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GB Wholesale Power Market Liquidity: Options Assessment

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Executive Summary

Ofgem introduced the Secure and Promote (S&P) Market Making Obligation (MMO) in 2014 to improve liquidity in the wholesale electricity market. Ofgem placed the obligation on the six largest vertically-integrated companies at the time of its introduction. Following market changes that led to a steady decline in the number of mandated market-makers, on 18 November 2019, Ofgem suspended the MMO.

In May 2019, Ofgem announced that it would conduct an Options Assessment to consider whether intervention to support liquidity in the GB wholesale electricity market was required. Ofgem commissioned NERA Economic Consulting to advise on, analyse and conduct part of the ongoing policy Options Assessment.

It is unclear what the economic rationale for further intervention may be

Low liquidity is not a market failure that in itself would justify intervention to increase it and may instead be an efficient response to market conditions. The case for intervention to support liquidity would rely on the market's failure to reach an efficient outcome.

There is no clear market failure leading to a lack of liquidity in the GB wholesale electricity market. However, the market is less liquid than others in Continental Europe, which may suggest some underlying market failures dampen liquidity in GB. As a result, the lack of a distinguishable market failure may not necessarily preclude further intervention. For instance, the risks of intervening and not intervening may be asymmetric and the negative consequences of failing to intervene where needed may be greater than those of unnecessary intervention. In such circumstances, it would be prudent for Ofgem to treat low liquidity as a symptom of an unknown problem, and intervene to increase liquidity.

Suspension of the S&P MMO provides Ofgem, and market participants, an opportunity to observe liquidity in the absence of intervention and assess whether further intervention would result in more efficient market outcomes.

Stakeholder feedback indicates that, should further intervention be required, a tendered MMO would be the preferred option

The feedback from industry participants at a stakeholder workshop conducted by Ofgem widely accepted that, should further intervention to support liquidity in the wholesale market be required, the intervention should be in the form of a tendered or voluntary MMO.

Our report assesses the net benefits of a tendered MMO that delivers the same level of liquidity (as measured by bid-ask spreads) as the S&P MMO against three counterfactual levels of liquidity that may prevail in the market with 'no-intervention', see Table 1 below. We have chosen bid-ask spreads for the counterfactual that do not necessarily correspond to our expectations of future spreads, but merely allow us to examine the net benefits of further intervention relative to a range of potential levels of liquidity.

Table 1: Our Estimated Current, Historical and Counterfactual Bid-Ask Spreads

	Baseload	Peakload
1. S&P MMO (2014-present)	0.36%	0.54%
2. High liquidity counter-factual	0.68%	0.97%
3. Historical (2009-2013)	0.99%	1.40%
4. Low liquidity counter-factual	1.98%	2.80%

Source: NERA Analysis.

We also estimate the potential gross benefits of a tendered MMO with relaxed requirements of market makers compared to the S&P MMO (i.e. a tender producing bid-ask spreads in the 'high-liquidity' counterfactual). However, we do not assess the net benefits of a tendered MMO with relaxed requirements because we do not have accurate information of how the costs of fulfilling the obligation may change with relaxed requirements.

We quantify the benefits of an MMO by simulating how lower transaction costs that result from an MMO may change the optimal hedging strategy of retailers and result in cost savings

We assume that the effect of intervention through an MMO is to reduce market bid-ask spreads on forward contracts, which lowers the transactions costs paid by suppliers and generators. In response to lower transactions costs, suppliers and generators change their optimal hedging strategy which lowers their costs of hedging for the same risk of a negative cash balance. We estimate the reduction in costs from suppliers and generators changing their optimal hedging strategies as the benefit from the MMO.

Like any modelling exercise, our approach flows from a series of assumptions which we discuss in full in Section 7.2 of our report. Stakeholders should interpret our results in light of the consequences of these assumptions, including (but not limited to):

- Our model understates the value of hedging (and the intervention) because we only analyse seasonal products and ignore any benefits of the MMO on other products e.g. monthly products.
- Our model does not account for any movement of liquidity to the mandated trading windows under the S&P MMO design. Moreover, we do not consider the benefit for retailers of having certainty of product availability during specific times of the day.
- In our model, we use the Weighted Average Cost of Capital (WACC) to calculate the benefit that market participants get from holding less risk capital in more liquid markets.[1] We assume a constant WACC which is independent of hedging strategy whilst, in practice, the WACC may reflect the hedging strategy followed by the retailer.
- Our model overstates risk capital benefits for generators, because we ignore fuel and cost correlation with market prices.

[1] Risk capital refers to the assets a market participant holds in order to ensure they avoid financial distress in the presence of volatile wholesale costs. Market participants face a trade-off between incurring the transactions costs of hedging their exposure to power prices and holding risk capital.

A tendered MMO that delivers the same market bid-ask spreads as the S&P MMO may not deliver a net benefit: Our estimates suggest that the tendered MMO would deliver a net benefit if liquidity fell below the level before the introduction of S&P

We estimate the net benefits of an MMO which delivers the same level of liquidity as the S&P MMO. We assume the historical costs of market-making reported by market makers under the S&P MMO. Our analysis suggests that:

- If liquidity falls to levels below those prior to the introduction of the S&P MMO, (i.e. close to our low liquidity counterfactual), intervention to restore liquidity to levels experienced under the S&P MMO could deliver net benefits in the range of £25.2m-£94.6m, see Table 2.
- If spreads return to historical levels (2009-2013) or doubled (the high-liquidity scenario) then the intervention would deliver a net benefit if it simultaneously:
  - delivered the upper bound of our estimated range of benefits i.e. £18.8m in the high liquidity scenario or £38.2m in the historical scenario; and
  - the costs of fulfilling the obligation were low relative to the range of historically reported costs of market making, i.e. £4.7m.

Table 2: Our Estimated Net Benefits of the MMO (Units in £m)

	High liquidity counter-factual bid-ask spreads		Historical bid-ask spreads		Low liquidity counter-factual bid-ask spreads	
	(Lower)	(Upper)	(Lower)	(Upper)	(Lower)	(Upper)
Benefit	14.5	18.8	29.5	38.2	76.7	99.3
Cost	51.5	4.7	51.5	4.7	51.5	4.7
Net Benefits	**-37.0**	**14.1**	**-22.0**	**33.5**	**25.2**	**94.6**

- *Source: NERA Analysis*

We also estimate the gross social benefits of a tendered MMO with relaxed requirements that delivers the same level of liquidity as the high liquidity counter-factual (i.e. double the market bid-ask spreads under the S&P MMO): We estimate the gross social benefits are around half of our estimated gross benefits of a tendered MMO with the same requirements as the S&P MMO.

The modelled net benefits of intervention set out in the table above may be greater or smaller than the total net benefits of intervention, after accounting for any unquantified costs and benefits in our modelling.

Stakeholders provided feedback on the design of a future MMO, should further intervention be required

Stakeholders indicated broad support for redesigning the requirements of the S&P MMO to allow market-makers more flexibility during volatile markets and reduce the costs of fulfilling the obligation. We summarise the feedback from stakeholders in Table 3.

Table 3: Summary of Stakeholder Feedback on Secure and Promote MMO Design

MMO Design Element	S&P MMO Design	Stakeholder Feedback on Future MMO Design
Maximum bid-ask spread	Baseload: 0.5% – 0.6 %. Peakload: 0.7% - 1%	Bid-ask spreads viewed as a significant driver of the costs of market-making. Stakeholders provided support for relaxing spreads in volatile markets or relaxing other requirements (e.g. availability) to provide flexibility in volatile markets and reduce costs of market-making
Clip size and number of lots	Up to 10MW in clip sizes of 5 MW	Largely viewed as appropriate but smaller lot sizes could provide additional flexibility and reduce costs of market-making
Products	Up to two years-ahead. Includes monthly, quarterly and seasonal baseload and peakload products	Products generally a good compromise – additional products or more granular products likely to increase the costs of market-making.
Trading windows	Two hour-long windows each day. Must be available 100% of the trading windows and replace bid-ask within five minutes of executing a trade.	100 per cent availability in the trading windows viewed as a significant driver of the costs of market-making; support for reducing the requirement, e.g. 80 per cent availability in the windows or on a monthly basis.
Suspension of obligation	The MM may cease trading for a particular product and trading window if the price changes by more than 4% in a single direction or it accumulates an open position of 30MW in a single direction.	General acceptance of need to relax the requirements, possibly by moving away from 100% availability requirement in two windows.
Number/selection of market makers	Number of mandated participants selected by criteria (degree of vertical integration).	Could be selected via a tender.

Source: NERA Analysis of stakeholder feedback collated by Ofgem.

Ofgem will need to make a number of design choices in the design of a tendered MMO, should it decide that further intervention through a tendered MMO is required

We summarise some of the design options of a tendered MMO in Table 4 and discuss them in more detail in Section 8.2 of our report.

Table 4: Summary of Tender Design Options for a Tendered MMO

Design Element	Option A	Option B	Preferred Option
Auction type	Sealed bid	Ascending price dynamic multi-round auction with feedback	A sealed bid auction may be cheaper for Ofgem to run and may allow Ofgem more flexibility in the design elements of the MMO it can determine through the tender process. A second-price sealed bid may be preferred to a first-price sealed bid to mitigate market power (if present) and ensure an efficient allocation. On the other hand, a dynamic multi-round auction with feedback allows applicants to observe the bids of other applicants. As a result, applicants may learn from the bidding behavior of other applicants and the auction may result in a more efficient price.
Market power mitigation	Multiple options may be used simultaneously. Options include: ▪ Use of a reserve price; ▪ demand curve bidding; and ▪ cost based bidding plus a margin.		If the tender only operates with licensed parties, market power could be a problem given the relatively few licensed parties who have previous experience market making. The combination of the options used in the final design will depend on other choices e.g. auction method. The feasibility of some of the options listed may depend on the extent to which further information is provided to Ofgem by industry.

Source: NERA Analysis

1. Background and GB's Current Market Making Obligation

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.[2] The vertically-integrated 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.[3]

In response, Ofgem launched an investigation (the Energy Supply Probe in 2008) into the competitiveness of Britain's electricity retail market.[4] Through this investigation, Ofgem became primarily concerned with the low level of liquidity in the electricity wholesale market and began a separate inquiry in response (Ofgem – Liquidity in the GB wholesale energy markets, 2009).[5] Ofgem stated:[6]

> "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."

After the Liquidity in the GB wholesale energy markets inquiry, Ofgem concluded that it needed to intervene in the electricity wholesale market to improve liquidity.[7] It argued that poor liquidity could be self-reinforcing: Poor availability of products and weak price signals reduces market participation and leads to further loss of liquidity.[8] This leads to a lower equilibrium, within which there do not exist the market incentives to escape.[9]

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[2] Ofgem (2008), Energy Supply Probe, p. 29.

[3] 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.

[4] Ofgem (August 2009), Energy Supply Probe – Proposed Retail Market Remedies.

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

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

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

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

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

1.1. Secure and Promote and the Market Making Obligation

Ofgem's intervened in the wholesale market through the Secure and Promote Licence (S&P), implemented on 31st March 2014.[10] The S&P Licence had three objectives:[11]

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.[12]

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 listed above.[13] 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.[14] Overall, with narrower and more available bid-ask spreads, Ofgem hoped to engineer the self-reinforcing cycle of liquidity in the market leading to large increases in traded volumes.[15]

1.2. The Design of the MMO

The MMO compelled mandated parties to post bid-ask spreads on an accessible trading platform[16] 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).[17] 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.[18] 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

[10] Ofgem (January 2014), WPML: decision letter, p.1.

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

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

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

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

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

[16] 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.

[17] 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

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

per cent. Ofgem permitted larger maximum bid-ask spreads (by 0.2 percentage points) for the first three months of the S&P Licence.[19]

Initially, Ofgem proposed that bid-ask spreads should be specified for more than 50 per cent of market opening time each month.[20] 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.[21] Ofgem argued that this was superior as it provided a guaranteed opportunity to trade each day as well as reducing compliance costs.[22] In the window, the MM has a maximum of five minutes to replace its bid-ask after an executed trade.[23] The MM is also compelled to post bid-asks for 5MW and 10MW lot sizes and must execute trades up to 10MW.[24]

Two exemptions were provided under which a MM is no longer obligated to post a bid-ask spread for a specific product in a particular trading window. The obligation is reinstated at the next trading window.[25]

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.[26] The price change is defined by the difference between the first trade and the trade that triggers the clause.[27] The first and last trades may be made by different traders on different trading platforms.[28] 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.[29]

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.[30] Trade sizes that exceeded the maximum obligated lot size (10MW) are not counted towards this volume cap.[31] The licensee must

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

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

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

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

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

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

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

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

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

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

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

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

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

report the windows and products for which this volume cap was hit to Ofgem in its quarterly report.[32]

1.3. 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.[33] Ofgem noted that these firms had stable shares of the market aided by their sticky customer base[34] and therefore would have more flexibility in identifying their optimal hedging strategy.[35] 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"[36].

In addition, given The Big Six were vertically-integrated, Ofgem argued that they would be naturally more robust to periods of low liquidity.[37] 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.[38] Ofgem also noted that the benefit of adding additional, smaller licensees to the MMO would be limited but the costs might be large.[39]

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.[40] The licensee retains the responsibility to meet the obligation should they nominate a third party.[41] In the case when a licensee nominates a third party, the volume of each bid-ask posted for each product must correspondingly double (to 5MW, 10MW, 15MW and 20MW).[42]

1.4. Effects on Liquidity

Ofgem argues that since the introduction of S&P, the volume of contracts traded has "slightly increase[d]"[43], although it recognises that the larger volumes, particularly in 2016, may be due to market volatility.[44] There was a 17 per cent increase in traded volume from 2013 to

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

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

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

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

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

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

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

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

40 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.

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

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

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

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

2017.[45] The difference in market churn 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.[46] There are also almost three times the number of suppliers in the market (as of June 2019) than in December 2013.[47] However, Ofgem states this is not entirely attributable to the S&P.[48]

Bid-ask spreads have also narrowed since the start of S&P,[49] which is unsurprising given the MMO specifies a maximum bid-ask spread.[50] 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.[51] However, churn did rise along with market volatility in Q4 2016.[52] In 2017, churn deteriorated and now remains comparable to levels before the introduction of the MMO.[53]

45 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.

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

47 Ofgem (October 2019), Number of active domestic suppliers by fuel type (GB), Link: https://www.ofgem.gov.uk/data-portal/number-active-domestic-suppliers-fuel-type-gb

48 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.

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

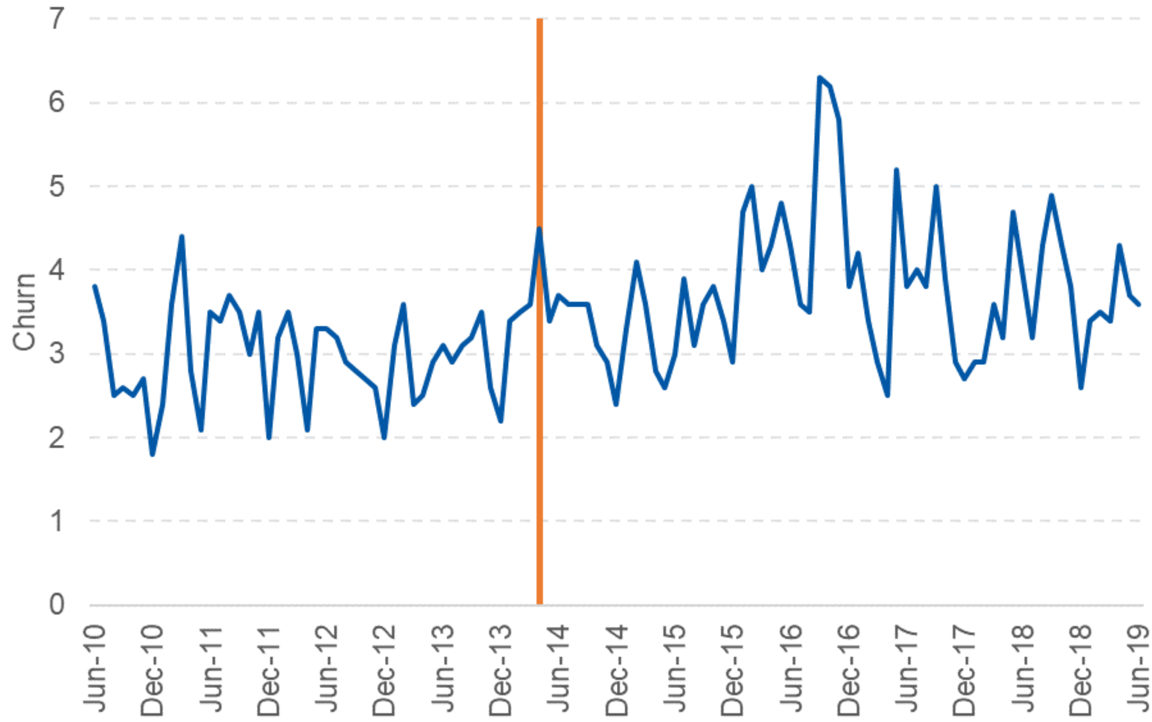
50 Ofgem (July 2017), S&P Review: Consultations, p.9, 1.9.

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

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

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

Figure 1.1: GB Historical Churn Ratio and the Introduction of the MMO (Total Traded Volumes by Total Power Demanded, 2010-2019)



Source: Ofgem (2019) Electricity trading volumes and churn ratio by month and platform, Link: https://www.ofgem.gov.uk/data-portal/electricity-trading-volumes-and-churn-ratio-month-and-platform-gb

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.[54] The CMA examined data outside the windows and found that "product availability had become worse since the introduction of S&P"[55] arguing that "these results paint a picture of relative, rather than absolute, availability".[56]

1.5. The Market Context Since the Introduction of the MMO Has Changed

Since the implementation of the MMO, wholesale market structure has changed substantially.[57]

In September 2016 E.ON SE separated its fossil fuel generation from renewable generation, supply, networks and trading business[58] The separation reduced E.ON SE's generation

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

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

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

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

[58] 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.

market share from 6 to 1 per cent.[59] Therefore, E.ON SE applied to have Ofgem remove the MMO (and other obligations under the S&P) which Ofgem approved in November 2016.[60] Ofgem argued that the reduction in vertical integration eliminated the disincentive to trade and justified the decision to remove the obligations.[61] 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.[62]

In December 2017, Centrica Group, owner of British Gas, applied to remove the MMO from its license.[63] Centrica argued that divestments of its generation arm representing a change in corporate strategy should justify this removal.[64] Centrica's generation market share fell from 4.5 per cent at the start of the S&P to 0.8 per cent at the time of application, and was therefore below E.ON's market share at the time of the removal of its MMO.[65] In its application, Centrica stated that MMO costs had risen over time and those costs incurred in 2016 due to market volatility, were much higher than the Ofgem ex-ante "high-case" scenario.[66] 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."[67]

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 into design elements of the MMO, in order to evaluate the MMO intervention in its entirety.[68] 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."[69]

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59 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.

60 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.

61 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.

62 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.

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.

64 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.

65 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.

66 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.

67 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.

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

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

In November 2018, Ofgem published this review and stakeholder responses.[70] 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.[71] The respondents were also concerned that the application of the MMO to vertically-integrated entities was increasingly arbitrary.[72] However, three quarters of respondents, mainly small suppliers, were against the suspension arguing that it would lead to wider spreads and reduced liquidity.[73] 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.[74]

Ofgem concluded that immediate suspension of the MMO would "lead to significant disruption of the market"[75]. However, with planned transactions involving SSE Generation and Npower and Scottish Power and Drax leading to the potential removal of its MMO, Ofgem was concerned that the remaining market maker (MM), EDF, may not "generate a robust price"[76]. 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"[77]

The SSE Generation/Npower merger was abandoned in December 2018.[78] 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.[79] 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."[80]

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

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

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

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

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

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

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

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

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

79 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.

80 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.

The MMO continued to operate with three participants: EDF Energy, SSE Generation and Npower.

1.6. The Future of the MMO

In May 2019, Ofgem invited stakeholders to submit feedback on liquidity policy and to help inform a policy options assessment into the future of the MMO. In particular, Ofgem identified three liquidity objectives for the market which changes to liquidity policy should address:[81]

1. "Ensure the availability of a range of longer-term products to support hedging of risk of exposure to large changes to prices
2. Support robust reference prices that are widely available to market participants
3. Promote an effective near term market which enables all companies to buy the power they need for their customers."

Ofgem also identified the criteria that it would use to assess potential policy options:[82]

- "Liquidity: an appropriate level of liquidity should be maintained to meet the relevant liquidity objectives.
- Future-proof: The policy should be resilient and flexible to changing market conditions.
- Proportionality: The costs of intervention should have a proportionate impact on market participants.
- Cost-effective: The policy objectives should be met at lowest cost to consumers."

As part of this policy options assessment, Ofgem commissioned NERA Economic Consulting to advise on, analyse and conduct part of the policy options assessment.

During the policy options assessment, Ofgem released RWE from its MMO licence condition on 30 October 2019 following RWE's sale of its shareholding in Innogy SE to E.ON on 18 September 2019.[83] Ofgem's decision to release RWE form its MMO licence condition left two MMs operating in the market: EDF and SSE.

On 14 November 2019, Ofgem announced that the MMO would be suspended, following Ofgem's consideration of stakeholder responses to an open letter on 8 October 2019.[84] Ofgem noted that evidence provided by stakeholders in their responses indicated that, following the removal of the obligation from RWE, the costs on the two remaining MMs had materially increased and that the policy had become less effective in meeting its objectives.[85]

[81] Ofgem (May 2019), Update: Wholesale Market Liquidity Policy, p. 2.

[82] Ofgem (May 2019), Update: Wholesale Market Liquidity Policy, p. 3.

[83] Ofgem (29 October 2019), Request for Schedule B of Special Condition AA to no longer have effect in RWE Generation plc's Electricity Generation Licence, p. 1.

[84] Ofgem (14 November 2019), Decision to suspend the S&P Market Making Obligation with effect on 18 November 2019.

[85] Ofgem (14 November 2019), Decision to suspend the S&P Market Making Obligation with effect on 18 November 2019, p. 2.

2. The Economic Rationale for Intervention

Typically, the economic justification for intervention in a market is to correct a market failure. If liquidity falls after the suspension of the S&P MMO, the prevailing low level of liquidity may not constitute a market failure in and of itself. Therefore, lower liquidity does not necessarily provide justification for further intervention. Indeed, lower liquidity in the market may be efficient. Moreover, if lower liquidity is efficient, then further intervention may create an inefficient market distortion.

Therefore, before we assess the policy options, we must first examine the economic rationale for intervention in the wholesale market to improve liquidity. Without evidence to suggest that either liquidity is inefficiently low, or a market failure exists that may result in inefficiently low liquidity, further intervention may not be justified.

Our key findings from our examination of the economic rationale for intervention are:

- We do not find that there is a clear cause of market failure that can be attributed to relatively low liquidity in the GB power market; and
- Suspension of the S&P MMO presents Ofgem and industry participants an opportunity to observe liquidity in the wholesale market, and outcomes in related markets, in the absence of intervention which may provide an indication as to whether future intervention may be required;
- Lower liquidity during suspension will not constitute a market failure or justification for intervention in and of itself;
- The lack of a clear cause of market failure does not preclude future intervention: On account of the potential benefits of a more liquid market, it may be prudent for Ofgem to intervene and treat low liquidity as a symptom of an unknown problem.

2.1. The Economics of Liquidity 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. Interventions to change liquidity should be aimed to correct these underlying market failures, which manifest themselves a low liquidity in the wholesale market.

We identify four main types of market failure that may justify intervention:

1. The original justification for intervention: Vertical integration which may lead to market failure. In particular:

   A. Asymmetric information between market participants may lead to barriers to entry in the retail market; and

   B. Market power may lead to barriers to entry in the retail market

2. Liquidity may be a public good

3. Asymmetric information between the physical and capital markets may result in higher than otherwise efficient demand for forward products.

2.1.1. The original justification for intervention no longer applies

Vertical integration may result in market failures which lead to low wholesale market liquidity and may justify intervention. Vertical integration can lead to a degree of asymmetric information between market participants. Vertically-integrated entities with a large volume of generation and supply may be able to better assess future prices and conditions relative to smaller, independent retailers without generation capacity. The asymmetric information 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.

Furthermore, there may be a natural hedge between generation and supply. In other words, instead of trading products in the forward market, vertically-integrated entities can choose to manage their risk internally. Vertically-integrated entities managing risk internally is not a problem in and of itself if the firms in question have no market power. However, vertically-integrated entities with sufficient market power, and a close correlation between the needs of their generation and retail businesses, may maintain barriers to entry in the retail market by withholding forward products from the wholesale market. For example, a vertically-integrated entity that is long on generation could strategically refuse to enter into forward contracts for its net generation position, and instead choose to manage its exposure through its retail arm which is short on generation.

If vertically-integrated entities strategically withhold forward contracts from the market, in order to protect their market positions, it may leave the market short of forward contracts and prevent independent retailers from obtaining the hedging contracts they need. The reduction in product accessibility for small retailers could result in inefficiently low liquidity in the futures market. Moreover, inefficiencies in the supply market may be created if the vertically-integrated entities raise consumer tariffs because of this market power.

As we discuss in Section 1.2 and Section 1.3, the original MMO was born from Ofgem's concern that the illiquid state of the wholesale market "act[ed] as a barrier to entry into both the generation and supply market and may act as a source of competitive disadvantage to small suppliers".[86] Ofgem therefore mandated vertically-integrated entities to market make. Ofgem argued that they would be naturally more robust to periods of low liquidity.[87] 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.[88]

However, the introduction of REMIT legally prevents firms trading on asymmetric information. Moreover, the CMA also assessed that product availability "is not a substantive issue" and that independent supplier's hedging strategies were not different because of product availability.[89] Therefore, asymmetric information is unlikely to be the underlying market failure that drives a suboptimal level of liquidity.

86 Square brackets added. Source: Ofgem (June 2009), Liquidity in the GB wholesale energy markets, p. 4.

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

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

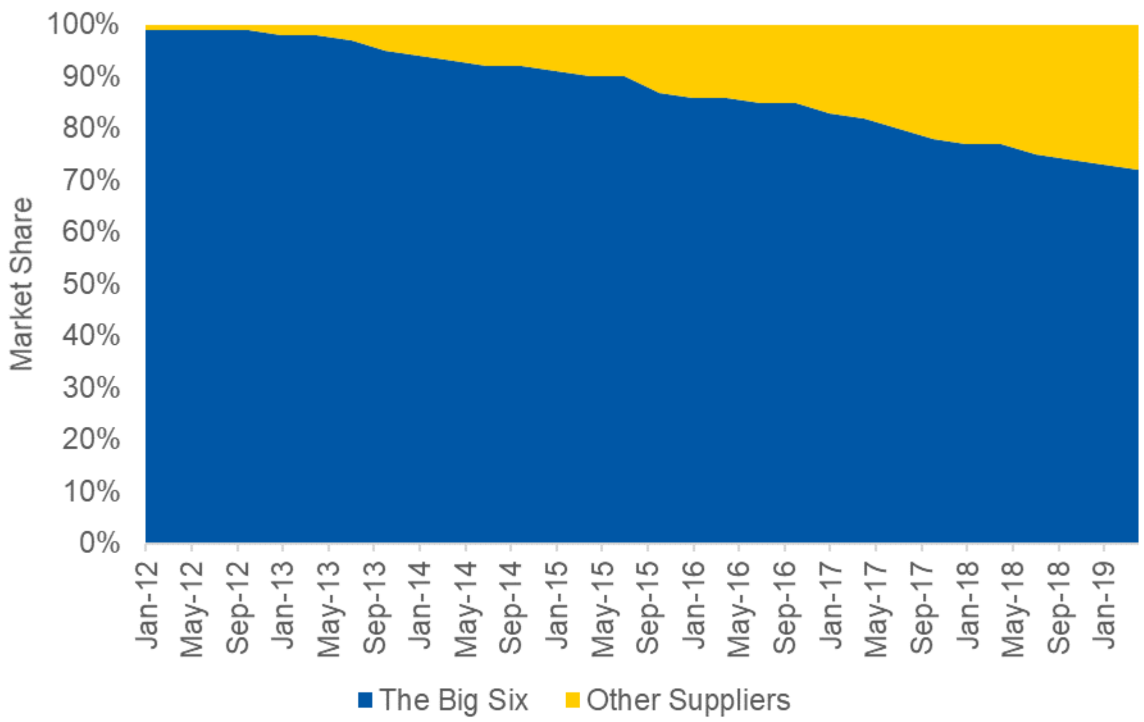
89 CMA (March 2015), Liquidity Working Paper, p. 47, para 157.

In addition, managing risk internally without external trade may only be possible for a perfectly vertically-integrated entity in principle. In practice, vertically-integrated entities are not perfectly vertically integrated and therefore often face strong incentives to trade and manage exposure in the forward market.

Vertical-integration may also be an efficient response to market conditions. For example, vertical-integration may be an efficient response to a lack of financial contracts that can be used to manage the risks of intermittent generation. Whilst strategically withholding products from the forward market may constitute a market failure and justify intervention, choosing not to trade forward products with external parties because the social marginal costs exceed the social marginal benefits is an efficient response to market conditions, and may not warrant intervention.

Moreover, as we discuss in Section 1.5, the degree of vertical integration and the market share of the Big Six has fallen substantially since the introduction of the MMO, see Figure 2.1. At the end of 2018, only 23 per cent of the total volumes supplied are accounted for by vertically-integrated entities.[90]

Figure 2.1: Supplier Market Share in GB (Q1 2012 to Q2 2019)



Source: NERA Analysis of Ofgem data.

Therefore, whilst it is unclear the extent to which vertical integration in the wholesale market constituted or resulted in market failure and previously justified intervention using the S&P MMO, it is clear that the prevalence of vertical integration has fallen, and no longer clearly justifies intervention.

90 CSS accounts for 2018-2019.

2.1.2. Liquidity may be a public good

If price discovery is costly, the absence of liquidity increases the costs of generating liquidity.[91] In other words, when the market is liquid, a market participant has price references to allow it to form clearer expectations of future market prices. Therefore, the participant can more accurately assess the prevailing market price and trade accordingly. When the market is illiquid, price discovery is harder and more costly and may result in a higher risk premium of trading. Higher risk premiums of trading may discourage further market participation, reducing liquidity further.

Therefore, liquidity may be a public good, in that the social marginal benefit of trading in the forward market and improving liquidity exceeds the private marginal benefit. The social marginal benefit may be greater than the private marginal benefit because price discovery is costly.

If liquidity is a public good, then intervention may be justified on the grounds that it resolves the coordination problem between participants to generate a step change in liquidity.

However, the extent to which liquidity is a public good may depend on the existing levels of liquidity in the market. Indeed, the degree to which liquidity is a public good likely diminishes as liquidity increases. Once liquidity has reached a critical level, one should not necessarily intervene to promote further liquidity because the externalities associated with price transparency and discovery may no longer exist.

2.1.3. 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) receives a higher weight than the upside potential (that wholesale market spot prices are lower than tariffs from consumers at the point of dispatch).

Hence, retailers may be required to hedge more than they would in an efficient market. If retailers are required to hedge more, they face higher capital requirements to enter the market, absent a liquid wholesale market in which they may trade.

As part of an Ofgem consultation on the S&P licence condition, Ofgem reported that independent suppliers reported "that getting desired credit lines and the costs of posting collateral remained the main difficulties" when purchasing forward products.[92] As such, many of the entrant suppliers may have relied on credit balances to fund their operations.

Therefore, asymmetric information in the credit market may result in market failure and justify intervention in the forward market to promote liquidity and reduce the costs of hedging for smaller suppliers. However, it is difficult for one to evaluate the degree to which this market failure drives low liquidity levels in the wholesale power market.

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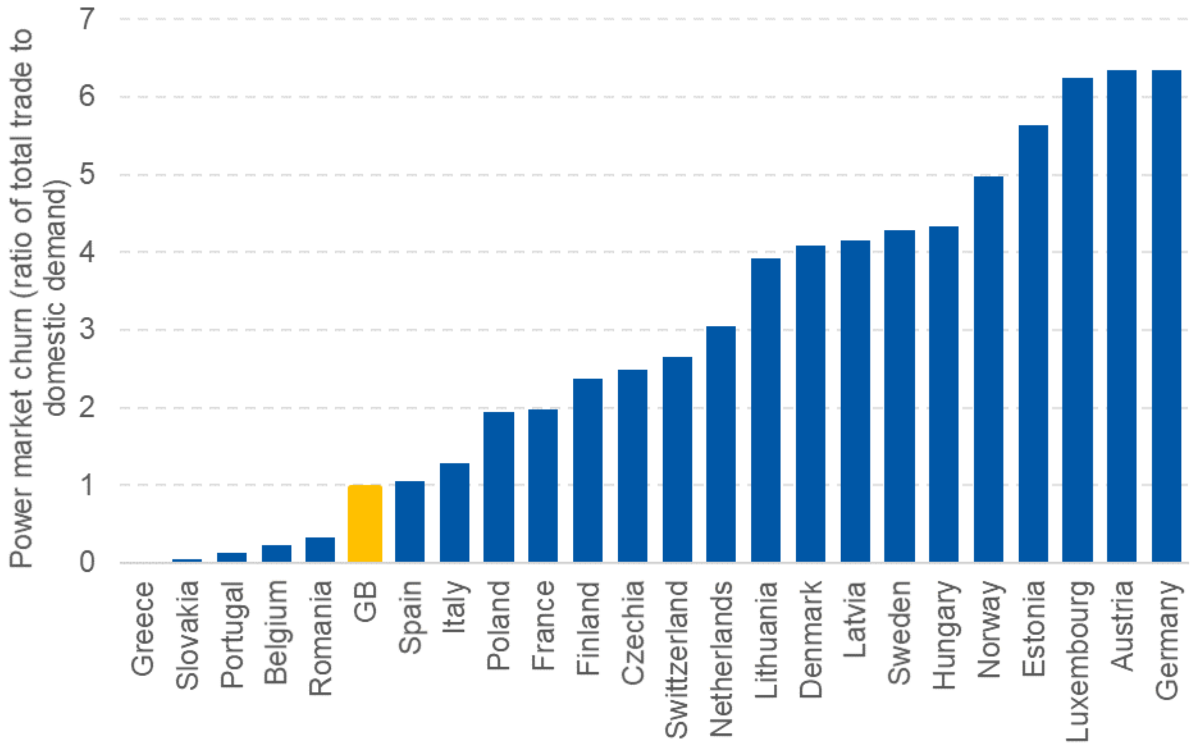
[91] Ofgem (December 2017), S&P review: Consultation on changes to the special licence condition, p.16, 2.8.

[92] Ofgem (September 2015), WPML Annual Report 2015, p. 6.

2.2. GB Power Market Liquidity is Low Compared to International Markets

It is difficult for one to determine which, and the extent to which, the abovementioned market failures may be causing a sub-optimal level of liquidity. Accordingly, it is also difficult for one to ascertain whether the current level of liquidity is sub-optimal. Figure 2.2 compares churn (a measure of liquidity) in the GB wholesale power market to that in other European markets.

Figure 2.2: Power Market Churn in GB Compared to European Markets (2015)



Source: NERA Analysis of ECA (September 2015), European Electricity Forward Markets and Hedging Products – State of Play and Elements for Monitoring: Submitted to ACER. Note: This data suggests a lower level of power market churn than Ofgem sources. We believe that this is because the ECA data does not include churn in day-ahead products, but we have not been able to confirm this. However, this data is the only single dataset to our knowledge that allows us to compare churn across European markets.

Churn in the Great Britain power wholesale market for forward products is markedly low compared to other European markets. However, because it is hard to identify an underlying market failure that drives the significantly lower market liquidity in Great Britain, it is unclear as to whether the observed lower level of liquidity is inefficient.

Instead, there may be structural reasons relating to the British market that result in efficiently low levels of liquidity and thereby do not warrant intervention.

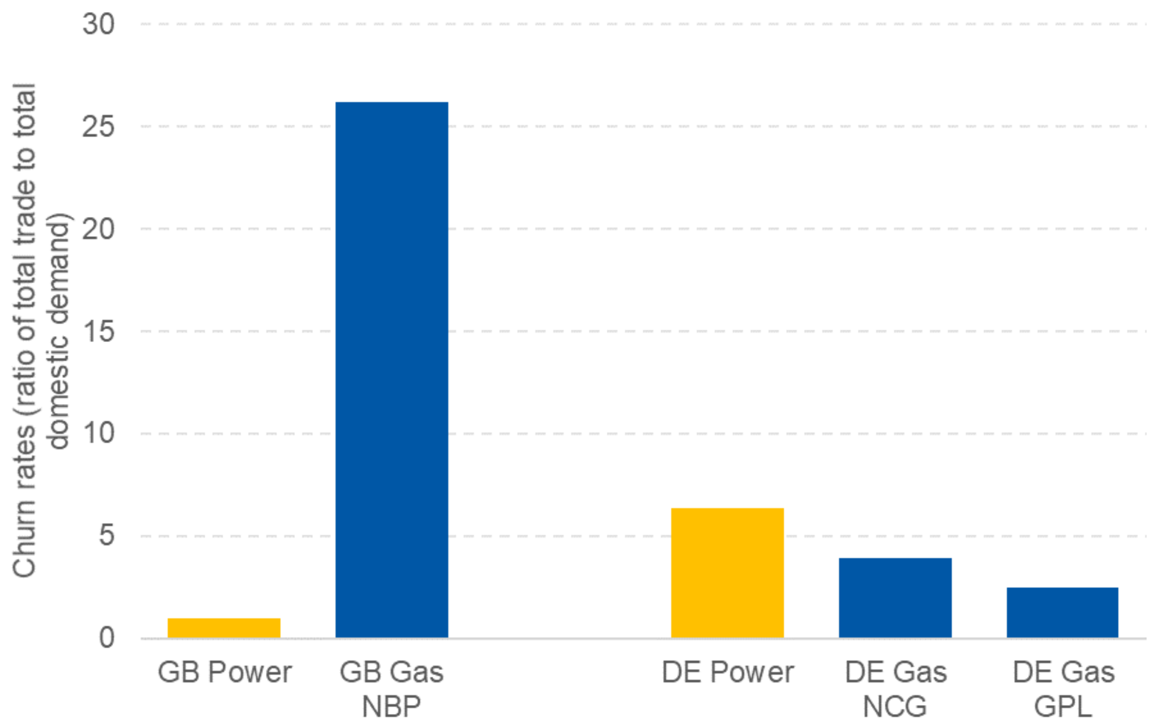
One potential reason why power market liquidity is comparably lower than European markets may be geographical. European countries with a high degree of interconnection, for example Germany, may have high liquidity because they are trading points for power across Europe, similar to the role of the NBP and TTF gas hubs. Therefore, higher levels of power liquidity may simply reflect more international trade, rather than inefficiently low levels of liquidity in other markets.

Moreover, the highly liquid British gas market may provide an alternative source of liquidity that may result in lower power market liquidity.

2.3. Higher Gas Market Liquidity May Substitute for Power Market Liquidity

The relative levels of liquidity in the power and gas market in Great Britain compared to Germany may support the theory that liquidity is a public good, see Figure 2.3.

Figure 2.3: Power and Gas Market Churn in GB and Germany (2015)



Source: Power market churn: ECA (September 2015), European Electricity Forward Markets and Hedging Products – State of Play and Elements for Monitoring: Submitted to ACER. Gas market churn: Heather (2010), Oxford Institute for Energy Statistics European traded gas hubs: an updated analysis on liquidity, maturity and barriers to market integration, primary sources: LEBA, ICIS, ICE, ICE-Endex, PEGAS, CME, CEGH, GME; MIBGAS; P. Heather.

If purchasing forward in gas is a close substitute to purchasing forward in power, and liquidity is a public good, liquidity may concentrate in one of the two markets. The market in which liquidity concentrates may be determined by structural reasons, for example, geographical location as we describe above, or historical reasons relating to the development of each market.

Liquidity in the German gas market, the NCG and Gaspool zones, may be lower because of the historical market structure. For example, Germany's gas market has been historically fragmented, and largely exempt from common government regulation and competition law.[93] The lack of government regulation resulted in the development of fragmented markets, which have been aggregated into the NCG and Gaspool.[94] In addition, each zone has both low and high calorific balancing due to the regional types of gas produced.[95]

On the other hand, the development of the British gas market has resulted in a highly liquid hub that has been historically used to benchmark prices across other European hubs.[96]

Therefore, if gas and power forwards are close substitutes and liquidity is a public good, the historical development of liquidity in gas markets may explain the patterns of liquidity observed in current gas and power markets in Great Britain and Germany.

However, if power and gas forwards are not close substitutes, then the pattern of liquidity across markets may indicate a market failure. Intervention may be justified on grounds that liquidity is a public good if, by coordinating trade in power forwards in Great Britain, liquidity increases and leads to a net social benefit of the intervention. In other words, intervention may allow participants to trade forward in the power market whereas they currently trade in the gas market because the benefits of higher liquidity in the gas market are greater than the costs and risks associated with gas forward contracts not being a perfect hedge for power market risk.

In Figure 2.4 and Figure 2.5 we show the prevailing forward prices for the season two-ahead contract and day-ahead contract, in British gas and power wholesale markets, respectively.

93 Heiko Lohmann (2006), The German path to natural gas liberalisation, Is it is a special case?, Oxford Institute for Energy Studies, p. 8.

94 Patrick Heather (June 2012), Continental European Gas Hubs: Are they fit for purpose?, p. 45.

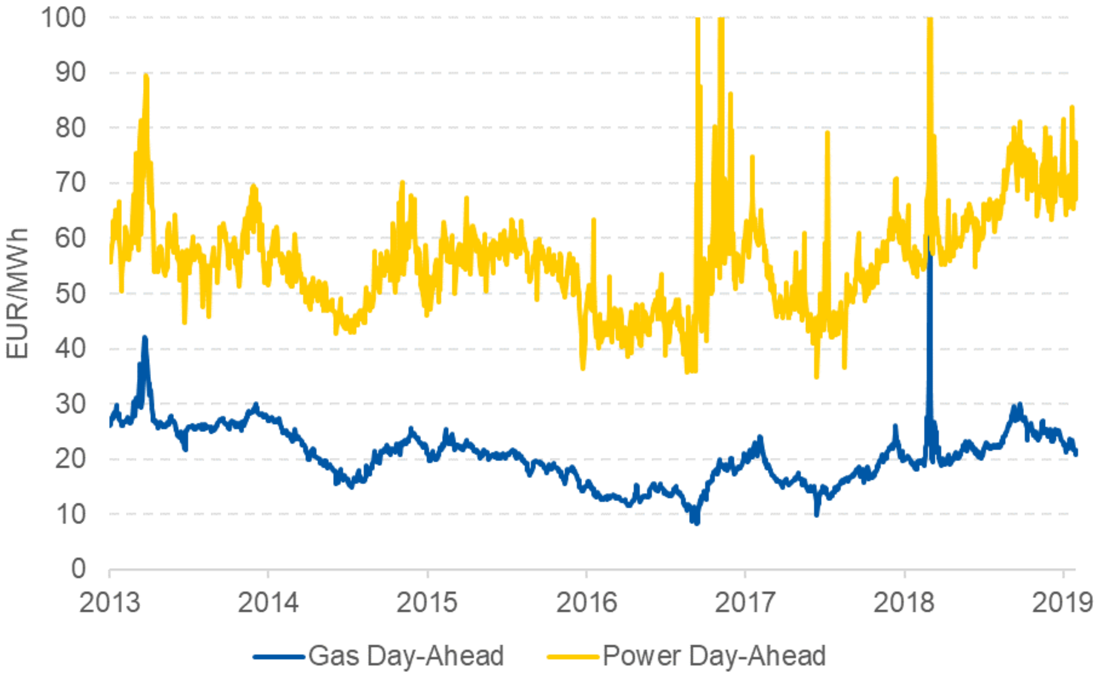
95 Patrick Heather (June 2012), Continental European Gas Hubs: Are they fit for purpose?, p. 45.

96 Patrick Heather (June 2012), Continental European Gas Hubs: Are they fit for purpose?, p. 44.

Figure 2.4: Two-Seasons Ahead Forward Contract Prices in GB (2013-2019)

Source: NERA analysis.

Figure 2.5: Day-Ahead Forward Contract Prices in GB (2013-2019)



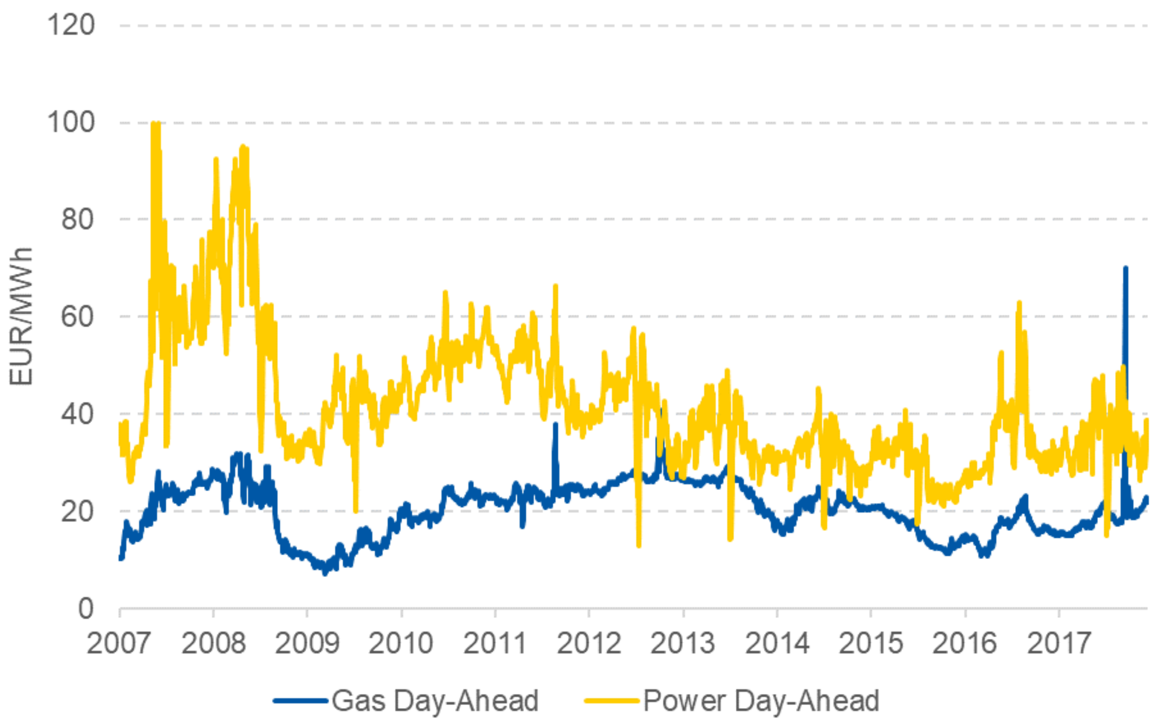
Source: NERA analysis.

Our analysis suggests that power and gas prices in Great Britain are correlated further down the forward curve, such that trading gas may substitute for trading power (season two-ahead correlation of 0.88).[97] On the other hand, the day-ahead prices in Great Britain appear less strongly correlated (correlation of 0.64), and in particular, the power day-ahead contract is much more volatile than the gas day-ahead contract (annualised daily volatility of 49.60 for power compared to 36.38 for gas).[98] The difference in volatility is unsurprising, as prompt price variation is largely driven by short-term demand and supply indicators e.g. the weather.

Therefore, whilst our analysis suggests that trading gas may substitute for trading power further down the forward curve, it is unclear whether this substitutability still exists in the prompt market. Consequently, whilst liquidity in the gas market may allow power market incumbents to hedge exposure further down the curve, it may still be that power market liquidity is sub-optimally low to support prompt trading.

However, the degree of substitutability in trading prompt gas and power products may still be relatively greater in Great Britain than it is Germany. In Figure 2.6, we show the day-ahead power and gas price in Germany. The day-ahead prices in Germany are less correlated than they are in Great Britain (correlation of 0.48 compared to 0.64).[99] The lower degree of substitutability in Germany may explain why gas market churn in Germany is relatively lower than in Great Britain, but power market churn is relatively higher.

Figure 2.6: Day-Ahead Forward Contract Prices in Germany (2007-2018)



Source: NERA analysis.

97 Source: NERA analysis of prices between January 2013 and January 2019.

98 Source: NERA analysis of prices between January 2013 and January 2019.

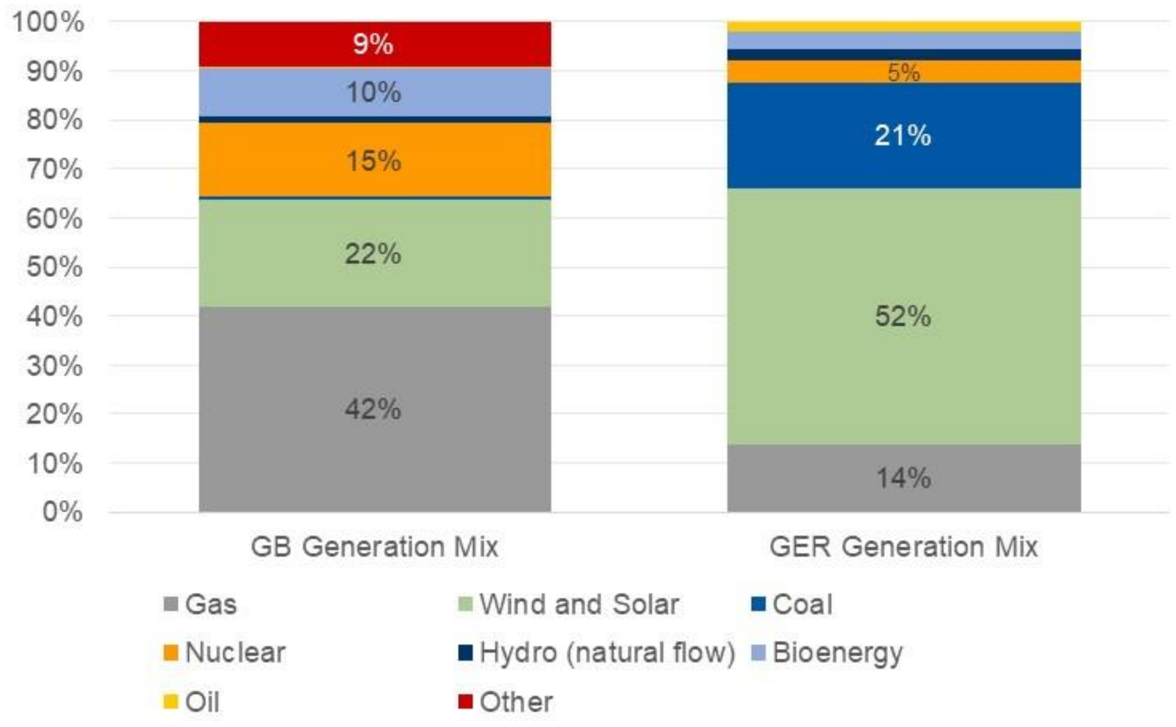
99 Source: NERA analysis of prices between June 2007 and January 2019.

It may be that the prevailing generation mix is the driving factor behind the degree of substitutability between trading forward in power and gas. The generation mix for Great Britain and Germany in 2019 is shown in Figure 2.7.

The prevalence of gas-based generation in Great Britain means that trading forward in gas may be more closely substitutable for trading forward in power. The prevalence of gas generation means the marginal plant setting prices in the British wholesale power market is often gas-fuelled. Therefore, the cost of generating power using that gas-fuelled plant is set by the associated forward price for the fuel, the wholesale cost of gas. In order to hedge the cost of power in the forward market, one may be able to use the gas market to hedge the cost of gas in the gas market.

On the other hand, the more varied generation mix in Germany may reduce the substitutability of trading forward in power or gas. The marginal plant setting prices in the wholesale power market may sometimes be gas-fuelled but on other occasions be coal or oil fuelled. Therefore, it may be harder to hedge forward in power by using gas contracts, because the relationship between gas prices and the wholesale cost of power may be weaker.

Figure 2.7: Generation Mix for GB and Germany (2019)



Source: GB generation mix: Ofgem (2019), Electricity generation mix by quarter and fuel source (GB), Last accessed: 04/11/19, Link: https://www.ofgem.gov.uk/data-portal/electricity-generation-mix-quarter-and-fuel-source-gb. *Q2 2019 data used. Germany generation mix: Fraunhofer ISE (31 October 2019), Net installed electricity generation capacity in Germany, Last accessed: 04/11/19, Link: https://www.energy-charts.de/power_inst.htm.*

Overall, it is possible that trading gas may substitute, to some extent, for trading power. This substitutability may especially be true further down the forward curve and for generators. However, the substitutability of forward products lessens in the near term. Moreover, whilst suppliers may be able to hedge baseload demand with the gas market, it is unclear whether suppliers can sufficiently hedge the shape of their expected demand in the gas market.

Moreover, many retailers, and particularly new entrants, are not able to trade forward in gas. Trading both gas and power is expensive and difficult. Trading power forward requires a supplier to establish agreements with a number of counterparties. To trade gas forward in addition to power, the supplier has to sign similar arrangements with counter-parties on the gas market, the carbon market and the foreign exchange market. Therefore, suppliers are often geared to trade power or gas, rather than both commodities.

2.4. It may be Prudent to Treat Liquidity as the Symptom Rather than the Cause of Market Failure

Therefore, our evidence that there exists a degree of substitutability between gas and power markets is insufficient to explain why power market liquidity in Great Britain is so much lower than in other European markets. In absence of a clear cause of low liquidity, but with evidence that liquidity in the power market is low, it may be prudent to treat low liquidity as a symptom of an unknown problem.

There are other possible interventions, asides from an MMO, which may change the level of liquidity in the British wholesale power market. Theoretically, the policy instrument used to intervene will be determined by the market failure that the intervention is aimed at correcting. For example, if vertical integration was deemed to be a market failure that manifested itself in low liquidity in the power market, then intervention could be aimed at forcing vertically-integrated entities to divest some of their generation or retail assets or business.

In practice, there are at least two reasons why the MMO may be currently the best option for intervention:

1. It is unclear whether a single market failure results in the relatively low level of liquidity in the wholesale market. Moreover, should a single market failure be the cause of the level of liquidity, it remains hard for policy makers to identify this market failure. As such, interventions which target the symptom of the market failure, i.e. directly targeting the level of liquidity in the wholesale market, may be a more efficient response to improve market liquidity than targeted interventions at potential market failures.
2. The previous existence of the S&P MMO in operation in the market may reduce the implementation costs of a new MMO relative to introducing a new policy aimed at improving wholesale market liquidity. Moreover, given other macroeconomic risks such as potential withdrawal from EU markets and other possible policy interventions in parallel workstreams, for example changes to the supplier licenses, intervention through an MMO may reduce costs and risks for industry.

We turn to briefly examine international experience with MMOs in Section 3, in order for us to examine the economic rationale used for intervention in other jurisdictions, as well as draw some key learnings from international experience. Using this background, and the economics for intervention discussed in this Section, we discuss the options for assessment and stakeholder feedback in Section 4.

3. International Experience with MMOs

In this section, we discuss the key observations from international experience with MMOs. We reviewed the following international experiences with MMOs in power markets: The S&P MMO imposed in Great Britain, New Zealand's "voluntary" MMO, Singapore "voluntary" and tendered MMOs, Australia's "voluntary" MMO, imposed in the National Electricity Market (NEM), and Germany's "voluntary" MMO. However, due to the recent introduction of the MMO in Australia, we are unable to draw conclusions relating to the effects of the intervention. We also reviewed the design of the tendered MMO imposed in the Spanish gas market. We provide more details for each case study in Appendix B.

3.1. 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.[100] 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.[101]

The generation fuel mix also substantially differs across countries. However, once again, the design of the MMO does not seem to relate to these differences. Singapore is characterised by almost only relying on natural gas (95 per cent of generation in 2015) with low penetration of renewables.[102] Great Britain, had some penetration of renewables, around 12 per cent of the fuel mix.[103] 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).[104] Australia's generation mix varies across states in the NEM, and constitutes a mix of coal generation (around 45 per cent in 2018) and renewables (around 30 per cent in 2018).[105]

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

101 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.

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

103 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.

104 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/.

105 AER (2018), State of the Energy Market report.

3.2. Most Regulators Introduced MMOs with an Objective of Improving Competition in the Retail Market

In most 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 vertically-integrated entities, 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.

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.

3.3. 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 introduction of an MMO also reduced bid-ask spreads. However, this improvement was marginal and did not result in the "step-change"[106] in liquidity that regulators was generally aiming to achieve.[107] 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).[108] In New Zealand, despite an increase in contracted volumes, churn remains less than 1.[109]

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.[110] However this improvement in liquidity in the windows may have been at the cost of liquidity at other parts of the trading day.

The exception to the argument that the MMOs have not led to a "step-change" in liquidity may be the EEX-operated "voluntary" MMO in Germany. In 2003, up to 80 per cent of the

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

107 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.

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

109 Electricity Hedge Disclosure System, EA EMI data on grid injections.

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

volume traded on the EEX derivates market was traded by MMs under the MMO.[111] However, traded volumes now only account for 8 per cent of total market volumes.[112]

3.4. It is Unclear Whether MMOs have Facilitated Increased Entry

In most 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.[113] 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 entities fell from 86 per cent to 75 per cent.[114]

However, it remains difficult to assess the relationship between the 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.

3.5. The Design of Incentives in Incentivised MMOs can lead to Windfalls for Participants and Larger Costs for Consumers

Depending on the choice of compensation mechanism 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 S$ 204m, which was passed on in tariffs to consumers.[115] 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.

The experience of Singapore 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

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111 EEX, Transparency at the European Energy Exchange, p. 10.

112 Bundeskartellamt (29 May 2018), Monitoringbericht 2018, p. 242.

113 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.

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

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

scheme would take several years to develop".[116] 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. For example, in New Zealand, the ASX and the MMs have been developing the design of an incentivised MMO and have stated that such a scheme could be implemented quite quickly.[117]

3.6. The Choice of MMs 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.

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 entities. 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. Moreover, regulators 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 vertically-integrated entities was Singapore. This was because the vertically-integrated entities 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.[118]

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

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

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

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

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.[119]

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.

3.7. Regulators have Typically Failed to Accurately Quantify Costs Ex-ante and 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 generally 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.

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.[120]
- 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.[121]

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

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

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

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

4. Options for Assessment

Following stakeholder feedback to an open letter (30 May 2019), Ofgem identified four policy options pertaining to the future of the MMO. These are:[122]

1. "Do nothing" and retain the S&P MMO;
2. "Remove and do not replace";
3. A re-designed mandatory MMO; and
4. A tendered MMO.

The criteria that we use to evaluate these options are those identified by Ofgem following consideration of responses to the May 2019 open letter:[123]

1. "Liquidity: an appropriate level of liquidity should be maintained to meet the relevant liquidity objectives.
2. Future-proof: The policy should be resilient and flexible to changing market conditions.
3. Proportionality: The costs of intervention should have a proportionate impact on market participants.
4. Cost-effective: The policy objectives should be met at lowest cost to consumers."

As part of the ongoing assessment of these options, Ofgem conducted a Liquidity Policy Options Assessment Stakeholder Workshop on 1 October 2019. This workshop was attended by over 30 market participants and included a range of generators, suppliers, and energy traders.

The feedback from the stakeholder workshop proved to be significant at shaping the options assessment. In particular:

- "Proportionality", in other words a more equitable distribution of the costs of market making, was the overriding issue of the workshop, with stakeholders agreeing that an obligation should not be placed on a small number of parties without those parties being appropriately compensated; and
- Widening eligibility under the S&P MMO was not viewed as "future-proof" or "proportionate". Several attendees also noted the potential for distortions to market competition due to the likely use of eligibility thresholds related to market presence. As a result, participants provided a strong majority view that widening the eligibility of the S&P MMO was less appropriate as a short or long-term measure.

Ofgem decided to narrow and discount some of its original policy options for the remainder of the options assessment. Its decision was based on feedback from stakeholders; learning from international experience discussed in Section 3; and the suspension of the Secure & Promote MMO in November 2019.

[122] Ofgem (May 2019), Update: Wholesale Market Liquidity Policy, p. 2.

[123] Ofgem (May 2019), Update: Wholesale Market Liquidity Policy, p. 3.

4.1. We Do Not Evaluate the S&P MMO and Remove and Do Not Replace As Future Policy Options

On account of suspension of the S&P MMO, we do not explicitly examine the retention of the S&P MMO as a future policy option. In addition, the "remove and do not replace" policy option is now equivalent to a decision as to whether further intervention may be required. We assess the net benefits of future policy options relative to counter-factual levels of liquidity intended to provide a range of possible, but not necessarily likely, levels of liquidity that may prevail under a "do not replace" policy.

Instead, we use the requirements of the suspended S&P MMO to model a potential tendered MMO. Should further intervention be required, it is not necessarily the case that a new MMO should be designed in a different way to the S&P MMO. In other words, it is not clear that a new MMO should obligate MMs to market make at different maximum bid-ask spreads or for different products to the S&P MMO: The new MMO may simply change the criteria or methodology by which MMs are selected.

For example, assume Ofgem were to introduce a new obligation in the form of a tendered MMO. If the tendered MMO was introduced with the same design as the S&P MMO, and assuming that the entities that won the tender were no more or less efficient than the parties under a mandatory obligation at market making, then the new tendered obligation would lead to the same social benefits as the S&P MMO. Therefore, the reintroduction of a tendered obligation with the same design as the S&P MMO may lead to the same net social benefits as the S&P MMO.

Hence, in our modelling approach we interpret the prevailing market liquidity under the S&P MMO as the prevailing market liquidity under the *requirements* of the S&P MMO. In other words, the introduction of a tendered obligation with the same requirements as the S&P MMO would lead to similar market outcomes in terms of bid-ask spreads and liquidity. We discuss the implications of this approach further in Section 4.4.

4.2. A Re-Designed Mandatory Obligation is Not the Preferred Option

A redesigned mandatory MMO received limited support from industry participants at the stakeholder workshop. Stakeholders argued that the introduction of a mandatory MMO, irrespective of whether the requirements of the obligation were re-designed, may lead to:

- policy costs being borne by a small number of parties that were mandated under the new selection criteria under a re-designed mandatory MMO, which was generally viewed as unfair;
- the difficulty in identifying a future-proof eligibility threshold to designate mandated parties that remains robust to market changes;
- potentially significant market distortions when selecting mandatory parties using eligibility criteria – both due to the costs borne by those mandated entities and the wider distortions to market competition around eligibility thresholds; and
- a risk that the parties mandated using the redesigned selection criteria would not be the most efficient MMs, and that therefore the social costs of the obligation would not be minimised across industry.

Some stakeholders argued that the introduction of any obligation may, in and of itself, result in significant market distortions that would constitute market failure.

4.3. A Tendered Obligation with Re-Designed Requirements

The feedback from industry participants at the stakeholder workshop widely accepted that, should further intervention to support liquidity in the wholesale market be required, the intervention should be in the form of a tendered or voluntary MMO. Stakeholders argued that a tendered approach should be the preferred method of intervention because:

- a tendered approach is best placed to ensure costs are transparently and equitably borne by market participants;
- a competitively designed tender process would ensure that the obligation is fulfilled at least cost to customers;
- a competitively designed tender process would introduce an element of price discovery of the costs of market making; and
- a tendered approach would not require the specification of an eligibility threshold which may distort competition and may not be future-proof.

In light of this feedback, we evaluate the benefits of a redesigned tender process in Section 5.

What remains unclear from the stakeholder feedback collected at the workshop is, should further intervention be required, whether the design elements of a tendered obligation should change or remain the same as the S&P MMO. For example, are the current maximum bid-ask spreads suitable or should Ofgem specify different spreads under a redesigned tendered obligation.

4.4. Our Approach to Assess the Options

The remainder of our report focuses on evaluating the net benefits of a tendered MMO that leads to similar levels of liquidity, as measured by bid-ask spreads, as the S&P MMO. We adopt this interpretation of current market bid-ask spreads because our modelling approach distinguishes different designs of MMOs only by the extent to which they result in different market transactions costs which we measure through bid-ask spreads. Consequently, our model is only able to distinguish tendered and mandatory MMO designs by the extent to which they result in different market bid-ask spreads.

We model the net benefits of an introduction of a tendered MMO with the same requirements as the S&P MMO relative to three counter-factual scenarios of market liquidity. We use the counter-factual scenarios to examine the case of no intervention, in other words, ‘do not replace’. We have chosen counter-factual scenarios that do not necessarily correspond to our expectations of future spreads, but merely examine the net benefits of further intervention relative to a range of potential counter-factual levels of liquidity.

We explain our approach to modelling the benefits of the MMO in more detail in Section 5.

5. Quantification of Benefits

In this Section, we estimate the gross social benefits of an MMO. 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 do so. For instance, in New Zealand, simplified metrics such as a percentage of industry costs were used to quantify the benefits of the obligation.

Ofgem performed an impact assessment of the S&P intervention before it was introduced, within which it qualitatively estimated the expected benefits of the S&P intervention, including the MMO.[124] However, Ofgem assessed the benefits through "break-even analysis". In other words, it assessed the size of benefits that would be required to cover the estimate costs of the MMO. Using 2012 consolidated segmental statements, Ofgem assessed that the Big Six would need to reduce operational costs by 0.5 per cent to offset the costs of the S&P licence. Alternatively, Ofgem assessed that the costs of intervention would translate to a 0.8 per cent reduction in earnings before interest and tax.[125]

The benefits we identify through our modelling approach all stem from the assumption that an increased ability to hedge reduces the costs and risks faced by generators and suppliers. Our model 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. The benefits we quantify are the cost-savings from the reduction in the required risk capital holdings and a reduction in transactions costs for the hedges entered into by the supplier and generator.

5.1. 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.

   Transactions costs include the exchange fees of the trade but also relate 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).

124 Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition – Impact Assessment, p. 4.

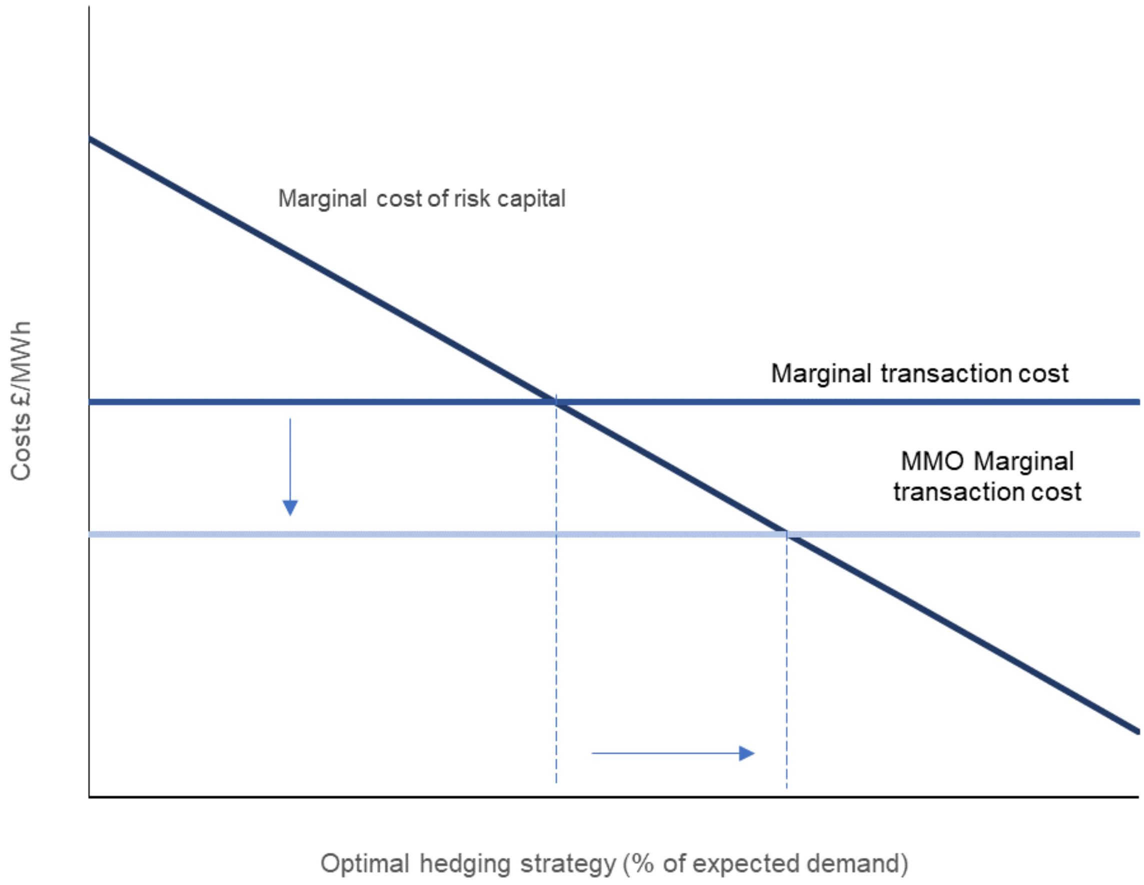
125 Ofgem (November 2013), WPML: statutory consultation on the 'S&P' licence condition – Impact Assessment, p. 35.

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. When the contract price falls below the strike price, the retailer provides 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 the hedging and risk capital trade-off for a representative retailer operating in the wholesale market in Great Britain. A potential benefit of an MMO is to ensure that forward products are available for trade at bid-ask spreads that are lower than levels that would otherwise prevail. Lower bid-ask spreads reduce the transactions costs of hedging forward, making it relatively more attractive for retailers to hedge rather than hold risk capital. Therefore, the benefit of increased liquidity can be quantified as the savings associated with the reduction in risk capital held by the retailer. More specifically, the risk capital savings are quantified by examining the rate of return, the weighted average cost of capital (WACC), on the reduction in risk capital.

In other words, we model how retailers change their optimal hedging strategy in markets with different levels of liquidity (measured by bid-ask spreads), influenced by the introduction of an MMO. We then examine how the retailer's cost savings from its hedging strategies vary with market liquidity to estimate the benefit on an MMO.

5.2. Summary of Our Modelling Approach

In order to quantify this benefit, we simulate the monthly cashflows of a single representative retail supplier. We summarise our model method in this section, but provide full details of our model in Appendix A.

5.2.1. Liquidity and the effect of further intervention

Our modelling approach distinguishes different designs of MMOs only by the extent to which they result in different levels of market liquidity which we measure through bid-ask spreads. Consequently, our model is only able to distinguish tendered and mandatory MMO designs by the extent to which they result in different market bid-ask spreads.

In order to estimate the benefits of a given design of MMO, we need to specify the prevailing bid-ask spreads in the market with and without the MMO imposed. The bid-ask spreads that prevailed in the market whilst the S&P MMO was imposed are, in our model, independent of how the S&P MMO was imposed i.e. as a mandatory obligation. In other words, should Ofgem introduce a tendered MMO in the future with the same maximum bid-ask spreads, number of market makers etc., we may expect the same level of liquidity to prevail in the market as the S&P MMO delivers.

Consequently, we estimate the benefits of an MMO with the same requirements of MMs as the S&P MMO design. We measure the benefits of an MMO relative to a 'do not replace' baseline.

However, we do not know what 'do not replace' market spreads may be. Therefore, we use a range of estimates for counter-factual bid-ask spreads. We have chosen counter-factual scenarios that do not necessarily correspond to our expectations of future spreads, but merely examine the net benefits of further intervention relative to a range of potential counter-factual levels of liquidity. More specifically, we estimate three sets of prevailing market spreads for the market:

- **Historical:** We estimate the historical bid-ask spreads prevailing in the market prior to the introduction of the S&P MMO, from 2009 to 2013 inclusively, and use the resulting spreads as an estimate for the counter-factual market spreads, should the current obligation be removed.

- **High liquidity counter-factual:** We use a midpoint between the estimated historical bid-ask spreads and current spreads prevailing under the MMO as a high-liquidity counter-factual.
- **Low liquidity counter-factual:** We use double the estimated historical bid-ask spreads as a low liquidity counter-factual.

Therefore, we estimate the benefits of an MMO with the same requirements of MMs as the S&P MMO relative to each of the above counter-factual market bid-ask spreads.

However, we recognise that, should further intervention be required, it may be that Ofgem chooses to relax the requirements of MMs under a redesigned MMO relative to the requirements under the S&P MMO. Consequently, the benefits of the redesigned MMO relative to the above counter-factual bid-ask spreads will be lower than our estimates, which assume the stricter requirements of the S&P MMO.

To account for the introduction of an MMO with more relaxed requirements relative to the S&P MMO, we also estimate the benefits of an MMO that delivers the bid-ask spreads specified under the high liquidity counter-factual, as we describe above. We estimate the benefits of an MMO that delivers the high liquidity counter-factual bid-ask spreads relative to counter-factual spreads specified by the historical and low liquidity counter-factual bid-ask spreads.

However, in Section 7, we only evaluate the net social benefits of an MMO with the same requirements of MMs as the S&P MMO. We do not estimate the net benefits of a redesigned MMO with different requirements because we do not have data for how the costs of market making may vary with the requirements of the MMO.

5.2.2. Modelling power prices

To model the costs of procuring electricity in the futures market, we assume that retail suppliers hedge their requirements using seasonal baseload and peakload contracts.

We base our assumed hedging strategy for retailers on the methodology that Ofgem uses to define wholesale costs in the default tariff cap. Ofgem sets the default tariff cap for a six-month period using wholesale costs determined using a "6-2-12 semi-annual approach".[126] Ofgem sets a tariff cap for a six-month period that corresponds to either a summer or winter seasonal contract. Winter seasonal contracts run October through March inclusively whereas summer seasonal contracts run April through September inclusively.

The wholesale costs for a given tariff cap, for example the summer 2019 price cap, are estimated by observing the average of daily wholesale prices of forward contracts that deliver in the summer 2019 and winter 2020 period. In other words, the "12" months from the start of the tariff cap.[127] The forward prices are observed for "6" months. More specifically, they are observed for the first "6" months in the eight months prior to the start of the tariff cap.

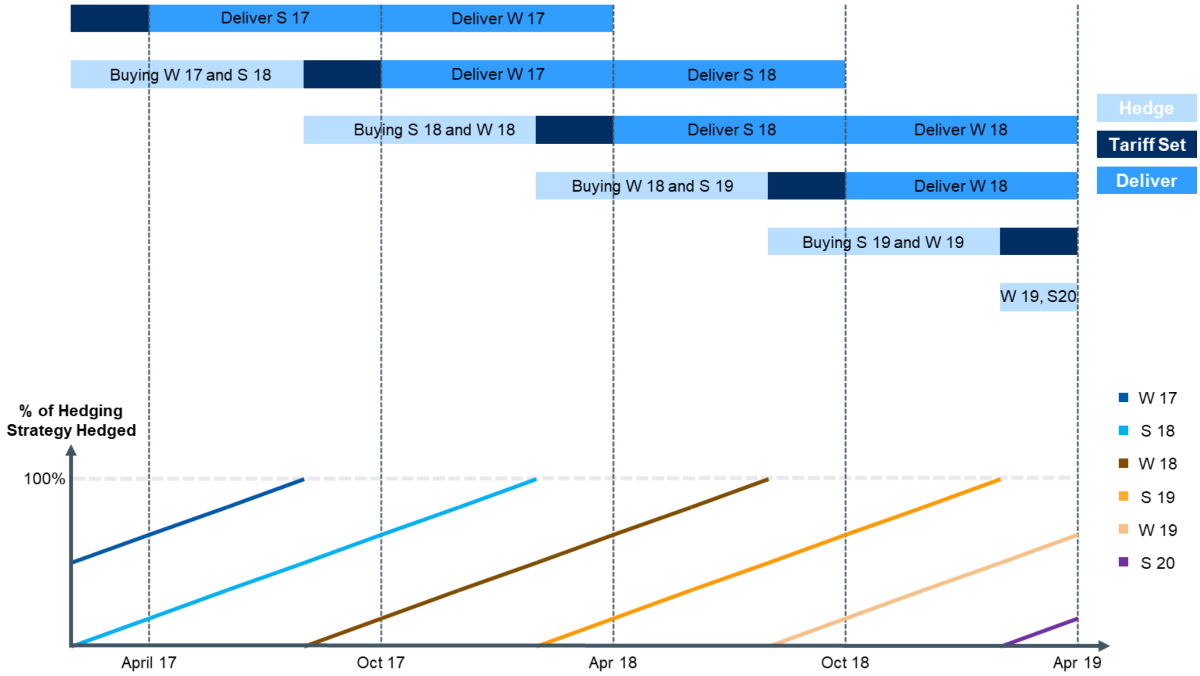
[126] Ofgem (6 November 2018), Decision Appendix 4 – Wholesale costs, p. 9.

[127] Ofgem (6 November 2018), Decision Appendix 4 – Wholesale costs, p. 10.

The remaining "2" months is assumed to be when retailers can set tariffs and inform their customers.[128]

We translate the tariff cap methodology into our assumed hedging strategy for retailers, see Figure 5.2. We assume that retailers only use baseload and peakload contracts to hedge their expected load. More specifically, we assume that retailers follow a similar "6-2-12" approach to hedge a given six-month period. However, each six-month contract appears in two subsequent tariff cap setting methodologies, because the tariff-cap methodology observes prices for 12 months including six months beyond the setting of any given tariff-cap. Therefore, we assume that retailers linearly accumulate hedges of their expected demand over a 12-month period.

Figure 5.2: Illustration of Our Assumed Hedging Strategy for Retailers



Source: NERA analysis

We simulate the seasonal product prices according to the volatility and co-movement of prices of different seasonal contracts traded on the same day. In particular, we use price data for futures contracts traded on each day between 6 September 2016 and 30 August 2018, inclusively. 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 Q1 2017. 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.[129]

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128 Ofgem (6 November 2018), Decision Appendix 4 – Wholesale costs, p. 10.

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

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 prompt of season baseload contract (i.e. the balance-of-season or zero-seasons-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 between February 2017 and March 2018 inclusive. 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.

5.2.3. Retailer cashflows and risk capital

We simulate the monthly cashflows of a single representative retail supplier 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. We use annual average customer switching rates to simulate customer numbers across the 12 months.[130] Randomised customer switching means that the retailer faces a volume risk when hedging.

  To simulate retailer revenues, we multiply our simulated customers number and consumption figures by a representative seasonal tariff. We estimate the representative tariff using data on the proportion of the default tariff cap which is made up of wholesale electricity costs.[131] Seasonal consumption shapes are aggregated from half hourly demand shapes and applied to the representative annual consumption to estimate seasonal consumption. We multiply our estimate for seasonal consumption by the average wholesale electricity price, estimated by the average simulated forward strike price, to estimate the wholesale cost of purchasing electricity. A representative tariff may be inferred by dividing wholesale costs by the proportion of the default tariff cap made up by wholesale costs.

- **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 change depending on whether an MMO is imposed in the market or not, as we describe in Section 5.2.1.

130 Ofgem (October 2019), Large suppliers: Internal and external switching rate by fuel type (GB), Last accessed: 7/11/19, Link: https://www.ofgem.gov.uk/data-portal/large-suppliers-internal-and-external-switching-rate-fuel-type-gb

131 Default tariff cap breakdown is sourced from the Ofgem data portal. Last accessed: 4/11/19, Link: https://www.ofgem.gov.uk/data-portal/breakdown-default-tariff-price-cap-gbp

- **Other costs not related to the purchase and sale of energy:** such as network charges, the costs of environmental subsidies, and other 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 the simulated retailer cashflow to calculate the risk capital that the representative retailer needs to hold to ensure their cumulative cash balance does not become negative in 95 per cent of the annual simulations. The cost of holding this risk capital is determined by the WACC. The total cost of risk capital is falling in the degree of hedging.

5.2.4. 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 model four bid-ask spread scenarios, as we describe in Section 5.2.1.

In line with our assumed hedging strategy for retailers, we estimate the average bid-ask spreads of baseload and peakload seasonal products. More specifically, we use the spreads of baseload and peakload seasonal products, one to three seasons-ahead. We show our calculated spreads in Table 5.1.

The benefits of implementing an MMO, with the same requirements as the S&P MMO, are estimated by comparing the S&P MMO liquidity scenario against the three other counter-factual cases.

Table 5.1: Our Estimated Current, Historical and Counter-Factual Bid-Ask Spreads Based on Market Data (2009-2019)

	Baseload	Peakload
1. S&P MMO (2014-present)	0.36%	0.54%
2. High liquidity counter-factual	0.68%	0.97%
3. Historical (2009-2013)	0.99%	1.40%
4. Low liquidity counter-factual	1.98%	2.80%

Source: NERA Analysis.

We assume that the removal of the S&P MMO will not improve market liquidity or reduce transaction costs.

We calculate the retailer cashflows for each of the levels of liquidity detailed in Table 5.1, and for hedging strategies between 62.5 and 77.5 per cent of expected demand at 2.5 per cent intervals. We then estimate the retailer's optimal choice of hedging strategy by equating the marginal risk capital savings with the marginal transaction costs from hedging more of their expected demand.

We recognise that most retailers in the GB market hedge more than 62.5 per cent of their expected demand. However, in our model we only consider a simplified hedging strategy using a subset of market products. Therefore, we can think of the optimal hedging strategy as the optimal amount of expected demand that the retailer should hedge through the seasonal products included in our model. In reality, the retailer may hedge a larger proportion of its expected demand using other products.

5.2.5. 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 over 5,000 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 5.1. We compare the net benefit of the hedging strategies across the bid-ask spreads to estimate the benefits per MWh of the S&P MMO. We then multiply by the total and unhedged volume of electricity generated and supplied in the domestic market to get the total benefit of the MMO.

Our implicit assumption is that generators are the counter-party to retailer hedging strategies 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 by retailers increases the minimum price, because the generator is less exposed to adverse wholesale price movements at the point of dispatch.

5.3. Model Results

We report our results in Table 5.2. Along the columns of each matrix is the hedging strategy for the retailer. Each row corresponds to a modelled bid-ask spread. As discussed above, we examine four bid-ask spreads: historical spreads, estimated spreads after the introduction of an MMO that delivers the same liquidity as the current obligation, and a low and high liquidity counter-factual case. Our estimated results are reported relative to a zero per cent hedging strategy baseline.

The first matrix details the risk capital saving per MWh from moving across hedging strategies. The risk capital saving for the representative retailer is increasing towards the top right of the matrix, because the risk capital saving increases as the retailer hedges more. The risk capital savings also increases slightly as transactions costs fall, 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.

The second matrix details transactions costs for the representative retailer. Transactions costs are increasing to the bottom right of the matrix, because transactions costs increase with the amount of hedging that the retailer undertakes. Transactions costs also increase with bid-ask spreads, as the transactions cost is defined as half of the bid-ask spread.

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 risk capital savings of increasing hedging with the marginal increase in transactions costs. The optimal hedging strategy for each bid-ask spread is highlighted in orange.

Table 5.2: Optimal Hedging Strategies (£/MWh)

Cash Balance Benefit			Hedging Strategy						
Bid-Ask Spread	**Peak**	**Base**	**65.0%**	**67.5%**	**70.0%**	**72.5%**	**75.0%**	**77.5%**	**80.0%**
MMO	0.54%	0.36%	13.53	13.54	13.64	13.54	13.44	13.41	13.29
High Liquidity	0.97%	0.68%	13.47	13.51	13.59	13.49	13.34	13.37	13.24
Historical	1.40%	0.99%	13.41	13.48	13.53	13.45	13.31	13.29	13.17
Low Liquidity	2.80%	1.98%	13.19	13.34	13.33	13.28	13.14	13.11	12.99
Additional Transaction Costs									
Bid-Ask Spread	**Peak**	**Base**	**65.0%**	**67.5%**	**70.0%**	**72.5%**	**75.0%**	**77.5%**	**80.0%**
MMO	0.54%	0.36%	0.06	0.07	0.07	0.07	0.07	0.08	0.08
High Liquidity	0.97%	0.68%	0.12	0.12	0.13	0.13	0.14	0.14	0.14
Historical	1.40%	0.99%	0.17	0.18	0.18	0.19	0.20	0.20	0.21
Low Liquidity	2.80%	1.98%	0.34	0.36	0.37	0.38	0.40	0.41	0.42
Optimal Hedging Strategy									
Bid-Ask Spread	**Peak**	**Base**	**65.0%**	**67.5%**	**70.0%**	**72.5%**	**75.0%**	**77.5%**	**80.0%**
MMO	0.54%	0.36%	13.47	13.47	13.57	13.47	13.37	13.34	13.21
High Liquidity	0.97%	0.68%	13.35	13.39	13.46	13.36	13.21	13.23	13.10
Historical	1.40%	0.99%	13.24	13.30	13.34	13.26	13.11	13.09	12.96
Low Liquidity	2.80%	1.98%	12.85	12.98	12.96	12.90	12.74	12.70	12.57

Source: NERA Analysis.

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 zero per cent hedging strategy. Where this difference is maximised determines the optimal hedging strategy for the representative retailer. A 70 per cent hedging strategy is optimal for the MMO, high liquidity counter-factual, and historical bid-ask spreads. However, the increased transaction costs associated with the low liquidity counter-factual results in a reduction in the retailer's optimal hedging strategy to 67.5 per cent.

The benefits of introducing an MMO, with the same requirements of MMs as the S&P MMO, consist of differences between the orange boxes in Table 5.2. For instance, the benefit to a retailer of moving from the historical market spreads to the MMO market spreads is £0.23/MWh consisting of:

- A reduction in risk capital of £0.11/MWh ("MMO" risk capital of £13.64/MWh at optimal 70 per cent hedging minus the "historical" risk capital of £13.53/MWh at 70 per cent hedging strategy); and
- A reduction in transaction costs of £0.11/MWh ("MMO" transactions cost of £0.07/MWh at optimal 70 per cent hedging minus the "historical" transactions costs of £0.18/MWh at 70 per cent hedging strategy).

We can perform a similar exercise, and estimate the benefits of introducing an MMO, with the same requirements of MMs as the S&P MMO, to the other counter-factual market bid-ask spreads. We summarise the results in Table 5.3.

Table 5.3: Estimated Benefits Relative to Counter-Factual Market Bid-Ask Spreads for the Optimal Hedging Strategy of Retailers (£/MWh)

Benefit	High Liquidity	Historical (2009-2013)	Low Liquidity
Retailer Benefits			
Cash Balance Benefit	0.05	0.11	0.31
Transaction Cost Benefit	0.06	0.12	0.29
Total Retailer Benefit	0.11	0.23	0.60
Generator Benefits			
Cash Balance Benefit	0.01	0.01	0.05
Transaction Cost Benefit	0.06	0.12	0.29
Total Generator Benefit	0.06	0.13	0.34
Total Benefits	**0.18**	**0.36**	**0.94**

Source: NERA Analysis.

The benefits of implementing an MMO, with the same requirements of MMs as the S&P MMO, depends on the extent to which the MMO reduces bid-ask spreads. The benefits of the "MMO" bid-ask spreads relative to each counter-factual case are as follows:

- £0.18/MWh relative to the high liquidity counter-factual spreads;
- £0.36/MWh relative to historical counter-factual spreads; and
- £0.94/MWh relative to the low liquidity counter-factual spreads.

Benefits are driven largely by those benefits accruing to retailers. The retailer benefits of an MMO, that delivers the same level of liquidity as the S&P MMO, relative to historical spreads account for approximately 64 per cent of the total benefits. Transactions costs account for the largest proportion of the total benefit. The transactions costs benefits of an MMO, that delivers the same level of liquidity as the S&P MMO, relative to historical spreads account for approximately 67 per cent of the total benefits.

5.4. Total Estimated Benefits

We calculate the total annual benefit in the market by multiplying by the annual total volume supplied to domestic customers.[132] We only examine the total volume supplied to domestic customers because non-domestic customers are likely to have tariffs that are not set by the default tariff cap, and may be more closely linked to outturn wholesale prices. We follow two methods in order to develop a low and high estimate of the benefits:

1. Our first method multiplies the per MWh benefits, shown in Table 5.3, by the annual total volume supplied to domestic customers. This assumes that all traded volumes are subject to the transactions cost benefits of the MMO and forms our high case estimate.
2. Our second method multiplies the per MWh benefits, shown in Table 5.3, by the annual total of estimated "unhedged" volume supplied to domestic customers. We calculate the

[132] BEIS (September 2019), Supply and consumption of electricity, Last accessed: 7/11/19, Link: https://assets.publishing.service.gov.uk › attachment_data › file › ET_5.2.xls, [last accessed: 07/11/2019], sheet "Annual", cell V26

"unhedged" volume by subtracting the total volume of generation from the total volume of power supplied for each vertically-integrated entity.[133] In other words, we assume that the overlap in generation and supply is fully hedged for vertically-integrated entities. As such, total "unhedged" volume forms a low case estimate, because in reality it is likely that even a fully vertically integrated entity would trade forward: The vertically-integrated entities' own generation is unlikely to be the lowest cost method of meeting its customers' load in real time.

Our estimates for the total benefits from the introduction of an MMO, with the same requirements of MMs are the S&P MMO, are reported in Table 5.4. We report a high case estimate corresponding to total volume of power supplied to domestic customers and a low case estimate corresponding to the total "unhedged" volume of power supplied to domestic customers. The actual benefits may fall between the two estimates.

Table 5.4: Total modelled benefits of the MMO relative to counterfactual bid-ask spreads (£m)

Counterfactual	**High Liquidity**		**Historical (2009-2013)**		**Low liquidity**	
Volumes	Unhedged	Total	Unhedged	Total	Unhedged	Total
Retailer Benefits						
Cash Balance Benefit	4.4	5.7	9.4	12.2	25.2	32.6
Transaction Cost Benefit	4.8	6.2	9.6	12.5	23.8	30.8
Total	9.2	12.0	19.0	24.7	49.0	63.5
Generator Benefits						
Cash Balance Benefit	0.4	0.6	0.9	1.1	3.9	5.0
Transaction Cost Benefit	4.8	6.2	9.6	12.5	23.8	30.8
Total	5.3	6.8	10.5	13.6	27.7	35.8
Total Benefits	**14.5**	**18.8**	**29.5**	**38.2**	**76.7**	**99.3**

Source: NERA Analysis.

We estimate that the total benefits of an MMO, with the same requirements as the S&P MMO, compared to historical counter-factual spreads are £29.5m when multiplying by unhedged domestic volumes, and £38.2m when multiplying by total domestic volumes.

However, we estimate that the benefit of an MMO is roughly double when we move from the low liquidity counter-factual bid-ask spreads (£76.7m, and £99.3m when multiplying by unhedged and total domestic volumes respectively). Symmetrically, we estimate that the total benefit falls when moving from the high liquidity counter-factual bid-ask spreads (£14.5m and £18.8m when multiplying by unhedged and total domestic volumes respectively).

5.5. Estimated Benefits of an MMO With Relaxed Requirements

As we discuss further in Section 8, feedback from industry participants at the stakeholder workshop suggested that, should further intervention be required, it should occur through a

133 If generation is greater than supply, we assume all of the entity's power supplied is hedged and therefore its unhedged volume is zero.

tendered MMO. Moreover, there was support from stakeholders for a redesigned obligation that relaxed the requirements placed on MMs.

If a redesigned MMO relaxed the requirements placed on MMs, it may reduce the costs of market making but also the liquidity delivered by the obligation. Therefore, in order to estimate the benefits of introducing an MMO with relaxed requirements, we assume that a redesigned obligation would deliver market bid-ask spreads at the level specified by the high liquidity counter-factual discussed above.

Therefore, we estimate the benefits of moving from historical or low liquidity counter-factual spreads to the spreads delivered by the redesigned MMO, the high liquidity counter-factual spreads. Our estimated benefits are shown in Table 5.5.

Table 5.5: Total Modelled Benefits of a Redesigned MMO Relative to Counterfactual Bid-Ask Spreads (£m)

Counter-factual	**Historical (2009-2013)**		**Low Liquidity**	
(Volumes)	**Unhedged**	**Total**	**Unhedged**	**Total**
Retailer Benefit				
Cash Balance Benefit	5.0	6.5	15.8	20.5
Transaction Cost Benefit	4.8	6.2	14.1	18.3
Total	9.8	12.7	30.0	38.8
Generator Benefit				
Cash Balance Benefit	0.4	0.5	3.0	3.9
Transaction Cost Benefit	4.8	6.2	14.1	18.3
Total	5.2	6.8	17.2	22.3
Total Benefits	**15.0**	**19.5**	**47.2**	**61.1**

Source: NERA Analysis

We estimate that the total benefits of a redesigned MMO, with relaxed requirements of MMs, compared to historical counter-factual spreads are £15.0m when multiplying by unhedged domestic volumes, and £19.5m when multiplying by total domestic volumes.

However, we estimate that the benefit of an MMO is roughly triple when we move from the low liquidity counter-factual bid-ask spreads (£47.2m, and £61.1m when multiplying by unhedged and total domestic volumes respectively).

5.6. Sensitivity Analysis

To examine the sensitivity of our modelled estimated benefits, we test whether the magnitude of our estimated benefits changes depending on the assumed risk of negative cumulative cash balance, and the assumed WACC. Throughout our sensitivity analysis, we compare total benefit figures found by multiplying by total annual MWh supplied to domestic customers.

5.6.1. Modelled risk of negative cumulative cash balance

In our primary results, we assume the risk of negative cumulative cash balance to be equal to 5 per cent. However, we test the sensitivity of results to increasing this risk to 10 per cent.

We show in Table 5.6 that the optimal hedging strategy of retailers does increase with the higher assumed risk of negative cumulative cash balance for all transactions costs. Under the "MMO", we model that retailers optimally hedge 75 per cent of expected demand as opposed to 70 per cent under an assumed 5 per cent risk of negative cumulative cash balance. Similarly, in the low liquidity counter-factual, we model that retailers optimally hedge 70 per cent of expected demand, as opposed to 67.5 per cent under a 5 per cent risk of negative cumalitive cash balance.

Table 5.6: Optimal hedging strategies for a 10 per cent risk of negative cumulative cash balance (£/MWh)

Cash Balance Benefit			**Hedging Strategy**						
Bid-Ask Spread	**Peak**	**Base**	**65.0%**	**67.5%**	**70.0%**	**72.5%**	**75.0%**	**77.5%**	**80.0%**
MMO	0.54%	0.36%	8.95	9.00	9.04	9.03	9.06	9.00	8.91
High Liquidity	0.97%	0.68%	8.91	8.97	8.98	8.95	8.99	8.95	8.86
Historical	1.40%	0.99%	8.85	8.93	8.95	8.91	8.93	8.87	8.80
Low Liquidity	2.80%	1.98%	8.70	8.75	8.77	8.75	8.75	8.69	8.65
Additional Transaction Costs									
Bid-Ask Spread	**Peak**	**Base**	**65.0%**	**67.5%**	**70.0%**	**72.5%**	**75.0%**	**77.5%**	**80.0%**
MMO	0.54%	0.36%	0.06	0.07	0.07	0.07	0.07	0.08	0.08
High Liquidity	0.97%	0.68%	0.12	0.12	0.13	0.13	0.14	0.14	0.14
Historical	1.40%	0.99%	0.17	0.18	0.18	0.19	0.20	0.20	0.21
Low Liquidity	2.80%	1.98%	0.34	0.36	0.37	0.38	0.40	0.41	0.42
Optimal Hedging Strategy									
Bid-Ask Spread	**Peak**	**Base**	**65.0%**	**67.5%**	**70.0%**	**72.5%**	**75.0%**	**77.5%**	**80.0%**
MMO	0.54%	0.36%	8.89	8.94	8.97	8.96	8.99	8.93	8.84
High Liquidity	0.97%	0.68%	8.79	8.85	8.86	8.82	8.86	8.81	8.72
Historical	1.40%	0.99%	8.68	8.76	8.77	8.72	8.73	8.67	8.59
Low Liquidity	2.80%	1.98%	8.36	8.40	8.40	8.37	8.36	8.28	8.22

Source: NERA Analysis

However, our estimated benefits of an MMO, with similar requirements of MMs as the S&P MMO, does not change significantly with the assumed higher risk of negative cumulative cash balance. We report our results in Table 5.7.

Table 5.7: Sensitivity of our modelled benefits of the MMO to the assumed risk of a negative cumulative cash balance for retailers (£m)

Counterfactual	**High liquidity**			**Historical (2009-13)**			**Low liquidity**		
(Risk)	**(10%)**	**(5%)**	**(2%)**	**(10%)**	**(5%)**	**(2%)**	**(10%)**	**(5%)**	**(2%)**
Retailer Benefits									
Cash Balance Benefit	8.0	5.7	6.5	11.4	12.2	12.2	30.6	32.6	34.6
Transaction Cost Benefit	5.7	6.2	6.9	12.0	12.5	13.8	31.7	30.8	35.7
Total	13.8	12.0	13.4	23.4	24.7	26.1	62.3	63.5	70.3
Generator Benefits									
Cash Balance Benefit	4.3	0.6	0.5	4.8	1.1	0.9	6.4	5.0	2.2
Transaction Cost Benefit	5.7	6.2	6.9	12.0	12.5	13.8	31.7	30.8	35.7
Total	10.0	6.8	7.4	16.8	13.6	14.8	38.1	35.8	37.9
Total Benefits	**23.8**	**18.8**	**20.8**	**40.2**	**38.2**	**40.8**	**100.4**	**99.3**	**108.2**

Source: NERA Analysis

The estimated benefits of the MMO, with higher assumed risk of a negative cumulative cash balance for retailers, relative to each set of counter-factual bid-ask spreads are (see Table 5.7):

- £23.8m relative to the high liquidity counter-factual spreads (increased from £18.8m);
- £40.2m relative to historical spreads (increased from £38.2m); and
- £100.4m relative to the low liquidity counter-factual spreads (increased from £99.3m).

We also test the sensitivity of our results to reducing the risk of minimum cumulative cash balance to 2 per cent. Under this assumption, the estimated benefits of the MMO, relative to each set of counter-factual bid-ask spreads are (see Table 5.7):

- £20.8m relative to the high liquidity counter-factual spreads
- £40.8m relative to historical spreads; and
- £108.2m relative to the low liquidity counter-factual spreads.

5.6.2. Weighted average cost of capital (WACC)

Our estimated benefits of an MMO are increasing in the assumed WACC. A higher WACC increases the benefits of hedging by increasing the value of risk capital savings. We examine the sensitivity of our results to the range of WACCs proposed by the Competition and Markets Authority (CMA)[134].

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

In our reported results, we assume that the generator WACC and retailer WACC are the midpoint of the respective ranges estimated by the CMA.[135] We assume that the generator WACC is equal to 8.8 per cent and the retailer WACC is equal to 10.15 per cent.

We test the sensitivity of our estimated benefits to our WACC assumptions by examining a high and low case WACC estimate for the generator and the retailer. We set the high and low case WACC estimates equal to the upper and lower bounds of the CMA's estimated ranges respectively. The upper bounds of generator and retailer WACC are 9.3 and 11 per cent respectively, and the lower bounds of generator and retailer WACC are 7.9 and 9.7 per cent respectively. We report our results in Table 5.8.

Table 5.9: Sensitivity of our modelled benefits of the MMO to our WACC assumptions (£m)

Counterfactual	**High Liquidity**		**Historical (2009-13)**		**Low Liquidity**	
(WACC)	**(Low)**	**(High)**	**(Low)**	**(High)**	**(Low)**	**(High)**
Retailer Benefits						
Cash Balance Benefit	5.2	6.2	11.1	13.2	29.9	35.4
Transaction Cost Benefit	6.2	6.2	12.5	12.5	30.8	30.8
Total	11.5	12.4	23.6	25.7	60.7	66.2
Generator Benefits						
Cash Balance Benefit	0.5	0.6	1.0	1.2	4.5	5.5
Transaction Cost Benefit	6.2	6.2	12.5	12.5	30.8	30.8
Total	6.8	6.9	13.5	13.7	35.3	36.4
Total Benefits	**18.2**	**19.3**	**37.1**	**39.4**	**96.1**	**102.5**

Source: NERA Analysis

The estimated range of benefits of the MMO, with higher assumed WACC, relative to counter-factual bid-ask spreads are:

- £19.3m relative to the high liquidity counter-factual (increased from £18.8m);
- £39.4m relative to historical spreads (increased from £38.2m); and
- £102.5m relative to the low liquidity counter-factual (increased from £99.3m).

The estimated range of benefits of the MMO, with lower assumed WACC, relative to counter-factual bid-ask spreads are:

- £18.2m relative to the high liquidity counter-factual (decreased from £18.8m);
- £37.1m relative to historical spreads (decreased from £38.2m); and
- £96.1m relative to the low liquidity counter-factual (decreased from £99.3m).

The range defined by our estimates from using a high WACC and low WACC correspond to roughly six per cent of our estimate for the benefits in Section 5.4. Therefore, our results seem to be insensitive to the use of alternate WACC assumptions within the CMA's estimated ranges.

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

6. Costs of the MMO

In this Section, we outline the reported costs of the S&P MMO in Great Britain. We then use these estimates to construct estimated costs of a tendered MMO design. We assume that the tendered MMO design places the same obligation on MMs as the S&P MMO.

We will use these estimated costs and our estimated benefits from our modelling approach to estimate the net benefits associated with the introduction of a tendered MMO.

6.1. Estimated Costs of the S&P MMO

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".[136] "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 6.1.

Table 6.1: 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.[137]

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 6.2.[138] 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 open positions and traded volumes from strong assumptions which related to the design of the MMO, in particular the volume cap rules.

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

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

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

Table 6.2: 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 6.3.[139]

Table 6.3: 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.[140] In particular, licensees stated costs arose from the start of the trading windows, when price discovery was harder and yet the bid-ask spreads for mandatory products were small.[141]

6.2. Estimated Costs of a Tendered MMO

The costs of fulfilling an MMO are difficult to estimate. Therefore, we take the above reported cost estimates to construct an estimated gross social cost of a tendered MMO that delivers the same level of liquidity as the S&P MMO. In addition, we add the cost of operating and designing the tender process. In Section 7, we compare the estimated total costs of the tendered MMO to the estimated benefits of the MMO in Section 5 to estimate the net-benefits of the MMO.

To estimate the total, market-wide, cost of fulfilling the MMO, we multiply the reported costs per MM in Table 6.3 by the number of MMs originally obligated under the S&P MMO. We assume that, with the exception of the costs of design and operation of the tender and

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

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

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

assuming all other design features of the MMO remained the same as the S&P MMO in the new tendered MMO, the cost of fulfilling the new tendered design would be equivalent.

We construct high and low total cost estimates using the variation in the cost of market making reported in Table 6.3. Our low case is constructed by taking the minimum cost of fulfilling the obligation reported in Table 6.3. The minimum cost of fulfilling the obligation was reported in 2014 at £0.7m per MM per year. Our high cost case is constructed by taking the minimum cost of fulfilling the obligation reported in Table 6.3. The highest cost of fulfilling the obligation was reported in 2016, when the market was more volatile in Q3 and Q4, at £8.5m per MM per year.

If Ofgem intervened through a tendered MMO, then Ofgem will incur a cost of designing and running the tender process. To estimate the cost of operating and designing the tender process, we examine the cost incurred by MIBGAS to operate a tender for the MMO in the Spanish gas market. We understand from Ofgem that MIBGAS estimate its total annual costs of operating its tendered MMO and compensating the tendered MMs is approximately £0.5m.[142] We adopt this figure as the administrative cost of running a tendered MMO in Great Britain. The cost of MIGBGAS's tender is likely to be a conservative estimate of costs, since it also includes the payment to the market makers according to their compliance. On the other hand, Ofgem would need to incur additional costs if it were to design the first tender process rather than implement an already designed tender process.

We summarise our estimated gross social costs of fulfilling a tendered MMO in Table 6.4.

Table 6.4: Estimated annual gross social costs of a tendered MMO

	Number of MMs	Cost of Tender (£m)	Estimated Cost /MM (£m)		Total Estimated Cost (£m)	
			Low Case	High Case	Low Case	High Case
Tendered MMO	6	0.5	0.7	8.5	**6.7**	**53.5**

Source: NERA Analysis.

There may exist other gross social cost savings from a tendered MMO that we do not include in our above cost estimates. For example, if the auction process in a tendered MMO is well designed, then the most efficient MMs may be selected to provide market making services. The most efficient MMs selected under a tendered MMO may be different to those MMs mandated under the S&P MMO. Consequently, our estimated costs of fulfilling the obligation, for the same requirements under the MMO, may be lower in the case of a tendered MMO.

In addition, if the eligibility threshold that defines MMs under the current mandatory MMO is leading to market distortions, and movement to a tendered MMO removes these distortions, our estimate of the social costs of a tendered MMO may be too high (or our estimate of the social benefits of the tendered MMO may be too low).

[142] MIBGAS report estimated costs of EUR 600,000. We use a UK Pound Sterling/Euro Exchange Rate conversion rate of 1.1888 Euros to Pounds to estimate a cost of GBP 504,711. Financial Times (December, 2019). Link: https://markets.ft.com/data/currencies/tearsheet/summary?s=gbpeur. Last accessed [09/12/2019]

7. Options Assessment and Estimated Net Benefits

In this Section, we combine our estimated benefits of the MMO from Section 5 with our estimated costs of the MMO in Section 6 to estimate the net benefits of a tendered MMO which results in the same market bid-ask spreads as under the S&P MMO.

We do not estimate the net benefits of a redesigned MMO with different requirements because we do not have data for how the costs of market making may vary with the requirements of the MMO.

7.1. Our Estimated Net-Benefits

To assess the net benefits of the tendered MMO, that delivers the same market spreads as the S&P MMO, we use the range of benefits estimated in Section 5, and the range of costs estimated in Section 6.

We define a range of estimated net benefits. We estimate the upper bound of net benefits by subtracting the lower bound of estimated costs from the upper bound of our estimated modelled benefits. We estimate the lower bound of net benefits by subtracting the upper bound of estimated costs from the lower bound of our estimated modelled benefits. We estimate the upper bound of our modelled benefits by multiplying £/MWh benefits by the total annual volume of power supplied to domestic customers. We estimate the lower bound of our modelled benefits by multiplying by the total annual "unhedged" volume of power supplied to domestic customers. We show our results in Table 7.1.

Table 7.1: Our Estimated Net Benefits of the MMO (Units in £m)

	High liquidity counter-factual bid-ask spreads		Historical bid-ask spreads		Low liquidity counter-factual bid-ask spreads	
	(Lower)	(Upper)	(Lower)	(Upper)	(Lower)	(Upper)
Benefit	14.5	18.8	29.5	38.2	76.7	99.3
Cost	51.5	4.7	51.5	4.7	51.5	4.7
Net Benefits	**-37.0**	**14.1**	**-22.0**	**33.5**	**25.2**	**94.6**

Source: NERA Analysis

The range of net benefits of an MMO, that delivers the same level of liquidity as the S&P MMO, relative to the counter-factual bid-ask spreads are:

- £-37.0m to £14.1m relative to the high liquidity counter-factual bid-ask spreads;
- £-22.0m to £33.5m relative to historical spreads; and
- £25.2m to £94.6m relative to the low liquidity counter-factual bid-ask spreads.

Our estimates suggest that unless liquidity falls to levels beyond those observed prior to the introduction of the S&P MMO, further intervention may not deliver a net benefit. We estimate that, in both the case of intervention with prevailing spreads at the high liquidity counter-factual and the historically observed spreads, the net benefits of introduction with an MMO that delivers the level of liquidity currently prevailing in the market may lead to net benefits at the upper bound of our range, but may lead to net losses at the lower bound.

However, we estimate that if liquidity, in the absence of intervention, falls to the low liquidity counter-factual spreads, intervention through an MMO may deliver substantial net benefits.

Further information on the costs of fulfilling the obligation may narrow the range of net benefits between the upper and lower bounds.

7.2. Caveats to Modelling Approach

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 seasonal products. It therefore ignores any benefits of the MMO on other products e.g. monthly 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 market.
- Our model does not account for any movement of liquidity to the mandated trading windows under the S&P MMO design. In addition, our model does not account for any loss of liquidity in non-mandated products. 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.[143]
- In our model, the 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.
- We do not consider product availability in our model. At each hedging level, the retailer may 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 may be greater than one which means that power is traded more times than it is consumed. This increases the benefits from the reduction in

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

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 the strategy used to set the default tariff cap. 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. An 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 an 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, 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.
- We may understate the benefits of market making because we do not examine non-domestic customers. Moreover, we do not multiply our benefits by non-domestic annual volume. We expect the benefits of market making to suppliers serving non-domestic customers to be limited because non-domestic customers are likely to have tariffs that more granularly reflect the wholesale market price of power.
- 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 five per cent of the observed distribution. That is to say that, because we use the case where five 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 five per cent of the total simulations.

  We have used a large number of simulations, around 5000, 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 would be unlikely to be statistically significant.

8. Design of a Tendered MMO

Our estimates of the net-benefits of an MMO in Section 7 suggest that, if market transactions costs increase significantly in the absence of an MMO, further intervention may be justified in the wholesale market. As we discuss in Section 4, industry participants at the stakeholder workshop were broadly in agreement that, should further intervention be required, the intervention should be in the form of a “voluntary” or tendered MMO.

In this Section, we discuss, in light of the feedback from industry participants, how a tendered MMO could be designed should further intervention be required. We also examine design options that specifically relate to the design of a *tendered* MMO, for example, the type of auction that may be most suitable.

8.1. Design Elements: The Requirements Under a Re-Designed MMO

The design elements that Ofgem would need to specify in a tendered MMO broadly correspond to the design elements of the S&P MMO. Table 8.1 summarises the design elements and requirements of the S&P MMO.

Table 8.1: Summary of Requirements Under the S&P MMO

MMO Design Element	S&P MMO Design
Maximum bid-ask spread	Baseload: 0.5% – 0.6 % Peakload: 0.7% - 1%
Clip size and number of lots	Up to 10MW in clip sizes of 5 MW
Products	Up to two years-ahead Includes monthly, quarterly and seasonal baseload and peakload products
Trading windows	Two hour-long windows each day Must be available 100% of the trading windows and replace bid-ask within five minutes of trading
Suspension of obligation	The MM may cease trading for a particular product and trading window if the price changes by more than 4% in a single direction or it accumulates an open position of 30MW in a single direction
Number/selection of market makers	Number of mandated participants selected by criteria (degree of vertical integration)
Selection of MMs	Licensed MMs

Source: NERA Analysis.

We discuss each of the above design elements in turn and, using feedback from industry participants, evaluate the S&P MMO design choices. Our discussion of a redesigned tendered MMO does not assume that the introduction of a tendered MMO will be required.

8.1.1. Maximum bid-ask spreads

Industry participants at the stakeholder workshop generally agreed that the current maximum bid-ask spreads, in conjunction with the 100 per cent availability requirement in trading windows, significantly drive the costs of market making. Some stakeholders suggested that the current spreads were too restrictive and significantly contribute to the high costs of market making during volatile markets.

There are a number of ways that the MMO could be redesigned to give MMs more flexibility in volatile markets:

1. Wider spreads could be permissible when the market is more volatile: Whilst wider spreads in volatile markets may reduce the costs of market making, it may also significantly reduce the benefits. The benefits of market making are likely to be highest during volatile markets because the value of price discovery is the highest in a volatile market. Moreover, it is unclear how Ofgem could transparently define a volatile market. In addition, it may be costly for Ofgem to enforce, and MMs to report on, the permissible widening of bid-ask spreads in a volatile market.
2. The introduction of soft-landing rules and redesigned fast-market cap rules could reduce the costs of market making in volatile markets. We discuss the rules for temporary suspension of the obligation further in Section 8.1.5.
3. Ofgem could relax availability requirements, such that MMs are mandated to trade for less than 100 per cent of the time in trading windows. Reduced availability requirements give flexibility to MMs in volatile markets, and may supersede the need for redesigned maximum bid-ask spreads. We discuss availability requirements in more detail in Section 8.1.4.

In addition, some stakeholders suggested that the current maximum bid-ask spreads are too restrictive, regardless the volatility prevailing in the market. However, stakeholders did not suggest what alternative, less restrictive spreads, may be suitable. The specification of appropriate maximum bid-ask spreads is difficult without supporting evidence on how the costs, and benefits, of market making may vary with the change in spreads.

Under a tendered scheme, MMs will reflect the costs imposed by the maximum bid-ask spread in their bid. Therefore, whilst MMs will not be bear the higher costs of more restrictive maximum bid-ask spreads, the gross social costs of restrictive bid-ask spreads will still be borne by industry.

Therefore, it could be that Ofgem requires further evidence on the costs and benefits from industry participants in order to inform the choice of maximum bid-ask spreads under a redesigned obligation.

Alternatively, maximum bid-ask spreads could be determined through the tender process. In the tendered MMO in Singapore, applicants submit two sets of offers in the tender process, each corresponding to a different maximum bid-ask spread specified by the regulator.[144] This process therefore provides some information on the relative private costs of different maximum bid-ask spreads. The bid-ask spread is then chosen by the regulator after all applicants have submitted their offers.

Moreover, in the tendered MMO operating in the Spanish gas market, maximum bid-ask spreads are a flexible part of the applicant's offer in the tender. More specifically, applicants can offer a package of market making services at a bid-ask spread lower than the bid-ask

[144] 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.

spread cap set by the tender operator, Mercado Ibérico del Gas (MIBGAS). The cap is set at €0,40/MWh for within-day and day-ahead products and €0,35/MWh for balance of month and one month ahead products. Applicant offers with lower maximum bid-ask spreads are receive a higher score by MIBGAS in the bid evaluation process. We discuss the evaluation process used by MIBGAS in the tender in more detail in Section 8.2.6.

In addition, our modelling results suggest that relaxing the bid-ask spread would not substantially reduce the social gross benefits of the MMO, as Table 5.4 shows. If relaxing the bid-ask spreads substantially reduces the social gross costs of providing market making services, then relaxing the current maximum spreads may increase the overall net benefits of the MMO.

Overall, stakeholder feedback, and our modelling, suggests that relaxing the current obligation may be prudent if a tendered obligation were to be introduced. Relaxing the current obligation may be achieved through the following design changes:

- relaxing the maximum bid-ask spreads;
- relaxing the maximum bid-ask spreads in volatile markets;
- relaxing the availability requirement in windows, which may supersede the need to relax maximum bid-ask spreads; or
- a combination of above.

However, further evidence on the costs of market making, and how those costs vary with bid-ask spreads and market volatility, may be required to evaluate the abovementioned policy options. As already noted, this information may to an extent be obtained through a tender process.

8.1.2. Clip sizes for trade and number of lots

Stakeholders generally agreed that the current combination of clip sizes and number of lots were appropriate. Some participants called for lower minimum clip sizes, for example at 1 MW. In New Zealand's MMO, relatively more lots are made available at lower clip sizes compared to the S&P MMO in Britain.[145]

A redesigned tendered MMO with lower clip sizes may increase flexibility for trading and may reduce the costs associated with market making. Moreover, smaller lot sizes may provide more flexibility for purchasers of the products, and particularly for smaller suppliers. Indeed, futures contracts for the New Zealand power market were changed from 1MW to 0.1MW in 2015, with a large part of the justification being impact it would have on small suppliers.[146] However, it is unclear whether lower clip sizes would create sufficient flexibility to encourage more market participants to bid in a tender to become a MM. It could be that total volume exposure is the more important driver of costs of market making. In

145 As described in Electricity Authority (2015), *Hedge Market Development: Enhancing Trading of Hedge Products - Consultation Paper*, Electricity Authority, 1 May 2015, Last accessed: 11/11/19, Link: https://www.ea.govt.nz/dmsdocument/19441

146 See, e.g., Electricity Authority, *Reduction in size of New Zealand electricity products traded on ASX*, 11 November 2015, Last accessed: 11/11/19, Link: https://www.ea.govt.nz/about-us/media-and-publications/market-commentary/projects/reduction-in-size-of-new-zealand-electricity-products-traded-on-asx/)

addition, whilst smaller clip sizes may provide flexibility and lower costs of market making, smaller clip sizes may also reduce the benefits of the MMO.

Therefore, Ofgem could incorporate smaller minimum clip sizes into a redesigned tendered MMO. However, Ofgem may require further evidence from industry to ensure that the benefits of the MMO would not significantly fall with smaller clip sizes. In absence of reliable evidence on the effects of smaller clip sizes, and given the existing clip sizes and number of lots are generally agreed to be appropriate, it may be practical for a redesigned obligation to maintain the requirements specified under the S&P MMO.

8.1.3. Products

In general, industry participants in the stakeholder workshop agreed that the products mandated under the S&P MMO are a good compromise. Some participants called for an increased number of granular products to allow them to shape hedging strategies to expected demand, for example the week-ahead, weekend, or block 6 contracts.

However, market participants recognised that the additional costs of market making, should the tendered MMO require market making for an increased number of products, are uncertain. Without reliable estimates for the additional costs incurred to market make for the additional products, it may be prudent for Ofgem to specify the same products as the S&P MMO in a redesigned tendered MMO.

8.1.4. Trading windows

Stakeholders did not provide a clear, unanimous position on the design of trading windows under the S&P MMO. In general, stakeholders agreed that liquidity in the market has concentrated to the two trading windows each day. Stakeholders also acknowledged that the 100 per cent availability requirement for MMs in the trading windows was a significant driver of the costs of market making.

Therefore, stakeholders generally provided support for reducing the availability requirement for MMs in trading windows. They argued that mandating MMs to market make for only 80 per cent of the time in trading windows, or in a month, would significantly reduce the costs of the obligation by giving MMs flexibility in volatile markets.

However, opinions diverged as to whether trading windows should be maintained under a redesigned MMO. Some stakeholders suggested removing trading windows and instead imposing an availability requirement throughout the day. They argued that this may lead to liquidity spreading throughout the day, allowing market participants to trade on events that would have otherwise been outside of the trading windows, for example changes to weather forecasts.

On the other hand, some stakeholders said they preferred the certainty of availability of products at specified times on each trading day. Some stakeholders instead argued for expanding the trading time in each of the current windows.

In addition, whilst many stakeholders were in support of a relaxed availability requirement within trading windows (or within the trading day in the absence of trading windows), some stakeholders were concerned about the associated costs of monitoring and enforcing the requirement. Whist it may be harder for Ofgem to enforce a relaxed availability requirement relative to the current obligation, it is unclear, from stakeholder feedback, the magnitude of the additional compliance costs placed on MMs relative to the cost savings of moving to the relaxed availability requirement.

Relaxed availability requirements have been used in international experience with MMOs. The Singaporean MMO has a relaxed availability requirement relative to the current British MMO. In Singapore, MMs must market make for 80 per cent of the total trading window time in a month.[147] The responsibility is placed on MMs to report their compliance to the availability requirement: MMs must submit compliance reports to the EMA at a frequency of no longer than six months.[148]

If Ofgem chose to relax the availability requirement in trading windows under a redesigned MMO, the costs of market making, particularly in volatile markets, would likely fall. However, further evidence is required on the additional costs of reporting compliance with a relaxed availability requirement to ensure that it is a feasible option. Otherwise, the costs of additional compliance, which would be included in an applicant's bid at tender, may offset the cost savings from relaxed availability requirements.

Any changes that Ofgem makes to the current trading window arrangements should ensure alignment with other markets. For example, alignment with other continental European markets and the British gas market are important to market participants wishing to trade spreads across markets.

8.1.5. Conditions which result in temporary suspension of the obligation

In general, participants at the stakeholder workshop recognised the need to relax the requirements relative to the S&P MMO. It is possible that moving away from a 100 per cent availability requirement during trading windows supersedes the need for conditions under which the obligation is temporarily suspended in a trading window.

The S&P MMO has two conditions which result in temporary suspension of the obligation for a particular product in a particular trading window: the net volume cap and fast market rule. Whilst 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,[149] Ofgem received feedback from MMs that the cap was too high and could instead be based on gross volume traded instead of net volume.[150]

The current fast market cap has been triggered fewer times than the volume cap.[151] Licensees 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 in 2016 Q3 and Q4.[152] As a result, Ofgem considered allowing a wider bid-ask spread (1 per cent for all products) beyond a 1 per cent

147 MMs must also respond to a request for quote when not actively quoting prices in the market at a higher maximum bid-ask spread. Source: EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.10.

148 EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.10.

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

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

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

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

threshold for market price movement.[153] Ofgem also considered implementing a soft-landing rule at the start of trading windows, when price discovery was more costly.

If Ofgem reduced the 100 per cent availability requirement in trading windows under a redesigned tendered MMO, it may not need to also specify net volume cap nor fast market cap rules. The extent to which Ofgem may still need to define conditions that allow for temporary suspension depends on by how much the availability requirement is reduced. Relaxed availability requirements do not entirely eliminate the risk of MMs being mandated to market make in volatile markets. Therefore, Ofgem should make decisions altering the rules allowing temporary suspension of the MMO in conjunction with decisions over adjustments to the requirements in trading windows.

On the other hand, if 100 per cent availability requirements are maintained in trading windows, tighter fast market rule caps with soft landing periods seem to be practical mechanisms by which Ofgem may relax the obligation in volatile markets. Ofgem has already discussed some of the potential changes to the rules allowing temporary suspension of the obligation with stakeholders in prior consultations.

8.1.6. Number of market makers

There was a limited discussion over the number of MMs at the stakeholder workshop, given that the S&P MMO mandates parties based on an eligibility threshold rather than selects an explicit number of MMs. In general, under a tendered MMO, participants suggested that there should be at least three MMs, and more than one for each product. In international experience with MMOs, generally four to six MMs are selected to market make. In the tendered MMO for market making in the Spanish gas market, one MM is chosen per product.

In Singapore’s tendered MMO, the number of MMs was a variable feature of the tender process. Each applicant to the tender submitted a set of offers stating the price it would need to be paid to market make for the given requirements, under scenarios where different numbers of MMs were selected (more precisely, four to seven MMs).[154] In other words, each applicant submitted an offer on the assumption that there were four MMs and a different offer on the assumption that five, six or seven MMs were selected. The Electricity and Markets Authority (EMA) then chose a corresponding set of MMs after all offers were received. The EMA selected six MMs.[155]

The design of a tender where applicants can vary their bid with the number of other MMs may be attractive, and allow Ofgem to manage the costs of the tender more effectively. However, it is unclear whether Ofgem could effectively and transparently specify selection criteria to assess bids after offers have been received. We discuss the specification of transparent selection criteria further in Section 8.2.6. If this is not possible, selecting four to six MMs may be more practical.

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

154 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.

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

8.1.7. Selection of market makers

A key potential advantage of a tendered MMO is that, should the auction be well designed, the most efficient MMs are selected to provide the service, and therefore the cost to industry of fulfilling the obligation is minimised. It is possible that the most efficient MMs to fulfil the obligation are not licensed parties and may instead be financial players.

For example, in the Singaporean MMO, the winners of the tender were independent trading operations, with only two of the six selected MMs having directly links to wholesale market participants through ownership.[156]

In order to be eligible to provide market making services in the Singaporean MMO, 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"[157] 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".[158]
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".[159]
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.

If Ofgem were to allow unlicensed entities to submit bids to the tender, the total industry costs of fulfilling the obligation may fall. However, it is unclear whether Ofgem has (or requires) jurisdiction to enforce the obligation with unlicensed MMs.

8.2. The Design of the Tender

The design of a tendered MMO also requires design choices pertaining to the tender process. The design elements that Ofgem would need to specify in a tendered MMO broadly correspond to the design elements of the S&P MMO. Table 8.1 summarises the design elements and requirements of the S&P MMO.

8.2.1. Auction type

The most significant design choice if Ofgem introduced a tendered MMO is the type of auction it uses to select MMs. For the purposes of this discussion, we assume that MMs bid to provide a package of market making services which is specified by Ofgem before the

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

157 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.

158 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.

159 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.

auction. Therefore, each MM may only bid to provide one package of services, and not multiple packages. The package of market making services may, for example, specify market making requirements similar to the S&P MMO.

There are two main ways that Ofgem could design the auction process:

- **Sealed bid auction:** A first-price sealed bid auction method is used in the Singaporean MMO and the Spanish gas market MMO. A sealed bid auction may be relatively simpler, and therefore cheaper, for Ofgem to run relative to a dynamic multi-round auction with feedback.

  A second-price sealed bid auction may be preferable to a first-price sealed bid auction. In a second-price sealed bid auction, applicants are incentivised to bid their expected costs of providing the service. On the other hand, in a first-price sealed bid, applicants are incentivised to bid their estimated costs of the next most expensive applicants' costs of fulfilling the obligation.

  However, a sealed bid auction has disadvantages. For example, the price bid by other applicants is not publicly available. Therefore, applicants may not learn from other applicants' bids what the cost of providing market making services may be. Applicants may be able to learn from the cost bid by other applicants if there are common sets of expectations which may drive the costs of fulfilling the obligation. For example, a significant cost of market making is market volatility. It may be efficient to allow applicants to observe the bids of other applicants to gauge other applicant's expectations of market volatility over the upcoming year.

  In a sealed bid auction, the lack of opportunity for applicants to view other applicant's bids may, more likely, result in an inefficient price.

- **Ascending-price dynamic multi-round auction with feedback** : On the other hand, an dynamic multi-round auction with feedback allows applicants to observe the bids of other applicants. As a result, applicants may learn from the bidding behavior of other applicants and use the information to augment their own bidding strategy. If Ofgem was to allow other applicants to use this information, it may result in a more efficient price of the auction process. Ofgem would need to decide in the design of the dynamic multi-round auction the information publicly made available about applicant's bids. For example, there may or may not be advantages in anonymising applicant's bids.

  However, a dynamic multi-round auction with feedback is likely more expensive for Ofgem to run. Moreover, a dynamic multi-round auction may reduce the number of variable features that Ofgem could include in the tender process. For example, it may be difficult to design a dynamic multi-round auction that allows MMs to specify their own bid-ask spreads.

Design of the auction type for market making, and the criteria that Ofgem uses for selection may be complicated. It may be that Ofgem should not just consider price of the bid, but also the information that the applicant may possess and reflect in their pricing as a MM. For example, Ofgem could pay a premium to have at least one generator as a MM rather than just suppliers without generation assets, if the generator could provide information through its prices when market making that would result in greater price discovery in the market.

Moreover, it may be in Ofgem's interest to select applicants who may be better at market making, because of experience or greater information, than other applicants who may not be as good at market making but submit cheaper bids. However, it may be difficult for Ofgem to objectively assess this in practice. It is also likely that the costs of market making and experience or competency with market making are highly correlated meaning selecting cheaper bids may select potential MMs with more information.

Ofgem, should it choose to intervene through a tendered MMO, must also decide the frequency on which the tender is run. Given the social costs of administering and operating the tender may be high, especially if Ofgem operates a dynamic multi-round auction , it may be impractical to operate the tender on a within-year basis. Therefore, Ofgem could operate the tender on an annual basis, or multi-year basis, depending on the social costs of operating the tender.

8.2.2. Compensation mechanism

If Ofgem were to introduce a tendered MMO, it would need to decide how selected MMs would be compensated. There are two main ways MMs could be compensated:

- A per monthly payment: In Singaporean and Spanish gas market tendered MMO's, MMs are compensated with a per monthly payment. The payment is determined from the offer made by MMs in the tender.
- Per unit volume: Alternatively, MMs could be compensated on a volumetric basis for the volume of market making that they deliver in a given month. MMs would need to fulfil the requirements of the MMO by positing bid-ask spreads for the specified products, number of lots and clip sizes. However, MMs would be compensated for the volume of trade actually executed under the MMO. In order to compensate MMs on a volumetric basis, MMs would need to distinguish trades pertaining to fulfilling the MMO and trades relating to the operation of its business.

Whilst compensation on a per monthly basis may be simpler for Ofgem to implement, compensation on a volumetric basis may more closely align applicant's revenues with the costs incurred from market making. Alignment of costs and revenues of MMs may protect them from years when the market is unexpectedly volatile. For example, in 2016 the market was more volatile and the reported costs of market making were significantly higher. Therefore, compensation on a volumetric basis may reduce the costs of providing the obligation, because applicants may not need to build in risk premia to their bids to guard against the unexpectedly volatile year.

8.2.3. Penalties and enforcement

The penalty and enforcement mechanism that Ofgem could use in response to non-compliance with the MMO requirements may depend on whether the MMs are licensed or unlicensed entities. The mechanisms that Ofgem could use may also depend on the design of the tender. Ofgem should consider the enforcement costs of any redesigned obligation as, alongside the costs of market making, they contribute to the total social costs of the obligation. Therefore, enforcement costs are also included in the estimated net-benefits of the MMO.

One potential way Ofgem could penalise non-compliance is by linking penalties to the tender price. For example, under the Singaporean MMO, there is a penalty for non-compliance with the obligation that is specified in relation to the tender price. The monthly tender payment will not be made if the MM fails to fulfil all of the obligations in that month.[160] If the MM fails to fulfil all of the 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.[161] Under termination in the two above cases, the MM pays an exit fee of 100 per cent of the total RFP price.[162]

8.2.4. Market power mitigation

To a large degree, if the package of market making services that applicants are bidding to provide is the same across MMs, and each applicant may only provide the package of services once, then market power is largely mitigated.

However, if the package of market making services may differ across applicant's bids, or applicants may bid to provide multiple packages of market making services, then there may be market power problems in the current market. There are several mechanisms to mitigate market power that could be incorporated into the tender design. For example:

- Reserve price (see Section 8.2.5): The use of a reserve price limits the rents captured by parties with market power in the tender process, and ensures that the social costs of the obligation do not exceed the estimated social benefits.
- Use of a demand curve to limit the rents captured by participants with market power: Ofgem could establish a demand curve for different volumes of market making, a different number of MMs, or different maximum bid-ask spreads. The use of a demand curve limits the rents that may be captured by parties with market power, by establishing a willingness to pay for market making services.
- Impose cost-based bidding plus a margin: Alternatively, Ofgem could impose cost-based bidding plus an allowed margin in the tender process. Cost-based bidding also limits the rents captured by applicants with market power because, by definition, the revenue recovered by MMs are equal to the costs incurred and the allowed margin. However, it may be difficult for MMs to report and Ofgem to monitor the costs incurred from market making, and particularly the management of open positions.

If the tender only operates with licensed parties, market power is likely to be a problem given the relatively few licensed parties who have previous experience market making. These experienced parties are likely to have significant cost advantages over other parties. Therefore, elements to mitigate market power should be incorporated into the tender design.

[160] 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.

[161] 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.

[162] 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.

The combination of the options used in the final design will depend on other choices e.g. auction method.

8.2.5. Reserve price-setting methodology

If Ofgem chooses to implement a tender process, it must ensure that the costs bid by and awarded to the chosen MMs do not exceed the expected benefits of the MMO. One mechanism that Ofgem may use to counteract this risk is a reserve price in the auction. If the total costs of market making submitted by applicants exceeded the reserve price, Ofgem could choose not to implement the obligation.

Ofgem could set the reserve price using an estimate of the social benefits of the obligation. The estimated social benefits may be estimated through a modelling approach, such as the one we develop in Section 5, through consultation with industry or through an estimate of the costs of fulfilling the obligation plus a premium. A modelling approach requires significant simplifications to be made in order to ensure tractability: We outline the caveats and assumptions to our modelling approach in Section 7.2. Therefore, relying solely on modelling results is unwise. Therefore, it may be that further evidence on the costs of market making and estimated benefits from industry participants may be required, in order for Ofgem to set the reserve price, should a tendered obligation be introduced.

Alternatively, a buy-side auction could be introduced to set the reserve price through a tender process. Industry participants would bid their willingness to pay for market making services. The aggregation of bids across the industry can be used as an estimate for social benefits, and used as a reserve price in the tender for MMs. A buy-side auction may also distribute the costs of market making amongst participants who value the service the most.

However, design of a buy-side auction is likely to be complicated. As we discuss in Section 2.1.2, if liquidity is a public good there may be a free-rider problem associated with bidding for the service of providing liquidity. In other words, liquidity may be non-excludable. Therefore, bidders would be incentivised not to pay for market making in the buy-side auction but wait for other participants to pay, and then subsequently benefit from any changes in market liquidity. To overcome the free-rider problem, market making, and the resulting changes in liquidity should be made excludable. In other words, only the parties that bid in the buy-side auction receive the service provided by market makers. However, ensuring excludability is difficult, and may be complex to enforce.

8.2.6. Flexibility versus transparency

Throughout our discussion of the design elements of the MMO, we discuss the possibility of determining various design elements of the tender process. For example, across international MMOs, the number of MMs, the maximum bid-ask spreads, and the volume of product committed in each trading window by MMs have all been made variable features in the tender process. Applicants have either specified these variables as part of their offer, or made offers in the tender process conditional on a number of possible choices for each design. In both cases, the final choice of design has been determined by the tender operated after the bids from applicants have been received.

Whilst flexibility in the tender process may let market participants determine key parameters of the MMO design, which may lead to cost savings, it may come at the cost of transparency in the rules Ofgem uses to select winning bids. The more variable components of the tender process, the more difficult it will be for Ofgem to develop a transparent set of criteria to assess bids.

In the tendered MMO in the Spanish gas market, MIBGAS uses the following set of criteria to select the winning bid. Applicant's bids may vary in the bid-ask spread, volume of product committed per trading window, and the price offered. Applicants bid separately, in a sealed bid auction, to provide market making services for each product. MIBGAS scores each applicant's bid for spread, volume, and price.[163] The maximum score for each bid is based on the number of offers submitted per product. More specifically:[164]

- "In relation to the spread, the highest score will be assigned to the offer with the lowest spread, assigning the rest of the points in the downward direction, and depending on the distance from the best offer.
- In relation to the limit for the amount to be matched per trading session, the highest score will be assigned to the offer with the greater amount, assigning the rest of the points in the downward direction, and depending on the distance regarding the best offer.
- In relation to the price offered, the highest score will be assigned to the offer which presents the smaller amount with respect to all the others, assigning the rest of points in downward direction, and depending on the distance from the best offer.
- In case that certain values coincide in the different offers presented, the same score will be assigned for all of them, maintaining the order described in the previous paragraphs."

The spread and price are weighted at double the points to the volume limit committed each trading window. In addition:[165]

> "MIBGAS is entitled to ask for a new version of the binding offers from all the bidders if it deems it necessary to modify the description of the requirements in the light of the bids submitted.
>
> MIBGAS may choose more than one service provider for each product, if it considers the choice is appropriate for achieving the proposed objective more effectively.
>
> MIBGAS may declare the tender null and void for one or more products when it considers that none of the bids received meets the right conditions for the provision of the service."

Hence, whilst MIBGAS specify explicit criteria, the tender process remains complex, and less transparent than a tender process based only on the applicants' offer price.

The EMA does not, to our knowledge, publish the criteria through which it assesses the bids in the Singaporean tendered MMO. Applicants in the Singapore MMO bid for each of the two specified options for maximum bid-ask spread, and for each of the four options for the

163 MIBGAS (October 2019), Rules on the call and request for tender for the market maker service: First half-year 2020, p.4.

164 MIBGAS (October 2019), Rules on the call and request for tender for the market maker service: First half-year 2020, p.4.

165 MIBGAS (October 2019), Rules on the call and request for tender for the market maker service: First half-year 2020, p.5.

total number of MMs selected (and therefore, for eight combinations in total). The EMA then assess and choose the winning MMs, the bid-ask spreads and the number of MMs after the tender.

Overall, if Ofgem specified variable design elements as part of the tender process, it may provide a mechanism by which the design of the MMO can be optimised to market participant needs and costs can be minimised. However, as more design elements are incorporated into the tender process, it may be difficult for Ofgem to develop practical and transparent criteria for which to assess applicant offers.

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. 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 two years and two months. In our model, the representative retailer's cashflows are driven by:

- **Revenues from tariffs**: driven by the 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 over 5,000 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 domestic electricity generated and supplied and by the volume of unhedged domestic electricity generated and supplied to generate a range of total benefits from each design. We only examine the total volume supplied to domestic customers because non-domestic customers are likely to have tariffs that are not set by the default tariff cap, and may be more closely linked to outturn wholesale prices.

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 domestic customers. In our simulation, tariff revenue in a given month is determined by our simulation of customer numbers, monthly demand quantities and an assumption of the representative annual 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 from February 2017 to March 2019 to estimate these monthly churn rates.[166] More specifically, we assume that the switching rate determines the probability that, in each month, a customer leaves the retailer and, symmetrically, the probability that, in each month, a customer joins the retailer. We use 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 and half-hourly data on electricity demand shape for 1 April 2018 to 31 March 2019. We aggregate the shape data to obtain monthly demand shapes and apply this shape to the annual consumption data to calculate monthly consumption. Average annual consumption is calculated for each of the UK big six energy providers by dividing total domestic volume sold by the number of domestic customers served using data from 2017 to 2018 consolidated segmental statements. The overall average annual consumption is estimated as an average of these values, weighting by the proportion of the market served by each company.

To simulate retailer revenues, we multiply our simulated customers number and consumption figures by a representative seasonal tariff. We estimate the representative tariff using data on the proportion of the default tariff cap which is made up of wholesale electricity costs.[167] Seasonal consumption shapes are aggregated from half hourly demand shapes and applied to the representative annual consumption to estimate seasonal consumption. We multiply our estimate for seasonal consumption by the average wholesale electricity price, estimated by the average simulated forward strike price, to estimate the wholesale cost of purchasing electricity. A representative tariff may be inferred by dividing wholesale costs by the proportion of the default tariff cap made up by wholesale costs.

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

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[166] Ofgem (October2019), Large suppliers: Internal and external switching rate by fuel type (GB), Last accessed: 11/11/19, Link: https://www.ofgem.gov.uk/data-portal/large-suppliers-internal-and-external-switching-rate-fuel-type-gb

[167] Ofgem (October 2019), Breakdown of the default tariff price cap, Last accessed: 4/11/19, Link: https://www.ofgem.gov.uk/data-portal/breakdown-default-tariff-price-cap-gbp

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 seasonal baseload and peakload contracts, up to three seasons ahead. Historical data is available for one to three-seasons-ahead products, whilst a zero-seasons-ahead (or balance of season) price is constructed depending on how long remains until product maturity. Table A.2 describes this construction:

Table A.2: Balance of Season Price Construction

Time to maturity	Balance of season price equals the average price of the following contracts
< 1 month	1 season ahead
> 1 month, < 2 months	1 month ahead
> 2 months, <3 months	1 month ahead, 2 months ahead
> 3 months, < 6 months	1 month ahead, 2 months ahead, 1 quarter ahead

Source: NERA Analysis.

We simulate seasonal prices according to the volatility and co-movement of prices of different seasonal contracts traded on the same day. In particular, we use price data for futures contracts traded on each day from 6 September 2016 to 30 August 2019 inclusively. We calculate separate volatilities and co-movements for each of the seasonal baseload and peakload contracts, from zero to three seasons ahead. Table A.1 below gives an illustrative example of this data.

Table A.1: Illustrative Historical Futures Prices

Trade Date	Maturity (Delivery Period)			
	S0 (S 2017)	S1 (W 2017)	S2 (S 2018)	S3 (W 2018)
1/2/2017	62.65	53.54	57.04	48.05
2/2/2017	63.51	53.18	57.82	47.75
3/2/2017	63.34	53.88	57.26	48.28

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-season-ahead contracts, even though the maturity of this series jumps by a season each time the trade date enters a new season. Therefore, our volatility analysis excludes natural price jumps (or drops) as the season 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 GBP 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 three seasons 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.

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 Q1 2017. We use these prices to represent the "starting point" prices applicable on 1 February 2017. On this day, we assume that retailers would begin to hedge to deliver electricity in April 2018 to March 2019 inclusively.

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 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.[168] 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 to the current trading date (e.g. one-season-ahead volatility, regardless of the trading season), 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-season-ahead contract (for delivery in Winter of that year) will be equal to the *two*-seasons-ahead price from 31 March, which is still in Winter of the previous year, scaled by a random shock.

Assuming fixed, known prices as February 2017, we simulate the futures prices for each day to the end of 31 March 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 three seasons ahead throughout 2019 (up to Summer 2020), even though the maturity periods of these contracts fall beyond the end of the period of our cashflow analysis.

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

In Figure A.1, we show our simulated price for a Summer 2019 peakload contract from February 2017 to March 2019 and compare this simulated price against the actual data for that contract for the same dates.[169]

Figure A.1: Summer 2019 Peakload Futures Price Simulation (Units in £/MWh)

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 to electricity as it is delivered. Therefore, we only simulate prices for the 12-month cashflow period of 1 April 2018 to 31 March 2019, 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 seasonal baseload contract (i.e. the balance-of-season or zero-seasons-ahead contract). In particular, using data between 5 September 2016 and 30 August 2019, we estimate an econometric equation which estimates the extent to which the daily-average price relates to (i) the previous day's power price, (ii) the active seasonal baseload contract and (iii) random unexplained shocks.[170]

Intuitively, if the daily price is far from the price of the active balance-of-season contract, the deviation should be reduced quickly as market participants arbitrage between the contracts.

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169 Note that our simulation uses Q1 2017 prices as its starting point and treats these as fixed prices on 31 January 2017.

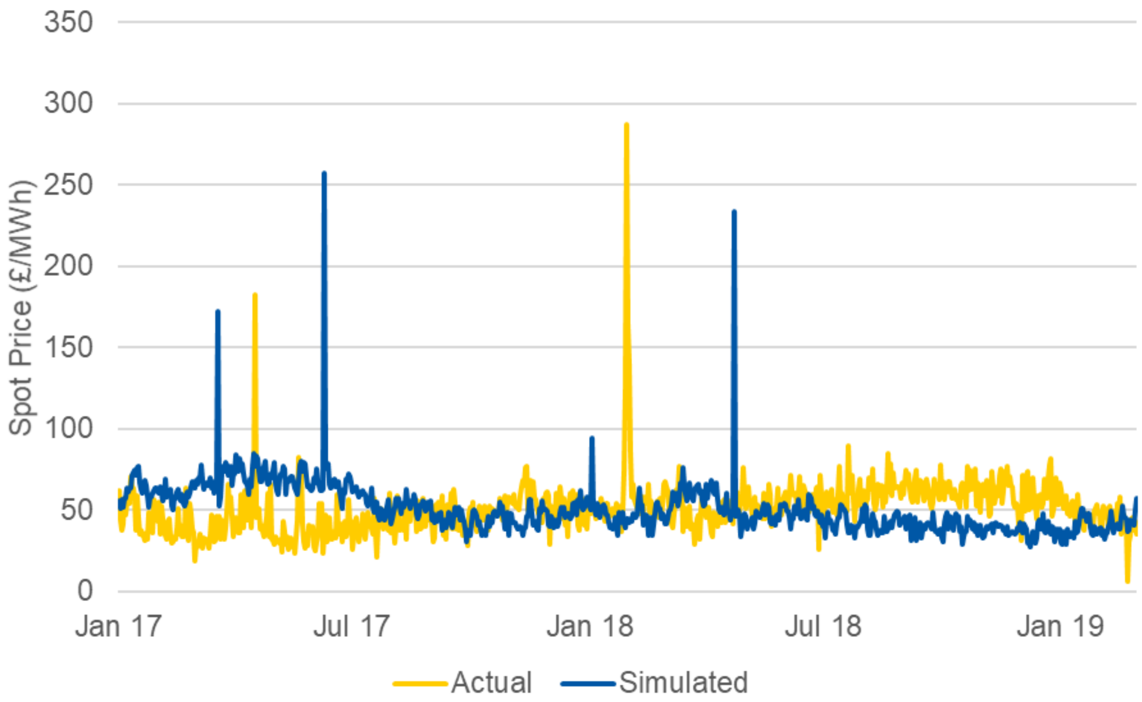
170 The precise equation is $P_t = Q_t + \alpha * (P_{t-1} – Q_t) + \text{shock}$, where P_t represents the daily price in period *t* and Q_t represents the price of the active quarter contract traded in period *t*. We can rearrange this equation such that the daily price is a weighted average of the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

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-season contract.

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 between 31 January 2017 and 31 March 2019. 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. For comparison, we also show the actual daily average power price over the same time period. On most days the daily average price tracks the balance of season price with some volatility around it. Occasionally, due to some random event, a "large daily price spike" occurs and the price jumps to £150 and above.

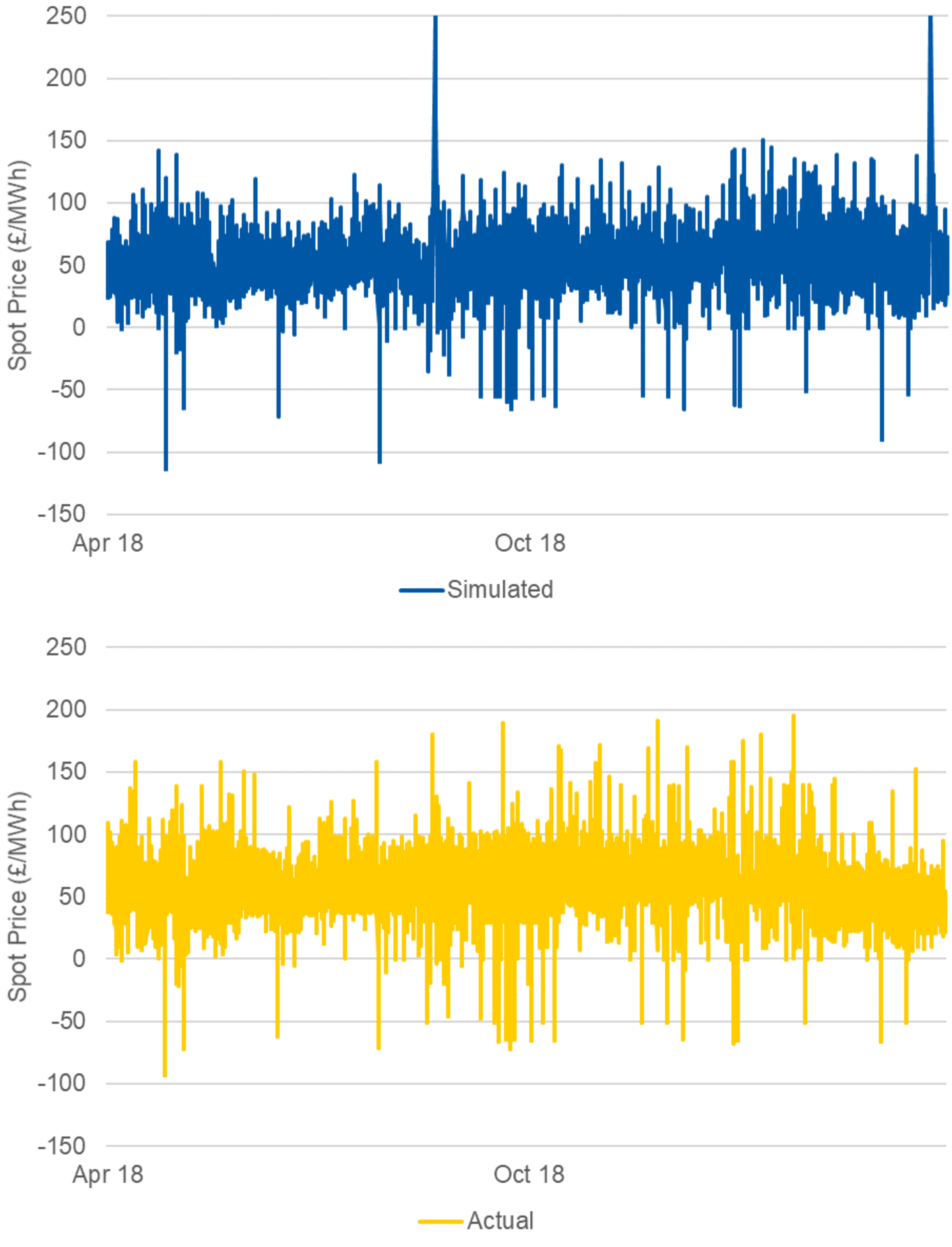
Figure A.2: Daily Price Illustration



Source: NERA Analysis.

Finally, we multiply our simulated daily prices by the observed 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 2018 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 2018 of £80/MWh, we would calculate the 14:00-14:30 price as £120/MWh (1.5 times the daily average). Figure A.3 provides one particular simulation of power prices. For comparison, we also show the actual daily average power price in 2018.

Figure A.3: Half-Hourly Price Illustration



Source: NERA Analysis.

A.2.3. Hedging strategies and costs

Retailer's wholesale procurement costs are defined by the prices of futures 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 seasonal contracts are based on a fixed number of MW in each period of the season, we assume that the supplier would target a certain percentage of its *average* demand over a season. 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 the proportion of the target level of hedging that the supplier wishes to procure in each month in advance of delivery. As discussed in section 5.2.2, we implement a linear hedging strategy which reflects the process by which a seasonal tariff cap is announced two months in advance of a delivery season. This strategy assumes that, for a given season, a supplier begins hedging fourteen months in advance of delivery and purchases one twelfth of their desired total hedge each month until two months before delivery. At this point, they are fully hedged, and the tariff cap is announced. Two months later, delivery begins. 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. 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.

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 position. To reduce its exposure to an out-of-the-money supplier defaulting on its settlement obligations, an exchange such as EPEX 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 the exchange 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-season 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 for that delivery period and the spot price, less any collateral already posted.

However, because the GB market operates under a net 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 difference between the average strike price and the spot price.

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). 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 season). This is partially offset by any collateral it has posted for that period (more specifically, the total collateral for that delivery season, 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 season 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 cost of any open out-of-the-money futures positions). 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 cost of out-of-the-money futures.

A.2.5. Other cost items

Suppliers incur additional overhead costs 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. These are calculated monthly as a percentage of the revenue, as per the default tariff cap breakdown data.[171]

A.2.6. Summary cashflow tables

We bring all revenue and cost items described in this section together into a cashflow calculation for our 12-month cashflow period of 1 April 2018 to 31 March 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. We assume our representative customer to be a domestic customer paying the default tariff cap. 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.

[171] Default tariff cap breakdown is sourced from the Ofgem data portal. Last accessed: 4/11/19, Link: https://www.ofgem.gov.uk/data-portal/breakdown-default-tariff-price-cap-gbp

Table A.2: Example Supplier Cashflow

Revenues	*Units*	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19
Tariff Recovery	£	3,096,285	3,036,450	2,771,651	2,761,933	2,794,149	2,807,346	5,785,132	6,914,940	8,028,928	8,255,401	8,112,525	8,317,762
Total Revenue	£	**3,096,285**	**3,036,450**	**2,771,651**	**2,761,933**	**2,794,149**	**2,807,346**	**5,785,132**	**6,914,940**	**8,028,928**	**8,255,401**	**8,112,525**	**8,317,762**
Costs													
Wholesale Procurement	£	1,334,006	1,219,081	1,162,648	1,063,919	956,794	1,136,560	1,716,593	2,083,711	2,553,508	2,297,190	2,005,493	2,389,129
CfD Payment	£	1,070	68,163	20,870	119,118	234,413	73,698	93,520	69,162	2,217	217,571	344,837	184,147
Collateral Costs	£	-574,095	271,294	105,663	29,409	988,195	284,815	-115,944	102,537	23,906	881,947	41,392	459,051
Transaction Costs	£	28,311	29,837	29,387	28,207	24,415	23,523	22,472	23,830	24,633	24,181	29,391	28,985
Overhead Costs	£	1,754,479	1,720,574	1,570,528	1,565,022	1,583,277	1,590,754	3,411,093	4,077,262	4,734,104	4,867,639	4,783,396	4,904,410
Total Costs	£	2,543,771	3,308,950	2,889,097	2,805,675	3,787,094	3,109,351	5,127,734	6,356,503	7,338,369	8,288,528	7,204,509	7,965,722
Cash Balance	£	552,514	-272,500	-117,446	-43,742	-992,945	-302,005	657,398	558,437	690,559	-33,128	908,016	352,040

Table A.3: Example Generator Cashflow

Gross Electricity Sales Revenue	£	**1,337,407**	**1,289,653**	**1,185,849**	**1,185,446**	**1,193,615**	**1,212,590**	**2,244,001**	**2,572,764**	**2,989,613**	**2,948,648**	**2,742,228**	**3,007,163**
Transactions Costs	£	28,311	29,837	29,387	28,207	24,415	23,523	22,472	23,830	24,633	24,181	29,391	28,985
Net Electricity Sales Revenue	£	1,309,096	1,259,817	1,156,462	1,157,239	1,169,200	1,189,067	2,221,528	2,548,935	2,964,979	2,924,467	2,712,836	2,978,178
Electricity Sold	*MWh*	25,879	25,379	23,165	23,084	23,354	23,464	26,077	31,200	36,233	37,259	36,613	37,580
Average Electricity Cost	*£/MWh*	51	50	50	50	50	51	85	82	82	78	74	79

A.3. Key Risk Metrics

Using the illustrative cashflow statements in A.2, we cycle through different combinations of bid-ask spread (proposed MMO design) and hedging strategy, and perform over 5,000 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. 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 cashflow year until that month.

We assume that suppliers seek to avoid a situation where the cumulative cash balance becomes negative. Because our cashflow model does not include any risk capital, our simulations frequently find that the cumulative cash balance does fall below zero in the absence of risk capital.

To measure the required risk capital, we therefore calculate the level of additional risk capital required (in GBP per MWh) to ensure that the cumulative cash flow becomes negative some optimal amount of the time (while cash flow problems can be disruptive, they are part of the natural process of a competitive market, and a policymaker would not necessarily want to remove the possibility entirely). We set this threshold at 5 per cent. In other words, to ensure that companies have a negative cumulative cash flow fewer than 5 per cent of the time, the risk capital costs would be sub-optimally high.

Amongst the distribution of cumulative cash balances from our approximately 5,000 simulations, we identify the (negative) cash balance level at the 5 percentile point in the distribution. If a supplier were to hold that much money in risk capital, then it would become have a negative cumulative cash balance 5 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 10.15 per cent, as we explain in Section A.3.3.

Therefore, under each combination of bid-ask spread and hedging strategy, 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 negative cumulative cash flows, 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 cash flow risk 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 £51/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 5 per cent cumulative cash balance threshold we use for suppliers, we identify the 5 percentile point of the distribution of minimum average monthly electricity price under each combination of bid-ask spread and hedging strategy.

We have not estimated the actual average electricity price below which a company's cumulative cash flow becomes negative. 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 GBP per MWh) by a WACC of 8.8 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 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 use The Competition and Markets Authority's (CMA) 2015 estimates of the WACC for electricity generation and retail companies in the UK;[172]

The CMA considers 24 energy companies to estimate the following WACC ranges:

- 7.9 – 9.7 per cent nominal pre-tax WACC for electricity generators;
- 9.3 – 11.0 per cent nominal pre-tax WACC for electricity retailers.

We model the midpoint of the above ranges, i.e. a WACC of 8.7 per cent for generators and 10.15 per cent for retailers, test the sensitivity of our results to the upper and lower bounds.

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

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. 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 5 per cent threshold, we examine the median level of transactions costs per MWh under each combination of bid-ask spread and hedging strategy. 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 bid-ask spread and hedging strategy. In this section, we bring together the different components to describe how we identify a GBP million benefit of each MMO option.

A.4.1. Identifying counter-factual scenarios to the MMO

To establish an appropriate assumed level of bid-ask spreads under an MMO, we use historical data of prevailing market spreads since MMO implementation (2014-2019).

However, we do not know what current market spreads may be, without the S&P MMO imposed in the market. Therefore, we use a range of estimates for counter-factual bid-ask spreads. More specifically, we estimate three sets of prevailing market spreads for the market:

- **Historical:** We estimate the historical bid-ask spreads prevailing in the market prior to the introduction of the S&P MMO, from 2009 to 2013 inclusively, and use the resulting spreads as an estimate for the counter-factual market spreads, should the current obligation be removed.
- **High liquidity counter-factual:** We use a midpoint between the abovementioned estimated historical bid-ask spreads and current spreads prevailing under the MMO as a high-liquidity counter-factual.
- **Low liquidity counter-factual:** We use double the abovementioned estimated historical bid-ask spreads as a low liquidity counter-factual, see Table 5.1.

Each counter-factual reduces transactions costs by a different amount. In our model, the reduction in transactions costs across scenarios 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, 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.

These benefits will be felt directly by independent generators and suppliers, who must sell or procure their entire volume externally. We therefore multiply figures shown in Table 5.3 by the volume of domestic electricity generated or supplied by independent parties.

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 vertically-integrated suppliers is added to the total volume from independent retailers and is used to scale the benefits for each proposed MMO design. Recognising this likely understates the benefits of hedging for vertically-integrated entities, this is our low case benefit. Our high case benefit scales our estimated benefits per MWh by total volume in the domestic market.

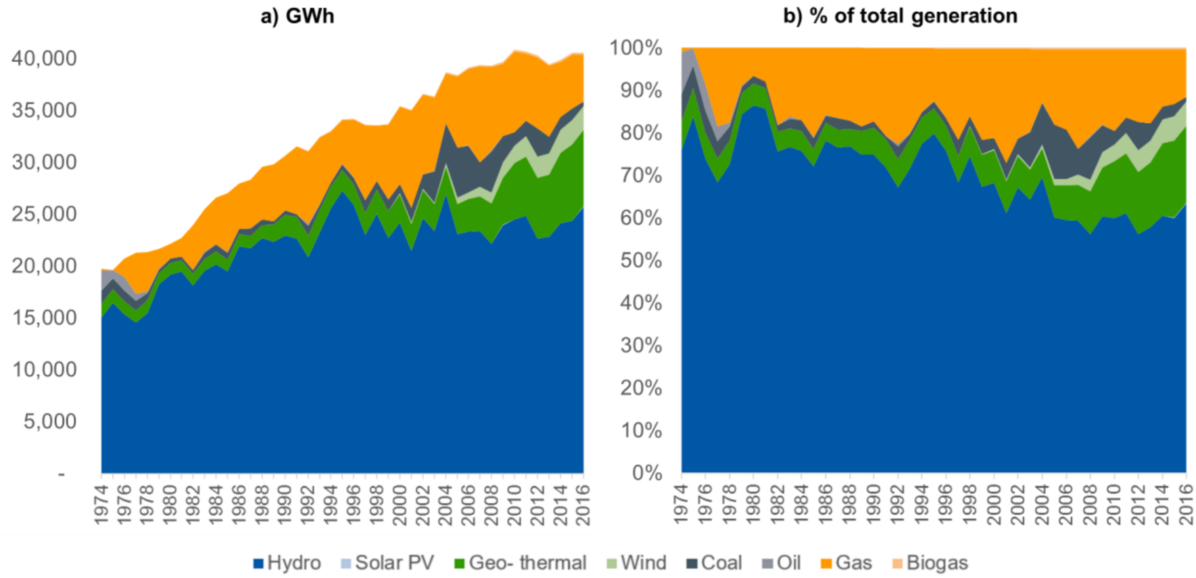
Appendix B. International Case Studies

B.1. New Zealand's Market Making Obligation

B.1.1. 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)



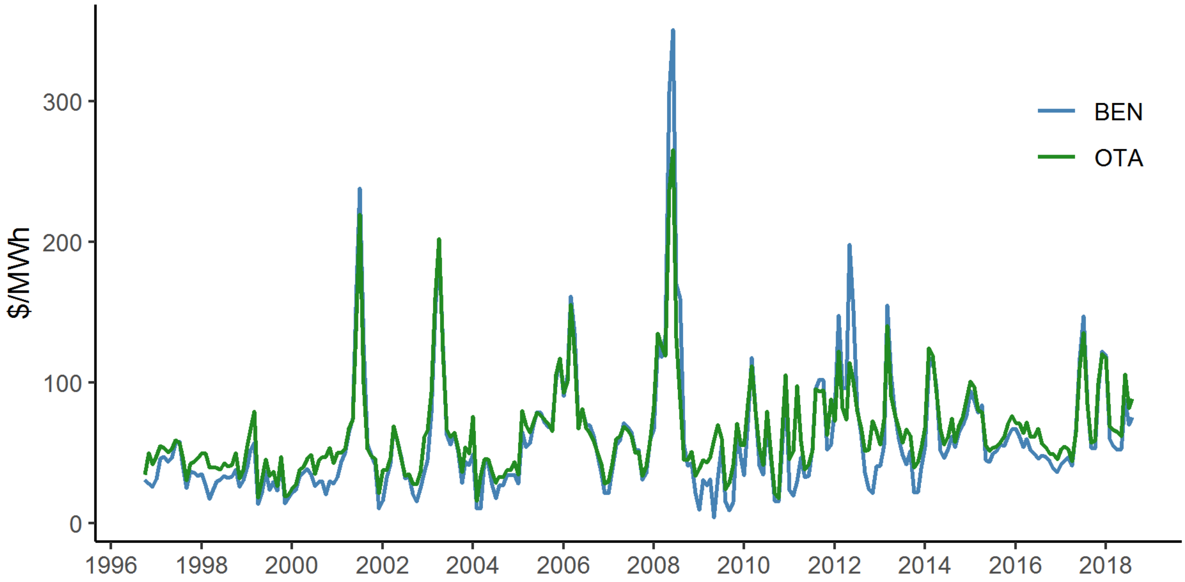
Source: NERA analysis of MBIE electricity data file.

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[173] 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.

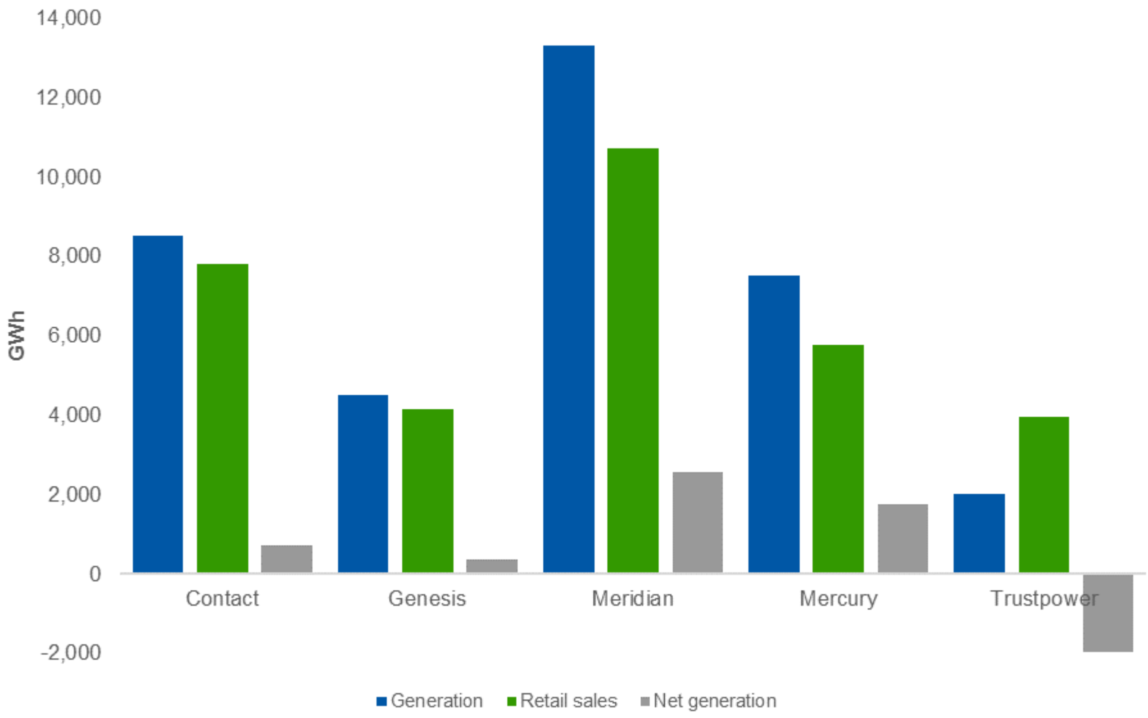
[173] Meridian (July 2017), Monthly Operating Report for July 2017, p. 4.

Figure B.2: New Zealand: Monthly Average Wholesale Spot Price (1996-2018)



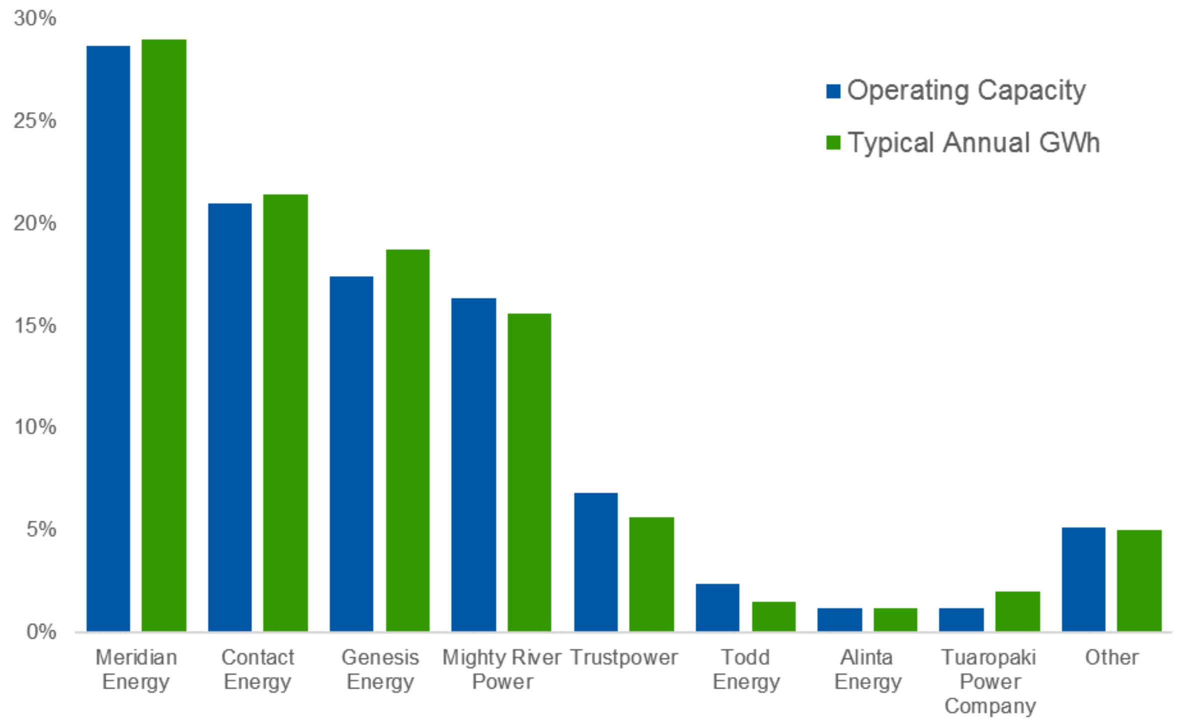
Source: NERA analysis of Electricity Authority EMI final pricing dataset.
Note: Calculated using daily average prices at the Otathuhu and Benmore grid reference points.

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.1.2. 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);[174]
- 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

[174] 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:[175]
  – 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.[176] 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:[177]

- June 2010: four of the five largest generators[178] 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-ask 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-ask 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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175 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/

176 NZ Decision Paper (2009), *Summary of Main Decisions: Ministerial Review into Electricity Market Performance*, Ministry of Business, Innovation and Employment, December 2009, paragraph 3.

177 Electricity Authority (2015), *Hedge Market Development: Enhancing Trading of Hedge Products - Consultation Paper*, Electricity Authority, 1 May 2015, Last accessed: 11/11/19, Link: https://www.ea.govt.nz/dmsdocument/19441

178 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.[179]

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.[180]

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.[181]

The EPR recognised that an incentivised scheme could be more efficient[182]

> “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 EA published their final EPR report on 30 May 2019. The EA stated:[183]

> “The current wholesale contract market is not working effectively. It relies heavily on the four biggest generator-retailers voluntarily quoting buy and sell prices with

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179 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/

180 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.

181 New Zealand Government (February 2019), EPR Options Paper, p. 19.

182 New Zealand Government (February 2019), EPR Options Paper, p. 20.

183 New Zealand Government (May 2019), EPR Final report p. 43

> spreads of no more than 5 per cent for certain contracts. When it works this way, it adds depth to the contracts market and ensures clear price signals. But spreads in recent times have been as wide as 50 per cent, apparently in response to uncertainty caused by low rainfall and/or gas shortages. We do not expect market-makers to assume undue risks, but they have been withdrawing from their obligation without publicly stating either the decision or the reasons for it. Once one leaves, the rest typically follow, rendering market-making fragile and unpredictable."

Not content with the liquidity resulting from the S&P MMO, the EA issued an ultimatum:[184]

> "The Electricity Authority should impose a mandatory market-making obligation on vertically integrated companies within 12 months unless the industry can develop an incentive-based scheme by then that is effective, funded largely by those companies and acceptable to the Authority."

Moreover, the EA stated that it would consider an interim intervention within the 12 month period if liquidity worsened "to safeguard the viability of the futures market".[185] Whilst the design of the mandatory MMO is not specified in the report, the EA stated that it would require mandated parties to post prices at maximum permissible bid-ask spreads with contracted volumes and certain conditions that would relax or suspend the obligation.[186]

B.1.3. Reported costs and benefits of the S&P 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.

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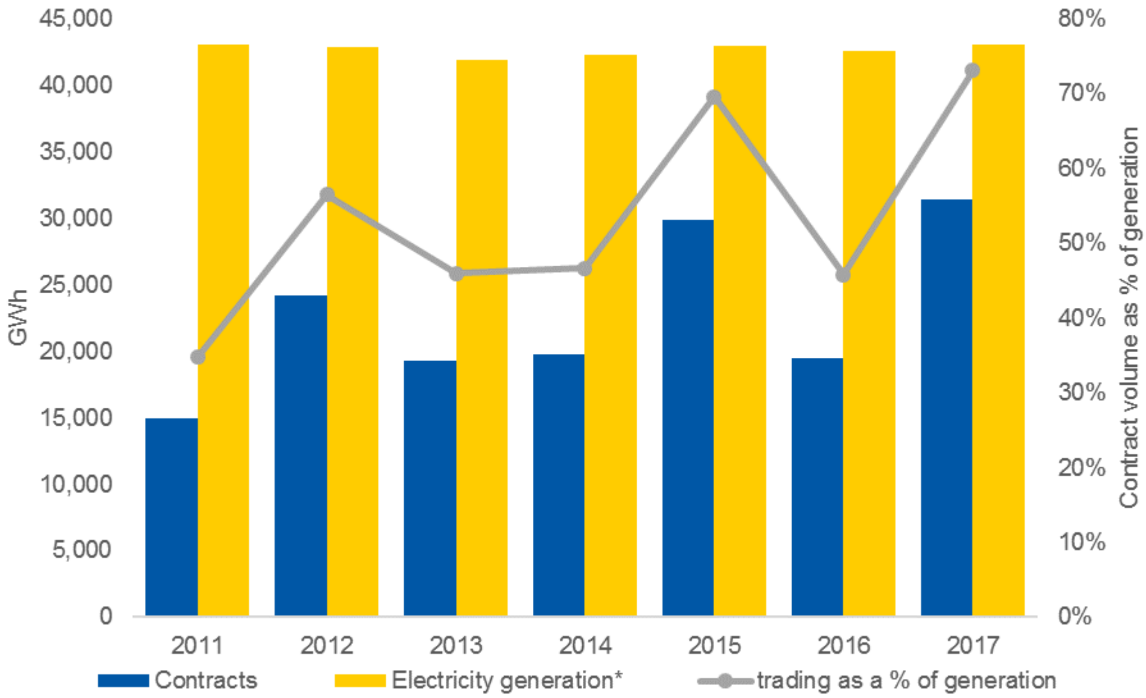
184 New Zealand Government (May 2019), EPR Final report p. 42

185 New Zealand Government (May 2019), EPR Final report p. 44.

186 New Zealand Government (May 2019), EPR Final report p. 43

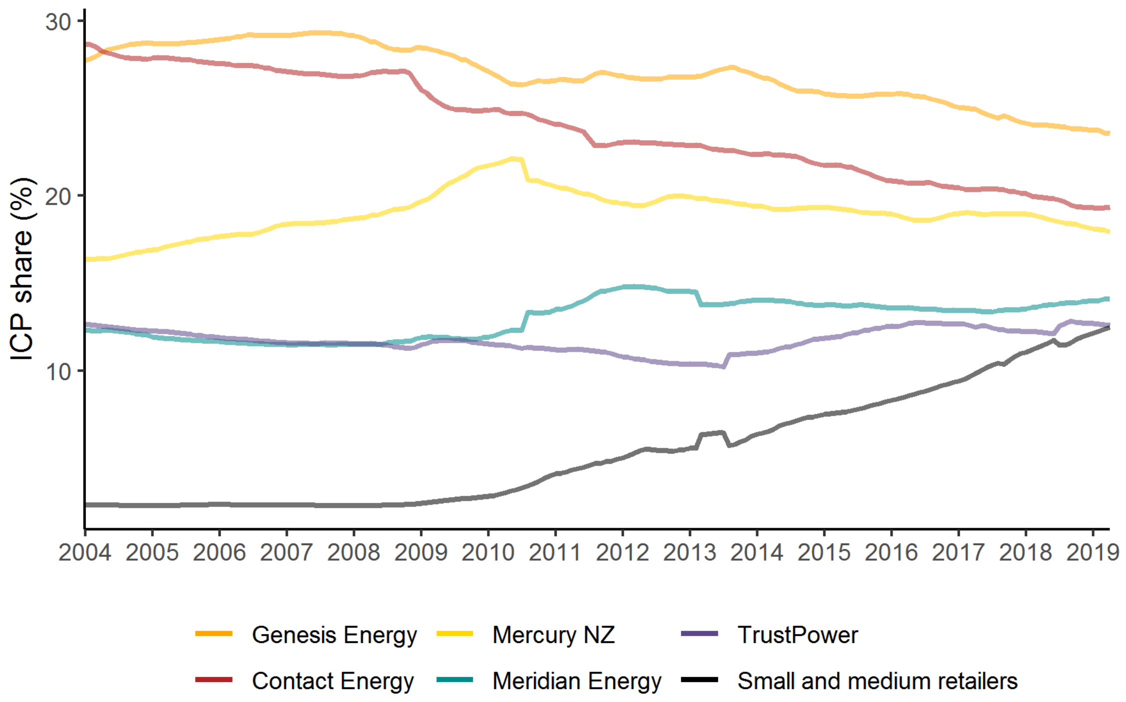
Figure B.5: Contract Volumes as a Percentage of Generation



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.[187] 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[188] and $4m[189] respectively.

In 2011, the Electricity Authority conducted a cost benefit analysis of a "code based" market making obligation.[190] 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.

187 Meridian, *Electricity Price Review Options Consultation: Meridian and Powershop submission*, 22 March 2019

188 Contact (August 2018), 2018 Full Year Results Presentation, p. 26.

189 Genesis (February 2019), HY19 Result Presentation, p. 9.

190 Electricity Authority (November 2011), "Information Paper: Cost Benefit Analysis – Market-Making Obligations".

The costs the EA considered are detailed in Table B.4.

Table B.4: 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.5: 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.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.[191] 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).[192]

The second stage of the reform was the creation of the Singapore Electricity Pool (SEP) in April 1998.[193] This was a day-ahead electricity market which allowed for trading between generators and SP Services Ltd in a competitive market.[194] 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.[195] 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.[196]

Electricity generation in Singapore relies almost solely on natural gas, which comprised approximately 95 per cent of the fuel mix in 2018.[197] This reliance has strengthened over time as Singapore has moved from steam turbine plants to new Combined Cycle Gas Turbine plants (CCGTs).[198] 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.[199]

The electricity generation market has become increasingly competitive in Singapore.[200] There are three Main Power Producers (MPPs): Senoko Energy, YTL PowerSeraya and Tuas Power Generation.[201] 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

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

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

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

194 EMA (October 2010), Introduction to the National Electricity Marker of Singapore, p.2-1.

195 EMA (October 2010), Introduction to the National Electricity Marker of Singapore, p.3-2.

196 EMA (October 2010), Introduction to the National Electricity Marker of Singapore, p.3-2.

197 EMA (August 2018), Singapore Energy Statistics 2018, p.14.

198 EMA (August 2018), Singapore Energy Statistics 2018, p.14.

199 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

200 EMA (August 2018), Singapore Energy Statistics 2018, p.18.

201 EMA (August 2018), Singapore Energy Statistics 2018, p.18.

cent in 2017.[202] 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).[203]

The wholesale market uses single-settlement locational marginal pricing (LMP) and is operated by the Energy Market Company (EMC).[204] The dispatch of electricity is determined by a spot market in every half-hour.[205] 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.[206] 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.[207] 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.[208] Originally, all customers were served by SP Services Ltd under a regulated tariff.[209] 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.[210] 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".[211] In April 2018, the threshold was eliminated in Jurong to soft launch the Open Electricity Market (OEM).[212] Currently, the EMA is rolling out the OEM to all states from Q4 2018 to Q2 2019.[213]

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.[214] The second is

202 EMA (August 2018), Singapore Energy Statistics 2018, p.18.

203 EMA (August 2018), Singapore Energy Statistics 2018, p.18.

204 Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.4.

205 EMA (October 2010), Introduction to the National Electricity Marker of Singapore, p.4-4.

206 Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.4.

207 EMA (October 2010), Introduction to the National Electricity Marker of Singapore, p.4-4.

208 EMA (August 2018), Singapore Energy Statistics 2018, p.30.

209 EMA (October 2010), Introduction to the National Electricity Marker of Singapore, p.4-6.

210 EMA (August 2018), Singapore Energy Statistics 2018, p.30.

211 EMA (August 2018), Singapore Energy Statistics 2018, p.30.

212 EMA (August 2018), Singapore Energy Statistics 2018, p.30.

213 EMA, Liberalisation of Retail Electricity Market, Accessed 05/04/19, Link: https://www.ema.gov.sg/electricity_market_liberalisation.aspx

214 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).[215] These non-residential consumers also constitute the majority of "contestable" customers (CC) and accounted for 76 per cent of total consumption in 2017.[216] 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.[217]

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).[218] 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.[219] However, the original six still constitute approximately 90 per cent of the market.[220] Only PacificLight has entered and now constitutes a comparable share of the market (6.1 per cent) compared to the original six.[221]

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.[222] The market shares of companies in the retail market generally mirror the annual generation shares of those companies.[223] Historical market entry to the retail market involved construction of a generation facility to sell to SP Services and CCs.[224] 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.[225] 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.[226] The futures market aimed to allow entrants to hedge against the half-hourly

215 Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.4.

216 EMA (August 2018), Singapore Energy Statistics 2018, p.32.

217 Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.7.

218 EMA (August 2018), Singapore Energy Statistics 2018, p.29.

219 EMA (August 2018), Singapore Energy Statistics 2018, p.29.

220 EMA (August 2018), Singapore Energy Statistics 2018, p.29.

221 EMA (August 2018), Singapore Energy Statistics 2018, p.29.

222 Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.5.

223 Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.5.

224 Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.5.

225 Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.6.

226 EMA (November 2012), Development of an Electricity Futures Market in Singapore Consultation Paper.

USEP and lower the financial risk of entry.[227] The market was established in April 2015 on the Singapore Exchange Limited (SGX).[228]

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."[229]

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.[230] The FSC is a Contract for Difference (CfD), where differences in settlement are paid through cash, with SP Services Ltd.[231] 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.[232] The CCs would not necessarily pay more as the FSC provides a hedge against fluctuations in the USEP.[233] 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).[234] The FSC price and volume is published publicly.[235]

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"[236]. 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.[237] 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.6. In the case where FSC volumes

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[227] Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.6.

[228] Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.6.

[229] EMA (September 2014), Procedures for Calculating Components of the Forward Sales Contracts, p.2.

[230] EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.5.

[231] EMA (April 2015), Enhancing Competition through the Development of an Electricity Futures Market in Singapore.

[232] EMA (April 2015), Enhancing Competition through the Development of an Electricity Futures Market in Singapore.

[233] EMA (April 2015), Enhancing Competition through the Development of an Electricity Futures Market in Singapore.

[234] EMA (September 2014), Procedures for Calculating Components of the Forward Sales Contracts, p.7.

[235] EMA (April 2015), Enhancing Competition through the Development of an Electricity Futures Market in Singapore.

[236] EMA (May 2013), Forward Sale Contract (FSC) Scheme to Facilitate the Development of an Electricity Futures Market in Singapore, p.2, 1.3.

[237] 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.[238]

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.[239] 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.6.[240]

Table B.6: 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.[241] Each MM is required to offer these contracts 8 quarters ahead and therefore market make for 9 total contracts (including the prompt quarter).[242] 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.[243] The MM market makes in a window for each Singapore business day (currently 4:30pm to 5:00pm).[244] 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.[245] 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.[246] The MM must submit compliance reports to the EMA at a frequency of no longer than 6 months.[247]

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

238 EMA (September 2014), Procedures for Calculating Components of the Forward Sales Contracts, p.4.

239 EMA (September 2014), Procedures for Calculating Components of the Forward Sales Contracts, p.3.

240 EMA (March 2015), Procedures for Calculating Components of the Forward Sales Contracts.

241 EMA (April 2015), Enhancing Competition through the Development of an Electricity Futures Market in Singapore.

242 EMA (April 2015), Enhancing Competition through the Development of an Electricity Futures Market in Singapore.

243 EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.7.

244 EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.9.

245 EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.9.

246 EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.8.

247 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"[248]. The EMA also states that the MMO has:

> "Safeguards to ensure orderly trading, e.g. position, daily, price, volume and concentration limits."[249]

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.[250]

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:[251]

4. For generation companies: The futures market provides an additional option to hedge and manage risk.
5. For CCs: The futures market can provide a way to secure future prices and provides a transparent platform to gauge prices.
6. 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.[252]

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.[253] This was despite the growing value of the FSC: the pool price in Singapore fell during the period due

248 EMA (May 2013), Forward Sale Contract (FSC) Scheme to Facilitate the Development of an Electricity Futures Market in Singapore, p.11.

249 EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.12.

250 EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.12, Footnote.

251 EMA (April 2015), Enhancing Competition through the Development of an Electricity Futures Market in Singapore.

252 EMA (November 2012), Development of an Electricity Futures Market in Singapore Consultation Paper, p.12.

253 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.[254]

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.[255] 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).[256]

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).[257] 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.[258] The maximum bid-ask spread for these volumes is S$4/MWh.[259] 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.[260] Liquidity has also increased but cumulative transaction volume is only 5 per cent of the underlying physical consumption annually.[261] In the first two years of futures market trading, Australia and New Zealand had 3 and 10 per cent cumulative transaction volume respectively.[262] 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.[263] The EMA justifies the extension of the market making

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

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

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

[257] EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.2.

[258] 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.

[259] EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.4.

[260] EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.2.

[261] EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.5.

[262] EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.5.

[263] 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.[264]

Wolak examines the benefits of the Singapore market making services arrangement quantitatively.[265] 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."[266]

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.[267] 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.[268]

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.[269] 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.[270]

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.[271] The EMA "intends to select four to

[264] EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.3.

[265] Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore.

[266] Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.13.

[267] Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.14.

[268] Frank Wolak (July 2017), Measuring the Impact of Purely Financial Participants on Wholesale and Retail Market Performance of Singapore, p.17.

[269] EMA (September 2018), EMA Annual Report 2017/2018, p. 19.

[270] EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.2.

[271] 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"[272]. 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.[273]

The winners of this tender enter into an agreement with SP Services Ltd which continues to facilitate the market making services arrangement.[274] In turn, the winners may not sub-contract or transfer their obligations without approval of the EMA.[275] 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.[276] 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.[277] In all three of these cases, the MM pays an exit fee of 100 per cent of the total RFP price to the MSSL.[278]

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"[279] 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"[280].
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"[281].
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.

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[272] EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.13.

[273] 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.

[274] EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.15.

[275] 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.

[276] 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.

[277] 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.

[278] 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.

[279] 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.

[280] 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.

[281] 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.[282] This is because the EMA noted demand was greater for shorter term (one year out) products.[283] In addition, the maximum bid-ask spread is altered:[284]

- 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:[285] 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.[286] 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"[287]. The RFQ has a maximum bid-ask spread of "no more than 1.5 times the prevailing maximum"[288] 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"[289].

We summarise the differences in the market making obligations under the original market making services arrangement and the FIS in Table B.7.

The EMA found six MMs through the tender process for the FIS.[290] These MMs were independent trading operations and only two of the six MMs are directly linked to wholesale

[282] EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.9.

[283] EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.3.

[284] EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.8.

[285] EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.11.

[286] EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.12.

[287] EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.10.

[288] EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.10.

[289] EMA (February 2018), Enhancing the Development of the Electricity Futures Market Final Determination Paper, p.10, Footnotes.

[290] 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.[291] 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.[292]

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."[293]

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

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

[293] EMA (August 2017), Enhancing the Development of the Electricity Futures Market Consultation Paper, p.5.

Table B.7: 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. Germany's MMO

The German power market was liberalized in 1998 under the Energy Industry Act.[294] Following liberalisation, a series of mergers and acquisitions led to the eight major integrated generation companies becoming four. The capacity share of the largest four companies increased from 42 per cent to 61 per cent,[295] and the generation market share of the largest four companies had reached 95.6 per cent by 2004.[296] Meanwhile, the first German power exchanges (the Leipzig Power Exchange (LPX) and the European Energy Exchange (EEX)), began operating in 2000.[297] LPX merged into EEX in 2002.[298]

EEX has operated a "voluntary" MMO since 2003 whereby companies may opt to become a MM for power products on the exchange, but are not mandated to become MMs. MM agreements are intended to "promote steady trading and improve liquidity".[299] To incentivise participation, EEX compensates companies for providing market making services. The terms of the compensation for MMs are laid out in confidential individual agreements between the participants and EEX.[300]

Tendering for the right to act as a market maker occurs on a product-by-product basis.[301] Terms of the MMO are bilaterally negotiated by EEX and the potential market maker. The MMO is fully voluntary and a MM may resign at any time from its obligations for all or individual products upon providing written five-day notice to EEX.[302] The obligations of MMs may differ between each contract. EEX may specify maximum and minimum bid-ask spreads, minimum contract sizes, a minimum holding period for quotes, and a minimum period for maintaining quotes.[303]

EEX argues that the voluntary MMO is important to facilitate liquidity.[304] However, the proportion of total market trade attributable to MMs has fallen markedly since the introduction of the MMO. The proportion of total market traded volumes of market makers

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294 BNetzA (2019), History of liberalisation, Last Accessed: 18 November 2019, Link: https://www.bundesnetzagentur.de/EN/Areas/Energy/Companies/GeneralInformationOnEnergyRegulation/HistoryOfLiberalisation/historyofliberalisation_node.html

295 Müsgens (May 2004), Market Power in the German Wholesale Electricity Market, Energiewirtshaftliches Institut an der Universität zu Köln, EWI Working Paper No. 04.03, p. 5.

296 Hans-Böckle Stiftung (November, 2006), Liberalisation, privatisation and regulation in the German electricity sector, Torsten Brandt, Wirtschafts- und Sozialwissenschaftliches Institut, p. 5.

297 Müsgens (May 2004), Market Power in the German Wholesale Electricity Market, Energiewirtshaftliches Institut an der Universität zu Köln, EWI Working Paper No. 04.03, p. 5.

298 EEX (July 2002), Merger of the power exchanges finished: New EEX registered, Last accessed: 13/11/19, Link: https://www.eex.com/en/about/newsroom/news-detail/merger-of-the-power-exchanges-finished--new-eex-registered/22186

299 EEX (July 2018), Market Making at EEX, Last accessed: 13 November 2019, Link: https://www.eex.com/en/trading/market-making

300 EEX (2018), General Terms of Market Support Agreements for EEX Emissions Market Initiatives, p. 1.

301 EEX (May 2018), Exchange Rules, p. 22.

302 EEX (May 2018), Exchange Rules, p. 23.

303 EEX (May 2018), Exchange Rules, p. 23.

304 EEX (September 2010), Response by EEX to the consultation by Ofgem on GB wholesale electricity market liquidity: Summer 2010 assessment, p.4.

has dropped from 80 per cent in 2003[305] to 8 per cent in 2017/18.[306] Furthermore, the capacity share of the largest four electricity producers has increased from 61 per cent in 2001 to 69 per cent by 2015.[307]

305 EEX, Transparency at EEX, Last accessed: 13 November 2019, Link: https://www.ceer.eu/documents/104400/-/-/bab19d23-ef6e-100c-6f62-92031039da8d, p. 10.

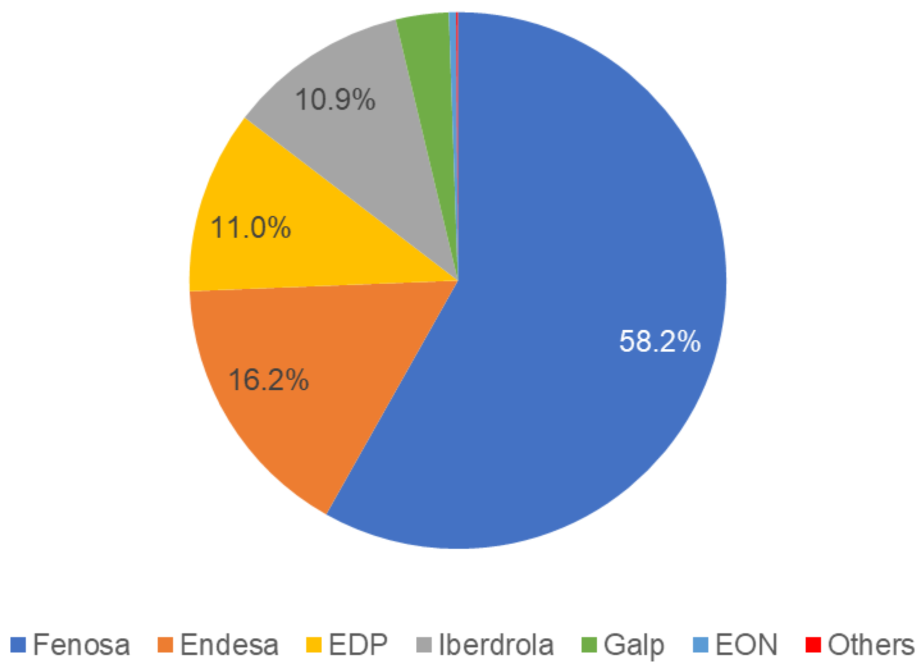
306 BNetzA (May 2019), Bericht Monitoringberict 2018, p. 242.

307 BNetzA (May 2018), Bericht Monitoringberict 2017, p. 7.

B.4. The Spanish Gas Market MMO

In 2014, the domestic retail gas market in Spain was relatively concentrated, with the Gas Natural Group Fenosa, now Naturgy, accounting for 58.16 per cent of customers and three other incumbents accounting for an additional as shown in Figure B.7.[308]

Figure B.7: Spanish Gas Retail Market Share in 2014 (Number of Customers)



Source: NERA Analysis of CNMC (23 July 2015), Spanish Energy Regulator's National Report to the European Commission 2015.

The Spanish competition regulator, Comisión Nacional de los Mercados y la Competencia (CNMC), became concerned over the lack of competition in domestic retail gas markets despite growing competition in the non-domestic market. CNMC argued that:[309]

> "This difference may be due to the high entry cost of the retail activity (commercial cost to contract new customers), the existence of economies of scale in managing retail customers that benefit incumbents, and the lack of a liquid gas market, that makes difficult the entry of retailers without international gas procurement activity."

In response to CNMC's concerns over the lack of liquidity in the wholesale market, the Spanish Government passed legislation in December 2015 permitting MIBGAS, the Spanish exchange, to enter into market making agreements with suppliers and generators. [310]

308 CNMC (23 July 2015), Spanish Energy Regulator's National Report to the European Commission 2015, p. 71.

309 CNMC (23 July 2015), Spanish Energy Regulator's National Report to the European Commission 2015, p. 74.

310 MIBGAS (October 2019), Rules on the call and request for tender for the market maker service: First half-year 2020, p. 2.

Under the tendered MMO arrangement, companies may bid in a tender for the right to operate as a market maker for the exchange under certain prespecified conditions. Companies may tender for market making services for within-day, one-day-ahead, balance-of-month, and one-month-ahead contracts. [311]

In order to be eligible to market make, the applicant "must be registered in the clearing house used for the settlement of these products (OMIClear)".[312]

MIBGAS does not specify a particular bid-ask spread at which companies must bid to market make. Rather, companies may submit a bid for the right to market make at a bid-ask spread less than or equal to €0,40/MWh for within-day and day-ahead products, and that are less than or equal to €0,35/MWh for balance-of-month and one-month-ahead products.[313]

Applicants may also specify their minimum volume requirement per trading session in their offer. The minimum volume commitments per trading session are 5 GWh/day for within-day and day-ahead products, and 2GWh/day for balance-of-month and month-ahead products. [314]

However, other parameters of the tender are fixed. More specifically:[315]

- Trading sessions are between 9:30am and 6pm each week day.[316] Applicants must market make for 80 per cent of the time the window is open and must replace bid-ask offers within five minutes of an executed trade.
- The applicant is exempt from a maximum of three trading sessions per month.
- The availability requirement for market making in the trading window is relaxed when the system operator is balancing the market.[317]
- The minimum clip size is set at "200 MWh/d, divisible, for Within-day and Daily products [and Balance of Month and Next Month products], in each purchase and sale order, in a visible manner".[318]

MIBGAS uses the following set of criteria to select the winning bid. Applicants bid separately, in a sealed bid auction, to provide market making services for each product.

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311 MIBGAS (October 2019), Rules on the call and request for tender for the market maker service: First half-year 2020, p. 7.

312 MIBGAS (October 2019), Rules on the call and request for tender for the market maker service: First half-year 2020, p. 3.

313 MIBGAS (October 2019), Rules on the call and request for tender for the market maker service: First half-year 2020, p. 7.

314 MIBGAS (October 2019), Rules on the call and request for tender for the market maker service: First half-year 2020, p. 7.

315 MIBGAS (October 2019), Rules on the call and request for tender for the market maker service: First half-year 2020, p. 7.

316 MIBGAS (October 2019), Rules on the call and request for tender for the market maker service: First half-year 2020, p. 17.

317 MIBGAS (October 2019), Rules on the call and request for tender for the market maker service: First half-year 2020, p. 7.

318 MIBGAS (October 2019), Rules on the call and request for tender for the market maker service: First half-year 2020, p. 7.

MIBGAS scores each applicant's bid for spread, volume, and price.[319] The maximum score for each bid is based on the number of offers submitted per product. More specifically:[320]

- "In relation to the spread, the highest score will be assigned to the offer with the lowest spread, assigning the rest of the points in the downward direction, and depending on the distance from the best offer.
- In relation to the limit for the amount to be matched per trading session, the highest score will be assigned to the offer with the greater amount, assigning the rest of the points in the downward direction, and depending on the distance regarding the best offer.
- In relation to the price offered, the highest score will be assigned to the offer which presents the smaller amount with respect to all the others, assigning the rest of points in downward direction, and depending on the distance from the best offer.
- In case that certain values coincide in the different offers presented, the same score will be assigned for all of them, maintaining the order described in the previous paragraphs."

The spread and price are weighted at double the points to the volume limit committed each trading window. In addition:[321]

> "MIBGAS is entitled to ask for a new version of the binding offers from all the bidders if it deems it necessary to modify the description of the requirements in the light of the bids submitted.
>
> MIBGAS may choose more than one service provider for each product, if it considers the choice is appropriate for achieving the proposed objective more effectively.
>
> MIBGAS may declare the tender null and void for one or more products when it considers that none of the bids received meets the right conditions for the provision of the service."

Either party may withdraw from the tender with two months notice.[322]

Since the introduction of the MMO scheme, the market share of Naturgy and Endesa has fallen, but not markedly, from approximately 75 per cent in 2015 to approximately 70 per cent in the second quarter of 2019.[323]

In January 2018, a further mandatory MMO was implemented in the Spanish Gas Market. The Spanish Government obligated Naturgy and Endesa to provide market making services

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319 MIBGAS (October 2019), Rules on the call and request for tender for the market maker service: First half-year 2020, p. 4.

320 MIBGAS (October 2019), Rules on the call and request for tender for the market maker service: First half-year 2020, p. 4.

321 MIBGAS (October 2019), Rules on the call and request for tender for the market maker service: First half-year 2020, p. 5.

322 MIBGAS (October 2019), Rules on the call and request for tender for the market maker service: First half-year 2020, p. 10.

323 Market share as measured by number of customers. Source: CNMC (October 2019), Informe trimestral de supervisión del mercado minorista de gas natural en españa. Segundo trimestre de 2019, p. 8.

for day-ahead and month-ahead products[324], for which bid-ask spreads must not exceed €0,50/MWh.[325] However, Naturgy and Endesa may still tender to provide market making services at smaller spreads, subject to restrictions on bid-ask spreads set by MIBGAS.

324 CNMC (July 2018), Spanish energy regulator's national report to the European commission 2018, p. 6.

325 Boletín Oficial del Estado (December 2017), Number 301, p. 122655.

Qualifications, assumptions and limiting conditions

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