

# Energy market investigation

## Liquidity

**13 March 2015**

This is one of a series of consultative working papers which will be published during the course of the investigation. This paper should be read alongside the updated issues statement and the other working papers which accompany it. These papers do not form the inquiry group's provisional findings. The group is carrying forward its information-gathering and analysis work and will proceed to prepare its provisional findings, which are currently scheduled for publication in May 2015, taking into consideration responses to the consultation on the updated issues statement and the working papers. Parties wishing to comment on this paper should send their comments to [energymarket@cma.gsi.gov.uk](mailto:energymarket@cma.gsi.gov.uk) by 7 April 2015.

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The Competition and Markets Authority has excluded from this published version of the working paper information which the Inquiry Group considers should be excluded having regard to the three considerations set out in section 244 of the Enterprise Act 2002 (specified information: considerations relevant to disclosure). The omissions are indicated by [✂].

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## Summary

1. In this paper we examine liquidity in GB wholesale electricity and its effects on competition. We explain what we mean by liquidity: primarily we use this term to mean good availability of products that market participants wish to trade. We explain how wholesale electricity is traded, and give some background on previous regulatory concerns and interventions in this area. We explain how poor liquidity could distort competition, and especially how it could benefit vertically integrated (VI) firms<sup>1</sup> at the expense of other firms.
2. We then assess the level of liquidity in the market by considering appropriate metrics and analysing data from suppliers, generators and brokers. We find that near-term liquidity appears strong; that a small number of the most traded wholesale electricity products have good availability; but that many other products have not been widely traded or made available for sale in any depth, especially products relevant to parties seeking to trade several months or more in advance of delivery. The introduction of Ofgem's Secure and Promote (S&P) licence conditions has improved this situation for selected products at certain times of day, but does not appear to have had any positive effect on more granular products or at other times. Therefore, we think it is appropriate that Ofgem continues to monitor liquidity and attempts to improve it. We do not see any major issues with regard to transparency: the large majority of trading takes place over platforms where prices are visible to all market participants.
3. We go on to examine the likely effects of the current level of liquidity on competition, in particular with respect to suppliers' ability to hedge their purchases in advance of the point at which electricity is consumed by their customers; and generators' ability to hedge their sales in advance of generation. We find that independent suppliers/generators do not, in general, hedge as far forward as the Six Large Energy Firms.
4. We consider whether there is evidence that the Six Large Energy Firms derive an advantage over independent suppliers or generators because their vertical integration enables them to trade internally products that are not liquid in external traded markets. In order to assess this, we examined whether products available to buy in external markets would allow a supplier or generator to match the hedging strategies followed by the Six Large Energy Firms. We consider whether there are any reasons why independent suppliers or generators might be able to hedge as far ahead as VI firms but still be

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<sup>1</sup> In this paper we use the term 'VI firms' generically to indicate any firm that engages in both generation and supply of electricity, or production and supply of gas where we use the term in the context of gas. We do not use it to refer to particular firms.

disadvantaged unless they could hedge *further* ahead than VI firms, but we think that the ability to match is the right test. Our evidence suggests that external product availability is good enough for independent firms to match the Six Large Energy Firms' hedging strategies, and indeed the Six Large Energy Firms in general trade enough externally to construct their own hedged positions, even if they also engage in internal trades. This suggests that the Six Large Energy Firms are not gaining a competitive advantage from their ability to trade internally.

5. We also looked at trading and hedging in wholesale gas. We note that there is a much lower degree of vertical integration, and liquidity is generally held to be better, in gas than in electricity. Our analysis showed that gas has better availability than comparable electricity products. Despite this, we see similar patterns of trading and hedging behaviour between gas and electricity. If there were fundamental deficiencies in liquidity in electricity, or if VI firms were forming their electricity hedges by trading internally, we would expect to see that comparable gas products are traded further ahead than electricity products in external markets; but that was broadly not the case. Similarly, if VI firms gained an advantage in electricity from having the option to trade internally, we might expect to see them hedging further ahead in gas than in electricity; but again, that was broadly not the case.
6. Therefore, our current view is that, although liquidity in electricity could be improved, current levels of liquidity are sufficient to allow independent suppliers and generators to trade and hedge in the same way as the Six Large Energy Firms; and there are probably other reasons for the independent suppliers and generators not doing so, when this is the case. In our view, this suggests that the current level of liquidity in GB wholesale electricity does not distort competition or act as a barrier to entry or expansion.

## **Introduction**

7. In this working paper we discuss the levels of liquidity in GB wholesale electricity trading, and its effects on competition. We also discuss some aspects of wholesale gas trading, as it may be a useful comparator in some ways.
8. One theory of harm in our issues statement was that 'Opaque prices and low levels of liquidity in wholesale electricity markets create barriers to entry in

retail and generation, perverse incentives for generators and/or other inefficiencies in market functioning.’<sup>2</sup>

9. We proposed to consider two related hypotheses under this theory of harm:
  - Hypothesis a: The market rules lead to opaque prices and low liquidity in wholesale electricity markets, creating barriers to entry in retail and generation, perverse incentives for generators and/or other inefficiencies in market functioning.
  - Hypothesis b: Vertical integration leads to opaque prices and low liquidity in wholesale electricity markets, creating barriers to entry in retail and generation, perverse incentives for generators and/or other inefficiencies in market functioning.
10. This paper focuses on **outcomes** in wholesale electricity markets, and considers whether vertical integration is a likely cause of any adverse outcomes (hypothesis b). It does not consider market rules, which we examine in other papers.<sup>3</sup>
11. Our primary concern about the level of liquidity is whether it distorts competition in relevant markets. This is most likely to occur if some parties are less able than others to: (a) ‘hedge’ their demand or supply (ie contracting wholesale electricity in advance of delivery as protection against spot price changes);<sup>4</sup> and/or (b) balance their position at delivery. If so, it could place certain suppliers or generators at a competitive disadvantage and/or act as a barrier to entry or expansion.
12. In this paper, first we explain what we mean by liquidity, explain how wholesale electricity is traded, and give some background on previous regulatory investigations and interventions in this area.
13. We then assess the level of liquidity in the market by considering appropriate metrics and gathering data from suppliers, generators and brokers. We explain how poor liquidity could distort competition, and especially how it could benefit VI firms at the expense of other firms. We go on to assess the likely effects of liquidity on competition, primarily by examining evidence on the hedging strategies of various parties and the role of liquidity in the implementation of these strategies.

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<sup>2</sup> CMA (2014) [Energy market investigation: statement of issues](#).

<sup>3</sup> Wholesale electricity market rules working paper.

<sup>4</sup> See paragraph 108 for a full discussion of our use of the word ‘hedging’ in this paper.

## Background

14. In this section we first define what we mean by liquidity (paragraphs 16 to 22). We then describe how wholesale electricity and gas are traded in GB markets (paragraphs 23 to 28). We comment on the extent to which liquidity in electricity and gas can be compared, and why gas is generally held to be more liquid (paragraph 29).
15. We then give a brief overview of recent regulatory investigations and interventions into electricity liquidity, notably Ofgem's recent introduction of Secure and Promote licence conditions (paragraphs 31 to 35). We summarise parties' views on liquidity (paragraphs 37 to 40). Finally, in this section, we explain why near-term liquidity is not a focus of our investigation (paragraphs 42 to 43).

### ***What is liquidity?***

16. Generally, liquidity is a measure of the availability of an asset to a market or company. More precise definitions are elusive, perhaps because liquidity can have different meanings in different contexts.
17. Ofgem has defined liquidity in wholesale energy markets as 'the ability to quickly buy or sell a desired commodity or financial instrument without causing a significant change in its price and without incurring significant transaction costs'. Ofgem has also noted that a feature of a liquid market is that it has a large number of buyers and sellers willing to transact at all times, and this facilitates product availability and price discovery.<sup>5</sup>
18. For the purposes of this working paper, we use a relatively narrow definition of liquidity. We want to focus on those aspects of liquidity that are common to market participants – we might describe this as product availability. In effect, we are assessing whether the market offers products that parties want to buy, whether these products are available in 'reasonable' quantity, and whether prices are well defined. In other words, in a liquid market for a particular product, will parties have a reasonable expectation that they could buy (or sell) a 'reasonable' quantity without affecting the price? In a liquid market, parties are able to engage in trading with the reassurance that they would also be able to sell back to (or buy back from) the market later at a similar price, unless new information has justifiably caused prices to change.
19. We do not include in our definition or analysis in this paper factors that may vary from party to party – for example, posting collateral on trades, where the

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<sup>5</sup> Ofgem (June 2009) [Liquidity in the GB wholesale energy markets](#), paragraphs 1.8–9.

amount of collateral will depend on (among other factors) the party's credit rating; or the amount a party can trade with any particular counterparty. We do not look at transaction costs under the heading of liquidity.<sup>6</sup> Therefore, our definition is narrower than Ofgem's.

20. There are a number of dimensions to trading in electricity. These dimensions, which give rise to a wide range of wholesale electricity products, include:
  - (a) the delivery start date (we often refer to trading ahead of delivery, or trading 'along the curve'; by 'further along the curve' we mean a greater time ahead of the start of delivery);
  - (b) duration of delivery (eg on a single day, or for every day in a Month, a Quarter, a 'Season' (six months) or a year);
  - (c) hours of delivery (eg 'Baseload', which delivers all day; a 12-hour 'Peak' period on weekdays; four-hour 'Blocks'; or a single half hour); and
  - (d) clip size (ie the size of the product in capacity terms).
21. This means that a single product (eg 10MW of Peak in June 2015) could potentially be traded at any time from several years ahead to just before the start of delivery, and it may be more liquid at certain points in time (typically closer to delivery). It also means that a unit of electricity delivered at a particular time could be included in any number of products. Therefore, for example, a party could trade a Quarterly product or a 'strip' of the three equivalent Monthly products and receive exactly the same delivery, but the Quarterly product may be more or less liquid than the three Monthly products.
22. This leads to some fragmentation of products. In particular, the electricity day is broken into 48 half-hour periods that can be traded individually. This contrasts with the gas market, where the smallest unit is a whole day. The most widely traded product types are Baseload and Peak for Seasons, Quarters or Months. Industry participants often refer to 'shape', which tends to mean either 'daily shape' (hours of delivery more granular than Peak to reflect the fact that demand varies over the course of the day) or 'annual shape' (relatively short durations of delivery – generally months or less – to reflect the fact that demand is seasonal).

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<sup>6</sup> We do look at bid–offer spreads, which could be viewed as a transaction cost. We view these spreads as a measure of product availability.



## ***How are wholesale electricity and gas traded?***

23. Parties have several choices about how to trade wholesale electricity and gas products. The two main routes for trading electricity and gas futures<sup>7</sup> are brokered over-the-counter (OTC) and exchanges:
- (a) Brokered OTC bilateral trades in futures are agreements to supply a particular volume of gas or electricity at a particular time. The majority of electricity trades take place via a small number of brokers<sup>8</sup> using a screen-based system provided by Trayport. Trading is continuous throughout the day. Parties post bids and offers, the brokers anonymise them, and one party may trade with another only if it has a trading agreement and the trade is within the parties' agreed credit limits.<sup>9</sup>
  - (b) N2EX and APX are the main exchanges where electricity is traded, and contracts on these exchanges are short term.<sup>10</sup> Much of this trading occurs through auctions at the day-ahead stage. ICE is a third exchange, but little trading in futures contracts takes place on it. GB power contracts are also listed on the Nasdaq OMX exchange.
24. There are also some direct bilateral trades and long-term contracts between parties that are not visible to the market. VI firms may also trade internally, and this will be similarly invisible to the market. Also, a party may employ an intermediary to trade on its behalf, rather than trading with the market directly.<sup>11</sup>
25. The Electricity Supply Board (ESB, a generator operating in Great Britain and the Republic of Ireland) submitted analysis of publicly visible trades. This showed that in 2013 (the most recent full year), 84.1% of volumes traded took place OTC via brokers, 14.9% via N2EX and the remainder via APX and ICE. This is broadly consistent with our analysis of the trading of 16 firms, which showed 81.2% by volume taking place OTC through brokers, 13.3% via exchanges and 5.5% via direct bilateral trades.<sup>12</sup>

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<sup>7</sup> While the distinction between 'futures' and 'forwards' may be relevant in other contexts (eg financial regulation), this paper uses the term 'futures' to refer to both types of products.

<sup>8</sup> Until recently there were four; now there are five. More brokers are active in gas.

<sup>9</sup> A grid trade master agreement (GTMA) sets out the terms on which two parties can trade. The software will make each party aware of whether it can take up a particular bid or offer, but does not reveal the identity of the counterparty until the trade is completed.

<sup>10</sup> N2EX provides its members with access to a market coupled day-ahead auction. APX provides its members with access to a market coupled day-ahead auction, an intraday market for half-hourly products, a market for prompt products up to two days in duration and a day-ahead auction for half-hour products.

<sup>11</sup> We discuss some of the specific arrangements that independent firms have with intermediaries further in our case studies on barriers to entry and expansion in the retail supply of energy working paper.

<sup>12</sup> This excludes cash-out, which represents a small proportion of most firms' volumes.

26. Some suggestions have been made that the wholesale energy markets lack transparency.<sup>13</sup> The figures above suggest that the large majority of external trading takes place via platforms where prices are transparent to any industry participant, or indeed any interested party willing to obtain a subscription.<sup>14</sup> This should be sufficient to give good price signals to any party interested in making investment decisions or planning energy trades. It should be noted, however, that the identities of parties and thus the costs of energy trades actually paid by individual parties do remain confidential.
27. VI firms engage in internal trading, and these prices are not reported to the market. It is difficult to measure the extent of internal trading: some of it takes the form of arm's-length trades comparable to external trades, but some VI firms also trade generation capacity rather than volume, or transfer between 'books'. This might be a concern if VI firms conducted little external trading, but all of them externally trade multiples of their output and demand;<sup>15</sup> this should be sufficient for them to play a role in price formation.
28. Price reporting agencies also play a role in the market: they validate and research trading data to produce price indices and carry out their own assessments of market prices. They carry out these activities with reference to their published methodologies, and make them available to subscribers. These agencies also contribute to the communication of industry data to those without a day-to-day interest in energy markets.

### ***Comparability of electricity and gas***

29. The trading of wholesale gas in Great Britain is generally held to be relatively liquid, and certainly more so than the trading of electricity. There are several possible reasons for this:
  - (a) It is more practicable to store gas than electricity; and electricity needs to match supply to demand within narrow margins at each moment, whereas gas needs only to maintain pressure within much wider margins. The consequences of this are that electricity is traded in half-hour periods and parties are incentivised to match their supply with demand before the start

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<sup>13</sup> For example, Which? (July 2013) *The imbalance of power: wholesale costs and retail prices*, p28.

<sup>14</sup> For example, Trayport provides software which allows firms to use, view and manage market data from a variety of sources (including platform operators). (Market participants do not need a commercial relationship with Trayport to view or trade prices.) Trayport's licence fee for a single read-only screen that would allow (with permission from platform operators), for example, a small supplier to see all GB power and gas market trades executed on those platforms would be between £[£] per month. Opus told us that it has 'read-only access to all the primary trading platforms used to trade electricity so that we can monitor the wholesale market prices', which shows that this is used in practice.

<sup>15</sup> See Table 2, below.

of each period, whereas gas is traded in daily (24-hour) periods and parties can balance supply and demand within each period.

- (b) Fragmented products: as a result of the above, there are 48 times as many basic products for electricity as there are for gas. These products can then be combined in any number of ways, so the market tends to adopt conventions to standardise product definitions. There is still a large number of potential products, so it is natural for liquidity to concentrate around certain popular products (particularly along the curve).
- (c) International links: the GB electricity system is connected to those of Ireland, France and the Netherlands. However, the level of interconnection in GB is low, particularly compared to other European markets.<sup>16</sup> In contrast, the GB gas market is a hub with a range of external supply sources (upstream production, interconnectors and liquefied natural gas imports). This creates a range of trading opportunities, and makes it an attractive market for participants across Europe.<sup>17</sup> A recent study by the Agency for the Cooperation of Energy Regulators (ACER) showed that the British and Dutch gas markets performed significantly better than other European gas markets against a range of wholesale market metrics.<sup>18</sup>
- (d) Vertical integration: electricity exhibits a high degree of vertical integration, with some internal trading that is never seen or recorded by markets taking place. The degree of vertical integration in gas is much lower. To the extent that VI firms trade internally, a certain amount of liquidity is removed from external markets (although all of the Six Large Energy Firms trade multiples of their generation and demand in electricity).
- (e) Regulatory uncertainty: several parties told us that there was uncertainty over the future level of the carbon price floor, which has a substantial impact on electricity prices. Therefore, it was not attractive to trade in electricity products beyond the time horizon at which the level of the floor is set.<sup>19</sup> In contrast, gas is not affected by this. Therefore, financial activity

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<sup>16</sup> Descriptive statistics: generation and trading working paper.

<sup>17</sup> E.ON told us that 'many companies across Europe trade NBP as a proxy for their own needs'.

<sup>18</sup> ACER (January 2015) [European gas target model review and update](#), Figure 3.

<sup>19</sup> E.ON told us that this policy adversely affects liquidity in two ways: first, through uncertainty as to the level of the tax that is set in the government's Budget each year for the tax year two years ahead, which means that generators have to take a higher risk in selling their output more than two years ahead, thus requiring a significant risk premium to sell output forward and also dampening the incentive for any supplier to buy on this timescale; and second, through the distortion the tax has caused in the differentials in costs between generation in GB and continental Europe, which has impacted flows across the interconnector. E.ON noted that it also had other concerns about higher regulatory uncertainty in electricity compared to gas.

(speculation) would be attracted to gas in preference to electricity.<sup>20</sup> More generally, it has been suggested that the gas market has benefited from greater regulatory and policy stability.

30. We acknowledge that the fundamental differences between gas and electricity mean that it would not be reasonable to set liquidity in gas as the benchmark against which to judge liquidity in electricity. Nevertheless, since many of the same parties are involved in both markets, we find it instructive at certain points to draw comparisons.

### ***Regulatory interventions – Secure and Promote***

31. Ofgem and the Department of Energy and Climate Change (DECC) have previously assessed liquidity in Great Britain. During Ofgem's 2008 investigation into energy supply ('the Probe'), small suppliers and potential new entrants highlighted the lack of liquidity in the wholesale electricity markets and raised concerns about the functioning of the wholesale market itself. Ofgem decided that action was needed to address these concerns.<sup>21</sup> In 2009 it published a discussion paper<sup>22</sup> that found that liquidity in electricity in Great Britain was lower than in other energy and commodity markets, including a number of European electricity markets. The report analysed a range of factors that had contributed to the low level of liquidity in the GB electricity market, and outlined possible policy options that could improve liquidity.
32. As part of this process, Ofgem developed three liquidity objectives:<sup>23</sup>
- (a) improved availability of products to support hedging;
  - (b) robust reference prices along the curve (prices along the forward curve that are trusted to provide a fair reflection of the value of products – these prices provide valuable signals for market participants); and
  - (c) an effective near-term market (so firms can avoid imbalance).

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<sup>20</sup> For example, Scottish and Southern Energy (SSE) said: 'The Carbon Price Floor (CPF) has had a negative impact on long-term liquidity due to uncertainty around future levels, which can be changed at every budget ... Why would a hedge fund choose to trade forward power (the value of which could be materially affected by a sentence of the Chancellor's speech on carbon taxation) when they can take equivalent commodity price risk in the UK gas market where none of the peripheral political risk exists?'

<sup>21</sup> Ofgem (October 2008) [Energy supply probe: initial findings report](#), paragraph 1.34.

<sup>22</sup> Ofgem (June 2009) [Liquidity in the GB wholesale energy markets](#).

<sup>23</sup> Ofgem (22 February 2012) [Retail market review: intervention to enhance liquidity in the GB power market](#), Figure 3.

33. By 2013, Ofgem considered that the third of these objectives was being met, even though it had not made any direct interventions. However, it still had outstanding concerns about the first two objectives relating to forward markets.<sup>24</sup> After further reports and consultations, Ofgem introduced the Secure and Promote (S&P) licence conditions,<sup>25</sup> which came into effect on 31 March 2014.
34. The S&P conditions have three distinct elements: Supplier Market Access rules; Market Making obligations; and reporting requirements.
- (a) The Supplier Market Access rules oblige the eight largest generating companies<sup>26</sup> to consider applications for trading agreements from smaller suppliers (defined by size) within specified timeframes.<sup>27</sup>
- (b) Under the Market Making obligations the Six Large Energy Firms must offer to trade certain products (buy and sell with prescribed maximum spreads) in two hour-long windows every day. These products are:
- (i) Baseload: Month+1, Month+2, Quarter+1, Season+1, Season+2, Season+3, Season+4; and
- (ii) Peak: Month+1, Month+2, Quarter+1, Season+1, Season+2, Season+3.
- (c) The reporting requirements imposed on the eight specified firms enable greater monitoring of the near-term market by the regulator. Ofgem published an interim report on S&P in December 2014.<sup>28</sup> Ofgem stressed that it would need to see the licence condition in operation for longer, in order to have sufficient data to identify its effects.<sup>29</sup> It also noted that a variety of other factors could have affected liquidity in the period, such as increases in the spark spread.<sup>30</sup> Ofgem observed that:<sup>31</sup>

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<sup>24</sup> Ofgem (12 June 2013) [Wholesale power market liquidity: final proposals for a 'Secure and Promote' licence condition](#), Figure 1.

<sup>25</sup> Generation Special Licence Conditions AA.

<sup>26</sup> The Six Large Energy Firms plus Drax and GDF Suez.

<sup>27</sup> The key requirements are to:

- consider applications for trading agreements from smaller suppliers within specified timeframes;
- offer proportionate credit and collateral terms;
- provide transparency, both in relation to the information required to open negotiations on a trading agreement, and in relation to the rationale for the credit terms offered; and
- offer to buy and sell a defined list of products with smaller suppliers (once a trading agreement is in place). The products must be available in small clip sizes, and generators are allowed to add only specific elements to the market price.

<sup>28</sup> Ofgem (18 December 2014) [Wholesale power market liquidity: interim report](#).

<sup>29</sup> Ofgem (18 December 2014) [Wholesale power market liquidity: interim report](#), p5.

<sup>30</sup> Ofgem (18 December 2014) [Wholesale power market liquidity: interim report](#), paragraph 1.14.

<sup>31</sup> Ofgem (18 December 2014) [Wholesale power market liquidity: interim report](#), pp4–5.

Our analysis shows that there has been some improvement in liquidity since Secure and Promote was introduced. Several independent suppliers have also told us that it is easier for suppliers and generators to access the products they need and that prices for those products are perceived by industry as more robust during the times when market making takes place.

In addition, trends such as increasing churn (the electricity traded compared to the amount delivered to consumers) and falling bid–offer spreads (the difference between the buy and sell price for a product) show that liquidity is improving.

Many factors can impact liquidity and it is difficult to isolate the effect of our reforms. In addition, liquidity follows seasonal trends. While there are positive signs so far, it is too early to draw more meaningful conclusions. At least a full year of data is needed.

35. Based on feedback from stakeholders, Ofgem reported that independent suppliers were finding it easier to access products under the Supplier Market Access rules.<sup>32</sup> However, independent suppliers were still finding credit and collateral to be an issue.<sup>33</sup>
36. We make some observations on the effects of S&P below (from paragraph 84), although we recognise that it is too early to draw robust conclusions on its implications for liquidity as a whole, and note that Ofgem will continue to monitor its effects on liquidity.

### ***Parties' views on liquidity***

37. In this section we summarise parties' views on liquidity.
38. The Six Large Energy Firms generally shared the view that liquidity was sufficient for their purposes, although all of them noted (either in their responses to our consultation or in internal documents) that it was limited in some products and/or if it is possible to improve liquidity in some products it would be to the benefit of all market participants.
39. Some, but not all, independent suppliers believed that liquidity was sufficiently low, at least in particular products, as to impose additional risk and/or costs on them ([REDACTED], First Utility, [REDACTED], Ecotricity). At least one (First Utility) also told us

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<sup>32</sup> Ofgem (18 December 2014) [Wholesale power market liquidity: interim report](#), paragraph 2.3.

<sup>33</sup> Ofgem (18 December 2014) [Wholesale power market liquidity: interim report](#), paragraph 2.3.

that it placed VI suppliers at a competitive advantage because they could trade internally even when products were not available, or when there was no confidence in prices, in externally traded markets. By contrast, Utility Warehouse told us that more than sufficient liquidity was available.

40. Independent generators including Drax, ESB and InterGen all told us that there were limits to liquidity that affected their businesses. However, Drax said that the lack of shape trading until close to delivery is because it is inconvenient for generators to trade non-standard products, and because suppliers' demand becomes more predictable closer to delivery.
41. The general view was that liquidity is good in the gas market. This opinion was held by both the Six Large Energy Firms and independent suppliers. However, several parties said that liquidity was lower towards the end of the curve and that liquidity in Monthly products declined over time.

### ***Near-term liquidity***

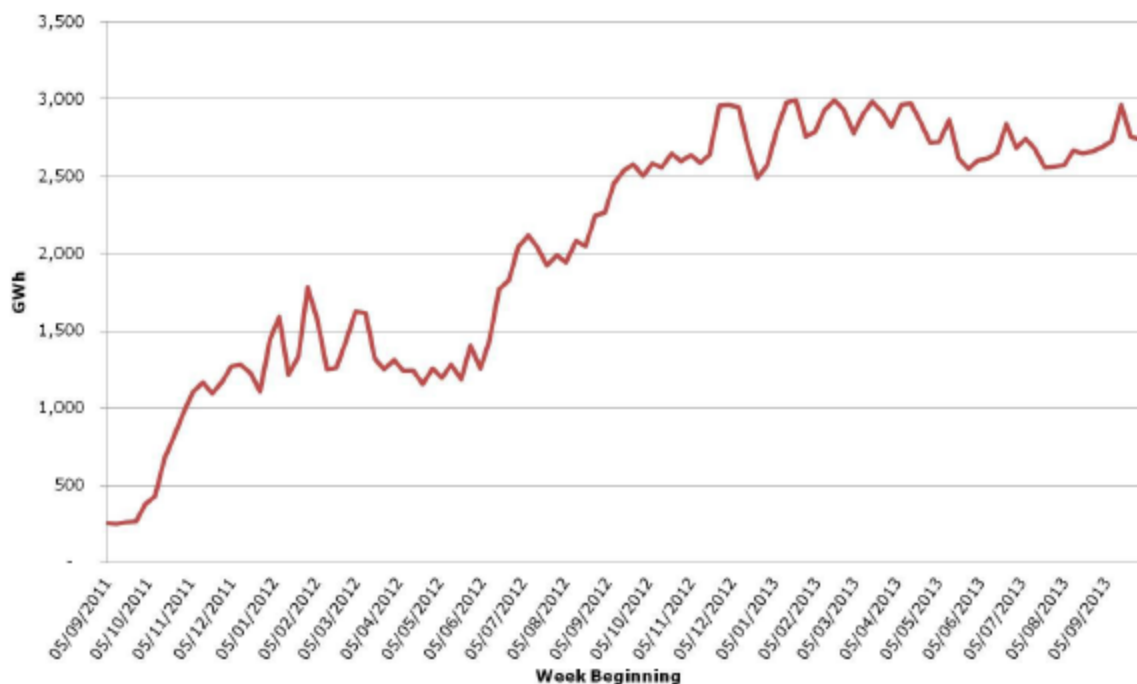
42. We did not look in detail at near-term liquidity (ie trading on the day of delivery and day ahead). Our understanding based on Ofgem's work and response to our issues statement is that liquidity here is good, and sufficient to allow firms to balance their positions. The volume traded on day-ahead auctions is one indicator of how well the near-term market is performing, and this has increased substantially in recent years – see Figure 1 below. Ofgem noted in 2012<sup>34</sup> that a number of market developments had contributed to near-term market liquidity: namely, that all of the Six Large Energy Firms had committed to trading on a day-ahead auction; that intra-day market offerings were deemed to be sufficient; and that GB market coupling via the 'virtual hub' was likely to enhance near-term liquidity (day-ahead market coupling with north-west Europe was introduced in February 2014).

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<sup>34</sup> Ofgem (July 2012) [Retail market review: GB wholesale market liquidity update](#) (letter to stakeholders).

FIGURE 1

### Day-ahead auction trading volumes (APX and N2EX)



Source: Ofgem (November 2013) [Wholesale power market liquidity: statutory consultation on the 'Secure and Promote' licence condition – impact assessment](#), Figure 13 (based on data from APX, N2EX).

43. We did not receive any comments from parties suggesting concerns about near-term liquidity; nor have we seen any evidence during our investigation to date that this should be a concern. Therefore, we have focused our analysis on liquidity in products for delivery further ahead.

### Our current assessment of liquidity

44. There is no single measure of liquidity, and no clear standard by which a market is judged to be liquid. Some widely used measures are:
  - (a) Volume or number of trades – this can be aggregate or of individual products. In our analysis we have identified commonly traded products and analysed the volume that is traded in various periods of time ahead of delivery.



- (b) Churn – this is the ratio of volumes traded to volumes consumed. It is usually reported as an aggregate measure, although it is also possible to take a ratio of a particular product to total volumes consumed.<sup>35</sup>
  - (c) Spreads – this looks at the difference between the buy price and the sell price of a particular product at a particular time. Generally, the smaller the spread, the more liquid a product is, because parties can both buy and sell at similar prices, and prices are well defined. It can be used to look at the availability of products (eg if there is little trading but tight spreads, this might suggest a lack of demand rather than a lack of availability).
  - (d) Depth – we consider availability and spreads at different depths. It may be possible to buy and sell small quantities at tight spreads, but a party wishing to trade larger quantities may not be able to do so, or may face significantly worse prices.
45. As noted above, our primary concern about the level of liquidity is whether it distorts competition in relevant markets, and in particular whether some parties are less able than others to hedge their demand or supply in advance of delivery. As a result, we have placed less emphasis on churn, because (a) it is a market-wide indicator, and (b) it is not clear what different levels of churn imply for this question. We are more interested in statistics that will give us an insight into availability for different products at different points in time ahead of delivery (including spreads and depth).
46. We present below a summary of the results of our analysis. First, we look at the volume of actual trading of particular firms for which we had good data (paragraphs 47 to 55). We also compare this with gas data, since we think the results are useful (paragraphs 56 to 59). Second, we briefly summarise findings on churn (paragraphs 60 to 61). Third, we look at the availability of products to be traded via brokers (spreads and depth) (paragraphs 62 to 83). Fourth, we look at the effects of S&P in its first months of operation (paragraphs 84 to 103). We then set out our current view of the state of liquidity in wholesale electricity (paragraph 104).

### ***Volume of trading***

47. We asked a number of suppliers and generators (including VI firms) for details of their external trades for delivery of electricity in the period January 2011 to July 2014. We categorised these products for the purposes of analysis in

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<sup>35</sup> It would not be meaningful to try to split volumes consumed into different products, so this type of measure would generally be used to compare products rather than to say anything about aggregate trading.

three ways: by time ahead of delivery, by duration, and by product type, and grouped them by type (see Table 1).

**Table 1: Categorisation of trades**

<i>Category</i>	<i>Product types</i>	<i>What does this provide?</i>	<i>Applies to gas?</i>
Time ahead of delivery	Over 36 months ahead, 24 to 36 months ahead, 12 to 18 months ahead, six to 12 months ahead, three to six months ahead, one to three months ahead, one week to one month ahead, one day to one week ahead, day ahead or less	Volumetric hedge	Yes
Duration	Beyond Season, Season (six months), Quarter, Month, Week, one day to one week, one day or less, other	Annual shape	Yes
Product type	Half-hour, Hour, Half Block (two hours), Block (four hours), Two Blocks (eight hours), Peak, Extended Peak, Off-Peak, Baseload, Custom, other	Daily shape	No

48. This data does not cover the entire market, and does not include internal trades for VI firms, but we believe we have sufficient coverage to give us a good view of trading behaviour.<sup>36</sup>

49. Over the last three years, each of the Six Large Energy Firms traded multiples of the size of their final consumption and generation, and therefore made a net contribution to liquidity (see Table 2). [X], indicating that it traded twice as much as the sum of its generation and consumption.

**Table 2: Average annual traded volume and physical volume (generation plus consumption)**

	<i>Centrica</i>	<i>E.ON</i>	<i>EDF</i>	<i>RWE npower</i>	<i>Scottish Power</i>	<i>SSE</i>
Average annual traded volume (TWh)	[X]	[X]	[X]	[X]	[X]	[X]
Average size of physical business (TWh)	[X]	[X]	[X]	[X]	[X]	[X]
Trading multiple	[X]	[X]	[X]	[X]	[X]	[X]

Source: Physical volumes from Ofgem segmental statements; parties' trading data; CMA analysis.

Notes: Annual average traded volume is based on all trades delivering in the period January 2011 to July 2014.<sup>37</sup> Average size of physical business is based on Ofgem segmental statements for 2011–2013.<sup>38</sup>

<sup>36</sup> Our data covers the following parties: Centrica, E.ON, EDF, RWE npower, Scottish Power, SSE, Co-op, Ecotricity, First Utility, OVO Energy (OVO), Utilita, Dong, Drax, ESB, GDF Suez and MPF Energy (MPF).

<sup>37</sup> Sleeve trades have been removed where possible.

<sup>38</sup> We used the supply volumes as reported in the segmental statements (after losses) – adjusting for losses would not have a material effect on this table.

50. Looking at overall volumes, we found that the majority of trading by the Six Large Energy Firms is within a year ahead of delivery, and this pattern is consistent between firms. However, the volumes traded towards the far end of the curve can still be significant. For example, Centrica traded nearly [X] per year over three years ahead of delivery. This is only [X] of Centrica's external trading, but, for comparison with the needs of an independent supplier, First Utility's consumption was 1.4TWh in the year from August 2013 to July 2014. This indicates that the volumes traded in the market even far down the curve are large, relative to the current size of independent suppliers.
51. The independent suppliers for whom we had data traded very limited volumes more than a year before the start of delivery. In general, they traded nearer to delivery than the Six Large Energy Firms. We observed a similar result for independent generators.
52. We looked at specific products and types of product. First, we compared Seasonal (six-month), Quarterly and Monthly products, focusing on Baseload and Peak products, as the two main product types for these durations. We found that Seasonal Baseload is traded along the curve, with some trading more than three years ahead of delivery. We observed that, by contrast, trading of Monthly Baseload is concentrated within three months of delivery (some parties traded small amounts of Monthly Baseload beyond six months ahead), with much lower volumes than the Seasonal product. Quarterly Baseload is traded slightly more three to six months out, but very little beyond that. There is a similar pattern for Peak – Seasonal products are traded much further ahead than Monthly or Quarterly products. For Monthly Peak products, the amount of activity beyond three months ahead is very small.
53. We then looked at daily shape. Having already looked at Peak products, we turned our attention to Block products.<sup>39</sup> Among the Six Large Energy Firms, the majority of trading in these products was closer to delivery – each firm traded at least 70% of its volume in these products within three months out. All firms carried out some trading more than a year ahead, although only two firms did so in larger volumes along the curve. Independent suppliers and independent generators also generally traded these products within three months of delivery.
54. We combined the trades made by all of the parties in our data set and looked at how the volume was split between products and over time. The results are

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<sup>39</sup> We are looking here at four-hour Blocks, and combinations of these Blocks (eg Overnights), but excluding Peak, as this was considered above. The amount of trading on products smaller than a four-hour Block is very small until shortly before delivery.

presented in Table 3. We do not claim that this is necessarily representative of all trading, but we have sufficient coverage that it should give a reasonable indication.<sup>40</sup> Over 50% was Seasonal Baseload, and much of this was traded well in advance of delivery. There was very little trading in Quarterly, Monthly and other products more than six months from delivery: only 2.3% of trading is both more than six months out and not in Seasonal products. Less than a month from delivery, trading switches predominantly to other products as forecasts of demand are refined and firms seek to shape their demand and output.

**Table 3: Split by product type of electricity volumes traded by energy firms in our data set**

	Seasonal Baseload	Quarterly Baseload	Monthly Baseload	Seasonal Peak	Quarterly Peak	Monthly Peak	Blocks*	Other	% Total (sum of columns)
Over 2 years	3.8	0.0	0.0	0.0	0.0	0.0	0.0	0.1	4.0
1–2 years	12.8	0.0	0.0	0.3	0.0	0.0	0.3	0.7	14.2
6–12 months	13.5	0.3	0.1	0.8	0.0	0.0	0.3	0.5	15.5
1–6 months	17.2	5.2	3.9	1.0	0.3	0.2	0.9	0.9	29.7
Less than 1 month	2.9	1.4	7.1	0.2	0.0	0.4	3.5	21.0	36.6
Total (sum of rows)	50.3	6.9	11.2	2.3	0.4	0.6	5.1	23.2	100.0

Source: CMA analysis, parties' data (the Six Large Energy Firms, Co-op, Ecotricity, First Utility, OVO, Utilita, Dong, Drax, ESB, GDF Suez, MPF)

\*Blocks include all combinations of standard Blocks, apart from standard Peak products.

55. Products covered by the S&P market making obligation accounted for 64% of trading by volume (among parties whose data we have analysed). Excluding products for delivery within a month, these obligated products accounted for 83% of trading by volume.

### *Comparison to gas*

56. We asked relevant parties for equivalent data on their gas trading. This data is somewhat simpler since it does not have the time-within-day dimension; but it is otherwise comparable. As noted above, there are a number of differences between electricity and gas, which mean that we should not use gas as a simple benchmark by which to judge electricity (ie a finding that gas is in any sense 'more liquid' than electricity does not itself imply that there is a problem in electricity liquidity).
57. We found that most gas trading by the Six Large Energy Firms was within a year from delivery. This pattern of when they traded was similar to electricity. However, they traded greater volumes (relative to consumption), so the

<sup>40</sup> Note that some trades will be included twice in our data, if they are conducted between two firms in our data set. However, we have no reason to think that this should cause bias.

absolute volumes that they traded along the curve were large, relative to electricity. Most trading by independent suppliers was within a year from delivery.

58. We found that the Six Large Energy Firms generally traded Monthly products within three months of delivery – the same as for electricity. Their trading beyond this therefore took the form of Quarters or Seasons. By contrast most independent suppliers in our data traded Monthly products as far out as they traded any products. However, these firms had agreements with a range of trading partners that may have permitted them to access products that were not necessarily traded in the market at the time, with the intermediary taking on the risk (eg Shell told us that it does so on request).

**Table 4: Split by product type of gas volumes traded by energy firms in our data set**

					%
	<i>Seasons</i>	<i>Quarters</i>	<i>Months</i>	<i>Other</i>	<i>Total (sum of below)</i>
Over 2 years	3.8	0.0	0.2	0.3	4.3
1–2 years	9.7	0.2	0.7	0.1	10.7
6–12 months	12.1	0.9	1.7	0.1	14.8
1–6 months	20.2	6.5	8.1	0.3	35.1
Less than 1 month	3.6	1.5	18.7	11.2	35.1
Total (sum of above)	49.4	9.1	29.4	12.0	100.0

Source: CMA analysis, parties' data (Co-op, Ecotricity, First Utility, Utilita).

59. Table 4 shows the split of aggregate gas volumes traded by the companies in our data (analogous to Table 3's electricity volumes).<sup>41</sup> Compared to electricity, we see a little more trading in Quarters and Months more than six months from delivery, but the proportions are still relatively small: only 4.2% of trading is both more than six months out and not in Seasonal products.<sup>42</sup> By comparing the 'total' rows and columns between the two tables, we see that patterns of trading by time ahead of delivery are very similar for gas and electricity: if anything, electricity trades slightly further ahead of delivery than gas. This is opposite to the result we would expect if liquidity in electricity were a concern. The main difference between the two tables is within one month of delivery, where there is a considerable amount of trading of Monthly gas products whereas more electricity trading is in 'Other'. This is likely to reflect the greater granularity of electricity products and the need to trade daily shape. We do not see anything in this comparison to suggest that there is frustrated demand for trading electricity products further down the curve.

<sup>41</sup> We note that the set of parties providing data is slightly different, although the bulk of the volume comes from the Six Large Energy Firms, which are included in both data sets.

<sup>42</sup> 4.2% is the sum of the Quarters, Months and Others for the top three rows.

## Churn

60. In March 2014, Ofgem<sup>43</sup> produced the following illustration of churn since 2000 (Figure 2), indicating that it has been at a level of between 3 and 4 for the last six years. Ofgem noted that this is much lower than in the GB gas market, which has a churn ratio typically in the range of 12 to 20, and below those for electricity in a number of other European countries. While volumes traded in the German and Nordic wholesale markets have fallen recently, they maintain consistently higher churn ratios than the GB market.<sup>44</sup> However, according to a recent report for ACER, GB liquidity is on a par with liquidity in Italy and Spain, and higher than in France or Portugal.<sup>45</sup> Therefore, international comparisons do not give a clear benchmark.<sup>46</sup>

FIGURE 2

### Wholesale electricity: overall volumes traded and degree of churn



Source: Ofgem (based on data from Digest of UK energy statistics (DUKES), ICIS Heren, APX, N2EX, ICE).

<sup>43</sup> Ofgem (March 2014) [State of the market assessment](#), Figure 39.

<sup>44</sup> Ofgem (March 2014) [State of the market assessment](#), paragraph 5.27.

<sup>45</sup> ACER (March 2014) [Report on the influence of existing bidding zones on electricity markets](#). We note that the churn figure reported for Great Britain in this report is significantly lower than Ofgem's estimates, suggesting that there may be some methodological issues.

<sup>46</sup> Some of these countries have very high levels of concentration, which might be expected to reduce market liquidity. For example, both France and Portugal have Herfindahl–Hirschman Indexes (HHIs) above 5,000 (European Commission (March 2013) [Completing the internal energy market](#), p8).

61. Ofgem's latest figures suggest that GB churn has risen above 3.5 since March 2014.<sup>47</sup> On the basis of this evidence it is not possible to say whether GB churn is 'too low'. Although churn has some attractions as a simple figure that can be compared with figures in other markets, as noted above (paragraph 45), we place limited weight on it as an absolute measure because it is not clear what constitutes an 'acceptable' or 'problematic' level of churn. Even a good aggregate churn level would not be informative as to the liquidity of individual products or at different points in time.

### ***Availability, spreads and depth***

62. In this section we assess evidence on the availability of products to trade, the spread between buy and sell prices, and the depth in which products were available. We think this information directly illustrates liquidity of individual products.
63. We obtained data on 'bids' and 'asks' in the OTC marketplace from the four brokers active in the market in that period.<sup>48</sup> Bids are the prices at which parties are willing to buy; asks (sometimes known as 'offers') are the prices at which parties are willing to sell. This took the form of snapshot data for 8am, 11am and 4pm on the second Tuesday of every month from January 2011 to October 2014.<sup>49</sup>
64. First, we looked at simple availability of products (ie whether a particular product was available both to buy and to sell in any quantity). Second, we looked at product depth – whether parties could buy and sell larger quantities. Third, we looked at spreads. Fourth, we looked at who was making products available for trade. We focused on the 11am snapshot, noting that this generally had the best product availability of our three times of day, and our analysis refers to this time of day unless otherwise stated. We also obtained daily data from ICIS Heren (a price reporting agency) on 'market close' spreads (paragraph 83).
65. This information on product availability should also give some indication of relative (not necessarily absolute) demand to trade different products – subject to one caveat, below. Products that are not widely available are likely

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<sup>47</sup> Ofgem (18 December 2014) [Wholesale power market liquidity: interim report](#), Figure 2. We discuss this further when looking at effects of S&P, below.

<sup>48</sup> GFI, ICAP, Marex Spectron and Tullett Prebon. A fifth broker has also recently become active in this area, but not during the period we investigated.

<sup>49</sup> We chose the day hoping that it would be representative (eg generally free of Bank Holidays, etc), and chose two times that fell within Ofgem's designated S&P windows (10.30am to 11.30am and 3.30pm to 4.30pm) and one that did not. We understand that Ofgem selected windows to coincide with times of day when traders were relatively active. Indeed, our data suggested that there were consistently more products available to trade at 11am and 4pm than at 8am.

to be those where there is relatively little demand both to buy and to sell. We have focused on products that are available to be traded in both directions, but we found it was rare for products to be available to buy but not sell, or vice versa. If there were products that firms wanted to sell but there was little demand to buy, we would still expect to see them posting prices in the market sometimes,<sup>50</sup> even if they were not resulting in trades; and vice versa, if there were products that firms wanted to buy but little supply of them.

66. The caveat is whether some firms are trading these illiquid products outside the observed market. If they were, then it might be wrong to say that there was relatively little demand to trade them. We address this below (paragraphs 116 to 157).

### *Availability to trade*

67. We looked at how often a particular product was available for trade in both directions, buy and sell.<sup>51</sup> Table 5, below, shows the proportion of dates in our sample when each listed product was available in some quantity. Cells with borders in Table 5 have been included in the S&P Market Making obligation since 31 March 2014. They would be available every day at 11am since then, so the table may understate their availability since – and overstate their availability prior to – that date.

**Table 5: Proportion of days when product was available both to buy and to sell at 11am (regardless of quantity)**

		%							
		<i>Time ahead of delivery (Season, Quarter, Month, respectively)</i>							
		+1	+2	+3	+4	+5	+6	+7	+8
Baseload	Season	100	100	98	93	80	54	9	4
	Quarter	85	48	30	15	0	0	0	0
	Month	100	98	76	59	28	15	7	2
Peaks	Season	85	78	70	46	17	7	0	0
	Quarter	57	26	9	2	0	0	0	0
	Month	93	65	46	26	17	11	7	0
Block 6	Month	33	11	0	0	2	0	0	0

Source: Data from brokers, CMA analysis.

68. This analysis suggested that availability of Baseload Season products (delivery for six months, October–March and April–September) was very good for more than two years ahead of delivery. Peak Season products were not always available, but had reasonable availability (70% or more) three seasons (18 months) ahead. Baseload Months were almost always available two

<sup>50</sup> Subject to the effort and risk involved for traders in posting and monitoring prices.

<sup>51</sup> In practice, we found that it was rare for a product to be available to buy but not to sell, or vice versa.



months ahead, and Peak Month availability was best one month ahead. Quarters were available less than Months.

69. Products other than these six had relatively little availability. For example, one product that we might expect to be attractive to domestic suppliers is Block 6, which runs from 7pm to 11pm and so adds an evening shape to the standard Peak product (7am to 7pm). We found that Block 6 products were rarely available both to buy and to sell. The most commonly traded was a Monthly product for the month ahead, available on a third of the dates in our data set.
70. We also looked at data for 8am (outside the S&P windows). We saw indications that product availability had become worse since the introduction of S&P. In Baseload Seasons (the most widely available product), only the front three Seasons have been available on our snapshots from June to October 2014, and those at wider spreads than had been generally observed since the start of 2013. We saw a similar picture for Baseload Months beyond the front two Months; and almost no availability of Peak Seasons, Quarters or Months since May 2014. Anecdotally, we have heard that trading before the morning S&P window has particularly suffered, and availability may be better between the windows. Our evidence does not address this point.
71. These results paint a picture of relative, rather than absolute, availability. A product that is not available at 11am may still be available at other points in time on the same day. A product available at 50% of our snapshots may be available on more than 50% of days, just not at this time. Therefore, the numbers in Table 5 may paint too pessimistic a picture of product availability. (We explore the opposite possibility when looking at spread sizes below.)
72. Industry participants do not necessarily need every product to be available at every moment of every day, as long as they are available sufficiently often for them to be able to enact hedging strategies. They may be comfortable buying both Baseload and Peak several Seasons ahead, one or two Quarters ahead and up to four Months ahead – all of these products had reasonable availability, and many of them are now covered by S&P so will be available for at least two known hours every day. However, shaping products, such as Blocks may have little availability until shortly before delivery.
73. However, speculative trading is more likely to be dissuaded. Various parties have told us that speculative traders do not find products attractive unless they can ‘get out of’ positions at short notice at any time. Therefore, there is likely to be a minimum level of liquidity of any given product at which it is attractive to speculative traders, and many electricity products are likely to fall short of that. Various parties have commented that liquidity is a ‘vicious (or virtuous) circle’, and that ‘liquidity begets liquidity’. In other words, the better

liquidity is in a product (or a set of products that are substitutable), the more players will be attracted to trading in it, and the better liquidity will become; and vice versa.

## Depth

74. We considered how the availability results varied when we increased product depth. One common clip size is 10MW, and at that depth we generally found that the same range of products was available. However, if we increased clip size to 50MW, availability declined substantially. Table 6 shows that at the larger clip size it was impossible to guarantee that any product would be available to buy and sell at 11am on any given day. Only Season+1 and Month+1 Baseload products looked to have reasonable availability in this depth over the entire period.

**Table 6: Proportion of days when product was available both to buy and to sell at 11am (50MW)**

		%							
		Time ahead of delivery (Season, Quarter, Month, respectively)							
		+1	+2	+3	+4	+5	+6	+7	+8
Baseload	Season	46	20	20	15	0	0	0	0
	Quarter	24	0	0	0	0	0	0	0
	Month	61	24	2	0	0	0	0	0
Peaks	Season	15	15	15	0	0	0	0	0
	Quarter	15	0	0	0	0	0	0	0
	Month	24	15	0	0	0	0	0	0
Block 6	Month	0	2	0	0	0	0	0	0

Source: Data from brokers, CMA analysis.

75. S&P has changed this for the products that are covered under the Market Making obligation (indicated with borders in Table 6); those products have all been, and will continue to be, available in this depth during the market making periods since 31 March 2014. Therefore, this table paints too pessimistic a view for the future. However, there is no sign that products that are outside the coverage of S&P will be available at depth.<sup>52</sup> We repeat the caveat that industry participants do not need all products to be available at all times.

## Spread sizes

76. We generally found that spreads were tighter the closer a product got to delivery. So, for example, looking at Baseload products, Season+1 spreads were less than 1% throughout this period and have been below 0.5% for the last two years; Season+2 has generally been below 1%; and Seasons+3 and

<sup>52</sup> We discuss the observed effects of S&P in more detail at paragraphs 84–103.

+4 have generally been below 1% in the last two years. Spreads for Season +5 have been above 2% on a number of occasions, and where further Seasons have been available, spreads are generally wider still.

77. Spreads for Peak Seasons are a little wider, but still generally below 1% for the first two or three Seasons in the last 18 months.
78. In Baseload, the first Month is often less than 0.5% and the first Quarter usually less than 1%, with subsequent Months and Quarters showing greater volatility of spread (sometimes tight, but at other times as wide as 2.5%).
79. We looked at how often a product had a spread of 1% or less,<sup>53</sup> and the pattern was broadly similar to Table 5, above, but with smaller numbers. There were only nine products with a spread this tight in at least half of the days in our sample: for Baseload, the first four Seasons, one Quarter and two Months; and for Peak, the first Season and Month. Again, we note that the introduction of S&P will improve this situation for all of these products (and for Peak Quarter+1 and Month+2): each obligated firm must offer a maximum spread (which varies from 0.5 to 1%, depending on the product),<sup>54</sup> and so the market spread will be no wider than this and generally tighter. Each of these products has had tight spreads since S&P was introduced, so these numbers understate liquidity since April 2014 but overstate liquidity before that point.
80. However, other products show no signs of benefiting from S&P. In our entire sample, there are only three occurrences of a Block 6 product with a spread that tight – a Monthly product on two days, and a Quarterly product on one day.
81. The average spread for any given depth can rise considerably as we look for further depth.

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<sup>53</sup> 1% is the largest of the permitted spreads under the S&P Market Making obligation. We recognise that this is not a precise definition of whether or not a product has tight spreads, but we consider that it is an appropriate screen for the purposes of this analysis.

<sup>54</sup> When market making, the licensee must maintain a spread between their bid and offer price narrower than:

<i>Baseload</i>		<i>Peak</i>	
Month+1	0.5%	Month+1	0.7%
Month+2	0.5%	Month+2	0.7%
Quarter+1	0.5%	Quarter+1	0.7%
Season+1	0.5%	Season+1	0.7%
Season+2	0.5%	Season+2	0.7%
Season+3	0.6%	Season+3	1%
Season+4	0.6%		

### *Active players*

82. We looked at the whole data set to see who was offering to trade, and who was offering the best prices for each product. We found that just over 70% of both bids and asks were from the Six Large Energy Firms. We also found that more than two-thirds of best prices were from the Six Large Energy Firms (ie roughly in proportion to the number of orders to trade). This was also the case when we looked only at Baseload and Peak products.

### *Market close data*

83. We also looked at data from ICIS Heren, which provided daily data on product bid–offer spreads at market close from January 2010 for gas and electricity.<sup>55</sup> We observed that:
- (a) spreads get wider further from delivery;
  - (b) Seasons have tighter spreads than Months, which in turn are tighter than Quarters;
  - (c) Baseload has tighter spreads than Peak;
  - (d) availability (based on when ICIS Heren made an indicative assessment, with bids, offers or transaction data unavailable or unconfirmed) followed a similar pattern to spreads; and
  - (e) gas products had tighter spreads than their electricity equivalents and were also available further ahead of delivery.

### ***Effects of Secure and Promote***

84. In this section we assess the effects of S&P, with the caveat that it came into effect recently and so there is limited data available. The period for which we had available data is too short to assess the effects of S&P fully and reliably because we had access to data from only the first six months or so of operation, industry participants can be expected to take some time to adjust to the new system, and less trading generally takes place in the summer (the season for which we had data) than in the winter.

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<sup>55</sup> ICIS Heren's assessments are 'based on bids and offers widely available to the market closest to the typically observed last point of liquidity', which for Great Britain is 4.30pm London time (apart from day-ahead and weekend products, which we excluded from this analysis). Where no bid, offer, transaction or spread data is available, ICIS Heren 'will work back in time from its published closing time to the last point of liquidity during the trading session and assess value at that point', according to its published methodology. See ICIS Heren (September 2014) [European daily electricity markets methodology](#).

85. We give Ofgem's views and parties' views, then look at evidence in data from brokers and ICIS Heren.

#### *Ofgem's views*

86. As noted in paragraph 34(c), Ofgem reported that it has found some improvement in liquidity since the introduction of S&P, but recognised that it was too early to draw strong conclusions. Ofgem's data indicated that 'trading volumes have risen in the windows and have remained broadly static between the windows'.<sup>56</sup>

87. Ofgem also reported that:<sup>57</sup>

The near term market is liquid and shows signs of improvement, particularly intraday trading. Our data shows that near term liquidity has remained secured.

#### *Parties' views*

88. Ofgem reported that 'stakeholders were generally fairly positive' about the Market Making obligation,<sup>58</sup> and that there was 'a sentiment of cautious optimism' about the Supplier Market Access Rules.<sup>59</sup> It said that its stakeholder responses showed that:
- (a) independent suppliers were finding it easier to access products and that the responsiveness of obligated licensees to trading requests had improved (stakeholders said that credit and collateral costs remained the main barriers to independent suppliers);<sup>60</sup> and
  - (b) general agreement that price formation and product availability within the windows had improved and that overall trading volumes had not been adversely affected. Many stakeholders said they thought that there was a concentration of liquidity in the windows. Some stakeholders thought that more depth was necessary in forward products and that there was not yet a kick-start in liquidity, simply a shift. They said price robustness had not been achieved throughout the day. Some also said that there needed to

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<sup>56</sup> Ofgem (18 December 2014) [Wholesale power market liquidity: interim report](#), paragraph 1.17.

<sup>57</sup> Ofgem (18 December 2014) [Wholesale power market liquidity: interim report](#), paragraph 2.30.

<sup>58</sup> Ofgem (18 December 2014) [Wholesale power market liquidity: interim report](#), paragraph 2.18.

<sup>59</sup> Ofgem (18 December 2014) [Wholesale power market liquidity: interim report](#), paragraph 2.5.

<sup>60</sup> Ofgem (18 December 2014) [Wholesale power market liquidity: interim report](#), paragraph 2.3.

be more financial players trading in the market to see a real improvement in liquidity.<sup>61</sup>

89. Ofgem also said that some stakeholders suggested that S&P needed to attract more financial players to create a significant improvement in liquidity.<sup>62</sup> In this context, it was suggested that windows were insufficient to attract financial players, who want to be able to trade out of positions throughout the day.
90. We received some views from parties on the effects of S&P in response to the issues statement, and we followed these up with additional questions to certain parties. We received mixed views. Some parties (including some of the Six Large Energy Firms and some independent suppliers and generators) thought that there had been an increase in liquidity, at least in the mandated products. There was little suggestion that S&P had led to an improvement in other products, and some parties suggested that liquidity had simply moved to the two daily windows at the expense of the rest of the day.
91. We also asked a range of companies that trade in electricity markets primarily as intermediaries (ie they do not have generation or supply businesses), and they had a similar range of views, with some citing positive effects of S&P but others suggesting that this had come at the expense of liquidity outside the windows.
92. The generator ESB submitted to us a report it had commissioned from London Economics (LE). LE looked at churn in various products and concluded that liquidity in forward trading on these metrics has not increased overall, and is possibly worse, than when Ofgem started studying it in 2009/10 (although some categories of products had improved either since then or since 2013). LE also conducted econometric modelling of bid–ask spreads in OTC on Trayport, using data from 2009 to September 2014. It found that there had been no significant net reductions in spreads as a result of the introduction of the windows; and that significant forward premiums exist that were not reduced by the windows.

## *Data*

93. The increase in electricity traded volumes in 2014 seems clear. According to data from the London Energy Brokers' Association,<sup>63</sup> OTC GB electricity volumes rose 26% in 2014 compared to the previous year. In contrast,

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<sup>61</sup> Ofgem (18 December 2014) [Wholesale power market liquidity: interim report](#), paragraphs 2.18–19.

<sup>62</sup> Ofgem (18 December 2014) [Wholesale power market liquidity: interim report](#), paragraph 2.19.

<sup>63</sup> [London Energy Brokers' Association \(December 2014\) OTC energy volume report](#).

volumes across other European electricity markets fell 6%, while volumes on the NBP gas market rose only 2%.<sup>64</sup>

94. We looked at the effects of S&P in our data on product availability from brokers, and our analysis is summarised above in paragraphs 67 to 82.
95. Our analysis of ICIS Heren's data on bid–offer spreads at close also showed that the seven mandated Baseload products and six mandated Peak products have had consistently tight spreads (all averaging below 0.8% on a monthly basis, and many below 0.5%) since April 2014. This has been an improvement on the previous three years. There was no sign of improvement for other products. ICIS Heren's close time (4.30pm) corresponds with the end of the afternoon window of S&P, and therefore does not give information about availability outside the windows.
96. We have not attempted to look at effects of S&P in our trading data, since our data relates to trading of products that commence delivery up to July 2014. Most of the forward products available to trade through S&P would not have started delivering by July 2014, hence we have very little relevant data.

#### *Our current view of the effects of Secure and Promote*

97. Based on the data we have collected, parties' comments and Ofgem's interim report,<sup>65</sup> we believe there is some evidence that liquidity has improved in the designated windows, although this may be at the expense of liquidity in other parts of the day. We certainly see signs that, since the introduction of S&P, the designated products are now available in windows when they were not previously regularly available, or are available in greater depth.
98. We think that, on balance, this is positive in the short term for suppliers and generators. When we look at products down the curve, it is probably sufficient for most industry participants to know that there will be points every day when they can trade a set of products that accounts for the majority of trading,<sup>66</sup> even if they cannot trade them all the time. There may be occasional exceptions, when rapidly changing market conditions mean that participants do want to trade more often; but from the data available to us, we have not been able to assess whether the volume of trading is naturally likely to increase at such times anyway. We would also expect that having well-defined prices for mandated products during the windows would help set price

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<sup>64</sup> However, volumes across other European gas markets rose 43%, meaning that GB electricity was not the best-performing market.

<sup>65</sup> Ofgem (18 December 2014) [Wholesale power market liquidity: interim report](#).

<sup>66</sup> As we explain below, these products seem to be broadly sufficient to carry out common hedging strategies.

expectations in the rest of the day, even if products are not widely traded outside the windows.

99. However, these changes are relatively marginal and do not seem likely to attract financial participants into (or back into) electricity trading. It has been put to us that this type of market participant needs good liquidity throughout the day, and that there will not be a 'step change' in the level of liquidity unless this type of player is attracted to the market. We note that there are also wider factors influencing the participation of financial participants, and that these affect commodities in general, rather than specifically GB power.
100. We also found that the benefits seem to be confined to the designated products and there is no obvious spillover to other products (eg Baseload Quarter+2) or windows; if anything, the availability of such products may have decreased as market makers focus on mandated products, although the historical availability of such products was also poor, so we do not consider this to be a robust conclusion. A reduction on availability of other products and times would be consistent with LE's econometric study.
101. We asked Ofgem about the costs and benefits of extending the Market Making obligation to other products. Ofgem told us that, during its consultation, some small suppliers suggested that the product list should include 'shaped' products (ie products that closely reflect the profile of physical demand for power throughout the day). These suggestions varied significantly and no true consensus was reached about which particular products would be helpful. Ofgem told us that, by way of illustration, it considered the addition of evening peak products to the product list for market making, but decided that to do so would add cost and risk to the intervention for limited additional benefit, because:
  - (a) failure to price the products accurately – even briefly – could lead to substantial trading losses for obligated parties, and the lack of current trading would make pricing difficult;
  - (b) it saw little evidence of suppressed demand;
  - (c) the introduction of evening peak products to the wholesale market would split the already limited trading in peak products, and thinner trading in these products could affect the robustness of the price signals generated by trading; and

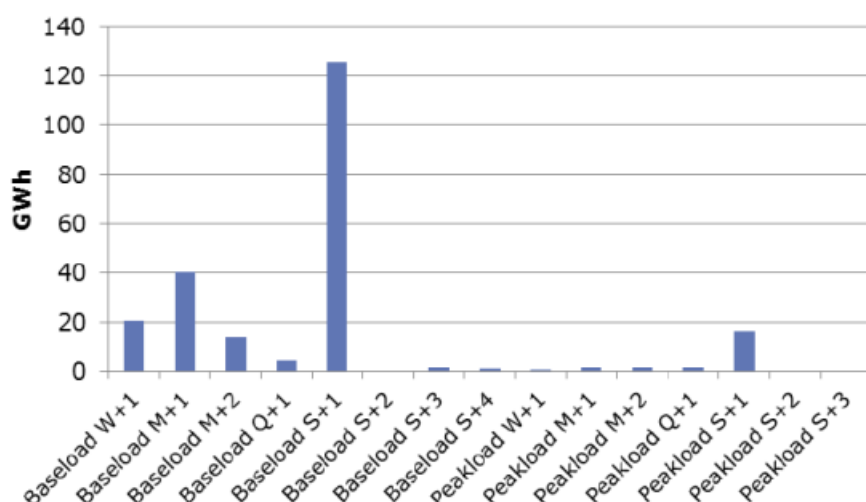


(d) it could lead to a substantial increase in the number of obligated products,<sup>67</sup> which would substantially increase compliance costs and risks for obligated parties.

102. On the demand point, we refer to one figure from Ofgem's interim report on Supplier Market Access volumes by product, reproduced below (Figure 3). This suggests that there has been very limited trading along the curve by the smallest suppliers, even though the introduction of the SMA rules would have addressed any issues with product availability, clip sizes, or ability to sign trading agreements. This may reflect a lack of underlying demand for these products, or issues with collateral that deter small suppliers from trading further ahead. Either way, it does not suggest that there would be substantial take-up of shaping products down the curve even if access to them were mandated. We also discuss apparent demand for particular products later in this paper.

FIGURE 3

**Supplier Market Access contracts traded in second and third quarters, 2014**



Source: Ofgem (18 December 2014) [Wholesale power market liquidity: interim report](#), Figure 9 (based on S&P licensees' data).

103. It seems clear from our work on product availability above that including other products in the market making obligation would cause a dramatic increase in availability of those products; but the worse availability is now, the greater the risk and costs to mandated firms of trying to price those products. Without strong evidence of frustrated demand for other products, the benefit of their availability may be limited. Therefore, we do not currently see a compelling

<sup>67</sup> As an example, Ofgem said that adding 'Weekday Blocks 5+6' and 'Weekend Blocks 5+6' products for each of weeks 1 to 52 (ie 3pm to 11pm for the front two seasons) would require an increase in the obligated product list from the 13 included at present to a total of 117.

case to suggest extending coverage of the mandated products under S&P. We understand that Ofgem will continue to monitor the effects of S&P and to consider whether S&P is meeting its goals. This seems appropriate to us.

### ***Our current view on liquidity***

104. Our current view is that liquidity has been generally good near-term; reasonable for Baseload Season products fairly far down the curve, and for more granular products close to delivery; but weaker for all other products further ahead of delivery. The introduction of S&P has improved availability and spreads of the included products (at least in the mandated windows), which account for the large majority of trading, and should ensure that there are no liquidity issues in those products while S&P remains in place. We saw no evidence that S&P had improved liquidity for any products that were not covered or outside the mandated windows. An improvement for other products and times would clearly give extra flexibility in trading and would likely be of benefit to anyone active in the market. However, after comparing with gas trading patterns and looking at emerging trading data since the introduction of S&P, we did not find indications that there was substantial demand for products much further out than they were currently traded.
105. Given that the introduction of S&P does not appear to have had broader effects on liquidity – in other products or other times of day, or a substantial increase in the volume of trading – it was not obvious to us that micro-level interventions had any potential to cause a step change in the overall level of liquidity in the market. Based on parties' comments, we thought a step change in liquidity may be unlikely without attracting more financial players and a consequent injection of substantial risk capital. For some of the reasons listed in paragraph 29, it may be that electricity continues to remain a relatively unattractive market for speculative activity.

### **The relevance of liquidity to competition**

106. Our motivation for looking at liquidity is its possible effects on competition between VI firms and independent suppliers and/or generators. Our concern is that if liquidity is poor down the curve, then independent suppliers or generators may be less able to hedge their demand or output, increasing their risk or causing them to pay a premium to reduce risk. This disadvantage may in turn affect competition in retail markets or generation.
107. Another possible concern would be that if near-term liquidity were poor, independent suppliers or generators would be more exposed to cash-out than VI firms, increasing their costs and again distorting competition. However, we

do not think this is a concern in practice, because the evidence on near-term liquidity summarised above, and the lack of concern from parties, suggests that near-term liquidity is good.<sup>68</sup> Therefore, in this section we focus on effects of weaker liquidity down the curve and its effects on ability to hedge. In this work we again distinguish between liquid wholesale markets (availability of products at fair prices) and other factors (such as need or ability to post collateral).

### ***What is hedging?***

108. Energy firms face various risks related to wholesale markets. In particular, suppliers set retail prices of electricity and gas to domestic and some commercial customers in advance and must give notice to vary them, while wholesale prices of electricity and gas can vary significantly from day to day and, in the case of electricity, from half hour to half hour. Suppliers often buy some quantity of their wholesale products in advance of delivery so that wholesale costs for that quantity are known. Similarly, generators face uncertainty about the wholesale price of electricity at delivery, so often choose to sell a certain quantity in advance to have revenue certainty. This is commonly referred to as ‘hedging’.<sup>69</sup> Of course, both parties are still exposed to risk over quantity: if a supplier has hedged a certain quantity, it will still unexpectedly need to buy or sell in the near term if demand does not match its earlier estimate; and, similarly, a generator may sell or buy in the near term if it produces more or less electricity than it has sold ahead. So hedging reduces but does not remove risk.<sup>70</sup>
109. A supplier or generator may hedge by trading forward itself, or by engaging an intermediary. Intermediaries may fulfil various functions, including: carrying out trades; removing the need for its client to post collateral; and supplying its client with products that are not being traded in the market, so taking on risk itself until those products become liquid. We discuss some of the specific arrangements that independent firms have with intermediaries in more detail in a separate working paper.<sup>71</sup> Liquidity can be expected to affect all industry players: it will directly affect the ability of parties to trade directly, and it will

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<sup>68</sup> See paragraphs 42–43.

<sup>69</sup> In broader terms, a hedge is an investment position intended to offset potential losses or gains that may be incurred by a companion investment. There is more than one way to hedge a given position, and some energy firms engage in ‘indirect hedging’, where they invest in a product that is correlated to the product concerned but not directly linked. For example, an electricity supplier might invest in oil, gas, or even financial instruments linked to the weather (which drives demand). For the purposes of this paper, when we talk about hedging, we refer simply to taking contractual positions in wholesale electricity to hedge electricity supply or generation, and in wholesale gas to hedge gas supply.

<sup>70</sup> Hedging may also move risk from one category to another. A supplier who buys electricity reduces its price risk, but now faces counterparty risk of the seller going bankrupt.

<sup>71</sup> Case studies on barriers to entry and expansion in the retail supply of energy working paper.

likely affect the fees charged by intermediaries as it affects their perceived risk.

### ***How does the ability to hedge affect competition?***

110. One hypothesis we have considered is that VI suppliers have an advantage over their non-integrated competitors because they can trade internally, even when products are not available or prices are not well defined in external markets, whereas independent suppliers would not be able to do so. Therefore, VI firms could hedge earlier in volumetric terms and/or hedge shape earlier, reducing their risk and thus imposing a comparative 'risk premium' on independent suppliers. In other words, VI firms would be at an effective cost advantage over independent suppliers. A similar theory could apply with regard to VI firms having advantages over independent generators. In this part of the paper, we assess whether the limits on liquidity that we observed are likely to distort competition in this way.
111. Before describing our approach, we note two potential reasons why VI firms might not choose to trade internally:
- (a) The optimal trade for the hedged position of a supply arm is unlikely to coincide with the optimal trade for the hedged position of the generation arm. For example, baseload generation would not provide the daily shape a supply arm needs. (However, all of the Six Large Energy Firms have some non-baseload generation that is likely to share some annual and/or daily shape with retail demand. To the extent that there is common shape between the two arms, a VI firm could decide to carry out an internal transfer. This would allow it to choose when to execute the trade, meaning it would not be constrained by the liquidity of shaped products in external markets.)
  - (b) One view of retail competition is that the absolute level of costs is less important than a supplier's costs relative to its competitors. Under this view, a supplier wants to avoid being a cost outlier, and the best way to achieve this is to hedge in a similar way to its competitors. (This is clearly not the only potential strategy; a supplier may want to adopt a different approach in the hope of becoming more competitive.)<sup>72</sup>
112. It seems clear that the supply and generation arms of VI firms have the **ability** to access a greater range of products than non-integrated firms by trading internally, especially given the limited liquidity that we have found in some

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<sup>72</sup> We recognise that some firms, particularly independent suppliers, may be more inclined to take the risk of having a different hedging strategy in pursuit of growth.

products. But for the reasons outlined in the previous paragraph, their **incentive** to act on this is less clear cut. We therefore need to assess whether this ability to access a greater range of products confers on VI firms an advantage that distorts competition, or creates a barrier to entry or expansion to non-VI firms.

113. We have approached this issue by seeking to assess whether, based on product availability, independent firms have the ability to hedge in the same way as the Six Large Energy Firms actually do. For the purpose of this assessment, we have examined volume, annual shape (ie the way demand varies over the year) and daily shape (ie the way demand varies over the day). We have then broken this down into two questions:
- (a) Do independent firms currently hedge in the same way as the Six Large Energy Firms? (See paragraphs 122 to 134.)
  - (b) If not, could the Six Large Energy Firms reach their current hedged positions using their trades in externally available products? (See paragraphs 135 to 141.)
114. A positive answer to either of these questions could suggest that the current level of liquidity in GB wholesale electricity is sufficient to allow independent firms the ability to replicate the hedging strategies of VI firms. If so, that would suggest that liquidity does not distort competition, nor raise barriers to entry or expansion. By approaching the issues in this way, we are making a presumption that the Six Large Energy Firms' hedging is a desirable pattern for independents. Our view is that this is a reasonable presumption. If anything, we might expect that independent suppliers, at least, would be likely to want to hedge **less** far ahead than the Six Large Energy Firms, for example because of their customer mix.<sup>73</sup> We acknowledge two caveats here that may mean this is not the appropriate standard:
- (a) The 'natural hedge' might reduce the Six Large Energy Firms' need or desire to hedge. If so, that would mean that independent firms would require a greater degree of hedging than the Six Large Energy Firms in order to have a level playing field. To address this, we consider the Six Large Energy Firms' hedging strategies to see if the natural hedge seems to be affecting them. We also look at gas hedging, where there is a much smaller degree of vertical integration. (See paragraphs 144 to 150 below.)
  - (b) The Six Large Energy Firms all serve both domestic and non-domestic customers, and these two groups typically have different shapes of

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<sup>73</sup> See paragraph 157.

demand. This may mean that these suppliers want a different daily shape than suppliers serving only domestic or only non-domestic customers. We note that technically this is to do with scope of retail operations rather than vertical integration, but the Six Large Energy Firms all have this wide retail scope, whereas independent firms primarily focus on one group or the other.<sup>74</sup> In order to address this question, where possible we look at those of the Six Large Energy Firms that have separate hedging strategies for domestic and non-domestic customers. (See paragraphs 151 to 156 below.)

115. We also acknowledge that there may be other reasons why independents may not hedge in the same way as the Six Large Energy Firms – for example, they may not have as wide a range of trading partners, or collateral may be a constraint. We explore the trading arrangements of independent suppliers in our case studies on barriers to entry and expansion in the retail supply of energy working paper. Our goal in this paper is to assess whether liquidity (product availability) is a constraint.

### ***Our approach to assessing the effects of liquidity on competition***

#### *Methodology*

116. We gathered three and a half years of data on the hedging behaviour of a range of parties. As a metric, we looked at their actual consumption and/or output on the second Tuesday in each month, and calculated what proportion of that consumption and/or output they had hedged at particular points in advance of that date, up to three years ahead. At each specified point ahead of delivery, we then calculated the median percentage for each party. This allowed us to make comparisons between firms.
117. Some parties told us that they use more than one hedging strategy. For example, a hypothetical large VI firm with a broad generation portfolio might have different hedges for:
- domestic customers on variable tariffs;
  - domestic customers on fixed tariffs;
  - SME customers;
  - industrial and commercial customers;

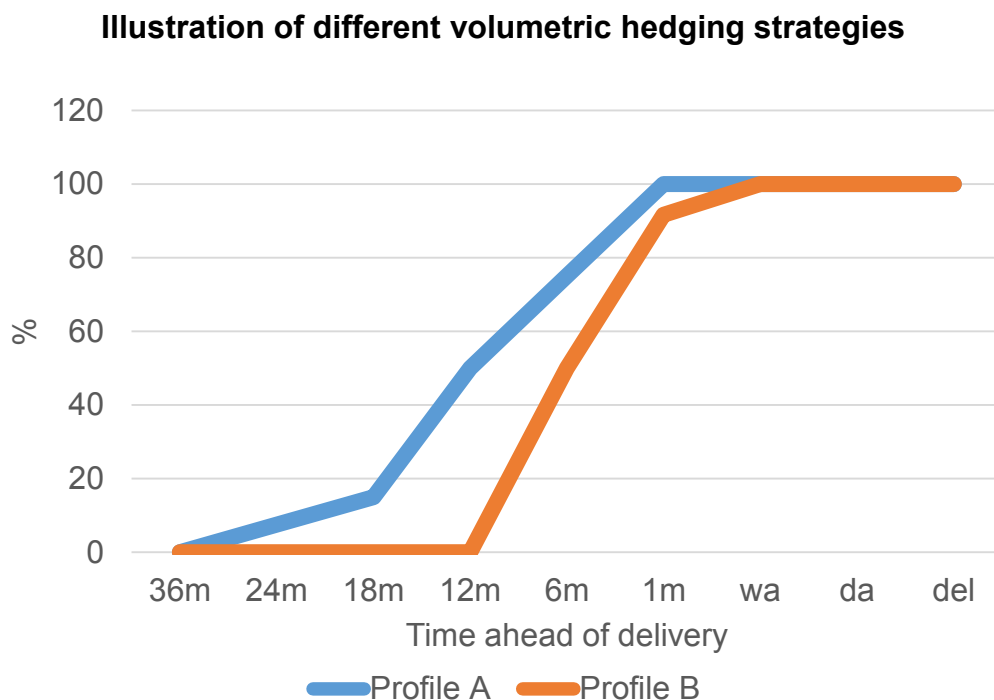
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<sup>74</sup> [✂]

- gas-powered generation;
  - coal-powered generation;
  - nuclear generation; and
  - renewable generation.
118. Some parties subdivided several of these categories further. Others took a more aggregate approach. Different hedges within a firm can be added together: for example, adding up hedged volumes for the first four hedges listed above would give an aggregate hedge for the whole supply business. Therefore, we can compare supply hedges across parties even if some parties think of them at a less aggregate level than others.
119. Ideally, we would have compared hedged volumes with forecast volumes at each point in advance. For example, if we looked at delivery on 10 January 2014, we would compare **the amount a supply firm had hedged** on 10 January 2013 for delivery on 10 January 2014 with its **forecast** dated 10 January 2013 for its demand on 10 January 2014. However, forecast volumes were not available for all parties, so we used actual volumes for consistency. By using actual volumes, a party that has grown faster than it expected will tend to appear less hedged than it was in actuality (because actual volumes tended to exceed forecasts), and vice versa. We compared the results for the two measures where possible, and took this into account in our interpretation of results.
120. We looked at both volumetric hedging and shape. Volumetric hedging simply tells us what proportion of actual volume for a settlement period has been traded in advance. Shape includes both annual shape (ie the fact that demand tends to be seasonal) and daily shape (ie the fact that demand is higher during the day, and especially during the evening, than overnight).
121. Figure 4 displays two different hedging profiles. This chart is purely illustrative; it should not be taken as representative of any party or type of party. It shows that different hedging profiles can have different lengths – profile A starts earlier than profile B. Hedging profiles can be simply linear, such as profile B, which hedges a twelfth of final demand each month from 12 months before delivery. Alternatively, a hedging profile can have inflection points where the rate of hedging changes – for example, at 18 months ahead for profile A. Although all hedging profiles should ultimately reach 100%, this can occur at different points in time. For example, profile A reaches a 100% hedge at month ahead, whereas profile B reaches this level only at week ahead. In this

chart, we can say that A is 'more hedged than' B at every point from 24 months ahead to week ahead.

FIGURE 4



Source: CMA.

Note: Profile B is not a straight line on this chart because our time axis is not to constant scale.

### *Hedging strategies of the Six Large Energy Firms*

122. We looked at overall supply hedges for the Six Large Energy Firms,<sup>75</sup> based on their entire supply businesses. We looked at volumetric measures, annual shape and daily shape.
123. We found a fairly similar volumetric pattern between these firms, especially within 18 months from delivery. All of them hedged some volume 24 months ahead. They typically hedged 15 to 30% of volume 18 months ahead of delivery, and had almost a full volumetric hedge by a month ahead of delivery.
124. We also looked at their hedged profiles in domestic supply only, where available.<sup>76</sup> There was slightly more variability on the early part of the curve, and in general firms had hedged a greater proportion of domestic demand than of overall demand up to six months ahead, but the overall picture was similar to that of the overall supply hedge.

<sup>75</sup> Excluding SSE, because it manages a single group portfolio including both generation and supply. This means that contracted volumes cannot be attributed to a particular business area.

<sup>76</sup> Scottish Power did not conduct its hedging at this less aggregated level.



### *Annual shape*

125. The data suggested that most of the Six Large Energy Firms do not hedge annual shape until within six months of delivery. Before that point they appear to hedge primarily using Seasonal products (which deliver the same output over a six-month period), rather than hedging more for those months that typically have higher demand and vice versa. Only E.ON displays a different pattern to the rest of the Six Large Energy Firms. This is because [✂].<sup>77</sup> However, E.ON's external trading pattern remains similar to those of the other Six Large Energy Firms.

### *Daily shape*

126. Most of the Six Large Energy Firms shape only in Baseload and Peak products until inside a year ahead. Some firms trade small amounts of Block products within year, but supply arms' contracted positions resemble their final demand only close to delivery (often only at day ahead). Again, E.ON displays a different pattern.

### *Generation*

127. Percentage hedges vary more between firms in generation than in supply. There was some hedging more than 36 months ahead of delivery, longer than for supply. In general, firms tended to have a larger (percentage) hedge in generation than in supply a year or more ahead of delivery; within a year, there was little systematic difference.

### *Independent suppliers' hedging strategies*

128. The independent suppliers who provided data had a more diverse range of hedging strategies. In general, independent suppliers seem to have shorter hedges than the Six Large Energy Firms. Before a year ahead, all independent firms in our data have smaller hedged percentages than the Six Large Energy Firms. By a month ahead of delivery they have caught up and, like the Six Large Energy Firms, seem to be almost fully hedged volumetrically. These descriptions apply to both the entire supply hedge and the domestic-only supply hedge.
129. Independent suppliers have grown over the period. (See descriptive statistics: retail working paper.) It is therefore possible that using final demand as a metric may underestimate the extent to which growing independent suppliers

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<sup>77</sup> [✂]

were hedged at particular points in time. Our figures may therefore present an upper bound on the difference in hedged percentages between the Six Large Energy Firms and independent suppliers.

#### *Annual shape*

130. There was a mixed picture for independent suppliers. A couple of firms displayed a similar pattern to the Six Large Energy Firms, hedging in Seasons along the curve. Another supplier did show some signs of annual shape, which may be the result of trading Monthly products up to a year ahead.

#### *Daily shape*

131. We found that some independent firms ([X]) hedge daily shape early, either through trading with counterparties or through their deals with intermediaries. Others (Utilita, OVO) do not hedge much shape until within a week from delivery.<sup>78</sup> Utilita told us that it trades only Baseload and Peak forward because ‘at least you have got some chance of knowing whether you are paying a reasonable price or not’.

#### *Independent generators’ hedging strategies*

132. We found that the independent generators we investigated had very different hedging strategies, so we could not draw wide-ranging conclusions. We noted that Drax’s hedging was within the range of the generation arms of the Six Large Energy Firms, and in fact Drax hedged more 36 months ahead than any of the Six Large Energy Firms. GDF Suez hedged a little less at each point in time than the Six Large Energy Firms, but this may partly reflect technology mix: GDF Suez’s gas-powered generation hedging was similar to the gas-powered generation hedging of the Six Large Energy Firms, although it hedged less on its coal assets.
133. Like the Six Large Energy Firms, independent generators generally seem to trade Baseload and Peak forward, although GDF Suez also hedged a small amount using Blocks six months ahead. Most firms seem not to do any shaping until inside 18 months ahead. MPF is an example of a non-baseload generator – we observed that Peak is an important product for it, and it

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<sup>78</sup> OVO trades some four-hour and two-hour Blocks in Monthly and Quarterly products but does the majority of its electricity shaping at the day-ahead stage. Utilita trades shape on a weekly basis, and this appears in the hedging data by day-ahead.

appeared to trade Peak extensively once within 18 months. Some independent generators appeared to trade predominantly or only near term.<sup>79</sup>

134. There are several possible reasons for the differences between independent generators:
- (a) Plant types: Drax and GDF Suez own coal power stations, while the other independent generators do not. In recent years coal generation has been lower cost than gas generation, so coal-based generators have been keen to hedge to lock in high 'dark spreads'; whereas, for gas-based generators, 'spark spreads' have been low and it may have been more attractive to wait and see how prices developed.<sup>80</sup>
  - (b) Drax and GDF Suez are larger than the other independent generators, which may mean that they find it easier to trade (eg through access to credit).
  - (c) Drax and GDF Suez both have non-domestic supply businesses, which could offer some opportunities to trade internally. However, GDF Suez said that its supply business is separate, and determines its own hedging strategy.<sup>81</sup> Drax also said that its supply business is separate, but said that it will trade long-term power products internally 'even if the wholesale market is illiquid'. However, in such circumstances, Drax will not exclusively consider trading internally.

#### *The Six Large Energy Firms – connection between trading and hedging*

135. We looked at the external trading activity of some of the Six Large Energy Firms and compared it with their hedging strategies. Our motivation for doing so was to see whether they could construct their hedged positions using only their external trading – both volumetrically and in shape. This would give us an insight into whether vertical integration was giving them a particular advantage in hedging, or whether we would expect an independent supplier of the same size or smaller to be able to match their supply hedging strategy (and likewise for generation) – subject to trading agreements, credit rating, collateral requirements and so on.

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<sup>79</sup> In the case of InterGen, this is partly due to the nature of its tolling agreement with Centrica for Spalding (one of InterGen's three power stations).

<sup>80</sup> In simple terms, dark spreads are effectively the margin between electricity prices and coal prices. A coal-based generator can hedge by forward contracting both its coal input and its electricity output to guarantee a margin (as long as it is able to generate the contracted output). Spark spreads are the equivalent for electricity and gas prices. See descriptive statistics: generation and trading working paper.

<sup>81</sup> GDF Suez told us that it hedges using Blocks as it owns low load-factor generation, which is better hedged through individual Block products than through Baseload or Peak.

136. First, we looked on a volumetric basis: at each point down the curve ahead of delivery, we compared the volume a firm had hedged for its supply arm with the volume it had purchased externally. We found that at each point down the curve, every firm's external trading was equivalent to a substantial percentage of its hedged volume, and in most cases the external trading exceeded the hedged volume.<sup>82</sup> This is consistent with each of them being able to support hedging externally. This did not mean that these firms **were** constructing their hedges entirely through external trading; only that they **could** do so. In other words, there appeared to be substantial volumes available to purchase in external markets at prices the Six Large Energy Firms were willing to pay. Those volumes would be many multiples of the volume requirements of an independent supplier.
137. Similarly, the volume they sold generally equalled or exceeded the hedge requirement for their generation business.
138. We then looked at annual shape. As described in paragraph 52, the majority of trading by volume is in Seasonal Baseload products, and they are traded well in advance. In contrast, trading of Monthly Baseload is generally concentrated within three months of delivery (some parties traded small amounts of Monthly Baseload beyond six months ahead), and Quarterly Baseload is traded slightly more three to six months out, but very little beyond that. There is a similar pattern for Peak Seasonal products are traded much further ahead than Monthly or Quarterly products. For Monthly Peak products, the amount of activity beyond three months ahead is very small. This timing of trading would support the hedging patterns that we saw, as described in paragraph 125.
139. Finally, we looked at daily shape. As mentioned above, there was very little shape to hedging at 12 months ahead of delivery, and that was primarily just standard Peak until there was less than a month to delivery. We looked at trading on Peak and Block products. Most of the Six Large Energy Firms seem to trade Baseload and Peak products only until close to delivery,<sup>83</sup> and

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<sup>82</sup> This analysis is necessarily approximate, with several caveats, because our hedging data is a snapshot, whereas our trading data covers the full period:

- The hedge volume requirement will be a slight overestimate. This is because the hedging data covered only Tuesdays, but weekends have lower demand.
- The hedged volume is based on the time until a particular delivery date, whereas the traded volume is categorised by the time until a product starts delivering. As the categorisation is stricter for traded volume, this will also tend to make the hedge volume requirement harder to meet.
- For the supply comparison, the traded volume is based on purchases. In reality the supply arm will sell as well as buy, but we cannot identify which trades were carried out for supply purposes. (Similarly, the generation arm will sometimes buy as well as sell.)

However, these caveats are largely conservative (ie they make the hedge volume requirement harder to meet).

<sup>83</sup> E.ON's graph is different, as it shows some shape. However, this seems to be the result of eight months (August 2011 to March 2012) of trading in its coal portfolio only.

many of them fully shape their positions only at the day-ahead stage. As described in paragraph 53, all firms carried out some trading more than a year ahead, but only two firms did so in larger volumes along the curve, and each firm traded at least 70% of its volume in Blocks within three months of delivery. This timing of trading would support the hedging patterns that we saw, as described at paragraph 126. In each case, the party started trading the relevant product at or before the time its hedge started taking on the corresponding type of daily shape.

140. Our current view is therefore that there was no evidence of these firms hedging annual or daily shape further ahead of delivery than they traded the products that would allow them to do so. Based on annual and daily shapes, we thought that five of the Six Large Energy Firms (with the exception being E.ON) would be able to construct their hedged positions until around six months ahead or less to delivery largely using the mandated products under S&P, and then supplemented with a small volume of trading in other products (such as Quarterly or Monthly Baseload) closer to delivery.<sup>84</sup>
141. Therefore, we could not see any evidence that generation arms are selling bespoke hedging products to their supply arms ahead of market availability. (The possible exception to this is E.ON, due to the way its trading arm functions. E.ON appears to transfer hedging risk to its trading arm, and it is unclear how this affects its supply arm. However, if E.ON were gaining some competitive advantage from doing so, we would expect other VI firms to have adopted the same model.)
142. This suggests that product availability was sufficient for independent firms to replicate the hedging strategies of the Six Large Energy Firms.

### ***Relevance of this test***

143. As noted above in paragraph 114, we now consider whether the ability to replicate the Six Large Energy Firms' hedging strategies through external trading is the right test in order to assess whether the current level of liquidity in GB wholesale electricity affects competition. First, we consider whether the natural hedge of VI firms means that independent firms might want to hedge

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<sup>84</sup> We also asked the Six Large Energy Firms what proportion of their hedged positions were made up of internal transfers from their generation arms. Several firms were unable to answer this, and said that it may not be meaningful to do so. Suppose that a generation arm sells 30MWh to the supply arm, and the supply arm subsequently sells 10MWh externally when prices or demand estimates change, and then buys another 20MWh externally. Even in this simple example, it is not obvious how much the supply arm's position can be said to be sourced internally. Moreover, one's view of this may change if the external trades were conducted in a different order. Our current view is that we should not be too concerned by the level of internal trading, given that the Six Large Energy Firms carry out a large volume of external trading (see paragraph 27).

earlier than VI firms. Second, we consider whether supplying both domestic and non-domestic customers affects hedging.

### *The natural hedge*

144. The so-called natural hedge refers to the fact that both generators and suppliers are exposed to movements in volatile wholesale electricity prices, but in opposite directions. Therefore, without forward contracting, a VI firm can more easily absorb shifts in upstream and downstream margins, which are partially or wholly offsetting, whereas independent suppliers and generators are exposed to the full impact of such shifts.<sup>85</sup> This might mean that a centrally managed VI firm would be indifferent to the extent to which its supply and generation arms were individually hedged at any point in time (to the extent that they offset), and concerned about only its overall hedged position. In other words, it would be indifferent between hedging both arms two years in advance and not hedging them at all (to the extent that the two arms had offsetting volume). If this were the case, then we could not rely on its pattern of hedging over time as a test.
145. We asked the Six Large Energy Firms whether their supply arm considered their generation arm when hedging, or vice versa. Most said that they do not take into account other group activities when deciding how much a particular business is hedged. However, a couple of firms mentioned overarching risk assessments.
146. We also estimated the 'implicit hedge' for the Six Large Energy Firms: we looked at the supply arm's explicitly hedged volume, and then offset uncontracted expected generation against the remaining unhedged demand. We found that the Six Large Energy Firms tended to have a substantial degree of 'total hedge' (explicitly hedged demand plus uncontracted generation) even three years ahead of delivery – at least 50% hedged at that point, and in some cases around 100%. This might mean that it would be harder for a non-integrated firm to achieve the same total hedge as a VI firm, as the former would require larger amounts of purchases along the curve.
147. Therefore, we looked at how independent supply firms and the Six Large Energy Firms' supply arms hedge their gas activities. The degree of vertical

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<sup>85</sup> Some parties put it to us that the natural hedge does not apply to vertical integration of supply with thermal generators in practice, because wholesale prices often move in line with fuel input prices and so thermal generators (a) already have an intrinsic hedge, and (b) tend to forward-contract both their fuel input costs and their output to lock in a margin; therefore, there is no further 'offset' against supply. By contrast, nuclear and renewable generators do not have the same type of input costs and so integration with a supply business does form a natural hedge. Given the results of our work in this area, we have not found it necessary to evaluate this argument.

integration is much lower in gas, so there are smaller or no natural hedges in gas than in electricity.<sup>86</sup> Therefore, we thought a comparison with gas might help us to understand how the Six Large Energy Firms would hedge electricity if they were not vertically integrated.

148. We found that VI suppliers do not generally seem to hedge further out in gas than in electricity – in terms of both volume and shape. If the natural hedge were important for firms' hedging decisions in electricity, then we might expect them to react by hedging more explicitly in gas, so as to achieve the same overall effect. This does not appear to be the case. In fact, in volume terms, the Six Large Energy Firms generally have larger hedges for electricity than for gas (with minor exceptions). As in electricity, some of the Six Large Energy Firms appear to be leaving their monthly shaping until closer to delivery.
149. Therefore, both the internal behaviour of the Six Large Energy Firms and their hedging patterns in gas support the view that vertical integration does not substantially affect their supply hedging, so the Six Large Energy Firms' supply hedging is probably a good test against which to compare independent supply hedging. We do not have a gas equivalent to generation, but again internal behaviour suggests that this is a sensible test for generation hedging.
150. We also looked at whether independent suppliers have longer hedges in gas or in electricity, and found a mixed picture. If liquidity were the key constraint preventing independent firms from trading forward in electricity, then we might expect to see independent firms hedging further ahead in gas, but this was not consistently the case.

#### *Economies of scope between domestic and non-domestic supply*

151. We compared the Six Large Energy Firms' overall supply hedging strategies with those of independent suppliers. However, it might be objected that independent suppliers are primarily active in either domestic or non-domestic supply, whereas the Six Large Energy Firms serve both groups.
152. This might affect comparability of hedges between the types of supply firms in one of two ways:

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<sup>86</sup> Four of the Six Large Energy Firms have or had some kind of upstream gas production assets in Great Britain: Centrica, E.ON, RWE npower and SSE. (RWE npower sold its upstream gas production assets in March 2013.) All of them also operate gas-powered electricity generation, and for all except Centrica, their generation requirements significantly exceeded their production in the period we investigated. (RWE npower also noted that, even prior to the sale of its upstream gas assets, their production accounted for only 8% of its total GB supply and generation requirements in 2013.) Therefore, only Centrica has an upstream position that could contribute to its retail demand, and it is still significantly 'short'. See descriptive statistics: generation and trading working paper.

- (a) Volume: if one group of customers has greater churn, or shorter fixed contracts, or is expected to reduce in size relative to the other, a firm might wish to hedge volume in relation to the former group less far ahead. In general, we expected that independent suppliers would have a greater proportion of customers on fixed-term contracts, and a smaller proportion of sticky customers, than the Six Large Energy Firms. They would therefore tend to have shorter hedging strategies than the Six Large Energy Firms. Therefore, this would not undermine the test we set out in paragraph 113.
- (b) Daily shape: domestic customers typically (at least in winter) have their highest peak demand in the evening (roughly 5pm to 10pm), whereas non-domestic demand peaks during the day (roughly 7am to 5pm). This leads to different shape for the two types of supplier. Furthermore, for the Six Large Energy Firms serving both groups, depending on the balance of customers, it may mean a single, flatter period of peak demand from roughly 7am to 9pm. Since the standard Peak product is from 7am to 7pm, the Six Large Energy Firms may find it easier to hedge using Peak products than independent domestic suppliers do.<sup>87</sup>
153. We investigated the latter by looking at internal hedging strategies and by comparing the Six Large Energy Firms' domestic-only shape with those of independent domestic suppliers.
154. Four of the Six Large Energy Firms maintained hedging data on domestic-only supply (and three of them on a more granular level), and one of the others managed a net position with generation and supply combined; only Scottish Power hedged its entire supply position together. We understand that energy firms often try to hedge large non-domestic customers when a contract is signed, which would limit the ability to hedge all customers together. This all suggests that these firms set their domestic supply hedges separately from their non-domestic supply hedges.
155. As noted above, we also looked at the Six Large Energy Firms' domestic-only supply hedged position and compared that with (a) their overall supply hedged position and (b) independent suppliers' hedged positions. Our observations were not substantively affected.
156. We cannot rule out the possibility that, in practice, the Six Large Energy Firms benefit from economies of scope (ie that their trading arms may be carrying out hedging instructions for both domestic and non-domestic customers, and therefore it happens that they can more easily purchase both together as

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<sup>87</sup> We did not expect that there would be such a pronounced difference in annual shape.



closer to standard Peak products). But on the basis of the above considerations, we do not think this affects the test we have performed.

### *Reasons for the differences in hedging strategies*

157. We have found that the Six Large Energy Firms' trading and hedging patterns differed from those of independents: supply arms in particular hedged further ahead than independent suppliers. There are several possible reasons for this. One is product availability; but our analysis suggests that this is not a substantial issue. A second is collateral and credit, where the Six Large Energy Firms may have an advantage (we are continuing to explore this area). A third is that different firms simply have different commercial strategies. For example, most independent suppliers' customer bases are dominated by customers on fixed-term tariffs, whereas the majority of customers of the Six Large Energy Firms are on open-ended variable tariffs. One effect of this may be to incentivise independent suppliers to seek to hedge over the term of the contract, while the Six Large Energy Firms pursue a longer-term hedging strategy since they expect to retain a broadly similar size of customer base for periods longer than most fixed-term contracts.

### **Our current views on the effects of the level of liquidity on competition**

158. We found that the degree of liquidity varied between products. In particular, we found that near-term liquidity was good; that, historically, liquidity was reasonable for Baseload Seasonal products fairly far down the curve, and for more granular products close to delivery; but that there was relatively little trading of other products further ahead of delivery. However, the introduction of S&P improved availability of the products it covers, even if it has not led to clear improvements in other indicators of liquidity. We did not find indications that there was substantial demand for products much further out than they were currently traded. Based on parties' comments, we thought that liquidity in many products could be improved; but it was not obvious how this could happen without the injection of substantial risk capital.
159. We found that the Six Large Energy Firms' trading and hedging patterns differed from those of independents. We did not find evidence that product availability was likely to be causing this. The Six Large Energy Firms generally conducted their hedging strategies using products that were available and traded; there was no indication that they were gaining an advantage by systematically using internal trades of products that were not available to other, non-integrated (or less integrated) parties. We also found that they did not hedge further ahead in gas than in electricity, which we would expect to

be the case if vertical integration were distorting their hedging strategies in electricity, or if liquidity in electricity were a serious constraint on their trading.

160. If product availability is not the cause of this difference between the Six Large Energy Firms and independents, it may be that the main causes are either other factors (such as collateral and credit) or simply different commercial strategies. Neither of these implies any competitive harm arising from the state of liquidity. Therefore, we did not find evidence to suggest that liquidity was causing competitive distortions.