEMC has advised that an established supplier will procure electricity using an exponential hedging strategy over 24 months in advance of delivery. On the other hand, an entrant supplier will procure electricity using an exponential hedging strategy over 12 months in advance of delivery. Given we model a representative supplier, we generate a weighted-average hedging strategy, weighted by the volumes delivered by established versus entrant suppliers.[138] We divide the monthly procurement target by the number of days in each month to derive the daily procurement target.

Multiplying the first three steps above, we estimate the volume of electricity that a supplier procures for each delivery period on each day. For simplicity, we assume that a company enters into futures contracts on every day of the week, including weekends, though this simplification will have little impact on the results of our modelling. We multiply these volumes by the corresponding futures price (as described in Section A.2.2) and the number of hours in the delivery period to determine a procurement cost for each contract and trading day. However, as discussed in Section A.2.4, these contracts are purely financial Contracts for Difference (CfDs). Therefore, the supplier does not face any direct procurement costs at the time that it enters into a contract, but instead settles the difference between the contract strike price and the spot price at the time of delivery.

[138] Based on data provided by the AEMC.

In advance of delivery on a particular contract, the supplier faces two cost items:

1. **Transactions costs:** We assume that the supplier pays a transactions cost on the day it enters into a contract, based on half of the bid-ask spread (the generator incurs the other half), multiplied by the strike price of the contract on that day. The bid-ask spread, and therefore the transactions cost, varies with the different proposed MMO designs.
2. **Collateral requirements:** If the market price for a particular delivery period falls below the average strike price already paid for that period by the supplier, that supplier is "out of the money". In this case, if prices did not change further before the delivery period, the supplier would have to pay an additional amount to settle its CfDs. To reduce its exposure to an out-of-the-money supplier defaulting on its CfD obligations, an exchange such as ASX will require the supplier to post collateral payments when it is out of the money.

   In our model, we assume that a supplier that is out of the money on a particular trading day must post the full difference between the current market price and its average strike price. We treat this as a negative cashflow at the time the collateral is posted. If the supplier becomes further out of the money, our model requires it to post additional collateral; if it becomes less out of the money, our model assumes that ASX will refund the equivalent level of collateral, which we treat as a positive cashflow. For simplicity, we assume that any collateral in place once the delivery period begins remains in place until the electricity is actually delivered. In other words, a supplier does not receive collateral refunds if the balance-of-quarter price increases.

The two cashflow items occur before the delivery period (and, in the case of transactions costs, at the point of trade). Therefore, the hypothetical supplier will face transactions and collateral cashflows on contracts with maturity beyond the end of our modelling period.

A.2.4. Half-hourly Procurement Costs

The majority of electricity procurement cashflows occur at the half-hourly point of delivery. This is when suppliers must purchase the full volume of its demand on the spot market, and resolve any differences in the average strike price of its CfD for that delivery period and the spot price, less any collateral already posted.

However, because the NEM operates under a gross pool scheme, a supplier must procure its entire demand requirement in each half hour at the spot price, irrespective of any hedging it has already conducted. The hedging instead reduces the cashflow risk: as the supplier's spot market procurement costs increase due to price shocks, it will face a partially-offsetting increase in negative costs when settling the concurrent CfD.

To calculate cashflows in each half-hourly period, we multiply the supplier's actual demand in that hour (calculated in Section A.2.1) by the modelled spot price (calculated in Section A.2.2.2). The supplier then pays or receives any difference between its average strike price and the spot price, multiplied by the volume it has hedged for that half-hour (which is constant for all settlement periods in a quarter). This is partially offset by any collateral it has posted for that period (more specifically, the total collateral for that delivery quarter, pro-rated to the half hour in question). In the event that the supplier has posted positive collateral (because it is out of the money over the quarter in aggregate) but the spot price exceeds the average strike price, the retailer receives the full value of the difference, plus the pro-rated portion of its collateral posting for that half-hour period.

We model risk capital requirements for generation based on the average price it receives per MWh produced in each month (see Section A.3.2). Generator revenues are nearly symmetrical to supplier procurement costs (spot market revenues plus the resolution of CfDs). However, we assume that generators are not required to post collateral and are not on the receiving end of suppliers' collateral payments. Therefore, generator revenues in each half-hour are strictly limited to spot market revenues, plus the resolution of CfDs.

A.2.5. Other Cost Items

Suppliers incur additional cost items which are important for calibrating the balance between revenues and costs, but do not directly relate to the costs of procuring electricity in the futures or spot markets. In its breakdown of residential customer bills in its annual Residential Electricity Price Trends report, the AEMC estimates the cost of each of the following items in terms of AUD per customer per year, by state:[139]

- **Network charges:** Customers pay network charges to pay for the costs associated with owning and operating the relevant transmission and distribution networks. We assume that suppliers pay these charges on a fixed per-customer basis.
- **Environmental subsidies:** Customers pay for a range of environmental subsidies through bills paid to retailers. We assume that suppliers pay these charges on a fixed per-customer basis.
- **Overhead retail costs:** The AEMC's tariff breakdown presents the components of the typical residential tariff which relate to wholesale costs (which we model separately as the core of this modelling exercise), network charges and environmental costs. It identifies the remaining difference between these three cost items and the total tariff level as the "residual" component. This component implicitly includes overhead retail costs as well as the supplier's margin. We therefore calculate the level of overhead costs as the difference between the residual cost and the margin (described below) and assume that suppliers incur these costs on a fixed per-customer basis.
- **Margin:** Strictly speaking, we do not include the retail margin as a cashflow for suppliers, and instead leave it as an implicit part of the cash balance in the consolidated cashflow calculation. However, in order to estimate the size of the overhead retail costs, we must separate out the component of the residual tariff component which relates to margins. The ACCC's 2017 Retail Electricity Pricing Inquiry reported typical margin percentages by customer type, ranging from 2 per cent for commercial and industrial customers to 8 per cent for residential. We calculate a weighted average margin of 3.5 per cent, based on the 2018 relative load shares of residential versus business customers as reported in the 2018 Electricity Statement of Opportunities.[140] This likely underestimates retailers' margins because some business customers will be SMEs, on which retailers earn a similar margin as on residential customers. We multiply this margin share by the average tariff level and subtract the margin from the residual component of tariffs.

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139 AEMC, 2018 Residential Electricity Price Trends Report, Tables 4.1. & 5.1.

140 http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational

A.2.6. Summary Cashflow Tables

We bring all of the revenue and cost items described in this section together into a cashflow calculation for all 12 months of 2019. We provide a single iteration of this calculation in Table A.2 below, but this will vary according to (i) random shocks to power prices and customer numbers, (ii) different levels of bid-ask spreads and (iii) different hedging strategies.

For each of these cost items, we estimate the cost per MWh. However, MWh supplied by the retailer vary across customer types. By calculating margins as a weighted average of residential and C&I margins, we effectively increase costs to ensure that the expected margin per MWh is consistent with what it would be for a typical supplier serving a blend of customer types. Additionally, because it is important for identifying generators' risk capital requirements, we calculate a simplified generator's cashflow model, which only considers the electricity revenue it receives per MWh, less any transactions costs. We show this in Table A.3.

Table A.2: Example supplier cashflow

		Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
Revenues													
Tariff Recovery	$	17,076,407	14,861,548	15,994,919	12,950,956	16,176,113	19,687,611	19,820,273	18,924,240	14,249,648	11,297,843	13,552,383	13,066,865
Total Revenues	$	17,076,407	14,861,548	15,994,919	12,950,956	16,176,113	19,687,611	19,820,273	18,924,240	14,249,648	11,297,843	13,552,383	13,066,865
Costs													
Wholesale Procurement	$	7,115,789	3,258,170	3,747,981	2,520,386	7,520,876	8,611,474	8,477,609	8,070,711	8,356,584	2,398,670	2,484,539	553,777
CfD Payment	$	-4,714,756	-605,590	-1,583,451	1,539,281	-2,355,280	-1,678,623	1,052,312	795,282	-2,602,775	-594,926	-145,330	1,193,795
Collateral Payment	$	1,121,700	-1,258,593	2,533,641	-64,613	2,228,343	181,456	971,155	1,406,290	562,576	511,144	649,118	-209,073
Transaction Costs	$	142,781	140,887	139,550	135,198	129,200	130,321	84,661	87,481	94,904	112,270	119,236	130,347
Overhead Costs	$	8,054,858	7,304,427	7,991,091	7,790,863	7,981,632	7,686,527	7,807,450	7,894,318	7,682,145	7,896,035	7,742,849	7,948,466
Total Costs	$	11,720,371	8,839,301	12,828,812	11,921,115	15,504,771	14,931,156	18,393,187	18,254,082	14,093,434	10,323,192	10,850,413	9,617,313
Cash Balance	$	**5,356,036**	**6,022,247**	**3,166,107**	**1,029,841**	**671,341**	**4,756,456**	**1,427,087**	**670,158**	**156,213**	**974,651**	**2,701,970**	**3,449,552**

Table A.3: Example generator cashflow

		Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
Gross Electricity Sales Revenue	$	2,855,508	3,063,074	2,619,005	5,227,095	6,371,939	8,100,280	10,221,191	9,557,263	6,422,780	2,733,997	3,239,455	2,677,826
Transaction Costs	$	142,781	140,887	139,550	135,198	129,200	130,321	84,661	87,481	94,904	112,270	119,236	130,347
Net Electricity Sales Revenue	$	2,712,728	2,922,187	2,479,455	5,091,897	6,242,739	7,969,959	10,136,530	9,469,782	6,327,877	2,621,727	3,120,219	2,547,479
Electricity Sold	MWh	45,634	38,250	42,362	32,812	43,273	54,778	56,608	51,882	36,846	28,002	34,752	33,160
Average Electricity Cost	$/MWh	59	76	59	155	144	145	179	183	172	94	90	77

A.3. Key Risk Metrics

Using the illustrative cashflow statements in Table A.2 and Table A.3, we cycle through different combinations of bid-ask spread (proposed MMO design) and hedging strategy across each state, and perform approximately 4,000 simulations of power prices and customer numbers.

We use the results of these simulations to calculate the risk capital and transactions costs associated with each combination of bid-ask spread and hedging strategy in each state. We discuss our approach to measuring these costs below.

A.3.1. Supplier Risk Capital

Our cashflow model measures the net cash balance in each month based on tariff revenues and costs incurred. We assume that, if a supplier had several good months of cashflows, then it would retain this surplus cash to insure against less favourable months. To account for this pattern, we model the *cumulative* cash balance in each month: the total cash balance from the beginning of the year until that month.

We assume that if the cumulative cash balance becomes negative, then the supplier is insolvent, unless it has some additional risk capital in the business. Because our cashflow model does not include any risk capital, our simulations frequently find that the cumulative cash balance does fall below zero, indicating insolvency in the absence of risk capital.

To measure the required risk capital, we therefore calculate the level of additional risk capital required (in AUD per MWh) to ensure that the company becomes insolvent some optimal amount of the time (while insolvency can be disruptive, some churn amongst market participants is part of the natural process of a competitive market, and a policymaker would not necessarily want to remove the possibility entirely). As advised by the AEMC, we set this threshold at 2 per cent. In other words, to ensure that companies become insolvent fewer than 2 per cent of the time, the risk capital costs would be suboptimally high.

Amongst the distribution of cumulative cash balances from our approximately 4,000 simulations, we identify the (negative) cash balance level at the 2 percentile point in the distribution. If a supplier were to hold that much money in risk capital, then it would become insolvent 2 per cent of the time.

Because this additional capital is only an expense to suppliers in the event that the cumulative cash balance becomes negative, its actual cost to suppliers is equal to amount of capital employed times the weighted average cost of capital (WACC), which we assume to be 11 per cent, as we explain in Section A.3.3.

Therefore, under each combination of bid-ask spread and hedging strategy in each state, we calculate the cost of the additional risk capital per MWh.

A.3.2. Generator Risk Capital

Generators must also hold risk capital to prevent against insolvency, and they require more risk capital when the prices received are more volatile. We have not developed a detailed cashflow model for generators, which would require complex market modelling across many different generation technologies.

Instead, we proxy for the risk of insolvency by measuring the minimum average price of electricity received in a month by the typical, representative generation company. In the particular scenario shown in Table A.3 above, this is $59/MWh, in January.

A generator must be prepared for the times of the year when the average price it receives is lowest. For example, in one particular combination of bid-ask spread and hedging strategy, the average price received may be particularly volatile between months, so a generator must carry additional risk capital to insure against this risk. Using the same 2 per cent insolvency threshold we use for suppliers, we identify the 2 percentile point of the distribution of minimum average monthly electricity price under each combination of bid-ask spread and hedging strategy in each state.

We have not estimated the actual average electricity price below which a company becomes insolvent. Instead, we compare the outcomes of this measure across combinations. The difference in the minimum price between the scenarios proxies as the *difference* in risk capital required between the combinations, without making any assumption about the absolute *level* of risk capital required in any one case. Therefore, this risk metric can only be presented in comparison to some baseline scenario. We then multiply the difference in risk capital relative to the baseline (in AUD per MWh) by a WACC of 9.5 per cent (see Section A.3.3) to estimate the generator risk capital savings associated with each combination relative to the baseline.

This approach may overestimate the risk capital benefits, to the extent that falls in electricity prices are correlated with falls in fuel prices. However, electricity prices are driven by many other factors other than fuel price (e.g. intermittent renewable energy production), and a drop in the fuel price for the marginal generating technology (which would drive lower electricity prices) would not insulate a typical generating company on the costs of operating different types of plants.

A.3.3. Estimating the WACC

To quantify the cost of holding a given level of risk capital, we multiply risk capital levels by the Weighted Average Cost of Capital (WACC).

We did not undertake a detailed bottom-up estimation of the WACC but instead consider existing estimates. Specifically, we reviewed the following four sources:

- Frontier Economics' 2017 update of the Independent Pricing and Regulatory Tribunal of New South Wales' (IPART) estimate of the WACC for electricity generation and retail companies in New South Wales;[141]
- The UK Competition and Markets Authority's (CMA) 2015 estimates of the WACC for electricity generation and retail companies in the UK;[142]
- The Australian Energy Regulator's 2018 WACC guideline for Australian power transmission and distribution companies;[143] and

[141] Frontier Economics (December 2017), 2017 Residential Electricity Price Trends Report, p. 77.

[142] CMA (February 2015), Energy Market Investigation – Analysis of cost of capital of energy firms, p.2.

[143] AER (December 2018), Rate of return instrument – Explanatory Statement, p. 13-16.

- Prof. Aswath Damodaran's estimate of the global utility WACC.[144]

The first source is a 2017 report by Frontier Economics, which updated IPART's recent WACC decision to reflect more recent market conditions as part of the residential price trends report. Frontier Economics calculates a real, pre-tax WACC of 8.3 per cent and 9.53 per cent for electricity generators and retailers, respectively, based on IPART's methodology. We adopt IPART's most recent inflation assumption of 2.4 per cent[145] to convert these estimates to nominal terms. This yields the following estimates:

- 10.9 per cent nominal pre-tax WACC for electricity generators; and
- 12.16 per cent nominal pre-tax WACC for electricity retailers.

Second, we consider the estimates provided by the CMA, the primary competition and consumer authority in the UK, in its most recent investigation of the UK energy market. The CMA considers 24 international energy companies, including three Australian companies, to estimate the following WACC ranges:

- 8.2 – 10.0 per cent nominal pre-tax WACC for electricity generators;
- 9.3 – 11.5 per cent nominal pre-tax WACC for electricity retailers.

Our third source is the AER's 2018 decision on the WACC for energy transmission and distribution companies. As gearing and market risk exposure levels (as measured by the beta) typically differ between generation and retail companies; and transmission and distribution networks, we adjust the AER's calculation of the cost of equity by using the CMA's estimates for the beta and gearing for generators and retailers. Table A.4 summarises the estimates for the different WACC components by the two regulatory authorities and our resulting WACC estimate.

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144 Aswath Damodaran (January 2019), Discount Rate Estimation – Total Beta By Industry Sector, URL: http://people.stern.nyu.edu/adamodar/New_Home_Page/datacurrent.html. Last accessed on 14 May 2019.

145 IPART (February 2019), WACC model – February 2019, URL: https://www.ipart.nsw.gov.au/Home/Industries/Special-Reviews/Regulatory-policy/WACC/Market-Update/Spreadsheet-WACC-model-February-2019. Last accessed on 14 May 2019

Table A.4: WACC estimates based on AER and CMA

	Generation	Retail	Source
Risk Free Rate	2.70%	2.70%	AER
Equity Risk Premium	6.10%	6.10%	AER
Cost of debt (pre-tax)	4.70%	4.70%	AER
Asset Beta	0.5 - 0.6	0.7 - 0.8	CMA
Gearing	20 - 40%	0%	CMA
Equity Beta	0.63 - 1	0.7 - 0.8	Calculation using Miller Formula
Cost of Equity (pre-tax)	9.3 - 12.6%	10.0 - 10.8%	Calculation
WACC (Pre-tax)	8.4 - 9.4%	10.0 - 10.8%	Calculation

Source: NERA-Analysis based on AER, CMA.

We calculate a range of 8.4 per cent to 9.4 per cent for the nominal, pre-tax WACC for electricity generators and 10 per cent to 10.8 per cent for retail companies.

Lastly, we also consider the latest WACC estimate for global utilities by Prof. Aswath Damodaran, an expert on corporate finance who is known for his annual, sector-specific costs of capital estimates. Damodaran calculates a post-tax WACC of 5.5 per cent based on a sample of 54 international utility companies. We convert this figure to pre-tax terms using a corporate tax rate of 30 per cent, yielding a pre-tax figure of 7.8 per cent. As this estimate is based on a list of companies that also includes non-energy utilities and companies across the supply chain, it only serves as a broad reference point.

Table A.5 summarises the WACC estimates based on the different sources. The table reports the mid-point of the range in the case of the CMA and the modified AER estimates.

Table A.5: WACC estimates based on different sources

Approach	Generation	Retail
Frontier based on IPART (2017)	10.9	12.16
CMA (2015)	9.1	10.4
Modified AER (2018)	8.9	10.4
Damodaran	7.8	7.8

Source: NERA-Analysis based on Frontier Economics, CMA, AER and Damodaran data.

For our model, we adopt the estimate based on the modified AER approach, i.e. a WACC of 8.9 per cent for generators and 10.4 per cent for retailers. The advantage of this approach is that it combines up-to-date and Australia-specific estimates for the non-industry specific components of the WACC with beta and gearing estimates that are specific to generators and retailers. Further, the CMA estimates for the beta and the gearing are based on a large sample of international companies. Our assumed WACC for generators is only slightly below the average of the estimates based on the other three sources (9.3 per cent). The WACC we assume for retailers is only slightly above the average of the estimates based on the other three approaches (10.1 per cent).

A.3.4. Transactions Costs

One key benefit of an MMO is a reduction in the bid-ask spread on futures contracts, which therefore reduces the transactions costs paid by suppliers and by generators. Our model calculates the total supplier transactions costs per MWh associated with each combination of bid-ask spread and hedging strategies in each state. If a retailer hedges more of its expected demand, it faces higher transactions costs (while probably decreasing risk capital requirements), because transactions costs apply to futures trades.

As opposed to the risk capital requirement calculation, transactions costs are a direct, and reasonably well-known cost associated with each bid-ask spread. Therefore, rather than consider a 2 per cent threshold, we examine the median level of transactions costs per MWh under each combination of bid-ask spread and hedging strategy in each state. Transactions costs change little between iterations of the same combination, because they are only driven by futures prices (assuming a fixed bid-ask spread and hedging strategy).

We double the estimated value to reflect the transactions costs faced by generators.

A.4. Quantifying the Benefits of Each Option

In the previous sections, we have described our approach to identifying the risk capital and transactions costs per MWh under each combination of state, bid-ask spread and hedging strategy. In this section, we bring together the different components to describe how we identify an AUD million benefit of each MMO option.

A.4.1. Identifying the Status Quo

To establish a baseline level of bid-ask spread, we use historical data of bid-ask spreads in each region. We then examine the proportion of contracts which currently trade outside of the maximum bid-ask spread stipulated by each MMO design. This is the proportion of contracts upon which the MMO design "binds". We use this proportion to estimate the reduction in market-wide bid-ask spreads arising from the implementation of each MMO design. We calculate this reduction for each state, see Table 5.1.

We also consider the externality of liquidity as described in Section 5.1. Therefore, we consider a scenario where the introduction of the MMO leads to a "step-change" in liquidity. In other words, in this scenario the MMO has not merely the benefit of capping bid ask spreads at particularly volatile times but reducing bid-ask spreads across the market even when the MMO does not formally bind. We call this "MMO plus liquidity".

We calculate a different set of bid-ask spreads representing our "MMO plus liquidity" case. For QLD, NSW and VIC we use double the reduction in bid-ask spreads estimated above. This is equivalent to an additional 5-10 per cent reduction in transactions costs. For SA, where the MMO is most binding, we recognise that doubling the reduction will lead to a likely implausibly low bid-ask spread, even with a "step-change" in liquidity. We therefore use the New Zealand Electricity Authority's (EA) estimated market bid-ask spreads after introducing a maximum bid-ask spread on market makers.[146] We assume three market

[146] Electricity Authority (21 November 2011), "Cost Benefit Analysis – Market-Making Obligations", p.14.

makers and scale the EA's estimate for the 7 per cent maximum bid-ask spread in SA. This gives us an estimated spread of 4.06 per cent.

Table 5.6: Calculated historical and estimated bid-ask spreads arising from the MMO (% of bid price)

	MMO Cap	Historical average	"MMO" (historical average capped at MMO cap)	"MMO + Liquidity"
VIC	5.0	1.9	1.8	1.7
SA	7.0	6.7	5.1	4.06
QLD	5.0	1.9	1.8	1.7
NSW	5.0	2.0	1.9	1.8

Source: NERA Analysis.

Therefore, each MMO design reduces transactions costs by a different amount in each state. In our model, the reduction in transactions costs across MMO designs varies only if the stipulated maximum bid-ask spread varies across designs.

A.4.2. Selecting the Optimal Hedging Strategy for Each MMO Option

For each bid-ask spread, we identify the hedging strategy which minimises the supplier's combined risk capital and transactions cost per MWh supplied. For example, in Table 5.2, the boxes present the supplier's additional cost savings per MWh of each hedging strategy relative to no hedging at all, for each given bid-ask spread. The highlighted boxes represent the optimal strategy of those which we have simulated.

Because we explicitly measure supplier rather than generator cashflows, we assume that suppliers set the optimal hedging strategy. Because every hedge has a counterparty, we assume that generators take the same hedging strategy by default.

A.4.3. Identifying Benefits per MWh of Each MMO Option

We then hold fixed the risk capital requirement, transactions cost, and minimum monthly average electricity price from the status quo bid-ask spread constant, and calculate a difference in each of these parameters between different MMO options. Note that we compare only the optimal hedging strategy under each, including the status quo, to ensure that we do not overstate the benefits of an MMO scheme by allowing suppliers to move from a sub-optimal to an optimal hedging strategy.

A.4.4. Application of Results to Different Market Participants

Finally, we must scale these results by the appropriate volume of MWh generated and supplied in each state.

These benefits will be felt directly by independent generators and suppliers, who must sell or procure their entire volume externally. We therefore multiply each of the rates shown in the by the volume of electricity generated or supplied by independent parties in each state.

On the other hand, a perfectly vertically-integrated generator/supplier would not benefit at all from any intervention, because it has no need to hedge in the futures market: any exogenous price shock will have perfectly offsetting effects on its generation and supply arms.

However, no company is perfectly vertically-integrated. Some generate more than they supply, and some supply more than they generate. For this surplus generation or supply which we term "unhedged volume", these participants will engage in futures trading in a similar fashion as the independent suppliers.

This approach likely understates the benefits for vertically-integrated companies because it assumes that the non-surplus component is perfectly hedged, though this is unlikely to be the case in reality. For example, a hypothetical vertically-integrated company may generate 10 TWh in a year and supply 11 TWh in a year. Our "unhedged volume" method ignores all benefits on the 10 overlapping TWh and only applies supplier benefits to the 1 TWh residual. However, this requires the 10 overlapping TWh to overlap perfectly. In reality, the company probably generates more than its retail load in some hours, and less in other hours. In order to remain hedged, the company would then hedge this within-year non-overlapping generation and supply. However, with only yearly data on TWh generated and produced by each company, it is not possible to identify what proportion of the overlapping generation and supply totals does not actually align on an hour-by-hour basis.

This total "unhedged volume" from VI 'gentailers' is added to the total volume from independent retailers and is used to scale the benefits for each proposed MMO design in each state. Recognising, this likely understates the benefits of hedging for VI 'gentailers' this is our low case benefit. Our high case benefit scales our estimated benefits per MWh by total volumes in each state market.

Appendix B. International Case Studies

B.1. Great Britain's Market Making Obligation

B.1.1. The Basis for Intervention

The British government privatised the electricity supply industry as three large generating companies and twelve regional electricity distribution and supply businesses in England and Wales, and two vertically-integrated generation, distribution and supply utilities in Scotland. The UK Government liberalised the electricity market between 1996 and 1998 such that customers that were historically supplied by a local incumbent could choose their energy supplier. By 2002, Ofgem, the energy regulator, concluded that competition was sufficiently vigorous that it could remove price controls.

Ofgem's conviction that the energy supply market was competitive was short-lived. By 2008, six vertically-integrated suppliers had emerged from fourteen regional electricity supply companies at privatisation plus British gas through a series of mergers. The collapse of entrant generators in the late 1990s and early 2000s left over half of generation capacity concentrated in the hands of these large vertically-integrated supply companies.[147] These companies supplied 94 per cent of the domestic customers (at the time of the introduction of the MMO) and no new entrant from outside the electricity industry, except the previous national gas monopolist; British Gas, had managed to enter the market effectively.[148]

In response, Ofgem (The Office of Gas and Electricity Markets – the government regulator in Great Britain) launched an investigation (the Energy Supply Probe in 2008) into the competitiveness of Britain's electricity retail market.[149] Through this investigation, Ofgem became primarily concerned with the low level of liquidity in the electricity wholesale market and began a separate enquiry in response (Ofgem – Liquidity in the GB wholesale energy markets, 2009).[150] Ofgem stated:

> "Illiquid markets may act as a barrier to entry into both the generation and supply market and may act as a source of competitive disadvantage to small suppliers. Conversely, liquid markets provide investment signals to market participants and reduce the possibility of parties manipulating prices. Illiquid markets may therefore reduce the efficiency of wholesale energy markets and reduce competition between industry parties."[151]

After this enquiry, Ofgem concluded that it needed to intervene in the electricity wholesale market to improve liquidity.[152] It argued that poor liquidity could be self-reinforcing: Poor availability of products and weak price signals reduces market participation and leads to

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147 Ofgem (2008), Energy Supply Probe, p. 29.

148 Ofgem (2008), Energy Supply Probe, p. 27. Ofgem (April 2019), Electricity supply market shares by company: Domestic (GB), Last Accessed: 29/4/19, Link: https://www.ofgem.gov.uk/data-portal/electricity-supply-market-shares-company-domestic-gb.

149 Ofgem (August 2009), Energy Supply Probe – Proposed Retail Market Remedies.

150 Ofgem (June 2009), Liquidity in the GB wholesale energy markets, p.4.

151 Ofgem (June 2009), Liquidity in the GB wholesale energy markets, p.4.

152 Ofgem (June 2009), Liquidity in the GB wholesale energy markets, p.66, 4.65.

further loss of liquidity.[153] This leads to a lower equilibrium, within which there do not exist the market incentives to escape.[154]

Initially, Ofgem considered a mandatory auction (MA) to improve liquidity. The MA would obligate The Big Six to auction 25 per cent of their generation as a range of mandated forward electricity products in an ascending clock auction. Ofgem argued that the prices resulting from the MA would increase forward product transparency.[155] Alongside the obligation to auction generation, Ofgem proposed a set of buy-side rules to prevent obligated parties buying back their auctioned supply. These restricted the bid price at volumes within 20 per cent of the obligated volume. Respondents to the consultation argued these rules would lead to volatility in the auction clearing price.[156] In addition, The Big Six argued that they could be forced to become distressed sellers in products which did "not fit with portfolio or strategy"[157]. Therefore, Ofgem did not proceed with the MA, citing concerns over access costs and its ability to provide continuous opportunities to trade.[158]

Having abandoned the idea of a mandatory auction, Ofgem proceeded with a package of reforms known as the "Secure and Promote" licence condition.

B.1.2. Secure and Promote and the Market Making Obligation (MMO)

The intervention into the wholesale market came in the form of the Secure and Promote Licence (S&P), implemented on 31st March 2014.[159] The S&P Licence had three objectives:[160]

1. To increase the availability of products to support hedging;
2. To provide robust references along the forward curve; and
3. To maintain an effective near-term market.

To achieve each objective, Ofgem introduced three Schedules in the S&P Licence, including Schedule B: The Market Making Obligation (MMO). Licensees were subject to the different Schedules at the discretion of Ofgem.[161]

Schedule A, the Supplier Market Access Rules (SMA), was enforced to ensure that small independent suppliers could access relevant products, particularly those with sufficiently small volume, to aim to ease entrance into the market.[162] It set out minimum trading standards (e.g. fair and transparent prices, lot sizes, collateral etc.) that eligible (small and

153 Ofgem (June 2013), WPML: final proposals for a 'S&P' licence condition, p.7, 1.4.

154 Ofgem (June 2013), WPML: final proposals for a 'S&P' licence condition, p.7, 1.4.

155 Ofgem (June 2013), WPML: final proposals for a 'S&P' licence condition - Draft Impact Assessment, p.44.

156 Ofgem (December 2012) WPML: consultation on a 'S&P' licence condition p. 47, 3.6.

157 EDF (February 2013) Response: WPML: consultation on a 'S&P' licence condition, p.2.

158 Ofgem (June 2013), WPML: final proposals for a 'S&P' licence condition, p. 5.

159 Ofgem (January 2014), WPML: decision letter, p.1.

160 Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition - Impact Assessment, p.8, 1.7.

161 Ofgem (January 2014), Liquidity in the Wholesale Electricity Market (Special Condition AA of the electricity generation licence): Guidance, p.7, 1.6.

162 Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition - Impact Assessment, p.16, 2.10.

independent) suppliers could expect in the wholesale market.[163] This aimed to address the first objective and applied to the largest eight generators who, at the time, made up over 80 percent of the generation market.[164]

Schedule B, the MMO, was implemented to provide liquidity and opportunities to trade in the wholesale market in line with meeting the first two objectives.[165] Through the MMO, Ofgem aimed to provide regular opportunities to trade for smaller suppliers, establish a reference of prices along the forward curve and to increase wholesale competition, to benefit the retail market and consumers.[166] Overall, with narrower and more available bid-offer spreads, Ofgem hoped to engineer the self-reinforcing cycle of liquidity in the market leading to large increases in traded volumes.[167] We discuss the design of the MMO in more detail below.

Finally, Schedule C, the S&P Reporting Requirements, was enforced to ensure compliance with SMA and MMO interventions and to monitor the near-term market in line with the third objective above.[168] At the point of S&P implementation, Ofgem considered that the third objective was already being met.[169] The same eight licensees subject to the SMA were also subject to the reporting requirements.[170]

Ofgem has discretion to remove or add Schedules to licensees on an ongoing basis.[171] This decision is based upon the sustained achievement of the objectives of the licence, whether an existing licensee faced “disproportionate costs and risks in continuing to meet the licence condition”[172] and any significant changes in generation output or market share, as well as other factors.[173] In addition, specifically to the MMO, Ofgem stated it would consider any significant changes to the share of the domestic supply market.[174] Licensees can apply to Ofgem to request a review of their obligations.[175]

163 Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition - Impact Assessment, p.16.

164 In addition to the ‘Big Six’, GDF Suez and Drax Power were chosen to face the SMA rules. Source: Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition, p.5. Ofgem (June 2013), WPML: final proposals for a 'S&P' licence condition, p.17, 2.10.

165 Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition, p.18, 4.1.

166 Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition, p.18, 4.1.

167 Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition, p.18, 4.2.

168 Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition, p.25, 5.1.

169 CMA (June 2016), Energy Market Investigation Final Report: Liquidity Appendix, p. A7.1-8, 24.

170 Ofgem (January 2014), Liquidity in the Wholesale Electricity Market (Special Condition AA of the electricity generation licence): Guidance, p.7, 1.6.

171 Ofgem (January 2014), Liquidity in the Wholesale Electricity Market (Special Condition AA of the electricity generation licence): Guidance, p.8, 1.10.

172 Ofgem (January 2014), Liquidity in the Wholesale Electricity Market (Special Condition AA of the electricity generation licence): Guidance, p.8, 1.10.

173 Ofgem (January 2014), Liquidity in the Wholesale Electricity Market (Special Condition AA of the electricity generation licence): Guidance, p.8, 1.10.

174 Ofgem (January 2014), Liquidity in the Wholesale Electricity Market (Special Condition AA of the electricity generation licence): Guidance, p.9, 1.14.

175 Ofgem (January 2014), Liquidity in the Wholesale Electricity Market (Special Condition AA of the electricity generation licence): Guidance, p.9, 1.17.

B.1.3. The Design of the MMO

The MMO compelled licensees to post bid-offer spreads on an accessible trading platform[176] for the following Peakload and Baseload products: Month+1, Month+2, Quarter+1, Season+1, Season+2, Season+3 and Season+4 (Baseload only for Season+4).[177] The spread (between bid and offer prices) is limited for most Baseload products to 0.5 per cent and for most Peakload to 0.7 per cent.[178] For Season+3 and Season+4 Baseload products the spread is limited to 0.6 per cent and for Season+3 Peak products the spread is limited to 1 per cent. These spreads were larger (by 0.2 percentage points) for the first three months of the S&P Licence.[179]

Initially, Ofgem proposed that bid-offer spreads should be specified for more than 50 per cent of market opening time each month.[180] However, Ofgem later revised this (before implementation) and stipulated that the licensee should market make for two hour-long windows each day (from 10:30am and 3:30pm), the latter of which was aligned to peak activity in the gas market.[181] Ofgem argued that this was superior as it provided a guaranteed opportunity to trade each day as well as reducing compliance costs.[182] In the window, the MM has a maximum of five minutes to replace its bid-offer after an executed trade.[183] The MM is also compelled to post bid-offers for 5MW and 10MW lot sizes and must execute trades up to 10MW.[184]

Two exemptions were provided under which a MM is no longer obligated to post a bid-offer spread for a specific product in a particular trading window. The obligation is reinstated at the next trading window.[185]

Firstly, the existence of a fast market, defined as when the price changes by more than 4 per cent in a single direction in a given window.[186] This price change is determined by the difference between the first trade and the trade that the licensee observes triggers the

176 A platform qualifies if one or more products may be sold on the platform, it is independent from the licensee, at least five other persons can trade on the platform (other than the licensee), data from the platform operator can be supplied to Ofgem and there is reasonable expectation that the relevant product will be traded on the platform. Source: Ofgem (January 2014), Liquidity in the Wholesale Electricity Market (Special Condition AA of the electricity generation licence): Guidance, p.25, 3.4.

177 Month+1 describes the calendar month ahead, +2 describes two calendar months ahead etc. Baseload rate is electricity that is produced continually throughout the day. Peakload refers to electricity bought and sold for consumption at peak times (7am to 7pm). Source: Ofgem (March 2019), accessed on 13/3/2019, Link: https://www.ofgem.gov.uk/data-portal/electricity-prices-day-ahead-baseload-contracts-monthly-average-gb

178 Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition, p.35.

179 Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition, p.35.

180 Ofgem WPML: final proposals for a 'S&P' licence condition p 30

181 Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition, p.19, 4.4.

182 Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition, p.19, 4.5.

183 Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition, p.20, 4.7.

184 Ofgem (January 2014), Liquidity in the Wholesale Electricity Market (Special Condition AA of the electricity generation licence): Guidance, p.28, 3.19.

185 Ofgem (January 2014), Liquidity in the Wholesale Electricity Market (Special Condition AA of the electricity generation licence): Guidance, p.27, 3.14.

186 Ofgem (January 2014), Liquidity in the Wholesale Electricity Market (Special Condition AA of the electricity generation licence): Guidance, p.27, 3.14.

clause.[187] These trades may be made by different traders on different trading platforms.[188] The licensee must determine when this occurs and, if traded is suspended, record the time and date of the decision to suspend and details of the trades and platform, and report to Ofgem in its quarterly report.[189]

Secondly, a volume cap, defined as when a MM trades a net volume of 30MW in a particular direction in a single window for a single product.[190] Trade sizes that exceeded the maximum obligated lot size (10MW) are not counted towards this volume cap.[191] The licensee must report the windows and products for which this volume cap was hit to Ofgem in its quarterly report.[192]

B.1.4. The Choice of Licensees to Face the MMO

Ofgem concluded that the MMO should be faced by The Big Six: Centrica (British Gas), EDF Energy, E.ON SE UK, Npower, Scottish Power and the SSE Generation.[193] Ofgem noted that these firms had stable shares of the market aided by their sticky customer base[194] and therefore would have more flexibility in identifying their optimal hedging strategy.[195] The size of the firms would also be beneficial when adopting trading positions that are long or short and would allow the firms to market make at "reasonable cost and risk" [196].

In addition, given The Big Six were vertically-integrated, Ofgem argued that they would be naturally more robust to periods of low liquidity.[197] This is because of their generation arms, which would provide internal trading options to support the MMO at times when it is most beneficial to other suppliers.[198] Ofgem also noted that the benefit of adding additional, smaller licensees to the MMO would be limited but the costs might be large.[199]

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187 Ofgem (January 2014), Liquidity in the Wholesale Electricity Market (Special Condition AA of the electricity generation licence): Guidance, p.28, 3.17.

188 Ofgem (January 2014), Liquidity in the Wholesale Electricity Market (Special Condition AA of the electricity generation licence): Guidance, p.27, 3.14.

189 Ofgem (January 2014), Liquidity in the Wholesale Electricity Market (Special Condition AA of the electricity generation licence): Guidance, p.27, 3.14.

190 Ofgem (January 2014), Liquidity in the Wholesale Electricity Market (Special Condition AA of the electricity generation licence): Guidance, p.29, 3.21.

191 Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition, p.35.

192 Ofgem (January 2014), Liquidity in the Wholesale Electricity Market (Special Condition AA of the electricity generation licence): Guidance, p.29, 3.22.

193 Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition, p.5.

194 Ofgem (March 2013), Retail Market Review: Final Domestic Proposals, Consultation on policy effect and draft licence conditions, p18, 1.26.

195 Ofgem (June 2013), WPML: final proposals for a 'S&P' licence condition, p.16, 2.8.

196 Ofgem (June 2013), WPML: final proposals for a 'S&P' licence condition, p.17, 2.8.

197 Ofgem (June 2013), WPML: final proposals for a 'S&P' licence condition, p.16, 2.8.

198 Ofgem (June 2013), WPML: final proposals for a 'S&P' licence condition, p.16, 2.8.

199 Ofgem (June 2013), WPML: final proposals for a 'S&P' licence condition, p.16, 2.8.

The licensees are able to nominate a third party to market make on their behalf, but that third party may not be market making on behalf of more than one other licensee.[200] The licensee retains the responsibility to meet the obligation should they nominate a third party.[201] In the case when a licensee nominates a third party, the volume of each bid-offer posted for each product must correspondingly double (to 5MW, 10MW, 15MW and 20MW).[202]

B.1.5. The Estimated Costs of the MMO

To estimate the expected costs on the licensees of implementing the MMO, Ofgem performed an Impact Assessment in November 2013. Ofgem examined “set-up costs” and “on-going costs”.[203]

“Set up costs” included development of IT systems to provide information on the licensees’ trading position and credit exposure as well as legal costs when establishing agreements with a trading platform. The estimated range for total “set up costs” of the MMO was £100,000 to £400,000 with a best estimate of £200,000 for each licensee.[204]

“Ongoing costs” include transaction fees on trades (which would otherwise be avoided), additional staff costs, costs relating to open positions and costs from managing credit exposures. The estimated range for total annual operating costs of the MMO was £969,000 to £4,844,000 with a best estimate of £2,488,000 for each licensee.[205] These costs are not net of income from traded positions. For Npower, the smallest of The Big Six, this best estimate of annual ongoing cost was 0.12 per cent of domestic electricity generation total revenue and 0.13 per cent of domestic electricity generation total operating costs in 2013.[206]

B.1.6. The Performance of the MMO

B.1.6.1. Effects on Liquidity

Ofgem argue that since the introduction of S&P, the volume of contracts traded has “slightly increase[d]”[207] although it recognises that the larger volumes, particularly in 2016, may be due to market volatility.[208] There was a 17 percent increase in traded volume from 2013 to

200 The licensee must also be able to trade products with at least five market participants. Source: Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition - Impact Assessment, p.36.

201 Ofgem (January 2014), Liquidity in the Wholesale Electricity Market (Special Condition AA of the electricity generation licence): Guidance, p.25, 3.3.

202 Ofgem (January 2014), Liquidity in the Wholesale Electricity Market (Special Condition AA of the electricity generation licence): Guidance, p.28, 3.19.

203 Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition - Impact Assessment, p.29.

204 Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition - Impact Assessment, p.30, Figure 3.

205 Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition - Impact Assessment, p.30, Figure 4.

206 RWE (December 2013), RWE - UK Generation & Supply Consolidated Segmental Statement, p.9.

207 Ofgem (July 2017), S&P Review: Consultations, p.7, 1.6.

208 Ofgem (July 2017), S&P Review: Consultations, p.7, 1.7.

2017.[209] This difference has been particularly driven by increased trade of Peakload contracts where volumes traded two months to two years ahead of delivery have increased from 21.9 TWh in 2013 to 67.0 TWh in 2016.[210] There are also 2.5 times the number of suppliers in the market (as of August 2018) than in December 2013.[211] However, Ofgem states this is not entirely attributable to the S&P.[212]

Bid-offer spreads have also narrowed since the start of S&P.[213] This is unsurprising given the MMO specifies a maximum bid-offer spread.[214] In comparison, non-mandatory product spreads have widened over the period and are roughly three to four times the mandatory product spreads.[215]

Churn, measured as the number of times a unit of generation is traded before it is delivered to the customer, has remained stable in the S&P period until 2016.[216] However, churn did rise along with market volatility in Q4 2016.[217] In 2017, churn deteriorated and is comparable to levels before the introduction of the MMO.[218]

Whilst traded volumes have risen since the introduction of the S&P, they have fallen outside of the two trading windows specified by the MMO over the period.[219] The CMA examined data outside the windows and found that "product availability had become worse since the introduction of S&P"[220] arguing that "these results paint a picture of relative, rather than absolute, availability"[221].

As part of the CMA Energy Market Investigation (published in June 2016), the CMA assessed the success of the MMO, and more broadly the S&P:

> "Based on the data we have collected, parties' comments and Ofgem's wholesale power market liquidity annual report, we believe there is some evidence that liquidity

209 Ofgem (August 2018), Centrica Special Condition AA Decision Letter: Request for modification of special condition AA of electricity generation licences held by Centrica group, p.4.

210 Ofgem (July 2017), S&P Review: Consultations, p.8, Figure 3.

211 Ofgem (August 2018), Centrica Special Condition AA Decision Letter: Request for modification of special condition AA of electricity generation licences held by Centrica group, p.4.

212 Ofgem (August 2018), Centrica Special Condition AA Decision Letter: Request for modification of special condition AA of electricity generation licences held by Centrica group, p.5.

213 Ofgem (October 2018), State of the Energy Market Report 2018, p.58.

214 Ofgem (July 2017), S&P Review: Consultations, p.9, 1.9.

215 Ofgem (July 2017), S&P Review: Consultations, p.11, Figure 8. CMA (June 2016), Energy Market Investigation Final Report: Liquidity Appendix, p. A7.1-22, 72.

216 Ofgem (July 2017), S&P Review: Consultations, p.12, Figure 9.

217 Ofgem (July 2017), S&P Review: Consultations, p.12, 1.13.

218 Ofgem (October 2018), State of the Energy Market Report 2018, p.58, Figure 2.35.

219 Ofgem (July 2017), S&P Review: Consultations, p.13, Figure 11.

220 CMA (June 2016), Energy Market Investigation Final Report: Liquidity Appendix, p. A7.1-20, 62.

221 CMA (June 2016), Energy Market Investigation Final Report: Liquidity Appendix, p. A7.1-20, 63.

> has improved in the designated windows, although this may be at the expense of liquidity in other parts of the day."[222]

The CMA argued that the MMO is likely to be of benefit to smaller suppliers but that the overall changes are "relatively marginal"[223] and that "there is no obvious spillover to other products"[224]. However, Ofgem states that extending the MMO to those additional products would result in too higher risk for MMs, especially when little current trading in those products exists upon which to base prices.[225]

In August 2018, Ofgem stated that:

> "We consider that while a number of liquidity indicators have improved, the objectives of the S&P licence condition are yet to be fully realised. Total OTC trading was only 779 TWh in 2017, down from 1,083 TWh in 2016 and churn averaged 3.7 in 2017, down from an average of 4.7 in 2016. We therefore believe that the S&P licence condition cannot yet be considered a sustained success."[226]

We discuss the future of the MMO below.

B.1.6.2. Fast Market and Volume Cap Conditions

In July 2017 Ofgem reported the number of times that the fast market rule and volume cap had been triggered such that a MM was no longer obligated to post a bid-offer for the affected product in the market window.

The use of the volume cap has increased with market volatility: Rising from 32 times in Q2 2014 to 136 times in Q2 2016 and 515 in Q4 2016.[227] In December 2017, Ofgem received feedback on the volume cap with some respondents suggesting that the cap was too high and could instead be based on gross volume traded instead of net volume.[228]

The fast market cap has been triggered fewer times than the volume cap over the same period, although the use of the fast market cap has also increased.[229] In 2015 the cap was used 28 times whereas in 2016 it was used 117 times, including 64 times in 2016 Q4.[230] Table B.1 details the proportion of windows between 2015 and July 2017 where a fast market cap would be triggered for different fast market caps.

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222 CMA (June 2016), Energy Market Investigation Final Report: Liquidity Appendix, p. A7.1-20, 89.

223 CMA (June 2016), Energy Market Investigation Final Report: Liquidity Appendix, p. A7.1-27, 92.

224 CMA (June 2016), Energy Market Investigation Final Report: Liquidity Appendix, p. A7.1-27, 93.

225 CMA (June 2016), Energy Market Investigation Final Report: Liquidity Appendix, p. A7.1-27, 94.

226 Ofgem (August 2018), Centrica Special Condition AA Decision Letter: Request for modification of special condition AA of electricity generation licences held by Centrica group, p.5.

227 Ofgem (July 2017), S&P Review: Consultations, p.18, 2.4.

228 Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition, p.11, 2.12.

229 Ofgem (July 2017), S&P Review: Consultations, p.18, 2.5.

230 Ofgem (July 2017), S&P Review: Consultations, p.18, 2.5.

Table B.1: Proportion of windows where a fast market would be triggered by fast market cap, 2015 – 30 Jun 2017

Units: %	**Month+1**	**Month+2**	**Quarter+1**	**Season+1**	**Season+2**	**Season+3**	**Season+4**
1% cap	7.1	5.1	5.7	2.2	1.8	1.3	2.2
2% cap	2.8	1.9	2.1	0.5	0.2	0.3	0.3
3% cap	1.3	0.9	0.8	0.2	0.0	0.0	0.1
4% cap	0.7	0.4	0.3	0.1	0.0	0.0	0.1

Source: Ofgem analysis of ICIS Transaction Data. Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition.

The chosen cap of 4 percent corresponded to 0.7 percent of windows incurring a fast market cap between the beginning of 2015 and July 2017.[231] Licensees argued that the cap was set too high which resulted in costs arising from the obligation to market make in the volatile market in 2016 Q3 and Q4.[232] As a result, Ofgem considered allowing a wider bid-offer spread (1 percent for all products) beyond a 1 percent threshold for market price movement.[233] However, this adjustment and the consultation was suspended (detailed below).[234]

B.1.6.3. Costs of the MMO

As part of the consultation in 2017, four of the licensees submitted their estimated costs directly arising from the MMO.[235] The fixed costs comprise mainly of staff costs whereas variable costs relate to broker fees and the net trading costs arising from the MMO.[236] These are detailed in Table B.2.

Table B.2: Fixed and variable costs of licensees (£m)

Units: £m	**2014**	**2015**	**2016**	**H1 2017**
Fixed costs	~ 0.5	~ 0.5	~ 0.5	~ 0.5
Variable costs	0.2 - 0.7	~ 0.5	3.0 – 8.0	0.3 – 0.7

Source: Licensee submission to Ofgem. Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition.

Costs in 2014 and 2015 fell below the ex-ante estimates that Ofgem made prior to the implementation of S&P, although reported staff costs were double the estimate. However, variable costs in 2016 were 2-4 times ex-ante estimates. This is because of the volatility experienced in Q3 and Q4 of 2016.[237] In particular, licensees stated costs arose from the start of the trading windows, when price discovery was harder and yet the bid-offer spreads for

231 Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition, p.16, 3.11.

232 Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition, p.4.

233 Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition, p.16, 3.12.

234 Ofgem (November 2018), Update – S&P.

235 Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition, p.16, 2.7.

236 Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition, p.16, 2.7.

237 Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition, p.16, 2.8.

mandatory products were small.[238] In response, Ofgem considered adopting a soft-landing period of ten minutes at the start of each market making window, where bid-offer spreads would be wider (1 percent for all products) to allow for less risky price discovery.[239] Again, this adjustment and the consultation were suspended.[240]

There also exist indirect costs of the MMO for financial players in the market.[241] The movement of liquidity to the two market windows at the expense of other times during the day means speculative trading is likely to be dissuaded.[242] The CMA noted:

> "In this context, it was suggested that windows were insufficient to attract financial players, who want to be able to trade out of positions throughout the day. However, Ofgem told us that there was no consensus on this issue and Ofgem itself did not hold this view as it saw a number of other more significant factors that might dissuade financial players participating in the electricity market."[243]

Without the introduction of financial players, and the liquidity throughout the day to support them, the CMA argued there would not be the "step change" in the level of liquidity that Ofgem was targeting.[244]

B.1.7. The Future of the MMO

Since the implementation of the MMO, wholesale market structure has changed substantially.[245] In September 2016 E.ON SE separated their fossil fuel generation (which became Uniper UK Ltd) from renewable generation, supply, networks and trading business.[246] This reduced their generation market share from 6 to 1 percent.[247] Therefore, E.ON SE applied to have Ofgem remove the MMO (and other obligations under the S&P) which Ofgem approved in November 2016.[248] Ofgem argued that the reduction in vertical integration eliminated the disincentive to trade and justified the decision to remove the

238 Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition, p.16, 2.8.

239 Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition, p.14, 3.2.

240 Ofgem (November 2018), November 2018 Update – S&P.

241 Ofgem (July 2017), S&P Review: Consultations, p.26, 3.14.

242 CMA (June 2016), Energy Market Investigation Final Report: Liquidity Appendix, p. A7.1-20, 65.

243 CMA (June 2016), Energy Market Investigation Final Report: Liquidity Appendix, p. A7.1-25, 81.

244 CMA (June 2016), Energy Market Investigation Final Report: Liquidity Appendix, p. A7.1-27, 92.

245 Ofgem (August 2018), Open letter: S&P Update, p.2.

246 Ofgem (November 2016), E.ON Special Condition AA Decision Letter: Request for modification of special condition AA of E.ON's and Uniper's electricity generation licences, p.2.

247 Ofgem (November 2016), E.ON Special Condition AA Decision Letter: Request for modification of special condition AA of E.ON's and Uniper's electricity generation licences, p.3.

248 Ofgem (November 2016), E.ON Special Condition AA Decision Letter: Request for modification of special condition AA of E.ON's and Uniper's electricity generation licences.

obligations.[249] In addition, it argued that consequently reducing the number of MMs from six to five would not reduce the effectiveness of the MMO or S&P.[250]

In December 2017, Centrica Group, owner of British Gas, applied to remove (only) the MMO obligation from their license.[251] Centrica argued that divestments of their generation arm representing a change in corporate strategy should justify this removal.[252] Centrica's generation market share fell from 4.5 percent at the start of the S&P to 0.8 percent at the time of application, and was therefore below E.ON's market share at the time of the removal of their MMO.[253] In its application, Centrica stated that MMO costs had risen over time and those costs incurred in 2016 due to market volatility, which Centrica argued was not a unique event, were much higher than the Ofgem ex-ante "high-case" scenario.[254] Ofgem approved the request in August 2018 and removed the MMO stating that:

> "This is consistent with our previous decisions not to subject licensees without a significant GB electricity generation and domestic supply market shares to undertake market making activities."[255]

However, Ofgem's removal of the MMO from Centrica's licence resulted in only four licensees subject to the MMO. Therefore, Ofgem postponed the ongoing consultation (and the implementing of proposed changes described above) to evaluate the MMO.[256] In particular, Ofgem was concerned that:

> "the remaining obligated parties will face disproportionate costs and risks in continuing to meet the licence condition, and whether on balance there is a case for suspending the MMO pending completion of our review."[257]

In November 2018, Ofgem published this review and stakeholder responses.[258] Of the respondents roughly a quarter, including five of The Big Six, supported suspension of the MMO citing that the remaining costs would be disproportionate and the MMO had not improved overall market liquidity.[259] They were also concerned that the application of the

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249 Ofgem (November 2016), E.ON Special Condition AA Decision Letter: Request for modification of special condition AA of E.ON's and Uniper's electricity generation licences, p.5.

250 Ofgem (November 2016), E.ON Special Condition AA Decision Letter: Request for modification of special condition AA of E.ON's and Uniper's electricity generation licences, p.5.

251 Ofgem (August 2018), Centrica Special Condition AA Decision Letter: Request for modification of special condition AA of electricity generation licences held by Centrica group.

252 Ofgem (August 2018), Centrica Special Condition AA Decision Letter: Request for modification of special condition AA of electricity generation licences held by Centrica group, p.1. For example, Centrica divested 2.3 GW of installed CCGT capacity to EPH in 2017. Source: Ofgem (October 2018), State of the Energy Market Report 2018, p.50.

253 Ofgem (August 2018), Centrica Special Condition AA Decision Letter: Request for modification of special condition AA of electricity generation licences held by Centrica group, p.3.

254 Ofgem (August 2018), Centrica Special Condition AA Decision Letter: Request for modification of special condition AA of electricity generation licences held by Centrica group, p.4.

255 Ofgem (August 2018), Centrica Special Condition AA Decision Letter: Request for modification of special condition AA of electricity generation licences held by Centrica group, p.5.

256 Ofgem (August 2018), Open letter: S&P Update.

257 Ofgem (August 2018), Open letter: S&P Update, p.2.

258 Ofgem (November 2018), November 2018 Update – S&P.

259 Ofgem (November 2018), November 2018 Update – S&P, p.2.

MMO to vertically-integrated entities was increasingly arbitrary.[260] However, three quarters of respondents, mainly small suppliers, were against the suspension arguing that it would lead to wider spreads and reduced liquidity.[261] In addition, alternative measures were suggested in the review by respondents such as a tendered market-maker funded by socialised costs and the widening of the MMO to include other generators and retailers.[262]

Ofgem concluded that immediate suspension of the MMO would “lead to significant disruption of the market”[263]. However, with planned transactions involving SSE Generation and Npower and Scottish Power and Drax leading to the potential removal of their MMO, Ofgem was concerned that the remaining MM, EDF, may not “generate a robust price”[264]. In the review, Ofgem stated:

> “market participants should prepare for the suspension of the MMO if both the SSE/Npower merger and the acquisition of Scottish Power’s thermal generation units by Drax complete”[265]

The SSE Generation/Npower merger was abandoned in December 2018.[266] Meanwhile, the Scottish Power sale of generation to Drax was completed in December 2018, and Scottish Power’s obligations under the S&P subsequently removed in January 2019, Ofgem decided not to suspend the MMO.[267] It argued:

> “The robustness of the reference prices available and the overall effectiveness of the intervention may fall with a smaller number of market-makers. However, at this stage we do not have clear evidence to suggest that three obligated parties will be significantly less effective than four. We will continue to monitor and assess the effectiveness of the Market Making Obligation and the costs and risks to obligated parties in light of market developments. Alongside this, we will investigate potential options and alternatives to the Market Making Obligation to support liquidity.”[268]

Currently, the MMO continues to operate with three participants: EDF Energy, SSE Generation and Npower.

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260 Ofgem (November 2018), November 2018 Update – S&P, p.3.

261 Ofgem (November 2018), November 2018 Update – S&P, p.2.

262 Ofgem (November 2018), November 2018 Update – S&P, p.3.

263 Ofgem (November 2018), November 2018 Update – S&P, p.4.

264 Ofgem (November 2018), November 2018 Update – S&P, p.4.

265 Ofgem (November 2018), November 2018 Update – S&P, p.1.

266 SSE (December 2018), SSE Energy Services Transaction Not Proceeding, RNS Number: 6450K.

267 Ofgem (January 2019), ScottishPower Special Condition AA Decision Letter: Request for modification of special condition AA of electricity generation licences held by the ScottishPower group, p.4.

268 Ofgem (January 2019), ScottishPower Special Condition AA Decision Letter: Request for modification of special condition AA of electricity generation licences held by the ScottishPower group, p.5.

B.2. Singapore's Market Making Obligation

B.2.1. The National Electricity Market of Singapore

Electricity industry reform in Singapore began in 1995 when the government corporatised the Public Utilities Board (PUB) and vested the electricity undertakings of PUB in a government investment arm, Temasek Holdings.[269] PUB remained as the regulator of the electricity industry. Temasek Holdings created Singapore Power: the holding company for the generation companies, PowerSenoko (now Senoko Energy) and PowerSeraya; the transmission company, PowerGrid (now SP PowerAssets); and the sole supplier, Power Supply. Power Supply is now named SP Services Ltd which is the Market Support Services Licensee (MSSL).[270]

The second stage of the reform was the creation of the Singapore Electricity Pool (SEP) in April 1998.[271] This was a day-ahead electricity market which allowed for trading between generators and SP Services Ltd in a competitive market.[272] However, these companies remained government owned. The government reviewed the electricity industry in 1999 and concluded that further deregulation would lead to benefits from competition.[273] As a consequence, the National Electricity Market of Singapore (NEMS) was established to succeed the SEP under the authority of the Electricity Act in 2003. The Energy Market Authority (EMA), which was formed in 2001, was appointed as the regulator for the NEMS.[274]

Electricity generation in Singapore relies almost solely on natural gas, which comprised approximately 95 per cent of the fuel mix in 2018.[275] This reliance has strengthened over time as Singapore has moved from steam turbine plants to new Combined Cycle Gas Turbine plants (CCGTs).[276] Natural gas is imported from pipelines from Malaysia and Indonesia but also, more recently, through Singapore's LNG terminal on Jurong Island which opened in 2014.[277]

The electricity generation market has become increasingly competitive in Singapore.[278] There are three Main Power Producers (MPPs): Senoko Energy, YTL PowerSeraya and Tuas Power Generation.[279] The market share (measured as the fraction of total electricity generation) of these three MPPs has fallen from approximately 83 per cent in 2005 to 58 per

[269] EMA (October 2010), Introduction to the National Electricity Marker of Singapore, p.3-1.

[270] EMA (October 2010), Introduction to the National Electricity Marker of Singapore, p.3-1.

[271] EMA (October 2010), Introduction to the National Electricity Marker of Singapore, p.3-1.

[272] EMA (October 2010), Introduction to the National Electricity Marker of Singapore, p.2-1.

[273] EMA (October 2010), Introduction to the National Electricity Marker of Singapore, p.3-2.

[274] EMA (October 2010), Introduction to the National Electricity Marker of Singapore, p.3-2.

[275] EMA (August 2018), Singapore Energy Statistics 2018, p.14.

[276] EMA (August 2018), Singapore Energy Statistics 2018, p.14.

[277] Singapore LNG Corporation, Accessed 05/04/19, Link: https://www.slng.com.sg/website/index.aspx EMA (April 2014), Singapore's First LNG Terminal Launched, Accessed 05/04/19, Link: https://www.ema.gov.sg/cmsmedia/Newsletter/2014/04/spotlight-on/singapores-first-lng-terminal-launched.html

[278] EMA (August 2018), Singapore Energy Statistics 2018, p.18.

[279] EMA (August 2018), Singapore Energy Statistics 2018, p.18.

cent in 2017.[280] In particular, three other generators have entered the market: Keppel Merlimau Cogen (market share: 11.8 per cent), SembCorp Cogen (9.6 per cent) and PacificLight Power (9.0 per cent).[281]

The wholesale market uses single-settlement locational marginal pricing (LMP) and is operated by the Energy Market Company (EMC).[282] The dispatch of electricity is determined by a spot market in every half-hour.[283] Generators offer electricity onto the market in each half-hour based on forecasted load. Based on actual load, the Market Clearing Engine (MCE) then dispatches all power offered at a price below the market clearing price.

Market prices that generators receive depend on location: The EMC sets Locational Marginal Prices (LMPs) at every location where electricity is put on or taken off the network.[284] All wholesale buyers in the half-hour pay the Uniform Singapore Electricity Price (USEP) which is an average of off-take LMPs weighted by load withdrawn at each point.[285] Regulation, generation capacity that can adjust to variations in load within the half-hour, and reserve, unused capacity that can fulfil spikes in demand, markets are cleared along with the wholesale market.

The EMA has progressively introduced competition into the electricity retail market since 2001.[286] Originally, all customers were served by SP Services Ltd under a regulated tariff.[287] Over time, customers have become “contestable”, allowing the customer to choose to buy electricity from another retailer or at the USEP from the wholesale market.[288] The threshold by which a customer becomes “contestable” is determined by its power usage. The EMA has reduced this threshold over time: since July 2015 customers consuming more than 2 MWh a month are considered “contestable”.[289] In April 2018, the threshold was eliminated in Jurong to soft launch the Open Electricity Market (OEM).[290] Currently, the EMA is rolling out the OEM to all states from Q4 2018 to Q2 2019.[291]

Demand for electricity in Singapore is defined by two characteristics. The first is the tropical climate and the consequent demand for electricity to power air conditioning.[292] The second is

[280] EMA (August 2018), Singapore Energy Statistics 2018, p.18.

[281] EMA (August 2018), Singapore Energy Statistics 2018, p.18.

[282] Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.4.

[283] EMA (October 2010), Introduction to the National Electricity Marker of Singapore, p.4-4.

[284] Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.4.

[285] EMA (October 2010), Introduction to the National Electricity Marker of Singapore, p.4-4.

[286] EMA (August 2018), Singapore Energy Statistics 2018, p.30.

[287] EMA (October 2010), Introduction to the National Electricity Marker of Singapore, p.4-6.

[288] EMA (August 2018), Singapore Energy Statistics 2018, p.30.

[289] EMA (August 2018), Singapore Energy Statistics 2018, p.30.

[290] EMA (August 2018), Singapore Energy Statistics 2018, p.30.

[291] EMA, Liberalisation of Retail Electricity Market, Accessed 05/04/19, Link: https://www.ema.gov.sg/electricity_market_liberalisation.aspx

[292] Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.7.

the relatively high non-residential demand for electricity (85 per cent) compared to non-residential demand in Europe or the United States (70 per cent).[293] These non-residential consumers also constitute the majority of "contestable" customers (CC) and accounted for 76 per cent of total consumption in 2017.[294] These characteristics give rise to a flat daily load shape for electricity consumption which consequently leads to low volume risk for suppliers relative to European or United States markets.[295]

As the EMA has increased the number of CCs in the electricity retail market, by lowering the monthly consumption threshold, the number of retailers has increased. Only six retailers existed in 2005: SP Services (41.7 per cent of retail market sales), Senoko Energy Supply (17.5 per cent), Seraya Energy (16.8 per cent), SembCorp Power (7.6 per cent) and Keppel Electric (3.1 per cent).[296] The increase in entry of new retailers has been particularly marked in recent years (after the introduction of the futures market), with the entry of four new retailers in 2017.[297] However, the original six still constitute approximately 90 per cent of the market.[298] Only PacificLight has entered and now constitutes a comparable share of the market (6.1 per cent) compared to the original six.[299]

B.2.2. The Basis for Intervention

Vertical integration is prevalent in the NEMS: the seven largest generators were also the seven largest retailers in 2015.[300] The market shares of companies in the retail market generally mirror the annual generation shares of those companies.[301] Historical market entry to the retail market involved construction of a generation facility to sell to SP Services and CCs.[302] This strategy involves high barriers to entry through sunk costs, and associated high financial risks when recovering those sunk costs from the wholesale market.

As the EMA has moved towards the OEM, it has aimed to introduce further competition into the retail market.[303] In October 2012, to lower the cost of entry into both wholesale and retail markets, the EMA initiated an industry consultation to establish an electricity futures market in Singapore.[304] The futures market aimed to allow entrants to hedge against the half-hourly

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293 Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.4.

294 EMA (August 2018), Singapore Energy Statistics 2018, p.32.

295 Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.7.

296 EMA (August 2018), Singapore Energy Statistics 2018, p.29.

297 EMA (August 2018), Singapore Energy Statistics 2018, p.29.

298 EMA (August 2018), Singapore Energy Statistics 2018, p.29.

299 EMA (August 2018), Singapore Energy Statistics 2018, p.29.

300 Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.5.

301 Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.5.

302 Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.5.

303 Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.6.

304 EMA (November 2012), Development of an Electricity Futures Market in Singapore Consultation Paper.

USEP and lower the financial risk of entry.[305] The market was established in April 2015 on the Singapore Exchange Limited (SGX).[306]

To ensure that there was sufficient liquidity in the new futures market, the EMA implemented an incentivised MMO arrangement.

B.2.3. The MMO Design

The EMA incentivised the entry into an MMO arrangement with an exchange by compensating participating generators through a Forward Sales Contract (FSC). The EMA argues this would:

> "provide participating generators with a certain level of revenue certainty particularly in the start-up phase where generators are building the necessary capabilities in the electricity futures market."[307]

A FSC would allow the Market Maker (MM) to own a fixed volume indexed price contract, pegged to either the prevailing LNG Vesting Price or Balance Vesting Price.[308] The FSC is a Contract for Difference (CfD), where differences in settlement are paid through cash, with SP Services Ltd.[309] The EMA argued that given the primary beneficiaries of the futures market would be CCs, through increased retail competition, the other side of the FSC should be held by these CCs.[310] The CCs would not necessarily pay more as the FSC provides a hedge against fluctuations in the USEP.[311] When the FSC price is above (below) the USEP the CCs receive the credit (pay the debit) through their retailers or SP Services (if the CCs are buying at USEP).[312] The FSC price and volume is published publicly.[313]

The process of allocation of FSCs to MMs is twofold. First, each MM must sign a Memorandum of Understanding with an exchange to specify a "pathway for the development of the electricity futures market that is agreed between the interested generator and that exchange for the EMA's consideration"[314]. Secondly, pre-qualified generators must submit a single bid of its volume commitment in return for the FSC volume it would like to be allocated.[315] If a MM offered to market make at larger volumes, it would be compensated by a more than proportional rate of FSC volume, see Table B.3. In the case where FSC volumes

[305] Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.6.

[306] Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.6.

[307] EMA (September 2014), Procedures for Calculating Components of the Forward Sales Contracts, p.2.

[308] EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.5.

[309] EMA (April 2015), Enhancing Competition through the Development of an Electricity Futures Market in Singapore.

[310] EMA (April 2015), Enhancing Competition through the Development of an Electricity Futures Market in Singapore.

[311] EMA (April 2015), Enhancing Competition through the Development of an Electricity Futures Market in Singapore.

[312] EMA (September 2014), Procedures for Calculating Components of the Forward Sales Contracts, p.7.

[313] EMA (April 2015), Enhancing Competition through the Development of an Electricity Futures Market in Singapore.

[314] EMA (May 2013), Forward Sale Contract (FSC) Scheme to Facilitate the Development of an Electricity Futures Market in Singapore, p.2, 1.3.

[315] EMA (May 2013), Forward Sale Contract (FSC) Scheme to Facilitate the Development of an Electricity Futures Market in Singapore, p.10, 5.6.1.

went unallocated, new generators, who did not originally participate, would be allowed to bid for these volumes.[316]

The total volume of FSCs allocated by the EMA is 6 per cent of the forecasted total annual electricity sales from 2014 to 2016, with the planned introduction of the futures exchange in April 2015.[317] The EMA's allocation of this total FSC volume to each MM depends on the volume commitment that each MM offers to market make at, see Table B.3.[318]

Table B.3: FSC allocation rate

MM Volume	Total FSC (3 years)	Rate of Allocation
3 MW	1,400 GWh	467 GWh per MW of MM
0.5 MW	370 GWh	740 GWh per MW of MM

Source: EMA (March 2015), Procedures for Calculating Components of the Forward Sales Contracts, Table 2.

MMs are required to trade the SGX USEP electricity futures contract: a quarterly base load futures contract. The contract size offered must not be larger 0.5 MW per half-hour per day and settles at the USEP.[319] Each MM is required to offer these contracts 8 quarters ahead and therefore market make for 9 total contracts (including the prompt quarter).[320] The MM must put up 6 lots of 0.5 MW contracts (both bid and asks) for each product. Therefore, the minimum volume commitment to market make is 3 MW (on both sides) for each forward contract.

The maximum bid-ask spread for each contract was set at S$3/MWh.[321] The MM market makes in a window for each Singapore business day (currently 4:30pm to 5:00pm).[322] In addition, the MM must meet its obligations in at least 50 per cent of the window each day and 80 per cent of the cumulative time of all windows in a month.[323] The MM must refresh its bid-ask having had a trade executed at least once for each product in the window. This must happen within a 60 second grace period.[324] The MM must submit compliance reports to the EMA at a frequency of no longer than 6 months.[325]

The MMO does not detail any market making specific safeguards, for example a volume cap or fast market rule. Instead, the EMA stipulated that the bid submitted to provide market

[316] EMA (September 2014), Procedures for Calculating Components of the Forward Sales Contracts, p.4.

[317] EMA (September 2014), Procedures for Calculating Components of the Forward Sales Contracts, p.3.

[318] EMA (March 2015), Procedures for Calculating Components of the Forward Sales Contracts.

[319] EMA (April 2015), Enhancing Competition through the Development of an Electricity Futures Market in Singapore.

[320] EMA (April 2015), Enhancing Competition through the Development of an Electricity Futures Market in Singapore.

[321] EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.7.

[322] EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.9.

[323] EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.9.

[324] EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.8.

[325] EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.10.

making services "should also highlight the safeguards to be put in place by the exchange and the generators to ensure orderly trading"[326]. The EMA also states that the MMO has:

> "Safeguards to ensure orderly trading, e.g. position, daily, price, volume and concentration limits."[327]

However, these appear to be safeguards set by the SGX, in relation to any futures trading on its platform, rather than safeguards specific to the MMO.[328]

The aim for the incentivised MMO is to provide liquidity at the earliest stages of the electricity futures market. The EMA argued that there are three benefits of a liquid futures market, facilitated by the market making services arrangement:[329]

1. For generation companies: The futures market provides an additional option to hedge and manage risk.
2. For CCs: The futures market can provide a way to secure future prices and provides a transparent platform to gauge prices.
3. For potential new entrants: New retailers can use the futures market to secure prices for their customers and reduce barriers to entry, increasing retail competition and reducing retail prices.

The initial MMO was phased in over the first 3 to 6 months. In Phases 1 and 2, MMs were only required to offer contracts for quarters one and two years in advance respectively and MMs were allowed larger bid-ask spreads.[330]

B.2.4. Changes to the FSC Market Making Services Arrangement

The EMA has changed the MMO with the continued development of the futures market. In this section, we briefly explain the initial failed take-up of the incentivised MMO, the resulting changes and the subsequent introduction of monthly contracts to the MMO in April 2017.

B.2.4.1. Launch of the FSC

In the initial allocation process, incumbent vertically-integrated 'gentailers' refused to take up incentives to provide market making services. They argued that any benefit of the FSC that accrued to their generation arm would be offset by a cost on their retail arm.[331] This was despite the growing value of the FSC: the pool price in Singapore fell during the period due

[326] EMA (May 2013), Forward Sale Contract (FSC) Scheme to Facilitate the Development of an Electricity Futures Market in Singapore, p.11.

[327] EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.12.

[328] EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.12, Footnote.

[329] EMA (April 2015), Enhancing Competition through the Development of an Electricity Futures Market in Singapore.

[330] EMA (November 2012), Development of an Electricity Futures Market in Singapore Consultation Paper, p.12.

[331] Trustpower (March 2019), Trustpower Submission: Electricity Price Review's Options Paper, The Lantau Group: Market Making Requirements in New Zealand, p. 18.

to an oversupply of generation and therefore the margin between pool and vesting price grew substantially.[332]

In response to the 'gentailers'' refusal to take up incentives to market make, the EMA allowed new entrant retailers to apply to provide market making services. Given the growing size of the FSC windfall, six MMs were found (including one 'gentailer' who, after initially refusing, took up incentives to market make). As the pool and vesting price continued to diverge, the EMA decided to cap the value of the incentives provided by the FSC.[333] In the re-launch, the EMA also altered the design of the MMO to encourage participation. For example, the EMA changed the maximum bid-ask spread to 10 per cent of the bid price (directly copied from the New Zealand MMO).[334]

B.2.4.2. Monthly contracts

During the three years of the original incentivised market making mechanism, the SGX launched monthly base load futures contacts (in April 2017).[335] MMs were required to trade in these new contracts with similar restrictions to the original quarterly contracts. Specifically, MMs must provide 0.5 MW volumes in monthly contracts up to 6 months into the future.[336] The maximum bid-ask spread for these volumes is S$4/MWh.[337] The other restrictions remain from the original mechanism.

B.2.5. The Performance of the Market Making Services Arrangement

The number of electricity retailers in the NEMS increased from 7 to 25 (as of August 2017) since the introduction of the market making services arrangement in April 2015.[338] Liquidity has also increased but cumulative transaction volume is only 5 per cent of the underlying physical consumption annually.[339] In the first two years of futures market trading, Australia and New Zealand had 3 and 10 per cent cumulative transaction volume respectively.[340] In addition, the EMA argues that the growth in transaction volumes and open interest is largely due to MMs who, for quarterly contracts, accounted for approximately 75 per cent of the volume mix as of 31 May 2017.[341] The EMA justifies the extension of the market making

332 Trustpower (March 2019), Trustpower Submission: Electricity Price Review's Options Paper, The Lantau Group: Market Making Requirements in New Zealand, p. 18.

333 Trustpower (March 2019), Trustpower Submission: Electricity Price Review's Options Paper, The Lantau Group: Market Making Requirements in New Zealand, p. 18.

334 Trustpower (March 2019), Trustpower Submission: Electricity Price Review's Options Paper, The Lantau Group: Market Making Requirements in New Zealand, p. 18.

335 EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.2.

336 Months for a new quarter are listed upon expiry of the nearest quarter. Therefore, MMs only need to offer four to six monthly contracts at a time. Source: EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.7.

337 EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.4.

338 EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.2.

339 EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.5.

340 EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.5.

341 EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.4.

services arrangement to the Future Incentive Scheme (discussed in Section B.2.6) based on this observed importance of MMs.[342]

Wolak examines the benefits of the Singapore market making services arrangement quantitatively.[343] He uses an econometric model to explain retail prices with the average open position for in futures contracts that clear during the term of the retail contract (AVGQ) and the weighted average of the daily closing prices of futures contract for all trading days during the term of the retail contract (AVGP). The former, AVGQ, is a measure of the competition faced by incumbent retailers and is therefore expected to be negatively related with retail prices. The latter, AVGP, is the cost of hedging and is therefore expected to be positively related with retail prices. Wolak finds:

> "strong empirical evidence consistent with the hypothesis that the introduction of a futures market facilitated entry by independent retailers which increased competition in electricity retailing and reduced retail prices for contestable customers."[344]

In addition, Wolak estimates that the total savings attributable to the reduction in retail prices for CCs since May 2015 (to April 2016) is between 8 and 26 per cent.[345] Wolak also econometrically estimates the impact of futures market open positions on wholesale prices: the USEP. He finds that total savings in wholesale prices range from 7 to 22 per cent.[346]

As discussed above, these benefits to market liquidity did not come without significant costs. The value of the FSC windfall to MMs grew, and despite being capped by the EMA, reached at least S$204m by March 2018.[347] In light of these costs, the EMA overhauled the design of the MMO when it expired in July 2018.

B.2.6. Future Incentive Scheme

The FSC market making services arrangement expired at the end of July 2018. The EMA changed the FSC market making mechanism and named it the Future Incentive Scheme (FIS). The FIS runs for two phases. The first phase is the period from August 2018 to January 2020. The second FIS will run from February 2020 to July 2021.[348]

The main change with the FIS compared to the FSC market making mechanism is the abandonment of the allocation of FSCs as compensation for market marking. Instead, in the FIS, the EMA conducts a uniform price auction where the awarded price is based on the highest marginal bid (the RFP price) across applicants.[349] The EMA "intends to select four to

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342 EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.3.

343 Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore.

344 Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.13.

345 Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.14.

346 Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.17.

347 EMA (September 2018), EMA Annual Report 2017/2018, p. 19.

348 EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.2.

349 EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.13.

seven Applicants to be awarded the contract to provide market making services"[350]. A separate auction will occur for the first and second FISs.

The offer price submitted by an applicant to this tender must detail 8 bids: two for each of the possible number of selected participants (4 to 7 applicants), one for each of the two possible maximum bid-ask spreads (see below).[351]

The winners of this tender enter into an agreement with SP Services Ltd which continues to facilitate the market making services arrangement.[352] In turn, the winners may not sub-contract or transfer their obligations without approval of the EMA.[353] The payment for market making services is based on the RFP price.

The payment will not be made in a month if the MM fails to fulfil all of the market making obligations in that month.[354] If the MM fails to fulfil all of the market making obligations in two consecutive months, the EMA has the right to terminate the contract with the MM. The MM can also terminate the agreement with 20 days' notice.[355] In all three of these cases, the MM pays an exit fee of 100 per cent of the total RFP price to the MSSL.[356]

To be eligible to provide market making services, an applicant must fulfil three requirements:

1. The applicant must "have at least 2 years of continuous experience in electricity futures trading/market making either locally or in overseas markets"[357] or provide evidence that it will have the "required personnel (in-house or outsourced) to perform market making in the electricity futures market adequately, as well as to manage the overall risk monitoring and controls"[358].
2. The applicant "[m]ust maintain a minimum base capital of $1 million and must have at least $4 million of "liquid" capital to meet the required margin requirements and potential trading losses"[359].
3. The applicant must have opened a trading account with a clearing member of the exchange and have access to the platform prior to the start of the MMO.

[350] EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.13.

[351] EMA (March 2018), Request for Proposal (RFP) for the 1st Futures Incentive Scheme (FIS) to Provide Market Making Services for the Period 1 August 2018 to 31 January 2020, p.27.

[352] EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.15.

[353] EMA (March 2018), Request for Proposal (RFP) for the 1st Futures Incentive Scheme (FIS) to Provide Market Making Services for the Period 1 August 2018 to 31 January 2020, p.19.

[354] Except in the case of *force majeure events.* Source: EMA (March 2018), Request for Proposal (RFP) for the 1st Futures Incentive Scheme (FIS) to Provide Market Making Services for the Period 1 August 2018 to 31 January 2020, p.17.

[355] EMA (March 2018), Request for Proposal (RFP) for the 1st Futures Incentive Scheme (FIS) to Provide Market Making Services for the Period 1 August 2018 to 31 January 2020, p.18.

[356] Applicant insolvency that prevents it from providing market making services also requires that the applicant pays the exit fee. Source: EMA (March 2018), Request for Proposal (RFP) for the 1st Futures Incentive Scheme (FIS) to Provide Market Making Services for the Period 1 August 2018 to 31 January 2020, p.18.

[357] EMA (March 2018), Request for Proposal (RFP) for the 1st Futures Incentive Scheme (FIS) to Provide Market Making Services for the Period 1 August 2018 to 31 January 2020, p.26.

[358] EMA (March 2018), Request for Proposal (RFP) for the 1st Futures Incentive Scheme (FIS) to Provide Market Making Services for the Period 1 August 2018 to 31 January 2020, p.26.

[359] EMA (March 2018), Request for Proposal (RFP) for the 1st Futures Incentive Scheme (FIS) to Provide Market Making Services for the Period 1 August 2018 to 31 January 2020, p.26.

Under the first FIS, market making services for the same quarterly and monthly contract types as the original market making services arrangement are required. However, the MMs are required to offer 6 lots for the first year of quarterly contracts but only 4 lots for the final year.[360] This is because the EMA noted demand was greater for shorter term (one year out) products.[361] In addition, the maximum bid-ask spread is altered:[362]

- Quarterly contracts: From August to December 2018, the maximum bid-ask spread is S$2/MWh. From January 2019 onwards, it is S$1/MWh or 2 percent of the bid price, whichever is lower OR S$1/MWh or 2 percent of the bid price, whichever is lower. This is to be determined by the EMA after the tender.
- Monthly contracts: The maximum bid-ask spread is the prevailing quarterly contract maximum bid-ask spread plus S$1/MWh.

The refresh requirements under the first FIS are also more stringent. The EMA initially proposed continuous quoting, however, after consultation, this was reduced:[363] MMs are required to refresh prices after an executed trade no fewer than two times during the first six months, no fewer than three times in the next six months and no fewer than four times thereafter.[364] Unlike the original market making services arrangement, there is no grace period for refreshing the quotes.

Under the first FIS, MMs face a more stringent market making coverage requirement. MMs must continue to market make for 80 per cent of the total windows in a month. In addition, "MMs will be required to respond to a Request-for-Quote (RFQ) for the monthly and quarterly contracts, based on the prevailing Market Making Volume requirement during the Market Making Window when they are not quoting"[365]. The RFQ has a maximum bid-ask spread of "no more than 1.5 times the prevailing maximum"[366] bid-ask spread. The RFQ is conducted between the exchange and the MM and the volume of an "off-screen RFQ does not count towards the Market Making Coverage requirement"[367].

We summarise the differences in the market making obligations under the original market making services arrangement and the FIS in Table B.4.

The EMA found six MMs through the tender process for the FIS.[368] These MMs were independent trading operations and only two of the six MMs are directly linked to wholesale

360 EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.9.

361 EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.3.

362 EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.8.

363 EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.11.

364 EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.12.

365 EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.10.

366 EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.10.

367 EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.10, Footnotes.

368 The MMs are DRW Singapore Pte Ltd; ENGIE Global Markets, Singapore Branch; Epoch Energy Solutions Pty Ltd; Fenix One Asia Pte Ltd; Liquid Capital Australia Pty Ltd and RCMA Pte Ltd.

market participants through ownership.[369] The tender price was set at S$218,000 per month and the maximum bid-ask spread was selected as $1/MWh or 2 per cent of the bid price.[370]

After the second FIS finishes in July 2021, the EMA will re-assess market performance and the need for future market making services arrangements. It states:

> "Meanwhile, market players are advised to assume that EMA would make no further interventions beyond Jul 2021 when making their commercial decisions. Should the market be more sustainable, market making can be allowed to continue without the need for incentives."[371]

[369] Trustpower (March 2019), Trustpower Submission: Electricity Price Review's Options Paper, The Lantau Group: Market Making Requirements in New Zealand, p. 19.

[370] Trustpower (March 2019), Trustpower Submission: Electricity Price Review's Options Paper, The Lantau Group: Market Making Requirements in New Zealand, p. 19.

[371] EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.5.

Table B.4: Summary of differences between original market making services arrangement and FIS

Obligations	Contract Type	Original Scheme	FIS
Market Making Volume	Quarterly	6 lots of 0.5 MW contracts (totalling 3 MW) for each side of the 9 quarterly contracts.	6 lots of 0.5 MW contracts (totalling 3 MW) for the first 5 quarterly contracts and 4 lots for the last 4 quarterly contracts (the second year ahead).
	Monthly	6 lots of 0.5 MW contracts (totalling 3 MW) for each side of the 4 to 6 monthly contracts.	No change.
Maximum Bid-ask Spread	Quarterly	S$3/MWh, later 10% of the bid price.	*August 2018 to December 2018:* S$2/MWh *January 2019 onwards:* Lowest of S$1/MWh or 2 per cent of bid price
	Monthly	S$4/MWh	Prevailing quarterly spread plus S$1/MWh
Refresh Requirements		No fewer than one reload. 60 second grace period.	*August 2018 to January 2019:* No fewer than two reloads. *February 2019 to July 2019:* No fewer than three reloads. *August 2019 to January 2020:* No fewer than four reloads. No grace time in each case.
Contract Durations	Quarterly	Two years ahead and the prompt quarter.	No change.
	Monthly	4 to 6 months ahead including the current month. A new quarter of months is listed upon the expiry of the nearest quarter.	No change.
Market Making Coverage	Both products	Must meet obligations in at least 50 per cent of time of each market making window each day and no less than 80 per cent of cumulative window time in the month.	Must meet obligations in no less than 80 per cent of cumulative window time in the month. MMs respond to RFQ when not quoting with bid-ask spread no more than 1.5 times prevailing spread.

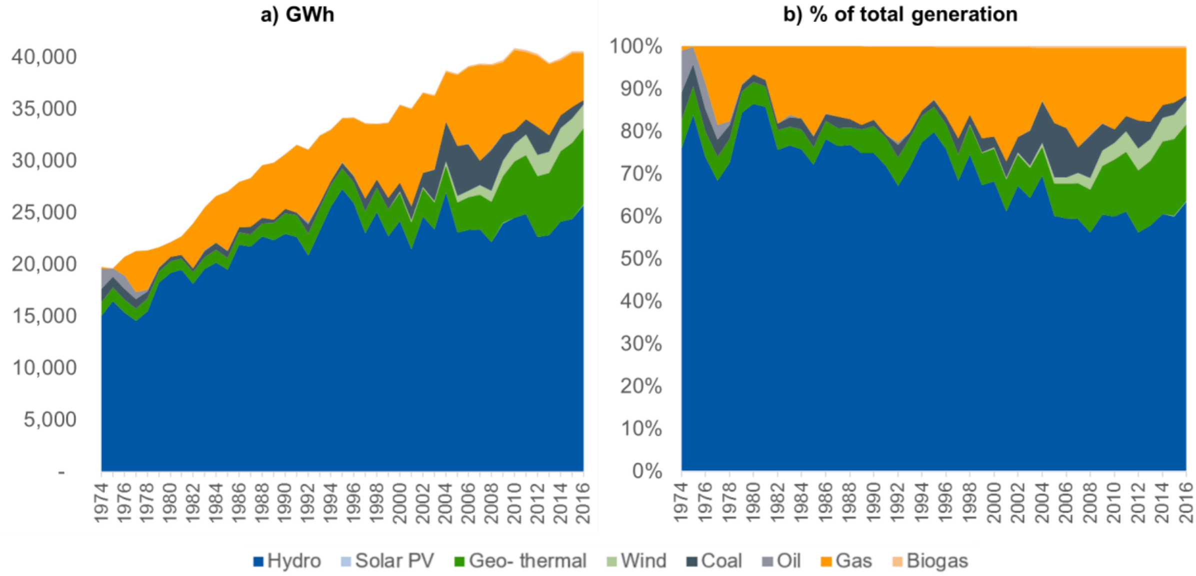
Source: EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.7 to 12.

B.3. New Zealand's Market Making Obligation

B.3.1. Market Context

Similar to the NEM, New Zealand has an energy only wholesale electricity market (henceforth, the NZEM). New Zealand has a very high penetration of hydroelectric generation and limited long-term hydro storage. Figure B.1 below shows the generation mix over time.

Figure B.1: New Zealand: Generation output mix (excluding cogen) (1974-2016)



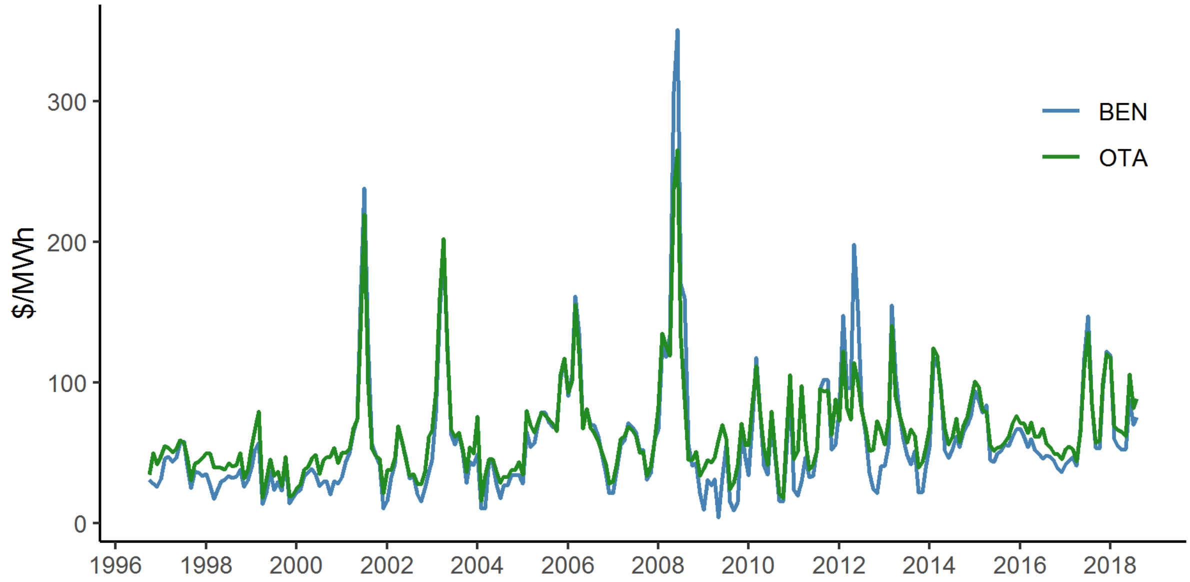
Source: NERA analysis of MBIE electricity data file.

While most electricity markets experience significant *within year* price volatility, this combination of a high proportion of hydro generation and lack of long-term hydro storage[372] results in an additional risk to be managed: *between year* or what is known as dry year risk. That is to say, during some years with low hydro inflows, there are *extended* periods of incredibly high wholesale prices. This is demonstrated in Figure B.2 which shows the wholesale spot price at the two main nodes in the NZEM.

As a result of this unique hydrological risk, the main players in the NZEM are all vertically integrated between generation and retailers. The generation market is also relatively concentrated amongst The Big Four 'gentailers' and Trustpower. Figure B.3 shows the generation and retail balance for each of the major 'gentailers' and Figure B.4 shows the generation market shares.

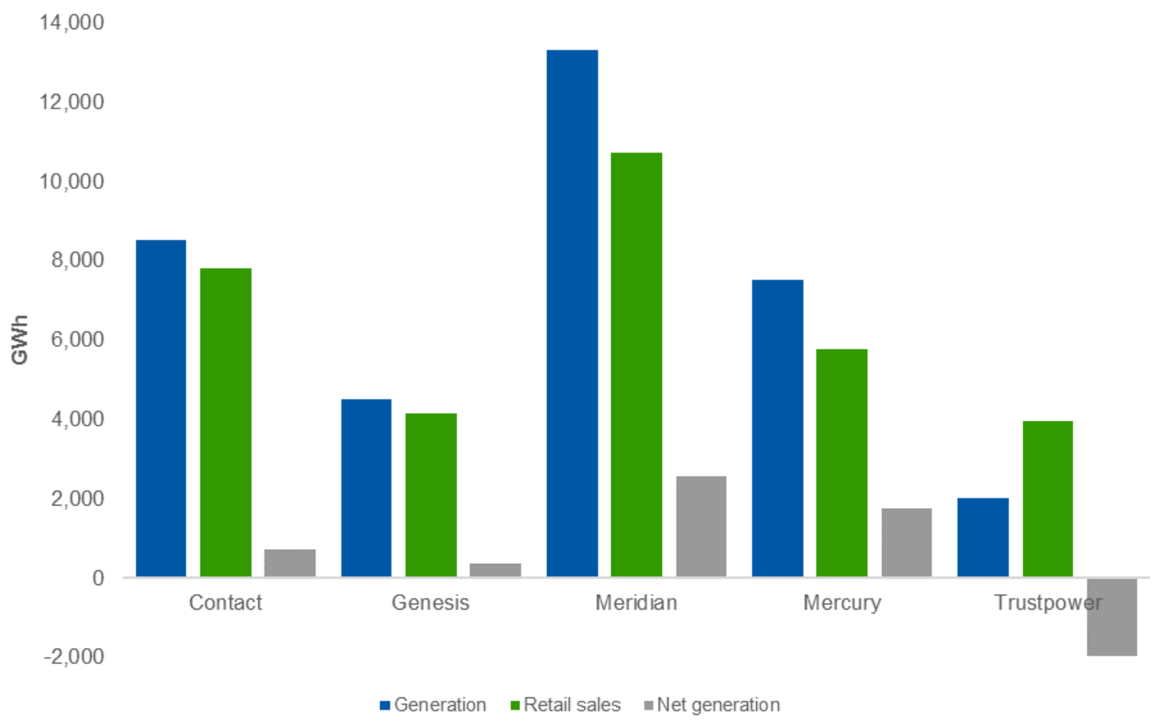
[372] See the 83-year average storage level on page 4 of the report available at: https://www.meridianenergy.co.nz/assets/Investors/Reports-and-presentations/Monthly-operating-reports/2018/July-2017-mo nthly-operating-report.pdf

Figure B.2: New Zealand: Monthly average wholesale spot price (1996-2018)



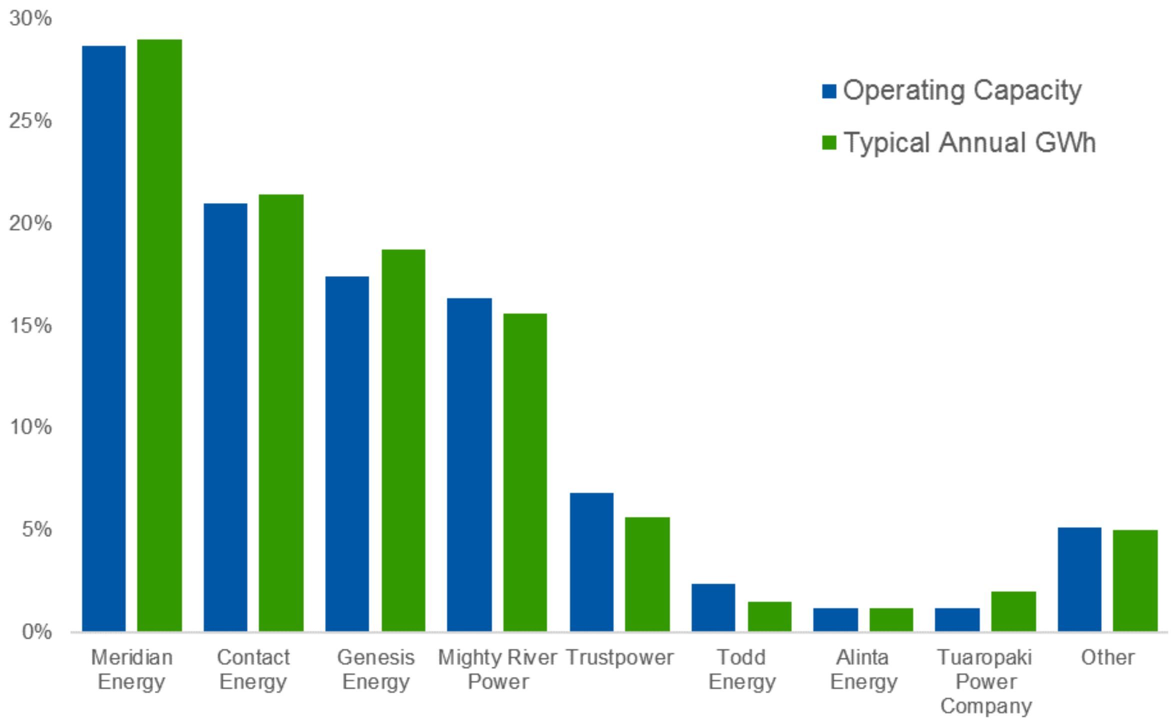
Source: NERA analysis of Electricity Authority EMI final pricing dataset.
Note: Calculated using daily average prices at the Otathuhu and Benmore grid reference points.

Figure B.3: New Zealand: Generation/retail sales balance (FY2017)



Source: Generator Annual and operational reports.

Figure B.4: Generation market share (capacity and typical output)



Source: NERA analysis of EA Existing Generation fleet dataset.

Before 2010, hedge contracts existed in the New Zealand electricity market as bi-lateral, non-anonymous contracts agreed through a trading platform called EnergyHedge, that was effectively restricted to the large 'gentailers'. Liquidity and access, form the perspective of a non-incumbent retailer, was therefore likely low. In July 2009, the Australian Securities Exchange (ASX) then began offering New Zealand electricity futures contracts, independently of the 2009 government review mentioned above. It is on this exchange which market making by the main 'gentailers' occurs, as we now discuss.

B.3.2. History of the MMO

Since 2004, policy makers and regulators have carried out several reviews of the NZEM, prompted by concern in dry years over high prices, security of supply and access to hedging contracts due to the predominance of vertical integration in the supply chain, including:

- 2006: a government review of the electricity market by the Ministry of Economic Development (MED);[373]
- 2006: a consultation on hedging conducted by the Electricity Commission (now known as the Electricity Authority);
- 2006-2009: an investigation into competitiveness and market power in the wholesale electricity market by New Zealand's competition regulator, the Commerce Commission; and

[373] Now known as the Ministry of Business, Innovation and Employment (MBIE).

- 2009: another government review led by the Minister of Energy and Resources and assisted by a group of academics and industry experts (the Electricity Technical Advisory Group).
- 2014: the Electricity Authority began two parallel processes:[374]
  - Its own review of options to enhance trading (i.e. liquidity) of hedge products; and
  - An investigation by the Wholesale Advisory Group (WAG) of whether the current hedge market arrangements allow participants to effectively manage spot market risk.

The outcome of the 2009 government review was a decision to oblige the major generators to establish a liquid hedge market by 1 June 2010. This market was to offer standardised, tradeable contracts and a clearing service for all transactions; it had to offer low barriers to entry, low transactions costs, and market makers offering to buy and sell with a low spread between their prices.[375] The government's aim was to create a liquid hedging market by 1 June 2011 with an "unmatched open interest" (UOI), i.e. a volume outstanding at any time, of 3,000 GWh.

The government's obligation on the generators to create a liquid hedge market was operationalized by the four main 'gentailers' entering into *voluntary* market making agreements with the ASX. A brief history of the products and market making obligations on the ASX is as follows:[376]

- June 2010: four of the five largest generators[377] enter into voluntary market making agreements with the ASX, offering a *quarterly baseload futures contract* (from which developed an annual "strip" of four quarterly contracts) with a maximum bid-offer spread of 10%. Market making covers all four quarters;
- October 2011: the four market makers voluntarily agree to tighter market making agreements, including a 5% bid-offer spread;
- December 2013: the ASX extends the list of products to include a *monthly baseload futures contract*, an *option on the quarterly baseload futures contract*, and a *quarterly peak futures contract*;
- June 2014: the market maker agreement is extended to the monthly baseload product for the front six months.
- November 2015: The contract size is changed from 1MW to 0.1MW.

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374 An overview of the various hedge market consultations conducted by the EA is available at https://www.ea.govt.nz/development/work-programme/risk-management/hedge-market-development/consultations/

375 NZ Decision Paper (2009), *Summary of Main Decisions: Ministerial Review into Electricity Market Performance*, Ministry of Business, Innovation and Employment, December 2009, paragraph 3.

376 As described in Electricity Authority (2015), *Hedge Market Development: Enhancing Trading of Hedge Products - Consultation Paper*, Electricity Authority, 1 May 2015. (Available at https://www.ea.govt.nz/dmsdocument/19441)

377 The smallest of the five large gentailers, Trustpower, chose not to enter into a market making agreement with the ASX.

- December 2015: The Electricity Authority recommends introduction of a "cap" product, i.e. an option contract with a strike price above the level of current fuel costs, intended to stabilise returns on, and therefore to encourage investment in, generation capacity.[378]

Participation in the *voluntary* market making scheme is incentivised in two main ways:

- Participants receive a share of a revenue pool; and
- The threat of further government intervention.[379]

On the threat of further intervention, the New Zealand Government's 2018/19 Electricity Price Review (EPR) has recently considered the issue of market making and recommended the introduction of mandatory market making. The basis for this recommendation is that:

- During times of tight supply, price signals become "muffled" (as spreads widen); and
- The voluntary arrangement is fragile and unpredictable.[380]

The EPR recognised that an incentivised scheme could be more efficient[381]

> *A mandatory market-making obligation could be replaced later by an incentive-based scheme whereby companies best placed to act as market makers could be paid to take on that responsibility. A levy on vertically integrated companies above a minimum size could help recover market-maker fees. This could be more efficient than a mandatory obligation, and compliance monitoring and enforcement costs could be lower. However, Singapore's experience suggests an incentive-*based scheme would *take several years to develop*

The EPR recommended a mandatory scheme, despite recognising that an incentivised scheme could be more efficient. This was on the basis that:

- A mandatory scheme could be introduced "relatively quickly"; and
- Singapore's experience suggests an incentivised scheme would take "several years" to develop.

The outcome of this process is still in development. The 'gentailers' and the ASX have already been working on the design of an incentivised scheme and have challenged the premise that it would be slow to implement.[382] Similarly, the generators have argued that the

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378 See statement by Electricity Authority at: https://www.ea.govt.nz/development/work-programme/risk-management/hedge-market-development/development/enhancing-trading-of-hedge-products-decisions-paper-published/

379 In a 2011 consideration of whether to introduce a market mandatory market making obligation with tighter spreads, the Electricity Authority decided not too, but noted:

If circumstances change, and in particular if observed spreads were to widen because the number of active market-makers were to decline (by formal withdrawal or via a change toward passive trading strategies), the CBA indicates that the justification for Code amendments would be stronger and therefore the Authority will reconsider this position.

Source: Electricity Authority (November 2011), "Information Paper: Cost Benefit Analysis – Market Making Obligations", par. 6.

380 EPR Options Paper, p. 19.

381 EPR Options Paper, p. 20.

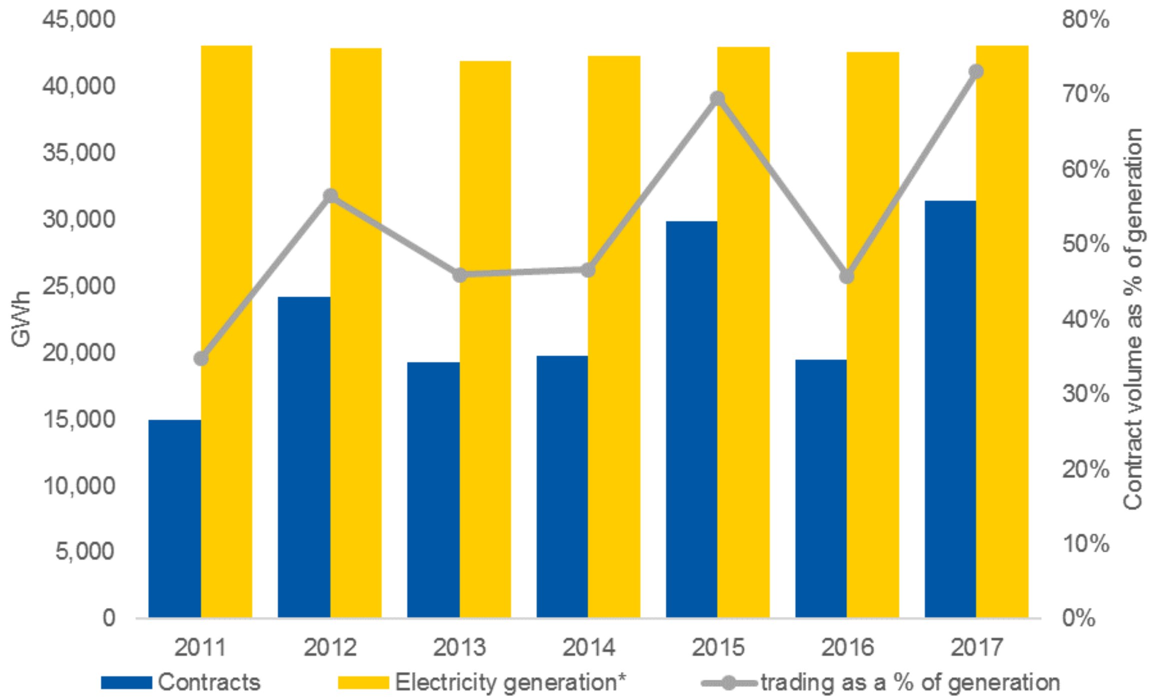
382 Meridian, *Electricity Price Review Options Consultation: Meridian and Powershop submission,* 22 March 2019

design of a mandatory obligation is complex and market specific, and therefore a “quick” mandatory obligation is likely to be a poorly designed one.

B.3.3. Costs and Benefits of the MMO

Liquidity, proxied by the churn ratio (contract volumes as a percentage of generation volumes) has improved since the introduction of ASX contracts and market making. Figure B.5 below takes data from the New Zealand Electricity Hedge Disclosure System and measured grid injections to measure contract churn over time.

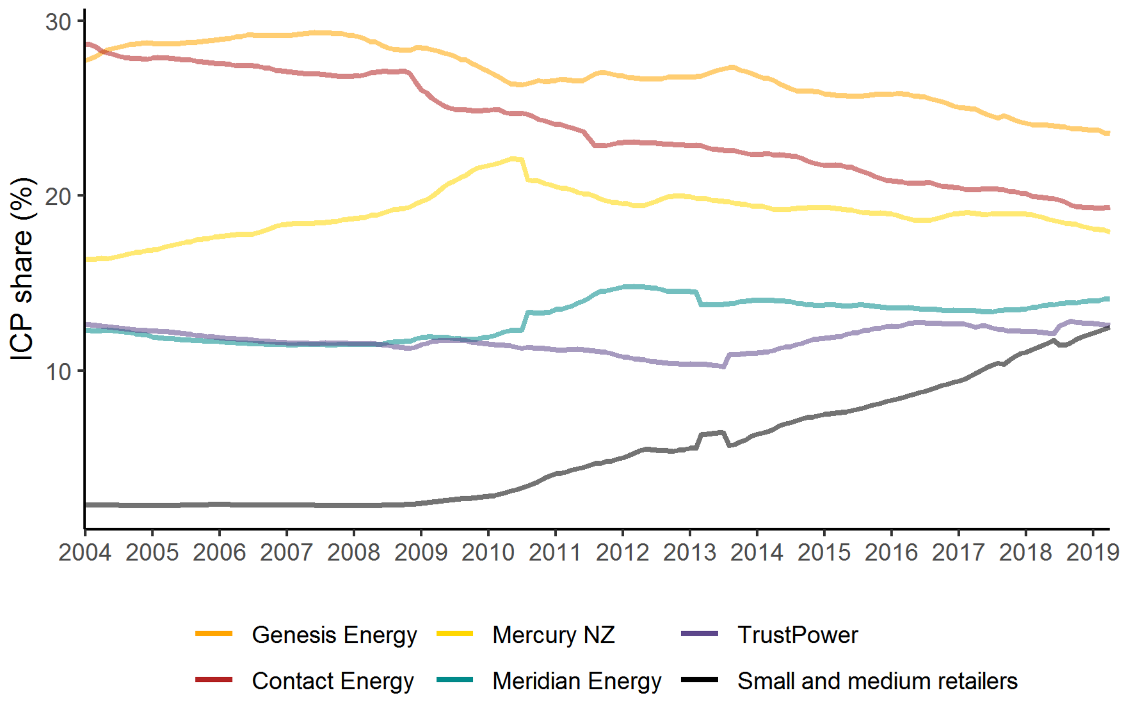
Figure B.5: Contract volumes as % of generation



Source: NERA analysis, Electricity Hedge Disclosure System, EA EMI data on grid injections.

Over the same period, there has been increased retail entry, as shown by Figure B.6 below. From 2009 to 2019, the combined market share of the largest four ‘gentailers’ fell from 86% in 2009 to 75% in 2019. On the other hand, the combined market share of Trustpower the smaller ‘gentailer’ and other small and medium retailers increased from 14% in 2009 to 39% in 2019.

Figure B.6: National retail market share by ICPs



Source: Electricity Authority EMI dataset.

However, it is hard to disentangle the impact on competition from voluntary making with the more general introduction of exchange based futures contracts (providing greater *access* to hedging) and parallel reforms such as the governments $15m consumer switching fund which came out of the 2009 Government review.

Regarding the costs, Meridian estimates that it has incurred costs of $1m to $2m per annum on average due to its voluntary market making agreement.[383] If the four 'gentailers' all incur similar costs, that is an annual cost of $4m to $8m. In the last year however, this cost has been much higher, with Meridian estimating the market marking agreement has resulted in a cost of $5m for YTD 2019. Contact and Genesis estimate that for the FY19 their making costs have been $2m[384] and $4m[385] respectively.

In 2011, the Electricity Authority conducted a cost benefit analysis of a "code based" market making obligation.[386] The key thing the EA attempted to quantify was a tightening of the maximum spread and thus this process was somewhat overtaken by the voluntary market makers voluntarily agreeing to lower the maximum spread in their agreements to 5%. Nonetheless, because the EA attempted to conduct a cost benefit analysis, it is useful precedent to consider with respect to categories of costs and benefits they considered.

383 Meridian, *Electricity Price Review Options Consultation: Meridian and Powershop submission*, 22 March 2019

384 Contact (August 2018), 2018 Full Year Results Presentation, p. 26.

385 Genesis (February 2019), HY19 Result Presentation, p. 9.

386 Electricity Authority (November 2011), "Information Paper: Cost Benefit Analysis – Market-Making Obligations".

The costs the EA considered are detailed in Table B.5.

Table B.5: Summary of costs and benefits identified by the EA

Cost / Benefit	Description	Quantification
Direct costs for market maker participants	Investing in systems or hiring more staff associated with the market-making obligation	Makes assumptions around set up and operating costs from $0 to $6m set up then $1.2 per annum
Costs arising from code-imposed, as opposed to voluntary obligation	Having a market-making obligation reduces flexibility and may need to be adjusted for new products or changes to existing products	N/A
Stronger retail competition	Greater confidence in forward prices is expected to facilitate entry and expansion as firms are better able to manage exposure to price risk. Puts downwards pressure on prices and increases incentives to innovate	Calculates the expected increase in retail efficiency benefit from a reduction in operating costs (due to improvements in market-making arrangements) of 0.25-0.75%
Improved fuel management decisions	Having a better idea of the forward price curve gives firms a better indicator of future conditions so can make better fuel management decisions	Calculates the cost savings of a 0.5% to 1% reduction in the swing component of thermal fuel use due to better decision making
Improved demand side operating decisions	Electricity users have a better idea of expected conditions and greater confidence to enter into contracts. They can make better decisions regarding whether to commit to a production order or buyback contract	Calculates the added economic value of a 0.5% to 1% improvement in demand variation costs relating to electricity purchased by basic metal processing, timber ands pulp and paper sectors.
Improved generation investment decisions	Firms have a better idea of expected future conditions so investment and operating decisions lead to stronger generation competition and investment efficiency	Calculates the added economic value of a 0.5% to 1% reduction in investment cost
Improved demand side investment decisions	Firms who are large electricity consumers have a better idea of future pricing so can make better investment decisions relating to production capacity or demand response capacity	Calculates the benefit of a 0.5% to 1% reduction in average investment costs, due to better information on forward price, for the pulp and paper, and basic metal sector

Source: Electricity Authority, Cost Benefit Analysis – Market-Making Obligations, 21 November 2011.

A summary of the expected benefits quantified by the EA is set out below.

Table B.6: Summary of estimated benefits

$m NPV	Low	Mid	High
Retail costs	27	54	81
Fuel management	9	14	18
Demand side operating decisions	2	3	5
Generation investment	11	16	21
Demand side investment decisions	4	5	7
Total	53	93	133

Source: Electricity Authority, Cost Benefit Analysis – Market-Making Obligations, 21 November 2011.

B.4. Western Australia's Market Making Obligation

The Economic Regulation Authority (ERA) imposed an MMO on Synergy in Western Australia (WA) in May 2014.[387] Synergy is a state-owned 'gentailer' that owns approximately 70 per cent of the generation in WA.[388]

The MMO or "Electricity (Standard Products) Wholesale Arrangements 2014"[389] requires Synergy to offer four quarterly products (up to one year ahead), up to two calendar year products (current year and next year ahead) and one financial year product.[390] Synergy must offer both flat and peak products and must offer a minimum of 150 MW for sale and 100 MW for purchase in each product.[391] This amount of energy is relatively small, representing five per cent of total WA market generation: in Ireland the Directed Contracts regime obligates ESB to offer ten per cent of total market generation.[392] The maximum bid-ask spread was phased in: a maximum spread of 25 per cent of the bid price was enforced until January 2015 when the maximum spread became 20 per cent of the bid price.[393] The aim of the MMO was to: [394]

- Restrict Synergy's wholesale pricing to encourage private sector activity,
- Act as a price discovery mechanism for market participants to benchmark competitive prices; and
- Provide standardise products for new entrant suppliers.

The ERA issued a public consultation on the performance of the wholesale electricity market in December 2018.[395] In response to this consultation, Kleenheat, a retailer in WA, argued that the current MMO places too much price setting power in the hands of Synergy.[396] As such, Kleenheat argued that Synergy could artificially set high bid prices which would deter new entrants. It argued that arrangements, such as Directed Contracts regime in Ireland, would provide superior arrangements. Other retailer responses to the consultation also agreed that Synergy was setting prices that were too high to restrict competition.[397]

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387 Western Australian Government Gazette (May 2014), Electricity (standard products) wholesale arrangements 2014, Schedule.

388 AEMC (December 2018), National Electricity Amendment (Market Making Arrangements in the NEM) Rule 2019 Consultation Paper, p. 10.

389 ERA (April 2019), Investigation into Synergy's pricing behavior, p. 1.

390 Western Australian Government Gazette (May 2014), Electricity (standard products) wholesale arrangements 2014, Schedule.

391 Western Australian Government Gazette (May 2014), Electricity (standard products) wholesale arrangements 2014, Schedule.

392 ERA (January 2018), 2016–17 Wholesale Electricity Market Report to the Minister for Energy, p. 9.

393 Western Australian Government Gazette (May 2014), Electricity (standard products) wholesale arrangements 2014, Schedule.

394 AEMC (December 2018), National Electricity Amendment (Market Making Arrangements in the NEM) Rule 2019 Consultation Paper, p. 10.

395 ERA (January 2018), 2016–17 Wholesale Electricity Market Report to the Minister for Energy.

396 Kleenheat (March 2019), Kleenheat confidential submission for "Report to the Minister for Energy on the Effectiveness of the Wholesale Electricity Market 2017/18. Discussion Paper".

397 ERA (January 2018), 2016–17 Wholesale Electricity Market Report to the Minister for Energy, p. 10.

Concurrently, the ERA began an investigation in July 2017 into Synergy's pricing.[398] In particular, the ERA was concerned that Synergy had switched its pricing model in 2016 and may had been setting bid prices above short run marginal cost.[399] In April 2019, the ERA "concluded that the prices offered exceeded Synergy's reasonable expectation of the short run marginal cost of generating the relevant electricity in 12,908 trading intervals, and that Synergy's behaviour was related to its market power"[400]. In addition, "The ERA has calculated that Synergy's pricing behaviour increased Synergy's revenue by between $40 million and $102 million above what it would have received over the 15-month investigation period"[401].

[398] ERA (July 2017), ERA starts investigation into Synergy's pricing behavior.

[399] ERA (April 2019), Investigation into Synergy's pricing behavior, p. 1.

[400] ERA (April 2019), Investigation into Synergy's pricing behavior, p. 1.

[401] ERA (April 2019), Investigation into Synergy's pricing behavior, p. 1.

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