Appendix 7.1: Liquidity

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Introduction

1. In this appendix 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. Some of our detailed analysis is presented in an annex, and summarised in the main body of this appendix.

2. Our primary concern about the level of liquidity is whether it is sufficiently low that 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);[1] 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.

3. In this appendix, 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.

4. 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 vertically integrated 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.

[1] See paragraph 102 for a full discussion of our use of the word 'hedging' in this report.

Background

5. In this appendix we first define what we mean by liquidity. We then describe how wholesale electricity and gas are traded in GB markets). After that, 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.

6. We then give a brief overview of recent regulatory investigations and interventions into electricity liquidity, notably Ofgem's recent introduction of Secure and Promote (S&P) licence conditions). We then summarise parties' views on liquidity. Finally, in this section, we explain why near-term liquidity is not a focus of our investigation.

What is liquidity?

7. 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.

8. 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.[2]

9. For the purposes of this appendix, 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 trade, 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, parties will 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 later to sell back to (or buy back from) the market at a similar price, unless new information has justifiably caused prices to change.

10. We do not include in our definition or analysis in this appendix factors that may vary from party to party – for example, posting collateral on trades, where the amount of collateral will depend on (among other factors) the party's credit

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[2] Ofgem (June 2009), *Liquidity in the GB wholesale energy markets*, paragraphs 1.8 & 1.9.

rating; or the amount a party can trade with any particular counterparty. We do not look at transaction costs under the heading of liquidity.[3] Therefore, our definition is narrower than Ofgem's.

11. 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).

12. This means that a single product (eg 10 MW 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.

13. 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).

[3] 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?

14. Parties have several choices about how to trade wholesale electricity and gas products. The two main routes for trading electricity and gas futures[4] 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[5] using a screen-based system provided by Trayport. Trading is continuous through 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.[6]

    (b) N2EX and APX are the main exchanges where electricity is traded, and contracts on these exchanges are short term.[7] 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.

15. There are also some direct bilateral trades and long-term contracts between parties that are not visible to the market. Vertically integrated 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.[8]

16. The Electricity Supply Board (ESB, a generator operating in GB and the Republic of Ireland) submitted analysis of publicly visible electricity 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.[9]

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[4] 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.
[5] Until recently there were four; now there are five. More brokers are active in gas.
[6] 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.
[7] 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.
[8] We discussed some of the specific arrangements that independent firms have with intermediaries further in our case studies on Retail barriers to entry and expansion.
[9] This excludes cash-out, which represents a small proportion of most firms' volumes.

17. Some suggestions have been made that the wholesale energy markets lack transparency.[10] 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.[11] 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.

18. Vertically integrated 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 vertically integrated firms also trade generation capacity rather than volume, or transfer between 'books'. This might be a concern if vertically integrated firms conducted little external trading, but all of them externally trade multiples of their output and demand;[12] this should be sufficient for them to play a role in price formation.

19. 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

20. The trading of wholesale gas in GB 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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[10] For example, Which? (July 2013), *The imbalance of power: wholesale costs and retail prices,* p28.

[11] 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.

[12] 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.[13] 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.[14] 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.[15]

(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 vertically integrated firms trade internally, a certain amount of liquidity may be 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.[16] In contrast, gas is not affected by this. Therefore, financial activity

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[13] See Section 4: Nature of wholesale competition.
[14] E.ON told us that 'many companies across Europe trade NBP as a proxy for their own needs'.
[15] ACER (January 2015) *European gas target model review and update*, Figure 3.
[16] 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.[17] More generally, it has been suggested that the gas market has benefited from greater regulatory and policy stability. In addition, Ofgem said that the perceived and actual regulatory risk stemming from the various strands of European financial legislation (such as MiFID II) also discouraged financial players.

(f) Ofgem also said that the returns available in a market that lacked price volatility were perceived to be low. It said it had been told that, in a period in which financial players had constrained risk capital, GB electricity trading was unlikely to be a high priority.

21. 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

22. Ofgem and the DECC have previously assessed liquidity in GB. 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 market and raised concerns about the functioning of the market itself. Ofgem decided that action was needed to address these concerns.[18] In 2009 it published a discussion paper[19] that found that liquidity in electricity in GB 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 GB electricity, and outlined possible policy options that could improve liquidity.

23. As part of this process, Ofgem developed three liquidity objectives:[20]

(a) improved availability of products to support hedging;

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[17] For example, SSE said: 'The Carbon Price Floor 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?'
[18] Ofgem (October 2008), *Energy supply probe: initial findings report*, paragraph 1.34.
[19] Ofgem (June 2009), *Liquidity in the GB wholesale energy markets*.
[20] Ofgem (22 February 2012), *Retail market review: intervention to enhance liquidity in the GB power market*, Figure 3.

(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).

24. 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.[21] After further reports and consultations, Ofgem introduced the S&P licence conditions,[22] which came into effect on 31 March 2014.

25. 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[23] to consider applications for trading agreements from smaller suppliers (defined by size) within specified time frames.[24]

(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.

26. Ofgem published the Wholesale power market liquidity: Annual report 2015 in September 2015.[25] Ofgem set out that:

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[21] Ofgem (12 June 2013), *Wholesale power market liquidity: final proposals for a 'Secure and Promote' licence condition*, Figure 1.
[22] Generation Special Licence Conditions AA.
[23] The Six Large Energy Firms plus Drax and ENGIE.
[24] 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.

[25] Ofgem (9 September 2015), *Wholesale power market liquidity: Annual report 2015*.

Our analysis shows that liquidity has improved in the first year since Secure and Promote was introduced, but has declined in the most recent quarter. We now have five quarters worth of data, but it remains difficult to isolate the effect of our reforms given the many factors that affect liquidity as well as the limited data set we hold.

We saw more trading and improved access to products in the first year of our reforms. Trends such as relatively higher churn (the number of times a unit of electricity is traded before delivery) and falling bid-offer spreads (the difference between the buy and sell price for a product) indicated that liquidity was improving.

Qualitative feedback has supported this data. Stakeholders have generally 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.

This notwithstanding, we have seen a fall in trading and churn in the most recent second quarter 2015. Many factors have contributed to the more volatile price environment seen in 2014 and into the start of 2015. Similarly, the reverse in trend in Q2 2015 reflects a low price, low volatility market. While this may have contributed to the more recent trends we have observed, it is not possible to determine the impact of the individual factors on liquidity and we continue to monitor the effect of our reforms.[26]

27. Based on feedback from stakeholders, Ofgem reported that independent suppliers were finding it easier to access products under the Supplier Market Access rules.[27] Ofgem noted that independent suppliers were still finding credit and collateral to be an issue.[28]

28. We make some observations on the effects of S&P below (from paragraph 76), 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.

[26] Ofgem (9 September 2015), *Wholesale power market liquidity: Annual report 2015*, pp5 & 6.
[27] Ofgem (9 September 2015), *Wholesale power market liquidity: Annual report 2015*, p6.
[28] Ofgem (9 September 2015), *Wholesale power market liquidity: Annual report 2015*, p6.

Parties' views on liquidity

29. We give parties' views on liquidity in detail in the Annex, and summarise them here.

30. 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.

31. 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 ([✄], First Utility, [✄], Ecotricity). At least one (First Utility) also told us that it placed vertically integrated 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.

32. 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.

33. 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.

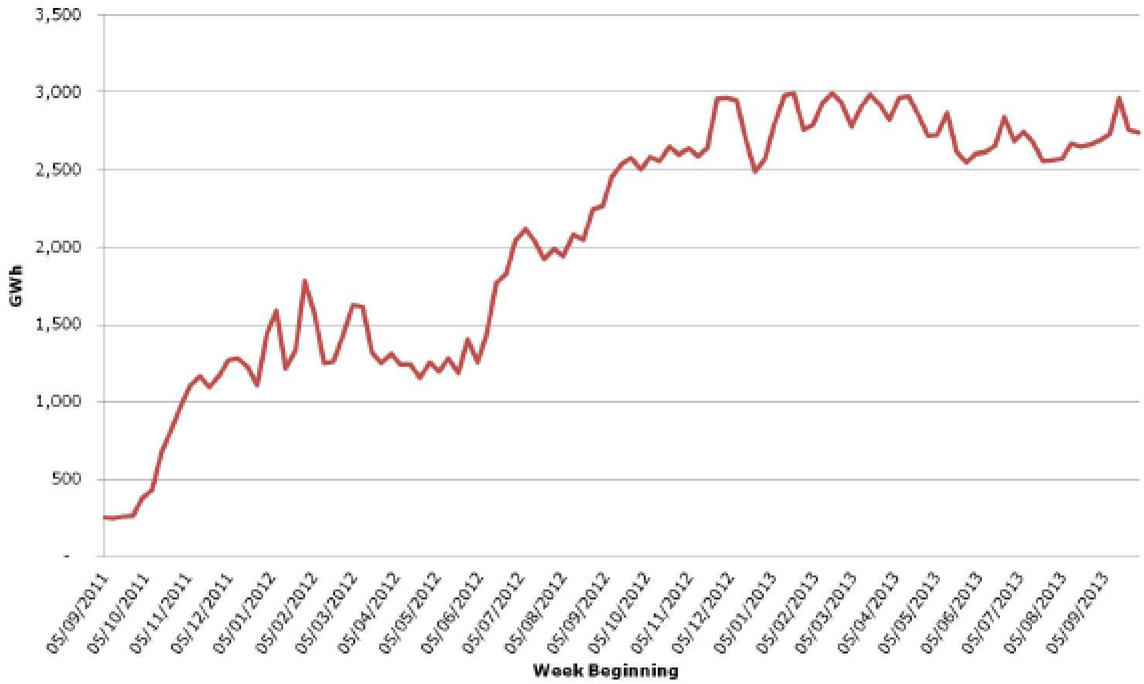
Near-term liquidity

34. 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[29] 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

[29] Ofgem (July 2012), *Retail market review: GB wholesale market liquidity update* (letter to stakeholders).

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).

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).

35. 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 assessment of liquidity

36. 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;[30]

(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); and

(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.

37. 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).

38. We present detailed results of our analysis in the Annex, and summarise them below. First, we look at the volume of actual trading of particular firms for which we had good data. We also compare this with gas data, since we think the results are instructive. Second, we briefly summarise findings on churn. Third, we look at the availability of products to be traded via brokers (spreads and depth). Fourth, we look at the effects of S&P in its first months of operation. We then set out our analysis of the state of liquidity in wholesale electricity.

Volume of trading

39. We asked a number of suppliers and generators (including vertically integrated 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

[30] 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.

purposes of analysis in 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

Category	*Product types*	*What does this provide?*	*Applies to gas?*
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

40. This data does not cover the entire market, and does not include internal trades for vertically integrated firms, but we believe we have sufficient coverage to give us a good view of trading behaviour.[31]

41. Over the period for which we received data, 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). The lowest trading multiple was [✂], 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)

	Centrica	*E.ON*	*EDF Energy*	*RWE*	*Scottish Power*	*SSE*
Average annual traded volume (TWh)	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Average size of physical business (TWh)	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Trading multiple	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: Physical volumes from Ofgem segmental statements; parties' trading data; CMA analysis.
Notes:
1. Annual average traded volume is based on all trades delivering in the period January 2011 to July 2014. Sleeve trades have been removed where possible.
2. Average size of physical business is based on Ofgem segmental statements for 2011–2013. 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.

42. 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 [✂] per year over three years ahead of delivery. This is only [✂] of Centrica's external

[31] Our data covers the following parties: Centrica, E.ON, EDF Energy, RWE, Scottish Power, SSE, Co-op Energy, Ecotricity, First Utility, OVO Energy, Utilita, DONG Energy, Drax, ESB, ENGIE and MPF.

trading, but, for comparison with the needs of an independent supplier, [✄] consumption was [✄] 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.

43. The independent suppliers for which 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.

44. 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.

45. We then looked at daily shape. Having already looked at Peak products, we turned our attention to Block products.[32] 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.

46. 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 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.[33] 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

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[32] 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.

[33] 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.

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 Energy, Ecotricity, First Utility, OVO Energy, Utilita, DONG Energy, Drax, ESB, ENGIE, MPF).
*Blocks include all combinations of standard Blocks, apart from standard Peak products.

47. 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

48. 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).

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

50. 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

	Seasons	*Quarters*	*Months*	*Other*	*Total (sum of columns)*
					%
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 rows)	49.4	9.1	29.4	12.0	100.0

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

51. Table 4 shows the split of aggregate gas volumes traded by the companies in our data (analogous to Table 3's electricity volumes).[34] Compared with 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.[35] 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.

Churn

52. In March 2014, Ofgem[36] 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.[37] However,

[34] 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.
[35] 4.2% is the sum of the Quarters, Months and Others for the top three rows.
[36] Ofgem (March 2014) *State of the market assessment*, Figure 39.
[37] Ofgem (March 2014) *State of the market assessment*, paragraph 5.27.

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.[38] Therefore, international comparisons do not give a clear benchmark.[39]

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).

53. Ofgem's latest figures suggest that GB churn was just over 3 in June 2015.[40] 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 37), 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.

[38] ACER (March 2014), *Report on the influence of existing bidding zones on electricity markets*. We note that the churn figure reported for GB in this report is significantly lower than Ofgem's estimates, suggesting that there may be some methodological issues.
[39] 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).
[40] Ofgem (9 September 2015), *Wholesale power market liquidity: Annual report 2015*, p6 Figure 2. We discuss this further when looking at effects of S&P, below.

Availability, spreads and depth

54. 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.

55. We obtained data on 'bids' and 'asks' in the OTC marketplace from the four brokers active in the market in that period.[41] 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.[42]

56. 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 75).

57. 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 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,[43] 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.

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[41] GFI, ICAP, Marex Spectron and Tullett Prebon. A fifth broker has also become active in this area, but not during the period we investigated.
[42] 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.
[43] Subject to the effort and risk involved for traders in posting and monitoring prices.

58. 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 112 to 155).

Availability to trade

59. We looked at how often a particular product was available for trade in both directions, buy and sell.[44] Table 5, below, shows the proportion of dates in our sample when each listed product was available in some quantity. Cells marked 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)

%

		Time ahead of delivery (Season, Quarter, Month, respectively)							
		+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.

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

61. 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

[44] In practice, we found that it was rare for a product to be available to buy but not to sell, or vice versa.

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.

62. 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.

63. 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.)

64. 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.

65. 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

66. We considered how the availability results varied when we increased product depth. One common clip size is 10 MW, and at that depth we generally found that the same range of products was available. However, if we increased clip size to 50 MW, 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 (50 MW)

%

		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.

67. 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.[45] We repeat the caveat that industry participants do not need all products to be available at all times.

Spread sizes

68. 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 +4 have generally been below 1% in the last two years. Spreads for Season

[45] We discuss the observed effects of S&P in more detail in paragraphs 76-97.

+5 have been above 2% on a number of occasions, and where further Seasons have been available, spreads are generally wider still.

69. 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.

70. 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%).

71. We present a summary of relevant results in the Annex. We looked at how often a product had a spread of 1% or less,[46] 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),[47] 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.

72. 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.

73. The average spread for any given depth can rise considerably as we look for further depth.

[46] 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.

[47] When market making, the licensee must maintain a spread between their bid and offer price narrower than:

Baseload		*Peak*	
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

74. 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. See the Annex for more detail.

Market close data

75. 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.[48] 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

76. In this section we assess the effects of S&P, with the caveat that it came into effect relatively 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

[48] 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 GB 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*.

the new system, and less trading generally takes place in the summer (the season for which we had data) than in the winter.

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

Ofgem's views

78. As noted in paragraph 26, 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, particularly in the afternoon, and have stayed broadly static between the windows'.[49]

79. Ofgem also reported that: 'The near-term market remains liquid since Secure and Promote. Exchange trading volumes are comparable year-on-year. Day-ahead exchange trading has remained comparable year-on-year and intraday trading is on a slight upward trend since Secure and Promote.' [50]

Parties' views

80. Ofgem reported that 'stakeholders have been fairly positive about the market-making reforms',[51] and that there was 'cautious optimism' about the Supplier Market Access Rules.[52] It said that its stakeholder responses showed:

(a) that 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);[53] 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

[49] Ofgem (9 September 2015), *Wholesale power market liquidity: Annual report 2015*, paragraph 1.17.
[50] Ofgem (9 September 2015), *Wholesale power market liquidity: Annual report 2015*, paragraph 2.31.
[51] Ofgem (9 September 2015), *Wholesale power market liquidity: Annual report 2015*, paragraph 2.18.
[52] Ofgem (9 September 2015), *Wholesale power market liquidity: Annual report 2015*, paragraph 2.6.
[53] Ofgem (9 September 2015), *Wholesale power market liquidity: Annual report 2015*, paragraph 2.4.

be more financial players trading in the market to see a real improvement in liquidity.[54]

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

82. 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 also received submissions in response to our updated issues statement and working paper. Respondents had mixed views, which we describe in more detail in the Annex. 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.

83. We also asked a range of companies that trade in the wholesale electricity market 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.

84. 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.

[54] Ofgem (9 September 2015), *Wholesale power market liquidity: Annual report 2015*, paragraphs 2.18 & 2.19.

Data and analysis

85. The increase in electricity traded volumes in 2014 seems clear. According to data from the London Energy Brokers' Association,[55] OTC GB electricity volumes rose 26% in 2014 compared to the previous year. In contrast, volumes across other European electricity markets fell 6%, while volumes on the NBP gas market rose only 2%.[56]

86. We looked at the effects of S&P in our data on product availability from brokers. The full relevant analysis is in the Annex, and is summarised above in paragraphs 59 to 74.

87. 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.

88. 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 assessment of the effects of Secure and Promote

89. Based on the data we have collected, parties' comments and Ofgem's wholesale power market liquidity annual report,[57] 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.

90. 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

[55] London Energy Brokers' Association (December 2014), *OTC energy volume report*.
[56] However, volumes across other European gas markets rose 43%, meaning that GB electricity was not the best-performing market.
[57] Ofgem (9 September 2015), *Wholesale power market liquidity: Annual report 2015*.

they can trade a set of products that accounts for the majority of trading,[58] 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 expectations in the rest of the day, even if products are not widely traded outside the windows.

91. In particular, we think that the Market Making obligation is likely to be of benefit to smaller suppliers and generators by giving them certainty over the availability of mandated products every day and absolute transparency over market prices for those products.

92. However, the changes caused by S&P 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 (although we have no evidence to suggest that S&P has made the market less attractive to them; it may well have made little difference to this type of player). 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.

93. 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 in the availability of other products and times would be consistent with LE’s econometric study.

94. 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

[58] As we explain below, these products seem to be broadly sufficient to carry out common hedging strategies.

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,[59] which would substantially increase compliance costs and risks for obligated parties.

95. 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. The fragmentation of electricity into so many wholesale products means it is inevitable that there will be some products that parties wish to trade but have limited availability. Therefore, we do not currently see a compelling 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.

96. We also received some comments from mandated generators who said that the obligation to have the mandated products available to trade 100% of the time during the windows was onerous. For example, RWE said that it would support longer windows with a less strict requirement. We think this is again something for Ofgem to consider as it reviews the operation of S&P.

97. Our assessment of the effects of liquidity on competition (presented in Section 7) do not rely on S&P; they are based on our analysis of data over a period of several years, whereas S&P was only introduced a few months from

[59] 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.

the end of the period we analysed. Therefore, it appears that the changes caused by S&P are likely to be beneficial to the majority of market participants and may contribute to competition in generation and supply, but S&P is not necessary for competition.

Our assessment of liquidity

98. Liquidity appears to have 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.

99. 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 20, it may be that electricity continues to remain a relatively unattractive market for speculative activity.

The relevance of liquidity to competition

100. Our motivation for looking at liquidity is its possible effects on competition between vertically integrated 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.

101. Another possible concern would be that if near-term liquidity were poor, independent suppliers or generators would be more exposed to cash-out than

vertically integrated 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.[60] 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?

102. 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'.[61] 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.[62]

103. 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 discussed some of the specific arrangements that independent firms have with intermediaries in more detail in a working paper.[63] Liquidity can be expected to affect all industry players: it

[60] See paragraphs 34 and 35.
[61] 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.
[62] 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.
[63] Retail barriers to entry and expansion working paper.

will directly affect the ability of parties to trade directly, and it will likely affect the fees charged by intermediaries as it affects their perceived risk.

How does the ability to hedge affect competition?

104. One hypothesis we have considered is that vertically integrated 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, vertically integrated suppliers could hedge earlier in volumetric or shape terms, reducing their risk and thus imposing a comparative 'risk premium' on independent suppliers. In other words, vertically integrated suppliers would be at an effective cost advantage over independent suppliers. A similar theory could apply with regard to vertically integrated 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.

105. Before describing our approach, we note two potential reasons why vertically integrated 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 vertically integrated 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.)[64]

106. It seems clear that the supply and generation arms of vertically integrated firms have the **ability** to access a greater range of products than non-

[64] 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.

integrated firms by trading internally, especially given the limited liquidity that we have found in some 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 vertically integrated firms an advantage that distorts competition, or creates a barrier to entry or expansion to non-vertically integrated firms.

107. 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 118 to 130.)

(b) If not, could the Six Large Energy Firms reach their current hedged positions using their trades in externally available products? (See paragraphs 131 to 138.)

108. 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 vertically integrated firms. If so, that would suggest that liquidity does not distort competition, nor raise barriers to entry and 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.[65] 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.[66] 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

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[65] See paragraph 155.
[66] We discuss the natural hedge at more length in Section 7: Vertical Integration.

smaller degree of vertical integration. (See paragraphs 1400 to 1488 below.)

(b) The Six Large Energy Firms all serve both domestic and non-domestic customers, and these two groups typically have different shapes of 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.[67] 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 14949 to 1544 below.)

109. 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. Our goal in this appendix is to assess whether liquidity (product availability) is a constraint.

110. First Utility submitted that we had set the wrong standard. It said:

> The question regarding liquidity is not whether independent suppliers and generators are able to hedge and trade in the same way as the [Six Large Energy Firms], but whether these non-vertically integrated market players can sell and buy electricity **as they require** in order to offer fair and stable prices to consumers.[68]

111. We did not think that this is a measurable standard. Liquidity is not binary. We agree with a proposition that, as liquidity improves, suppliers can reduce (but not eliminate) risk around their costs; and, depending on their attitude to risk and pricing strategy, this may lead to lower prices. However, in our analysis below, we assessed whether the basic requirements for liquidity were being met. It seemed to us that the standard First Utility was actually using was being able to sell and buy electricity **as they desire**. Traders always prefer more liquidity to less. The problems for traders in GB electricity are that *(a)* products are highly fragmented, meaning it is unlikely that all products

[67] [✂] supply small volumes to non-domestic customers.
[68] First Utility response to updated issues statement, paragraph 3.5 (emphasis in original).

would have good liquidity; and *(b)* trading requires willing sellers and willing buyers, but generators have different incentives from suppliers in terms of the timing and nature of products they wish to trade. We have tried to assess a realistic standard, and our view is that the hedging behaviour of firms that are not constrained by liquidity in the external market (because they can trade internally) is in principle a good guide to that, subject to the two caveats above.

Our approach to assessing the effects of liquidity on competition

Methodology

112. 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.

113. Some parties told us that they use more than one hedging strategy. For example, a hypothetical large vertically integrated 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;
- gas-powered generation;
- coal-powered generation;
- nuclear generation; and
- renewable generation.

114. 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.

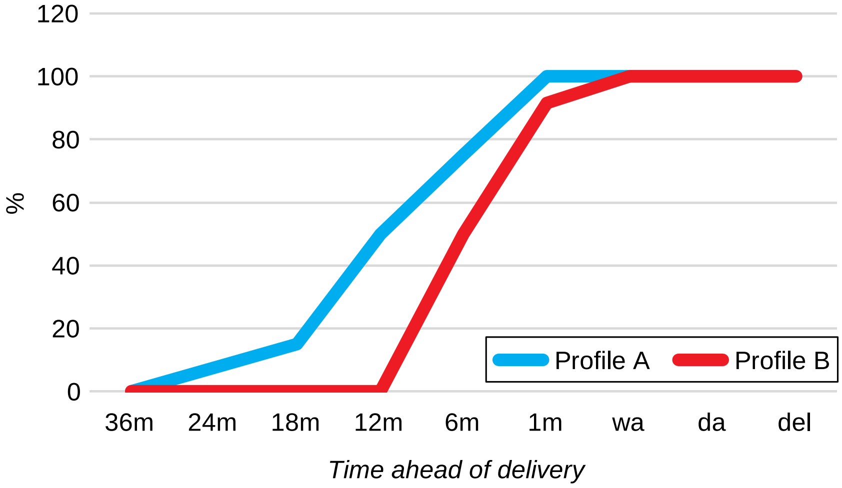
Therefore, we can compare supply hedges across parties even if some parties think of them at a less aggregate level than others.

115. 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 like to 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.

116. 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).

117. Figure 3 displays two different hedging profiles. This chart is purely illustrative; it does not depict any individual 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 3: Illustration of different volumetric hedging strategies



Source: CMA.
Note: Profile B is not a straight line on this chart because our time axis does not have a linear scale.

Hedging strategies of the Six Large Energy Firms

118. We looked at overall supply hedges for the Six Large Energy Firms,[69] based on their entire supply businesses. We looked at volumetric measures, annual shape and daily shape.

119. 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.

120. We also looked at their hedged profiles in domestic supply only, where available.[70] 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.

Annual shape

121. 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 [✂].[71]

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[69] Excluding SSE, because [✂].
[70] [✂] did not conduct its hedging at this less aggregated level.
[71] [✂]. See the Annex for a discussion of the possible effects of this.

However, E.ON’s external trading pattern remains similar to those of the other Six Large Energy Firms.

Daily shape

122. 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

123. 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

124. 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.

125. Independent suppliers have grown over the period (see Section 8). It is therefore possible that using final demand as a metric may underestimate the extent to which growing independent suppliers 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

126. 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

127. We found that some independent firms ([✂], [✂], [✂], [✂]) hedge daily shape early, either through trading with counterparties or through their deals with intermediaries. Others (Utilita, OVO Energy) do not hedge much shape until within a week from delivery.[72] 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

128. 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. ENGIE hedged a little less at each point in time than the Six Large Energy Firms, but this may partly reflect technology mix: ENGIE’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.

129. Like the Six Large Energy Firms, independent generators generally seem to trade Baseload and Peak forward, although ENGIE 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 appeared to trade Peak extensively once within 18 months. Some independent generators appeared to trade predominantly or only near term.[73]

130. There are several possible reasons for the differences between independent generators:

   (a) Plant types: Drax and ENGIE 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

[72] OVO Energy 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.
[73] 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).

generators, 'spark spreads' have been low and it may have been more attractive to wait and see how prices developed.[74]

(b) Drax and ENGIE 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 ENGIE both have non-domestic supply businesses, which could offer some opportunities to trade internally. However, ENGIE said that its supply business is separate, and determines its own hedging strategy.[75] 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'.

The Six Large Energy Firms – connection between trading and hedging

131. 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.

132. 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.[76] This is consistent with each of them being able to support

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[74] 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.

[75] ENGIE 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.

[76] 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).

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.

133. Similarly, the volume they sold generally equalled or exceeded the hedge requirement for their generation business.

134. We then looked at annual shape. As described in paragraph 443, 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 121.

135. 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 only Baseload and Peak products until close to delivery,[77] and many of them fully shape their positions only at the day-ahead stage. As described in paragraph 455, 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 122. 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.

136. Therefore, it appears that there is no evidence of these firms hedging annual or daily shape further ahead of delivery than they trade 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

[77] 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.

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.[78]

137. 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 vertically integrated firms to have adopted the same model.)

138. 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

139. As noted above in paragraph 108, 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 vertically integrated firms means that independent firms might want to hedge earlier than vertically integrated firms. Second, we consider whether supplying both domestic and non-domestic customers affects hedging.

The natural hedge

140. 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 vertically integrated 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. This might mean that a centrally managed vertically integrated firm would be indifferent to the extent to which its supply and generation arms were

[78] 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 30 MWh to the supply arm, and the supply arm subsequently sells 10 MWh externally when prices or demand estimates change, and then buys another 20 MWh 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 18).

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.

141. We considered this issue in our discussion of the effects of vertical integration.[79] We explained that in our view, although vertical integration reduced risk for the integrated business as a whole, it was unlikely that it would significantly affect the incentives of the supply arm or the generation arm to hedge.

142. 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 (see the Annex).

143. To get a sense of the extent to which vertical integration might reduce risk, we 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' for their supply activities (explicitly hedged demand plus uncontracted generation on a volumetric basis) even three years ahead of delivery – at least 50% hedged at that point, and in some cases around 100%.[80,81] This might mean that it would be harder for a non-integrated firm to achieve the same total hedge as a vertically integrated firm, as the former would require larger amounts of purchases along the curve.

144. Therefore, we looked at how independent supply firms and the Six Large Energy Firms' supply arms hedge their gas activities. The degree of vertical integration is much lower in gas, so there are smaller natural hedges in gas than in electricity (or none at all).[82] Therefore, we thought a comparison with

[79] See Section 7: Vertical integration.
[80] See the Annex (the section 'Effects of Vertical Integration').
[81] However, we did not take into account other factors which might reduce the 'implicit hedge', such as the extent to which input costs for generation were hedged (as discussed in our assessment of the effects of vertical integration). Given our findings, we did not find it necessary to refine our analysis in this way.
[82] Four of the Six Large Energy Firms have or had some kind of upstream gas production assets in GB: Centrica, E.ON, RWE and SSE (RWE sold its upstream gas production assets in March 2015). 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 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 Section 4: Nature of wholesale competition.

gas might help us to understand how the Six Large Energy Firms would hedge electricity if they were not vertically integrated.

145. We found that vertically integrated 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 hedge 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. This is despite the fact that product availability in gas appears superior to electricity.

146. 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.

147. The corollary of this is that if there were no vertical integration, we have no good reason to think that there would be greater availability of the type of products where we have found low liquidity. The level of overall trading (churn) might be higher,[83] but we would expect the majority of trading down the curve to be in the form of the small number of products (mainly Baseload Seasons) that are currently widely traded.

148. 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

149. 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.

[83] Although this is not certain, given that we have found that all of the Six Large Energy Firms trade multiples of their consumption.

150. This might affect comparability of hedges between the types of supply firms in one of two ways:

(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 107.

(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.[84]

151. 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.

152. 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 [✂] 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.

153. 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.

[84] We did not expect that there would be such a pronounced difference in annual shape.

154. 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 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

155. 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. 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.

Summary of the effects of the level of liquidity on competition

156. We found that the degree of liquidity varied between products. In particular, we consider 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.

157. 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 was distorting their hedging strategies in electricity, or if liquidity in electricity were a serious constraint on their trading.

158. 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.

Annex to Appendix 7.1: Liquidity

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Annex contents

1. This annex to Appendix 7.1: Liquidity has three sections:

   (a) Parties' views on liquidity.

   (b) Trading data.

   (c) Hedging analysis.

Parties' views and internal documents

Views on electricity liquidity: the Six Large Energy Firms

Centrica

2. Centrica said 'we do not believe that liquidity acts as a barrier to entry in either retail or generation'.[1] Centrica told us that it had not faced problems hedging in the electricity market,[2] though it said that 'there is room for improvement'.[3] Centrica also said that 'gas and power contracts are typically only traded at Seasonal granularity several years ahead of delivery'.

3. [✂].

4. Centrica did not offer further comments on liquidity in its response to provisional findings.[4]

[1] Centrica, Response to issues statement, p3.
[2] Centrica, Response to issues statement, p26.
[3] Centrica, Response to issues statement, p27.
[4] Centrica, Response to provisional findings.

E.ON

5. E.ON said that ‘liquidity is sufficient and does not create a barrier to entry’.[5] E.ON told us that its business relies on liquidity and that its structure demonstrates its confidence in market liquidity.[6] E.ON also questioned the extent to which market prices are required as a guide to action for generation investment.[7]

6. [✂].

7. E.ON welcomed the CMA’s finding that the levels of liquidity in the wholesale market is unlikely to have a detrimental impact on competition for independent suppliers and generators in its response to Provisional Findings. In addition, E.ON highlighted the potential impact on future liquidity that may result from some of the CMA’s proposed remedies. We have considered these points in finalising our remedies.[8]

EDF Energy

8. EDF Energy told us that wholesale market liquidity was ‘adequate for industry participants’.[9] It said that it had not experienced difficulty due to liquidity problems up to three years ahead.[10] EDF Energy said that it offered a four-year product in the small- and medium-sized enterprise (SME) market, which was beyond liquidity availability. [✂].

9. [✂].

10. [✂].

11. EDF Energy did not offer further comments on liquidity in its response to provisional findings.[11]

RWE

12. An internal document from April 2013 said that an advantage of changing hedging strategy was to: ‘Avoid liquidity constraints: [✂]. RWE told us, however, that it considered that there was sufficient liquidity.

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[5] E.ON, Response to issues statement, p3.
[6] E.ON, Response to issues statement, p11.
[7] E.ON, Response to issues statement, p17.
[8] E.ON, Response to provisional findings.
[9] EDF Energy, Response to issues statement, p5.
[10] EDF Energy, Response to issues statement, p20.
[11] EDF Energy, Response to provisional findings.

13. Another RWE internal document from 2011 referred to shape, saying [✄].

14. RWE did not offer further comments on liquidity in its response to provisional findings.[12]

Scottish Power

15. Scottish Power said that 'there are only limited products available in the market, mainly Peak and Baseload, in the longer term periods allowing only a very basic matching to the anticipated demand profile'. Scottish Power told us that, 'to the extent that there have been any problems with liquidity in wholesale markets, these have either already been or are likely to be alleviated by recent market developments on day ahead products and Ofgem's introduction of the Secure and Promote licence obligation'.[13] Scottish Power also said that any problems with liquidity would not have a larger cost impact on non-integrated firms.[14]

16. Scottish Power did not offer further comments on liquidity in its response to provisional findings.[15]

Scottish and Southern Energy

17. SSE said that bid offer spreads were 'now low and consistent with what is being achieved in other global electricity markets commonly acknowledged as being highly liquid'.[16] (SSE said that liquidity may have been suboptimal in previous years.)[17] It also said that liquidity was sufficient for independent suppliers to hedge.[18] SSE told us that limited liquidity beyond three years ahead meant that it did not generally sell large volumes of generation output beyond this time frame.

18. SSE did not offer further comments on liquidity in its response to provisional findings.[19]

[12] RWE, Response to provisional findings.
[13] Scottish Power, Response to issues statement, p8.
[14] Scottish Power, Response to issues statement, p9.
[15] Scottish Power, Response to provisional findings.
[16] SSE, Response to issues statement, p2.
[17] SSE, Response to issues statement, p1.
[18] SSE, Response to issues statement, p2.
[19] SSE, Response to provisional findings.

Views on electricity liquidity: mid-tier independent suppliers

Co-operative Energy

19. [✄].

20. Co-operative Energy did not offer further comments on liquidity in its response to provisional findings.[20]

First Utility

21. First Utility said that liquidity was limited in Baseload products from Season+4, Quarter+3 and Month+4, and in similar timescales for Peak. It said that Seasonal, Quarterly and Monthly shaped products (such as Blocks) 'very rarely openly trade'. It said that it wanted these shaped products to be available to allow it to manage the risks associated with the shape of its demand.

22. First Utility told us that a lack of liquidity in shaped products materialised through a lack of bids and offers in the market. This made it difficult to hedge shape risk, leading to it including a risk premium in its tariffs. First Utility told us that the resulting higher tariffs could reduce its growth, reduce its gross margin, or increase its exposure to market volatility. It said that this could place it at a disadvantage relative to vertically integrated suppliers.

23. First Utility also said that it needed a forward curve of up to three years in order to hedge its longest fixed tariff.

24. First Utility told us that it did not find clip sizes a problem currently, but that it had before its recent growth.

25. First Utility reiterated its concerns with liquidity in its response to provisional findings and the provisional decision on remedies. It set out that it considered that there was currently little to no liquidity in the more bespoke products and that there was still a distinct lack of forward shaped products in the market, and that this prevented independent suppliers from competing effectively with the Six Large Energy Firms, which could purchase these bespoke products internally.[21]

[20] Co-op Energy, Response to provisional findings.
[21] First Utility, Response to provisional findings, pp8 & 9.

OVO Energy

26. OVO Energy said: ‘It is also generally seen that small premiums are encountered on trade prices where there is little liquidity in the market and the third party is therefore taking on an exposure in order to trade the products requested by OVO [Energy].’

27. Ovo Energy did not offer further comments on liquidity in its response to provisional findings.[22]

Utility Warehouse

28. Utility Warehouse told us that liquidity was not an issue. It said: ‘In our experience, gaining access to the wholesale energy markets has never been a problem, and there is more than sufficient liquidity available from independent gas producers (eg BP), independent generators (eg Drax and International Power), from the Six Large Energy Firms directly, and/or by using various financial instruments for hedging and forward purchase.’[23]

29. Utility Warehouse did not offer further comments on liquidity in its response to provisional findings.[24]

Views on electricity liquidity: smaller independent suppliers

Ecotricity

30. Ecotricity said that there was limited availability for Baseload products further down the curve (eg beyond Season+3). It also said that ‘liquidity is particularly poor for non-standard products, such as Extended Peaks or separate blocks (eg Block 5, Block 6)’. Ecotricity told us that this affected its costs and its choice of hedging strategy. For example, it said that it tried to hedge a quarter of its demand between one and two years ahead, but found that it was very difficult to get liquidity, and [✂].

31. Ecotricity did not offer further comments on liquidity in its response to provisional findings.[25]

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[22] Ovo Energy, Response to provisional findings.
[23] Utility Warehouse, Response to issues statement, p2.
[24] Utility Warehouse, Response to provisional findings.
[25] Ecotricity, Response to provisional findings.

Opus Energy

32. [✂].'

33. In response to provisional findings, Opus set out its view that 'an investment-grade, vertically-integrated player has a significant financial advantage over a retail supplier who is not vertically-integrated or investment-grade', suggesting that this gave vertically integrated firms a competitive advantage over non-vertically integrated firms.[26]

Tempus Energy

34. In its response to the provisional decision on remedies, Tempus Energy set out its view that there was a lack of liquidity in the wholesale electricity market. It set out that this was a particular concern for 'medium to longer term trades'; especially those beyond the mandatory market maker window.[27]

Views on electricity liquidity: independent generators

Drax

35. Drax said that Baseload and Peak products were liquid for the first three Seasons, two Quarters and two Months. It told us that products beyond this were not liquid due to a lack of demand. It also said that the Carbon Price Floor and financial regulation had negatively affected liquidity along the curve.

36. Drax said that there were few trades in other products beyond a month out, with the exceptions of Overnights and Block 6. It said that this lack of shape trading occurs because: *(a)* there is a risk for generators associated with potential stranded unsold power from trading non-standard products (if a generator ends up selling power at less than full output the cost of production may be higher); and *(b)* suppliers' demand becomes more predictable closer to delivery.

37. Drax told us that low liquidity limited its ability to sell its output. [✂]. It also said that there are weak price signals on which to value future investments. However, it noted that the Capacity Market could be expected to provide investment signals in future. One way Drax had dealt with low liquidity was through buying a supply business.

[26] Opus, Response to provisional findings.
[27] Tempus Energy, Response to provisional decision on remedies.

38. Drax did not offer further comments on liquidity in its response to provisional findings.[28]

Electricity Supply Board

39. ESB (a generator operating in GB and the Republic of Ireland) said that the current level of liquidity in the electricity market was ‘insufficient’. It said that liquidity decreased along the curve, and that while there had been prices posted for Season+5, ‘there have been little or no trades to underpin them’. ESB said that the number of trades had fallen across all product types since 2009. It also told us that liquidity was poor in Monthly, Quarterly and Seasonal products ‘with the only meaningful activity being seen in the Secure & Promote (S&P) windows’. However, ESB did say that it did not find clip sizes to be a problem.

40. Regarding the impact of liquidity, ESB told us: ‘Low levels of liquidity limit our ability to manage key risks for our operational and development portfolios, thereby increasing costs relative to competitors with more vertically integrated positions. In particular, the wide bid-offer spreads make it more difficult to manage price risk.’

41. ESB also said that wholesale prices did not reflect its expectations, which were based on predictions of tighter capacity margins. ESB said it was ‘strongly of the view that the lack of liquidity is a key factor in this’. [✂].

42. ESB did not offer further comments on liquidity in its response to provisional findings.[29]

ENGIE

43. An internal document from ENGIE said that it uses a gas proxy hedge to help sell the output from its Rugeley power station. The document proposed that ENGIE should ‘increase GPH limit from [✂] to [✂] for Q2-15 to reduce liquidity constraint’.

44. Another internal document from ENGIE said that ‘liquidity in overnight product is poor in all but prompt market’. This was mentioned in relation to the hedging of its pumped storage plants.

[28] Drax, Response to provisional findings.
[29] ESB, Response to provisional findings.

45. ENGIE did not offer further comments on liquidity in its response to provisional findings.[30]

Intergen

46. Intergen told us that traded volumes were low for Baseload and Peak seasons, and that that they were ‘significantly lower’ beyond Season-ahead. There was a similar decline beyond Month-ahead. Intergen told us that liquidity was higher in the near term.

47. Intergen said that low liquidity meant that it did not have a robust forward price ‘to secure the cashflows it needs to meet its fixed operating costs and assess investment options for existing plant’. It also told us that this affected the demand for long-term tolling agreements.

48. In its response to our provisional findings, Intergen disagreed with our conclusion that vertical integration is not likely to have a detrimental impact on competition. It suggested that our analysis was both flawed and narrow, and that we should reconsider introducing remedies aimed at improving liquidity and increasing transparency (particularly full reporting of internal trades among group entities).[31]

Views on gas liquidity

49. We asked parties whether they saw limited liquidity in any gas market products. The general view was that liquidity was good in the gas market. This opinion was held by both the Six Large Energy Firms and independent firms. E.ON and SSE said that gas liquidity in GB was strong compared to other European markets.

50. Several parties said that liquidity was lower towards the end of the curve. Several parties also said that liquidity in Monthly products declined over time – for example, Scottish Power said that there is limited liquidity in the individual monthly products beyond Month +4. First Utility said that lack of availability of certain Monthly products affected its ability to match its contracted position to its demand. A couple of parties also noted possible minor improvements to the products available in gas, in particular to hedge gas-fired power stations better.

[30] ENGIE, Response to provisional findings.
[31] Intergen, Response to provisional findings.

Views on the effects of Secure and Promote

Six Large Energy Firms

51. We received mixed views from the Six Large Energy Firms on Secure and Promote (S&P). Scottish Power said that the requirements under S&P 'are contributing to a significant increase in liquidity for longer-dated and peak products'.[32] However, SSE said that S&P had not resulted in large numbers of additional trades, although it said that 'it is too early to judge the effects of these measures'.[33] EDF said that the Supplier Market Access rules involved a limited change because, 'in practice, EDF Energy has already provided such market access to some small suppliers'.[34]

52. A couple of parties also suggested that independent generators should be made subject to S&P.[35]

Independent suppliers

53. Two independent suppliers told us that liquidity had improved as a result of S&P. Ecotricity said that S&P had 'most definitely' improved liquidity in the products covered. However, both suppliers agreed that S&P had not led to increased liquidity in products outside the scope of the obligation.

54. Ecotricity told us that there had been improvements under the Supplier Market Access rules with respect to the speed at which quotes are provided and to the prices offered (although this varied between counterparties).

55. In contrast, First Utility said that 'S&P has had little or no impact on liquidity'. It told us that S&P had shifted liquidity into the mandated trading windows,[36] and said that continuous liquidity would be preferable.

Independent generators

56. Parties told us that S&P had created some improvements to liquidity within the windows. For example, Intergen said that S&P had increased liquidity of some products.

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[32] Scottish Power, Response to issues statement, p7.
[33] SSE, Response to issues statement, p2.
[34] EDF Energy, Response to issues statement, p12.
[35] EDF Energy, Response to issues statement, p21; SSE, Response to issues statement, p3.
[36] The hour-long periods starting at 10:30am and 3:30pm each working day during which the Six Large Energy Firms are required to market make.

57. However, two parties said that S&P had not improved liquidity outside the windows. Drax told us that S&P had concentrated volume in the windows, while ESB said that S&P had 'not created significant additional liquidity'.

58. Drax and Intergen also said that the volumes traded as a result of market making were limited by how market makers were choosing to carry out their obligations. For example, Drax said that some market making was occurring on less accessible platforms, such as Intercontinental Exchange (ICE).

59. Drax said that it had not developed trading relationships with any additional small suppliers as a result of the introduction of the Supplier Market Access rules. It has established new relationships with small suppliers to trade non-S&P products, and is negotiating relationships with others, but believed that those relationships would have developed without S&P.

Intermediaries

60. A number of parties said that there had been some positive effects on liquidity as a result of S&P:

(a) Haven said there was increased liquidity in Baseload products up to Season+1, as well as Peak products in the front months and Quarter+1. However, it said that liquidity had not increased significantly for products further along the curve, which is where liquidity had been most lacking. It said the lack of improvement in liquidity for these products primarily appeared to reflect an underlying lack of demand for such products from customers.

(b) Bank of America Merrill Lynch said there had been a reasonable increase in liquidity during the Market Making periods, especially for Peak products.

(c) Mercuria said the bid-offer spread between the two market-making windows had narrowed, despite limited volumes.

(d) DONG Energy said that S&P had increased liquidity for the mandated products.

61. However, several parties (including Macquarie, Shell, [✂], BP and SmartestEnergy) suggested that improvements in liquidity in the Market Making windows had come at the expense of liquidity outside the windows.

62. Goldman Sachs said the impact upon liquidity had been limited. However, Goldman Sachs and Mercuria both commented that S&P had had a positive effect on transparency.

Trading data

63. As background for this section, it is helpful to understand where firms can trade energy. The diagram below sets out these options, classifying them by type and timescale.

Figure 1: Options for trading electricity and gas externally

Electricity	Forward	Day-ahead	Intraday	Balancing
OTC	Brokers (eg GFI, ICAP, Marex Spectron, Tullet Prebon)			
Exchange	ICE Nasdaq OMX	APX and N2EX auctions	APX continuous	
Direct bilateral	Possible at any point before gate closure			
Central systems				Imbalances settled via cash-out

Gas	Forward	Intraday	Balancing
OTC	Brokers (eg GFI, ICAP, Marex Spectron, Tullet Prebon)		
Exchange	ICE	OCM (ICE Endex)	
Direct bilateral	Possible at any point (even after delivery)		
Central systems			Imbalances settled via cash-out

Source: CMA research.

64. The GB electricity market is largely made up of brokered over-the-counter (OTC) trading. In 2013, brokered OTC trading was estimated to represent 84.1% of the volume traded.[37] The only other significant platform type is near-term exchanges, which contributed at least 14.9% of volumes in 2013.[38]

65. The figures quoted above do not cover direct bilateral trading, because data on this is not generally available. If large volumes were being traded away

[37] London Economics, GB electricity markets liquidity report – a report for ESB, piii. This statistic is based on Trayport data, and so will also include any brokered trades that are then cleared through the Nasdaq OMX exchange. However, only 0.9 TWh was traded on this platform in 2014 (Nasdaq Commodities (December 2014) Market report, p2), so this should not affect the results.
[38] London Economics, GB electricity markets liquidity report – a report for ESB, piii.

from organised marketplaces, then there could be negative consequences for transparency, or for the ability of smaller players to access products. However, this does not seem to be a concern. Of the Six Large Energy Firms, the firm with the largest proportion of direct bilateral trades was RWE, and these trades made up only 7.5% of its total traded volume.[39] E.ON had [✂] of direct bilateral trades [✂]. The firms with the largest proportions of direct bilateral trades were independent generators and suppliers – [✂] firms[40] traded exclusively in this manner.[41]

66. Although our trading data set does not cover the whole market, it includes 16 firms. Our analysis showed 81.2% of trades in our data taking place OTC through brokers, 13.3% on exchanges and 5.5% through direct bilateral trades.[42] This is consistent with the figures reported above.

67. We have investigated trading by looking at three main areas. These are:

- actual trading by individual parties;
- product availability across the whole market; and
- Ofgem's S&P liquidity intervention.

68. We cover the first two of these areas below. Our assessment of S&P can be found in the main body of this appendix.

Trading – firm-level data

69. This section looks at the completed trades carried out by individual firms. This is only part of the picture for liquidity – a market could have a low number of trades, but still have products available. We look at product availability in the next section.

70. Ofgem and Energy UK have each published high-level information on trading previously.[43] Our analysis goes beyond this work by looking at trading activity in specific products. The aim is to understand how far ahead of delivery key products are traded.

71. The concerns expressed about liquidity generally related to the electricity market, so we spend most of this section looking at electricity. We also report

[39] RWE told us that if we excluded bilateral back to back power trades for the purpose of trading LECs only it estimates that direct bilateral trades would make up an average of less than 4% of trades by volume since 2009.
[40] [✂].
[41] All statistics calculated from parties' trading data.
[42] This excludes cash-out, which represents a small proportion of most firms' volumes.
[43] For example: Ofgem (12 June 2013), *Wholesale power market liquidity: final proposals for a 'Secure and Promote' licence condition*, Appendix 2; Energy UK (15 January 2015), *Wholesale electricity market report*.

some analysis on gas trading where we think this provides a useful comparison.

Our approach

72. We requested data from parties covering all their trades for delivery between January 2011 and July 2014. For each trade, we have information including:

- platform type;
- trade date;
- delivery start and end points;
- counterparty;
- whether a trade was a buy or a sell; and
- volume.

73. Our final data set includes information from a range of companies:

- the Six Large Energy Firms;
- independent suppliers – Co-op Energy, Ecotricity, First Utility, OVO Energy, Utilita; and
- independent generators – DONG Energy, Drax, ESB, ENGIE, MPF.

Categorising trades

74. We can classify trades in three ways: by time ahead of delivery, by duration and by product type.

Table 1: Categorisation of trades

Category	*Examples*	*What does this provide?*	*Applies to gas?*
Time ahead of delivery	200 days, 120 days, 45 days	Volumetric hedge	Yes
Duration	Season, Quarter, Month	Annual shape	Yes
Product type	Baseload, Peak, 4-hour block, hour	Daily shape	No

Source: CMA analysis.

75. In order to present the data, we have created discrete categories for each of these:

(a) 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.

(b) Duration: beyond Season, Season (six months), Quarter, Month, Week, one day to one week, one day or less, other.

(c) Product type: Half-hour, Hour, Half block (2 hours), Block (4 hours), Two blocks (8 hours), Peak, Extended peak, Off peak, Baseload, Custom, Other.

76. These ways of classifying trades form the basis for the questions we want to examine using this trading data. The first question relates to the overall volume of trading at different times ahead of delivery, while the second and third questions address different types of shaping.

Figure 2: Key questions for trading data

Source: CMA analysis.

Sleeve trading

77. In the OTC market, firms need a bilateral trading agreement in place in order to trade directly with each other. If they do not have an agreement, they can try to trade via a third company (which has agreements with both firms). The third company buys electricity from one firm, and sells the same amount to the other firm. In this case, the third company is said to be acting as a sleeve.

78. Where a firm is acting as a sleeve, we have removed those trades as far as possible before analysing its data.[44] This is because they do not represent the firm buying and selling electricity for itself.[45]

Our analysis and results

79. This section summarises the results of our analysis, with an effort to focus on the key evidence. First, we look at volumes traded over time (paragraphs 80–86). Second, we look at products by duration (paragraphs 87–99). Third, we look at products by type (paragraphs 100–107).

Analysis: all products by volume

- *Six Large Energy Firms*

80. Looking at overall volumes, we see that the majority of trading by the Six Large Energy Firms was within a year ahead of delivery. This pattern is consistent between parties. [✂] trading was within a year from delivery, giving it the largest proportion among the Six Large Energy Firms. [✂].

Figure 3: Volume of trading by time ahead of delivery (all products) by the Six Large Energy Firms

[✂]

Source: CMA analysis, parties' data. Note that the time categories in the chart are not of equal lengths.

81. However, the volumes traded towards the far end of the curve can still be significant. For example, Centrica traded nearly [✂] per year over three years ahead. As an illustration, [✂] supplied [✂] in the last year for which we have data. This means that Centrica trades over [✂] times the size of a mid-tier supplier at the far end of the curve.

82. We can also compare the Six Large Energy Firms. In most of the timeframes, the order of which firms trade most is similar to the order of the size of their GB businesses.[46] Scottish Power and Centrica have the smallest businesses,

[44] We asked parties to identify sleeve trades. Not all of them were able to do so. However, for firms who were able to provide this information, sleeve trades represented a small proportion of their overall traded volumes. The figure was [✂] for SSE and [✂] for Centrica. RWE could provide this information only for sample months, but it was between [✂] in each case. This suggests that any sleeve trades remaining in our data should not have a material effect on the results.

[45] A firm that acts as a sleeve is helping to facilitate a trade that might not otherwise have been possible, and therefore this is a practice that benefits liquidity. When considering the effect of sleeve trades on quantified measures of liquidity, it would be sensible to consider both halves of a sleeve trade as a single trade, and remove one half. We understand that this is the approach taken by price reporting agencies.

[46] Size of firms approximated based on the average of the sum of volumes generated and supplied in each of 2011, 2012 and 2013. Calculated from the segmental statements, available through Segmental statements. (SSE figures based on its financial year starting in April.) EDF Energy average 130.7 TWh; RWE average 85.1 TWh;

and these firms trade the least. On an overall basis, the total amount traded by each firm is greater than the size of its businesses in GB. The firm with the smallest ratio was EDF Energy, which traded [✂] the size of its physical business. RWE had the largest ratio – it traded 4.3 times the size of its physical business.[47]

- *Independent suppliers*

83. We now look at a set of independent suppliers (Co-op Energy, Ecotricity, First Utility, OVO Energy and Utilita). The graph below shows that these firms traded [✂] more than a year before the start of delivery in the period we examined. (The combined trading of these five firms beyond a year ahead was [✂] per year. This is equivalent to only [✂] in Seasonal Baseload.)[48] This is in contrast to the Six Large Energy Firms, which all carry out some trading right along the curve. Independent suppliers therefore traded nearer to delivery than the Six Large Energy Firms on this metric.

Figure 4: Volume of trading by time ahead of delivery (all products) by independent suppliers

[✂]

Source: CMA analysis, parties' data.

84. First Utility's trading pattern was unusual. However, we understand that First Utility's trading pattern from this period was not typical of its current trading owing to the change of trading counterparty during the period of observation. Under its agreement with the intermediary it was using at that time, it was able to obtain [✂] products. These trades cover a long period, even though they start to deliver soon after they are agreed. The volume-weighted average duration of First Utility's trades (in the data we collected) was [✂]. So on the metric we have used – time to start of delivery – First Utility does very little trading far ahead; but if we looked at time to end of delivery, [✂]. We understand that since it has changed intermediary to Shell, First Utility trades mainly [✂] wholesale products. It now trades [✂] up to [✂] forward. Therefore in our assessment of trading we have considered what First Utility told us about its normal trading behaviour as well as its actual (unrepresentative) behaviour in the period for which we collected data.

SSE average 82.7 TWh; E.ON average 75.8 TWh; Centrica average 65.8 TWh; Scottish Power average 42.1 TWh.

[47] This involves dividing the annual average volume traded by the average size of its physical business (as calculated above). Full results in the main body of this appendix.

[48] The standard clip size for forward products is 10 MW, and there are 4,380 hours in a season.

- *Independent generators*

85. We have a mixed picture from the independent generators in our data. ENGIE looks similar to the Six Large Energy Firms – it trades electricity up to 36 months ahead, but the majority (88%) of its trading is within a year from delivery. [✄],[✄]. Drax also traded electricity at the far end of the curve – it was the only independent generator to trade any volume before 36 months out. However, Drax was somewhat different from the Six Large Energy Firms in that the timeframe in which it traded the highest volume was between 18 and 12 months ahead (rather than closer to delivery).

86. In contrast, MPF looks more similar to the independent suppliers. [✄]. ESB presented a similar pattern, [✄].

Figure 5: Volume of trading by time ahead of delivery (all products) by independent generators

[✄]

Source: CMA analysis, parties' data.

Analysis: by product duration

87. We now look at the different lengths of products. These products can help firms to contract ahead to match their annual shape.

- *Six Large Energy Firms*

88. For the Six Large Energy Firms, there is little trading of Monthly Baseload beyond three months ahead of delivery. [✄] traded only [✄] of its Monthly Baseload beyond three months ahead – and the proportions were even smaller for the other parties. While most parties traded some volume in this product beyond year-ahead, the total volume (across all six firms) was small – under [✄] TWh per year. This suggests that these firms manage their annual shape near to delivery.

Figure 6: Volume of trading by time ahead of delivery by the Six Large Energy Firms – Monthly Baseload

[✄]

Source: CMA analysis, parties' data.
Note: This and the following Baseload charts for the Six Large Energy Firms are all plotted on the same scale to facilitate comparisons.

89. There is slightly more trading of Quarterly Baseload three to six months before delivery (compared to Monthly Baseload). The Six Large Energy Firms each traded at least 21% of their Quarterly Baseload beyond three months

ahead.[49] In contrast, the Six Large Energy Firms trade Seasonal Baseload along the curve – each of them traded some volume up to [✂] months ahead. The volumes traded in this product are also much higher. Each of the Six Large Energy Firms traded at least three times as much in Seasonal Baseload as in Monthly Baseload, and at least five times as much as in Quarterly Baseload.[50] As trading in Monthly and Quarterly products falls away, most trading beyond a year ahead is in Seasonal Baseload.

Figure 7: Volume of trading by time ahead of delivery by the Six Large Energy Firms – Quarterly Baseload

[✂]

Source: CMA analysis, parties' data.

Figure 8: Volume of trading by time ahead of delivery by the Six Large Energy Firms – Seasonal Baseload

[✂]

Source: CMA analysis, parties' data.

90. There is a similar pattern for Peak[51] – Seasonal products are traded much further ahead than Monthly or Quarterly products. (For all firms, the time category with the highest volume of Monthly Peak was between a week and a month from delivery, whereas for Seasonal Peak it was between six and 12 months ahead.) For Monthly Peak products, the amount of activity beyond three months ahead is very small. [✂] traded 0.08 TWh per year, which was the most of any party; this is equivalent to 35 trades per year.[52]

Figure 9: Volume of trading by time ahead of delivery by the Six Large Energy Firms – Monthly Peak

[✂]

Source: CMA analysis, parties' data.
Note: Smaller scale for Peak charts than Baseload charts.

Figure 10: Volume of trading by time ahead of delivery by the Six Large Energy Firms – Quarterly Peak

[✂]

Source: CMA analysis, parties' data.

[49] [✂] traded the smallest proportion beyond three months ahead.
[50] In each case, [✂] was the firm with the lowest ratios: [✂] between Seasonal Baseload and Monthly Baseload, and [✂] between Seasonal Baseload and Quarterly Baseload.
[51] A product that delivers a flat volume between 7am and 7pm on weekdays.
[52] Based on a standard forward clip size of 10 MW, and a four-week month under the EFA calendar.

Figure 11: Volume of trading by time ahead of delivery by the Six Large Energy Firms – Seasonal Peak

[✂]

Source: CMA analysis, parties' data.

- *Independent suppliers*

91. Like the Six Large Energy Firms, most independent suppliers trade Monthly Baseload largely within three months of delivery. [✂] trades a significant amount in this product within a week ahead (relative to its trading in other timescales). Two independent suppliers traded some volume in Monthly Baseload between [✂] ahead of start of delivery. For both of these firms, this was as far ahead as they traded any product.[53]

Figure 12: Volume of trading by time ahead of delivery by independent suppliers – Monthly Baseload

[✂]

Source: CMA analysis, parties' data.
Note: This and the following Baseload charts for independent suppliers are all plotted on the same scale to facilitate comparisons.

92. One independent supplier did not trade Quarterly Baseload at all. For the other four independent suppliers, the timeframe with the largest volume of trading in Quarterly Baseload was [✂].

Figure 13: Volume of trading by time ahead of delivery by independent suppliers – Quarterly Baseload

[✂]

Source: CMA analysis, parties' data.

93. OVO Energy traded its largest volume of Seasonal Baseload between six and 12 months from delivery. This is further ahead than it traded months and quarters. [✂] also traded seasons further ahead than it traded months and quarters. Each of the other three independent suppliers in this data traded the equivalent of [✂] per year in Seasonal Baseload.[54]

Figure 14: Volume of trading by time ahead of delivery by independent suppliers – Seasonal Baseload

[✂]

Source: CMA analysis, parties' data.

[53] Over 99% of [✂] Baseload trading is in Months.
[54] The results we calculated for First Utility may not be representative of its normal trading because of the way it traded in this period (discussed above).

94. Independent suppliers traded small volumes in Peak contracts. Only three independent suppliers traded any Seasonal Peak, and only two firms traded any Quarterly Peak.

95. For Monthly Peak, the graph below shows that independent suppliers fall into two categories. Three independent suppliers traded all (or the vast majority of) their Monthly Peak within three months from delivery. Two other independent suppliers traded some Monthly Peak up to 12 or 18 months ahead, but even these companies traded around half of their Monthly Peak within three months of delivery.[55]

Figure 15: Volume of trading by time ahead of delivery by independent suppliers – Monthly Peak

[✂]

Source: CMA analysis, parties' data.
Note: Smaller scale for Peak chart than for Baseload.

- *Independent generators*

96. Independent generators generally traded Baseload products of different durations in a similar way to the Six Large Energy Firms (the exception was [✂], which did not trade any Monthly, Quarterly or Seasonal Baseload products):

(a) Independent generators mostly traded Monthly Baseload within [✂] of delivery. The firm that traded the largest proportion beyond this was ENGIE (13.1%).

(b) Independent generators generally traded Quarterly Baseload a little further ahead than Monthly Baseload. Drax, [✂] and ENGIE all traded around 40% of their Quarterly Baseload beyond three months from delivery.

(c) [✂] independent generators traded some Seasonal Baseload at least two years ahead. However, each of these firms traded at least half of its Seasonal Baseload within a year from delivery.

Figure 16: Volume of trading by time ahead of duration by independent generators – Monthly Baseload

[✂]

Source: CMA analysis, parties' data.

[55] [✂] traded 48% of its Monthly Peak within three months of delivery. [✂] traded 51% of its Monthly Peak within three months of delivery.

Figure 17: Volume of trading by time ahead of duration by independent generators – Quarterly Baseload

[✂]

Source: CMA analysis, parties' data.

Figure 18: Volume of trading by time ahead of duration by independent generators – Seasonal Baseload

[✂]

Source: CMA analysis, parties' data.

97. Independent generators traded small volumes in Peak products. For example, ENGIE traded the most Monthly Peak, but still traded 8.6 times as much volume in Monthly Baseload. [✂], and [✂]. [✂].

98. Subject to these caveats, the pattern of when independent generators traded Peak products was similar to when they traded Baseload. For example, there was little trading of Monthly Peak beyond three months ahead. ENGIE traded 9.3% of its Monthly Peak beyond this point, which was the most of any independent generator.

Figure 19: Volume of trading by time ahead of duration by independent generators – Monthly Peak

[✂]

Source: CMA analysis, parties' data.

- *Summary*

99. The overall pattern (across all firm types) is therefore that Monthly products were generally traded within three months of delivery. Quarterly products were traded slightly further ahead, but this trading was nearly all within six months of delivery. Seasonal products were traded the furthest out.

Analysis: by product type

100. We now look at products other than Baseload and Peak. For the Six Large Energy Firms, the charts above (Figure 9, Figure 10 and Figure 11) show that most Peak trading was within a year from delivery. Peak was the third most important product type for the Six Large Energy Firms (after Baseload and individual Hours), but it still represented only 4.3% of their total traded volumes. Even within one year from delivery, Peak still made up less than 5% of total traded volumes by the Six Large Energy Firms.

101. We also looked at a wider range of products. For electricity trading, the day is divided into six Blocks of four hours. These are standardised – eg Block 5 is 3pm to 7pm. We created the category of 'other standard products', which

looks at four-hour Blocks, and cases where multiple Blocks are traded together (eg Overnights). It does not include Peak, as this has been covered separately.

Figure 20: Volume of trading by time ahead of delivery by the Six Large Energy Firms – other standard products

[✂]

Source: CMA analysis, parties' data.
Note: The product types included in this category are: four-hour Blocks, pairs of four-hour Blocks, Off-peak and Extended peak.

102. The graph above shows that there are differences between firms. Two parties traded significantly more in these products than the other four parties in most timeframes. For example, between three and six months ahead, RWE traded an average of 2.0 TWh per year and SSE traded [✂] per year; the other four firms each traded under [✂] per year. However, all firms carried out at least 70% of their trading in these products within three months from delivery, and the largest category for each party was day or less. This supports the proposition that firms generally shape their positions close to delivery.

103. We looked at independent suppliers' trading of Peak in paragraphs 94 and 95. Overall, at least half of each firm's trading in Peak occurred within three months of delivery.

104. Independent suppliers also traded 'other standard products' mostly within [✂] from delivery.[56] [✂]. [✂]. This perhaps illustrates that independent suppliers find different ways to manage their shape.

Figure 21: Volume of trading by time ahead of delivery by independent suppliers – other standard products

[✂]

Source: CMA analysis, parties' data.
Note: The product types included in this category are: four-hour Blocks, pairs of four-hour Blocks, Off-peak and Extended peak.

105. For independent generators, we covered Peak trading in paragraphs 97 and 98. [✂]. [✂], whose trading in Peak started to fall away only beyond year-ahead.

106. Independent generators generally traded other standard products only within a month from delivery. [✂] generally traded very limited volumes in these products beyond a month.) Drax traded only small volumes beyond this point. ENGIE's trading in other standard products looks more similar to that of some of the Six Large Energy Firms. It traded some volume in other standard

[56] The results we calculated for First Utility may be misleading because of the way it traded in this period (discussed above).

products up to two years ahead, although it still traded three-quarters of its volume within a month of delivery.

Figure 22: Volume of trading by time ahead of delivery by independent generators – other standard products

[✀]

Source: CMA analysis, parties' data.
Note: The product types included in this category are: four-hour Blocks, pairs of four-hour Blocks, Off-peak and Extended peak.

107. This section therefore shows that Peak is not traded as far out from delivery as Baseload, and that more specialised products are traded in a similar or shorter timeframe. The reason for this could be either a lack of demand for non-Baseload products or limited product availability. Credit and collateral is a less likely explanation, because we expect credit costs to be driven more by the time ahead of delivery than by the product type.

Comparison with gas

108. In this section we perform similar analysis on the pattern of trading in gas. We look first at all products by volume over time, and then at product duration. There is no equivalent 'product type' in gas because it is a daily product rather than half hourly, so there is no within-day shape.

Gas trading – all products by volume

109. The graph below shows gas trading by time ahead of delivery for the Six Large Energy Firms. Overall, the Six Large Energy Firms carried out 85% of their gas trading within a year from delivery, and that pattern was broadly similar across all six firms.

Figure 23: Gas trading by time ahead of delivery – Six Large Energy Firms

[✀]

Source: CMA analysis, parties' data.

110. The proportion of trading at the far end of the curve was small, although volumes were still large. The Six Large Energy Firms traded only 4.3% of their volumes beyond two years out. Three firms ([✀],[✀] and RWE) traded more beyond two years ahead than the size of their gas supply business.[57] (This does not give a full picture of firms' gas requirements, as they also need to buy fuel for their gas-fired power stations.) This suggests that these firms are

[57] Comparing the annual average volume traded between 2011 and July 2014 (from our data set), and the annual average volume supplied between 2011 and 2013 (from firms' Segmental statements, which are available on the Ofgem website).

able to trade reasonable volumes far out from delivery, but prefer to concentrate the bulk of their trading within year.

111. The pattern of the Six Large Energy Firms' gas trading was also similar to their electricity trading. The table below compares gas and electricity trading for the Six Large Energy Firms. The overall distribution of trading between times ahead of delivery appears similar to that for electricity. The biggest difference is that [✂] trades a greater proportion of its gas within a year from delivery, compared to electricity.

Table 2: Percentage of each firm's traded volume by time ahead of delivery – comparison between electricity and gas

%

	Centrica		*E.ON*		*EDF Energy*	
Time ahead	*Electricity*	*Gas*	*Electricity*	*Gas*	*Electricity*	*Gas*
Beyond 3 years	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2 to 3 years	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
1 to 2 years	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Inside 1 year	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE		*Scottish Power*		*SSE*	
Time ahead	*Electricity*	*Gas*	*Electricity*	*Gas*	*Electricity*	*Gas*
Beyond 3 years	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
2 to 3 years	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
1 to 2 years	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Inside 1 year	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis, parties' data.

112. For independent suppliers, most trading was also within a year from delivery. 92.3% of gas trading by these firms combined occurred in this timeframe. This appears to be a similar result to their electricity trading. This might suggest that they are not taking advantage of any greater product availability in gas.

Figure 24: Gas trading by time ahead of delivery – independent suppliers

[✂]

Source: CMA analysis, parties' data.

113. First Utility's trading was [✂]. However, as with electricity, its trades delivered over a long period.[58] The average length of its trades was [✂] days. Therefore, its trading is again difficult to compare with that of other firms. If we omit First Utility from the calculation above, 75.4% of gas trading by the other independent suppliers was within year.

[58] The results we calculated for First Utility may be misleading as to First Utility's normal trading behaviour because of the way it traded in this period (discussed above).

Gas trading – Monthly products

114. The graph below shows that the majority of trading in Monthly gas products by the Six Large Energy Firms was within three months of delivery.[59] This is in line with the qualitative statements we received on the length of liquidity in Monthly products. These suggested that liquidity was lower beyond four to six months out.[60]

Figure 25: Gas trading in Monthly products – Six Large Energy Firms

[✄]

Source: CMA analysis, parties' data.

115. If the Six Large Energy Firms were using internal transfers and/or an implicit hedge to provide Monthly shape in electricity, then we might expect them to trade Monthly products further out in gas. As this is not happening, there may simply be a lack of demand for Monthly products beyond a certain point. Even in the gas market, which is reputed to be liquid, trading of more granular products is concentrated closer to delivery.

116. Most of the independent suppliers for which we have data seemed to trade some Monthly products over six months ahead. This applies to [✄]. All these firms use an intermediary which provides them with access to Monthly products.[61] First Utility had a [✄].

Figure 26: Gas trading in Monthly products – independent suppliers

[✄]

Source: CMA analysis, parties' data.

117. By itself, this does not say anything about the availability of Monthly products in gas relative to electricity. [✄] do not have agreements with intermediaries in electricity. It is possible that they could therefore obtain Monthly products more easily in electricity if they had equivalent agreements; but it is also plausible that this would be more expensive if these products were less available.

Gas trading – Quarterly products

118. The pattern for Quarterly products was similar to that for electricity. For the Six Large Energy Firms, the timeframe with the highest traded volumes was

[59] The chart shows RWE trading Monthly products beyond this, but RWE told us that this is not correct. RWE informed us that 'the exchange trades that are reported as Monthly also include trades that may be Quarterly, Seasonal or Annual (because of the way the exchange records transactions)'
[60] Beyond four Months according to First Utility and Scottish Power, five months according to RWE, and six months according to Co-op Energy.
[61] [✄].

between one month and three months ahead. There was also some trading up to a year ahead, and negligible volumes beyond this.

Figure 27: Gas trading in Quarterly products – Six Large Energy Firms

[✂]

Source: CMA analysis, parties' data.

119. First Utility was the only independent supplier to trade large amounts of Quarterly products. Over [✂] of its Quarterly gas trading was between [✂].

Figure 28: Gas trading in Quarterly products – independent suppliers

[✂]

Source: CMA analysis, parties' data.

Gas trading – Seasonal products

120. As in electricity, the Six Large Energy Firms traded Seasonal products much further along the curve than Monthly or Quarterly products. However, the volumes traded within year were still the most significant. For each of the parties, the three timeframes with the highest volumes were those between one month and 12 months ahead.

Figure 29: Gas trading in Seasonal products – Six Large Energy Firms

[✂]

Source: CMA analysis, parties' data.

121. Independent suppliers traded minimal amounts of Seasonal gas – [✂]. None of the trading that did occur was beyond [✂] ahead.[62]

Figure 30: Gas trading in Seasonal products – independent suppliers

[✂]

Source: CMA analysis, parties' data.

Product availability, spreads and depth

122. We obtained data on 'bids' and 'asks' in the OTC market from the four brokers active in the market in that period: GFI, ICAP, Marex Spectron and Tullett Prebon. (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

[62] In the case of First Utility, this may be misleading because of the way it traded in this period (discussed above). First Utility told us that it now trades up to [✂] ahead [✂] (similar to its trading in electricity)

Tuesday of every month from January 2011 to October 2014.[63] We asked each broker for the best bids up to 50 MW in depth for each available product in each snapshot, and the equivalent best asks.

123. We combined this data into a common database that therefore showed all the best bids and asks in the market at those points in time. This would be equivalent to what a trader could have seen on a Trayport screen at those moments.[64] We used this to calculate, for each product, the spread between the best available bid price and the best available ask price. We also calculated the spreads at various different depths. For example, if someone wanted to buy 50 MW of a product, they would be interested in the weighted average of the ask prices for the cheapest 50 MW available.

124. The results we present below focused on the 11am snapshot, noting that this generally had the best product availability of our three times of day. As appropriate, we also note changes in the data since Ofgem introduced its S&P licence conditions, which are first reflected in our data in April 2014.

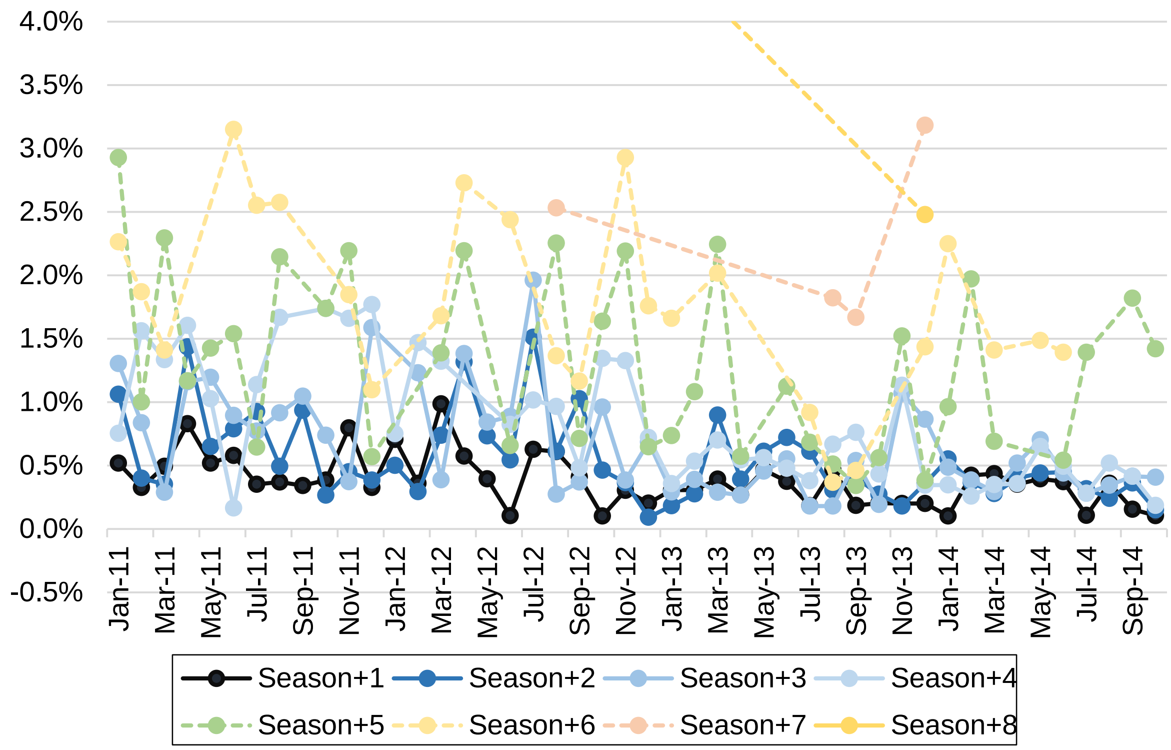
125. First, we show spreads (expressed as a percentage of the bid price) for products that were available to both buy and sell in any quantity. In all of these charts, months when products were available are marked with a dot, and those dots are joined with lines to help identify trends.

126. Figure 31 shows Baseload Seasonal products, which tend to have the best availability. Seasons+1, +2, +3 and +4 were available in almost every month in the period and at relatively tight spreads, particularly later in the period. Trading in these products would let a party purchase energy more than two years in advance of delivery. By contrast, Season+7 was available on only four of the days in our sample, and always at spreads of greater than 1.5%; and Season+8 only twice (one instance not shown because the spread was too wide for the axis we used).

[63] We chose this day in the hope that it would be representative (eg generally free of bank holidays). We 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 in forward products. Indeed, our data suggested that there were consistently more products available to trade at 11am and 4pm than at 8am.

[64] For products where more than 50 MW was available from one broker, we would not have the full set of possible trades, but we thought 50 MW was a reasonable cut-off (as 50 MW represents a substantial amount of electricity – for a Seasonal Baseload product, this could be worth around £10 million).

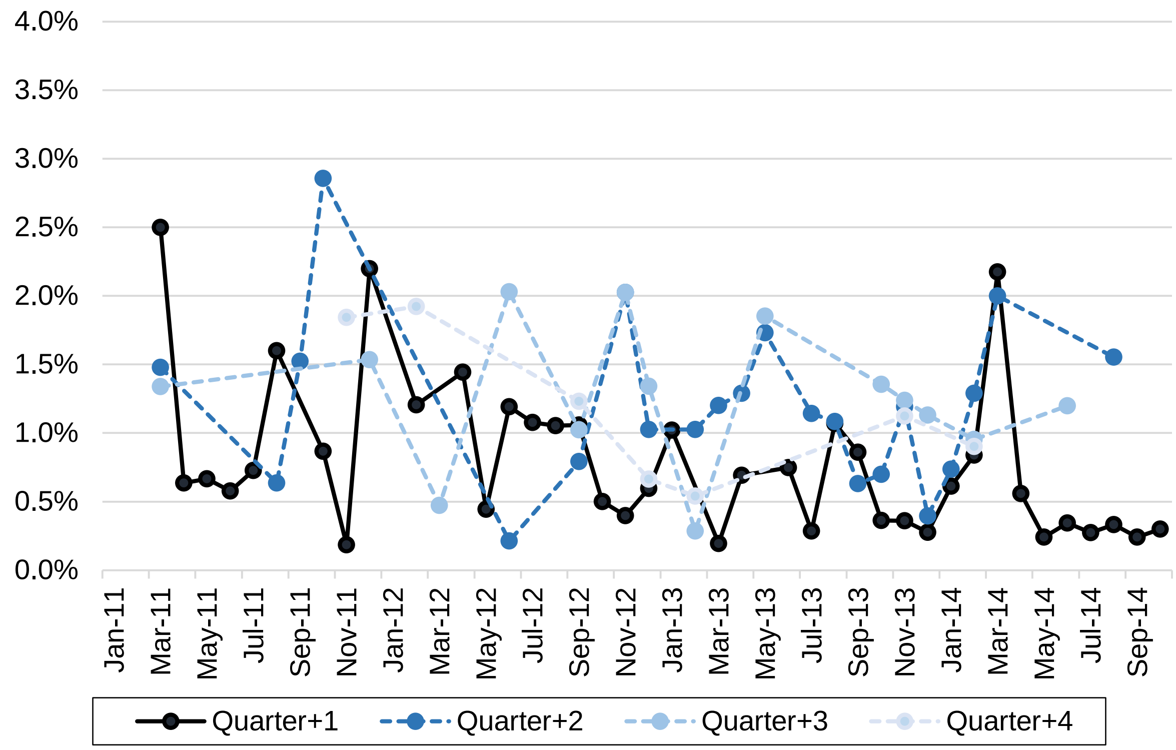
Figure 31: Spreads on Baseload Seasonal products



Source: CMA analysis, broker data.
Note: Solid lines are products that are included in the S&P Market Making obligation (since 31 March 2014).

127. Figure 32 shows Baseload Quarterly products. Availability here was worse and spreads were wider. Quarters beyond Quarter+4 were not available on any day in our data set. Even for Quarter+1 the spread is very variable until S&P comes into effect. The tight spreads on Quarter+1 – the only one to be included in S&P – after that point do not seem to have encouraged availability of subsequent Quarters.

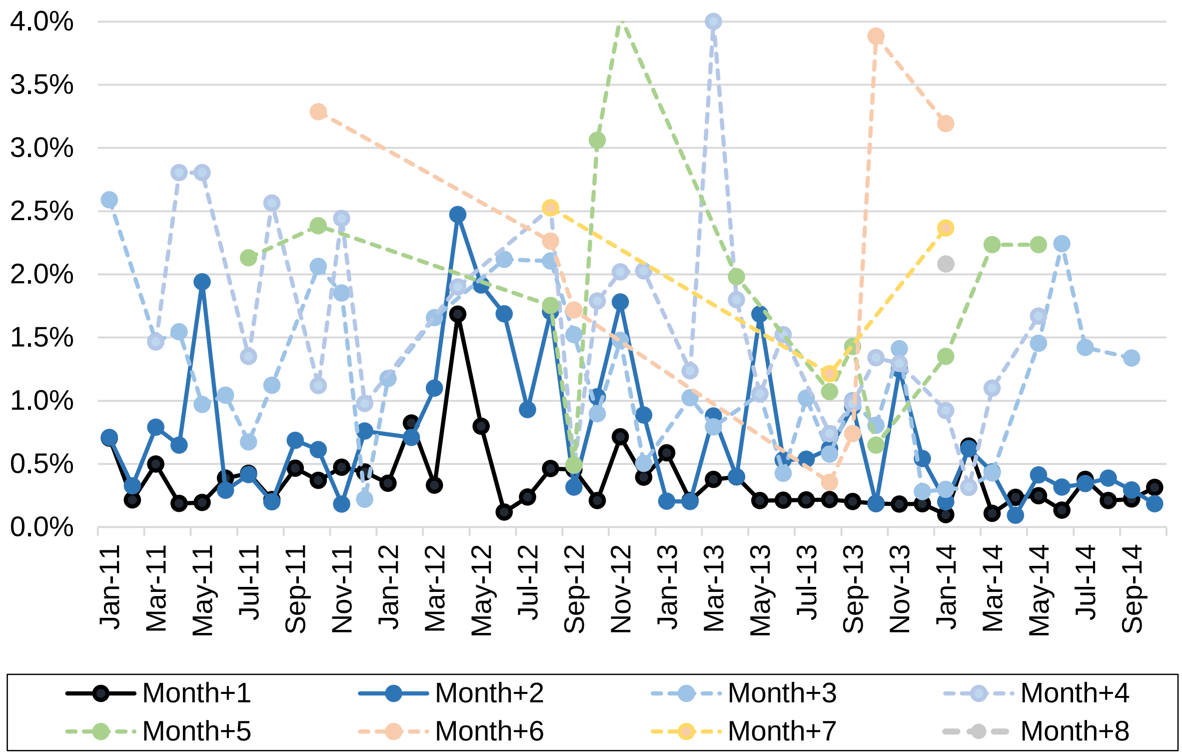
Figure 32: Spreads on Baseload Quarterly products



Source: CMA analysis, broker data.
Note: Solid lines are products that are included in the S&P Market Making obligation (since 31 March 2014).

128. Figure 33 shows Baseload Monthly products. Availability here was better than for Quarters, with sporadic availability up to Month+8 (only available on one day in our sample). However, spreads are wider than for Seasonal products. Only Month+1 has consistently low spreads until the introduction of S&P, which covers Months +1 and +2. Again, there is no positive effect of S&P on any other Monthly product; if anything, they look worse since April 2014.

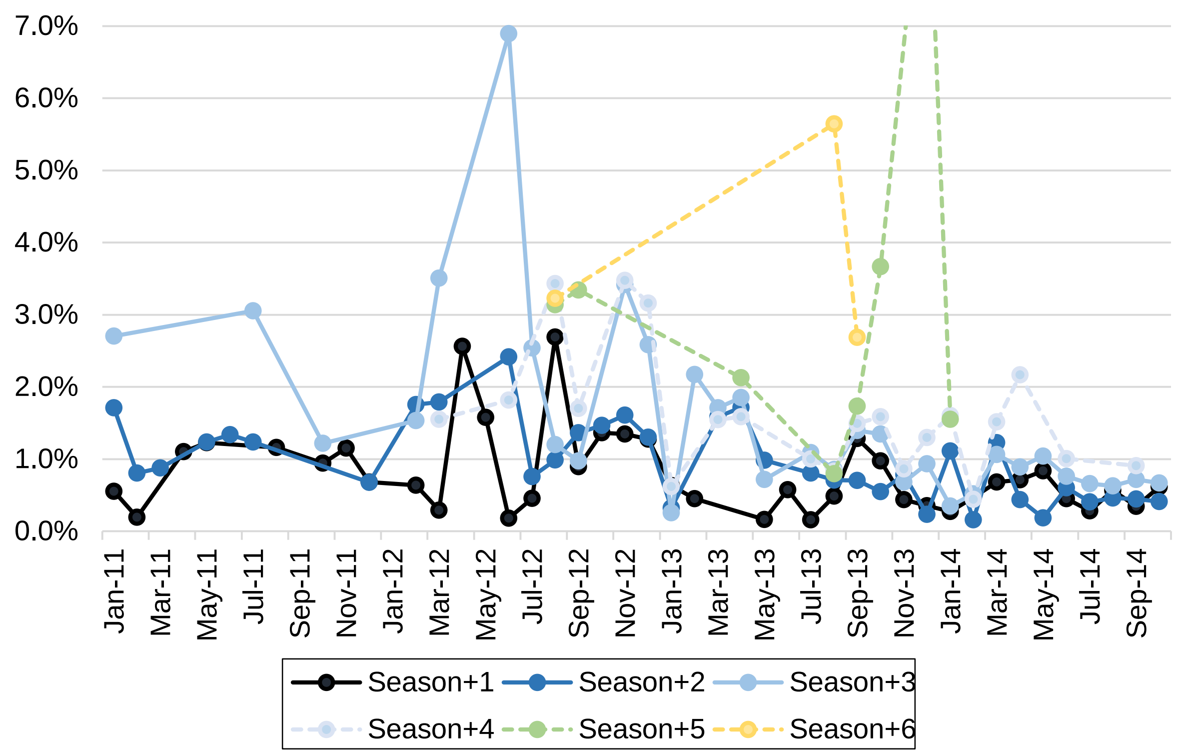
Figure 33: Spreads on Baseload Monthly products



Source: CMA analysis, broker data.
Note: Solid lines are products that are included in the S&P Market Making obligation (since 31 March 2014).

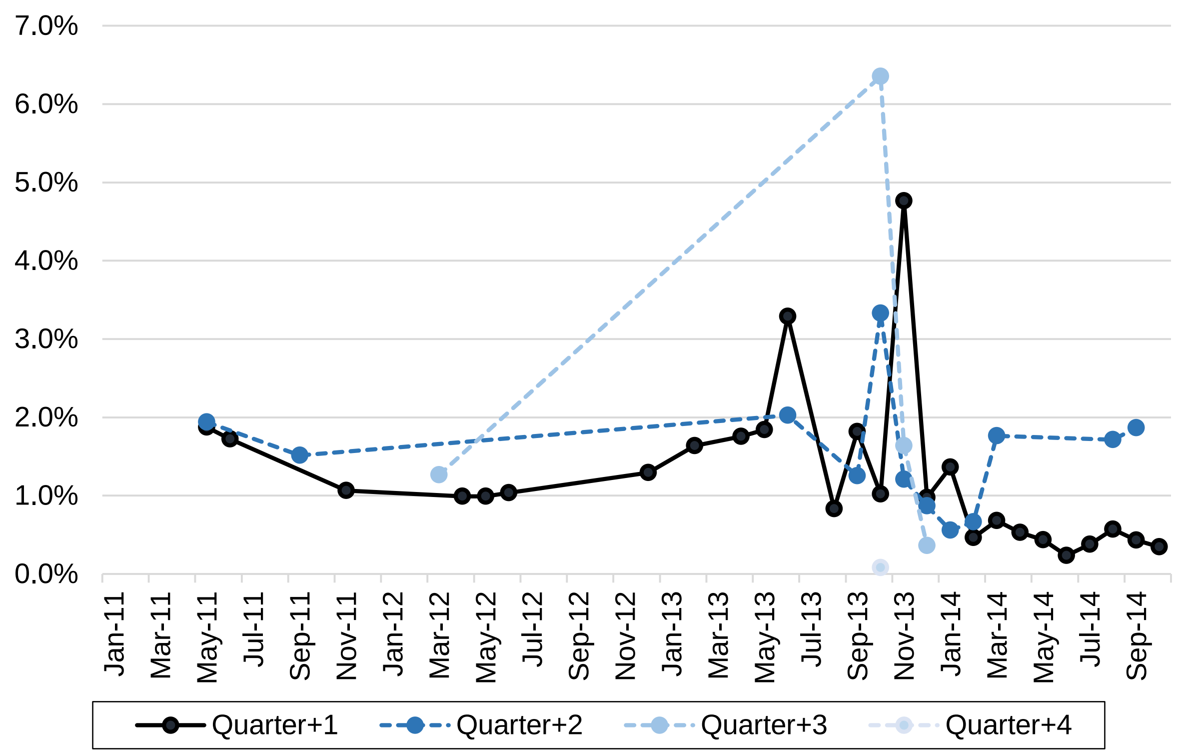
129. The following three figures show the equivalent Peak products for Seasons, Quarters and Months. Availability here was worse than for Baseload counterparts, but apart from that the patterns were similar. Seasons had good availability and spreads for Seasons+1 and +2, and at times as far as Season+4. (The first three Seasons are covered in S&P.) Quarterly availability was poor and spreads were wide until January 2014, when Quarter+1 spreads tightened. (This product was included in S&P and its spread has remained at that level since.) Months were somewhere in between, with S&P leading to more consistent low spreads for the first two Months (which are the products included in S&P).

Figure 34: Spreads on Peak Seasonal products



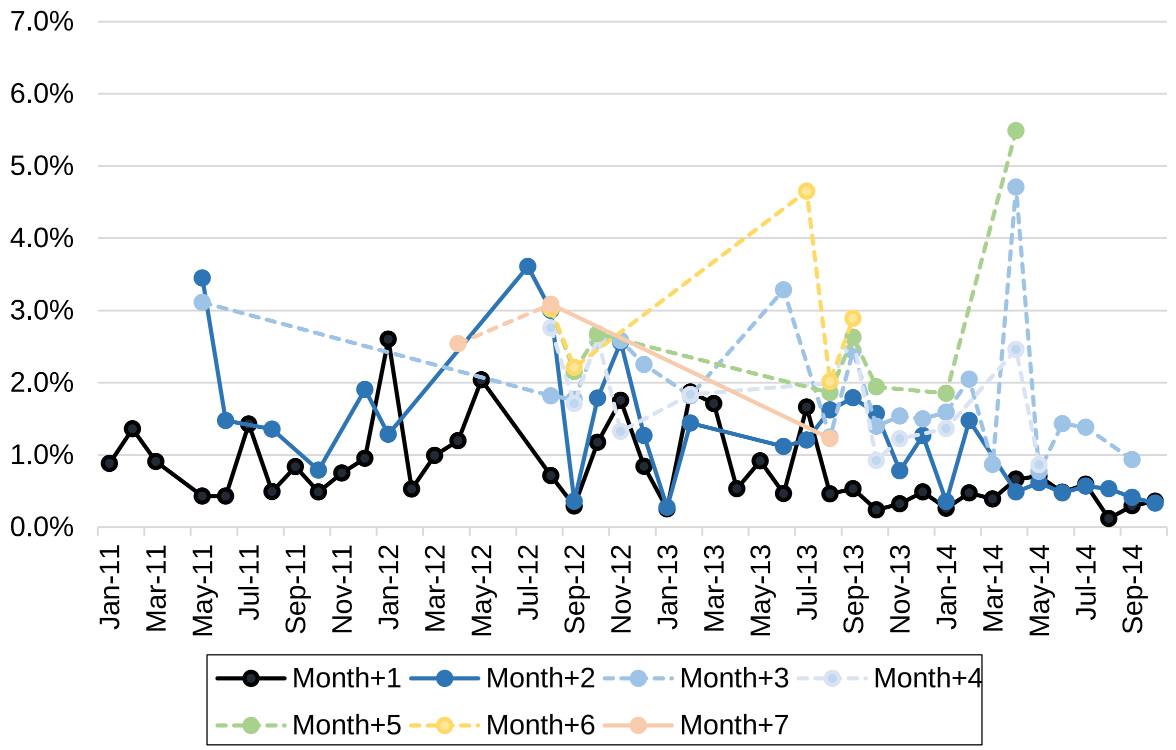
Source: CMA analysis, broker data.
Note: Solid lines are products that are included in the S&P Market Making obligation (since 31 March 2014).

Figure 35: Spreads on Peak Quarterly products



Source: CMA analysis, broker data.
Note: Solid lines are products that are included in the S&P Market Making obligation (since 31 March 2014).

Figure 36: Spreads on Peak Monthly products



Source: CMA analysis, broker data.
Note: Solid lines are products that are included in the S&P Market Making Obligation (since 31 March 2014).

130. In Table 3 below we summarise the availability information from the charts above by showing the proportion of dates in our sample when each listed product was available in any quantity to both buy and sell.[65] Products covered by the Market Making obligation in S&P are marked with an outline border.

Table 3: Proportion of days when product was available to both buy and sell (any quantity)

Time ahead of delivery (season, quarter, month, respectively)

		+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.
Note: Cells with borders are covered by Market Making Obligation in S&P.

131. This analysis suggested that availability of Baseload Season products was very good for more than two years ahead of delivery. Peak Season products

[65] In practice we found that it was rare for a product to be available to buy but not to sell, or vice versa.

were not always available, but had reasonable availability (70% or more) three seasons ahead. Baseload Months were almost always available two months ahead, and Peak Month availability was best one month ahead. Quarters were worse than Peaks.

132. Other products 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 to both buy and sell – the most commonly traded was a Monthly product for the month ahead, available on a third of the dates in our data set (see Table 3).

133. We also looked at spreads. We looked at how often a product had a spread of 1% or less,[66] and the pattern was broadly similar to that in Table 3, 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. 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.

Table 4: Proportion of days when product was available with a spread of no more than 1% (any depth)

%

Time ahead of delivery (season, quarter, month, respectively)

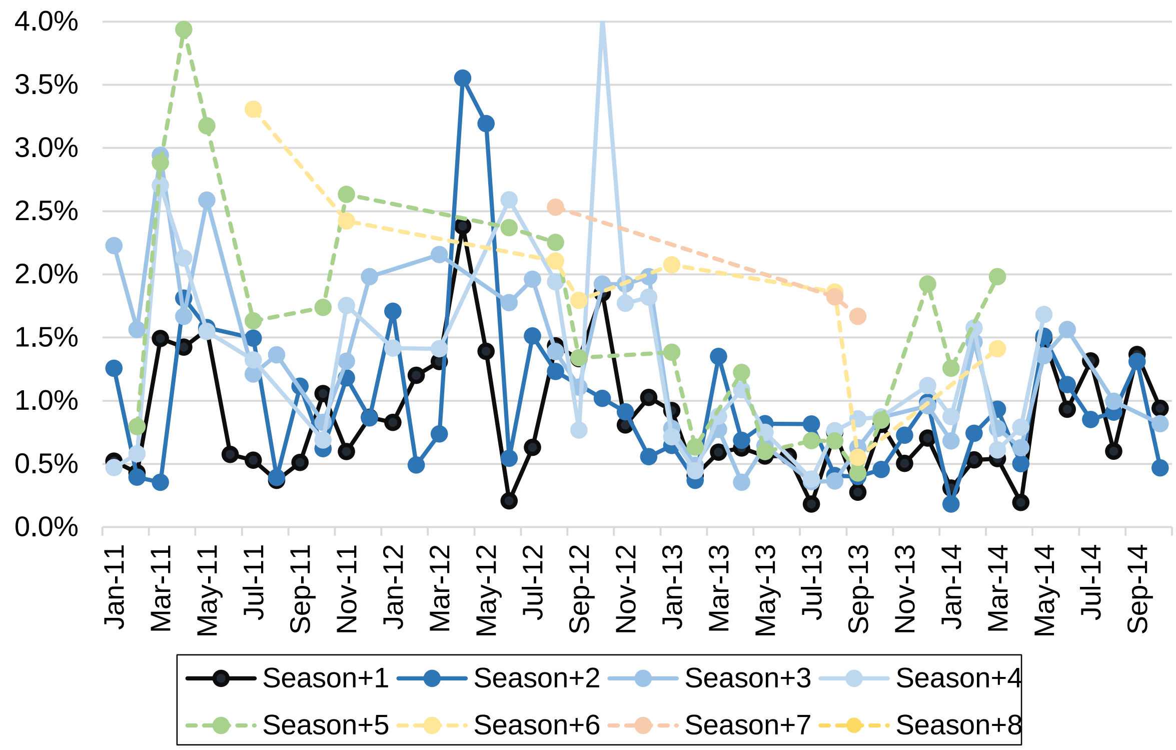
		+1	*+2*	*+3*	*+4*	*+5*	*+6*	*+7*	*+8*
Baseload	Season	100	89	78	61	35	7	0	0
	Quarter	59	15	7	7	0	0	0	0
	Month	98	76	28	13	4	4	0	0
Peaks	Season	61	46	30	11	2	0	0	0
	Quarter	28	7	2	2	0	0	0	0
	Month	72	26	7	4	0	0	0	0
Block 6	Month	4	0	0	0	0	0	0	0

Source: Data from brokers, CMA analysis.
Note: Cells with borders are covered by Market Making Obligation in S&P.

134. We also looked at data at 8am, outside the windows. Figure 37 shows spreads for Baseload Seasonal products (the most liquid products). This can be compared with Figure 31, which shows the same products at 11am. Availability and spreads are noticeably worse at 8am, and this was also true of the other products we reviewed. We also notice that spreads at 8am appear to have become worse following the introduction of S&P.

[66] 1% is the largest of the permitted spreads under the S&P Market Making obligation.

Figure 37: Spreads on Baseload Seasonal products (any depth), 8am



Source: CMA analysis, broker data.
Note: Solid lines are products that are included in the S&P Market Making Obligation (since 31 March 2014).

Depth

135. We considered how the results in the previous section varied when we increased product depth. A common clip size is 10 MW, and at that depth we generally found that the same range of products was available. However, if we increased the clip size to 50 MW, availability declined substantially. Table 5 shows that at this clip size it would not be possible to guarantee that any product would be available to buy and sell at 11am on any given day (prior to S&P). Only Season+1 and Month+1 Baseload products looked to have reasonable availability over the period of our sample. Those products covered by the Market Making obligation under S&P have been available at this depth since it came into effect, and will continue to be as long as the obligation is in effect. This means that many of the products here effectively have long periods of little or no availability before that time, followed by constant availability since then. This can be seen in the charts below.

Table 5: Proportion of days when product was available to both buy and sell (50 MW)

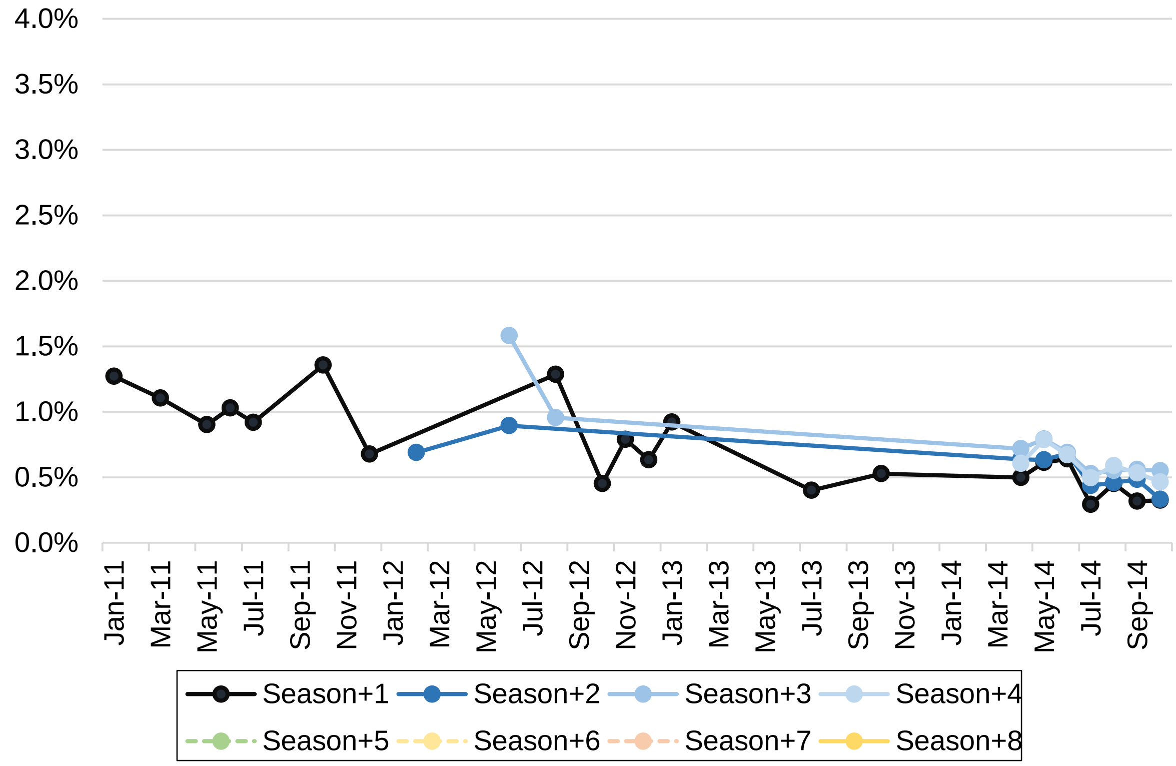
%

		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.
Note: Cells with borders are covered by Market Making Obligation in S&P.

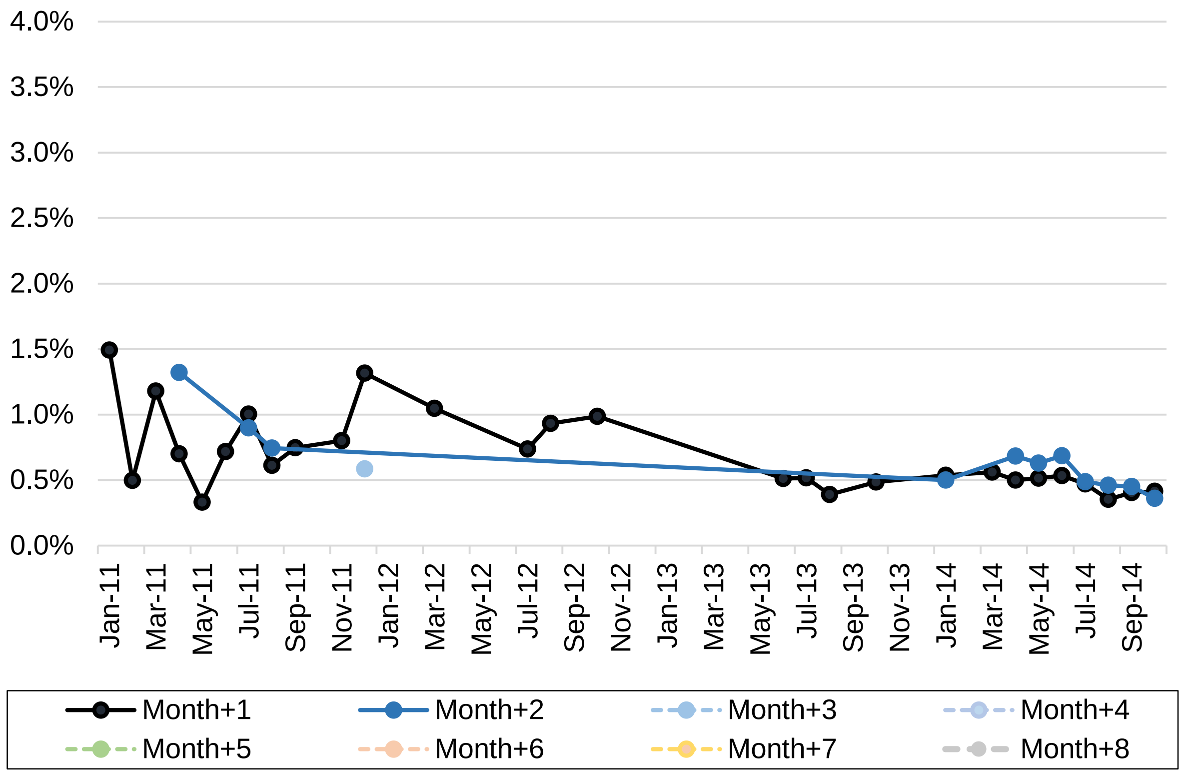
136. For those products that were available, spreads were also wider when looking at 50 MW of depth. The charts below show availability of Baseload Seasonal and Monthly products. It is notable that Seasons+2, +3 and +4 and Month+2, which are all covered by S&P, rarely appeared in this depth prior to the introduction of S&P (only at marked data points, and not in the months where a line connects two points).

Figure 38: Spreads on Baseload Seasonal products (50 MW depth)



Source: CMA analysis, broker data.
Note: Solid lines are products that are included in the S&P Market Making obligation (since 31 March 2014).

Figure 39: Spreads on Baseload Monthly products (50 MW depth)



Source: CMA analysis, broker data.
Note: Solid lines are products that are included in the S&P Market Making obligation (since 31 March 2014).

Active players

137. We looked at the whole data set to see who was involved in placing orders 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 are from the Six Large Energy Firms (ie roughly in proportion to the number of orders to trade).

Table 6: Proportion of orders to trade by the Six Large Energy Firms

%

	All futures		*Baseload and Peak products*	
	Bids	Asks	Bids	Asks
Percentage of prices posted by SLEFs	70.6	71.4	72.9	70.9
Percentage of best prices posted by SLEFs	67.4	70.1	69.4	67.1

Source: CMA analysis, broker data.

Market close data

Electricity

138. We also looked at data from ICIS Heren, which provided daily data on assessed product spreads at market close from January 2010.[67] The market close here is at the end of the afternoon S&P window, hence this data is likely to reflect availability during that window and does not tell us about other times of day outside the windows. The following four charts show monthly averages of this daily data for key Baseload and Peak products. We can make the following observations:

(a) Spreads get wider further from delivery.

(b) Seasons have tighter spreads than Months, which in turn are tighter than Quarters.

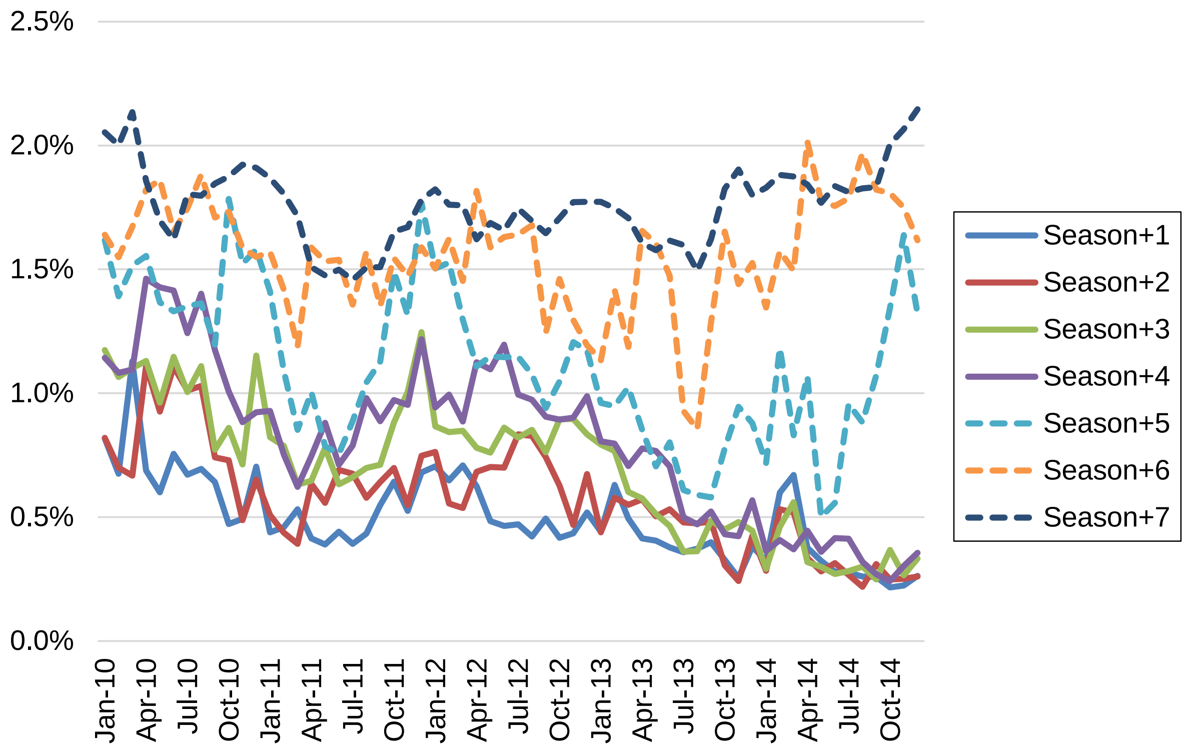
(c) Baseload has tighter spreads than Peak.

(d) the introduction of S&P, seen in this data since April 2014, has led to tighter spreads in mandated products, but there has been no apparent positive effect on other products. (For example, Season+3 and Season+4 Peak generally had similar spreads prior to the introduction of S&P. Season+3 Peak is a mandated product, and so the spreads have fallen since, but spreads for Season+4 Peak have increased.)

---

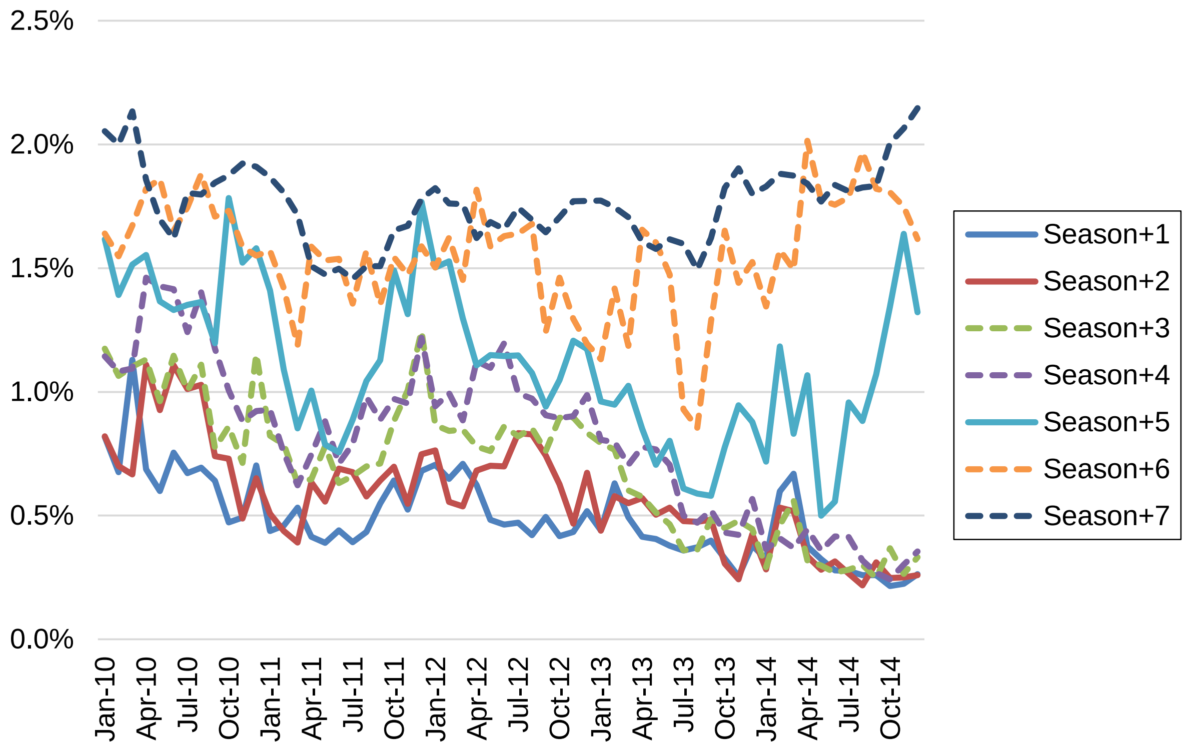
[67] ICIS Heren's assessments are 'based on bids and offers widely available to the market closest to the typically observed last point of liquidity', which for GB is 4.30pm (apart from Day Ahead and Weekend products, which we excluded from this analysis). Where a bid or offer is not available, ICIS 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 (2014) *European daily electricity markets methodology*. This does not account for product depth.

Figure 40: Monthly average spreads for Seasonal Baseload products



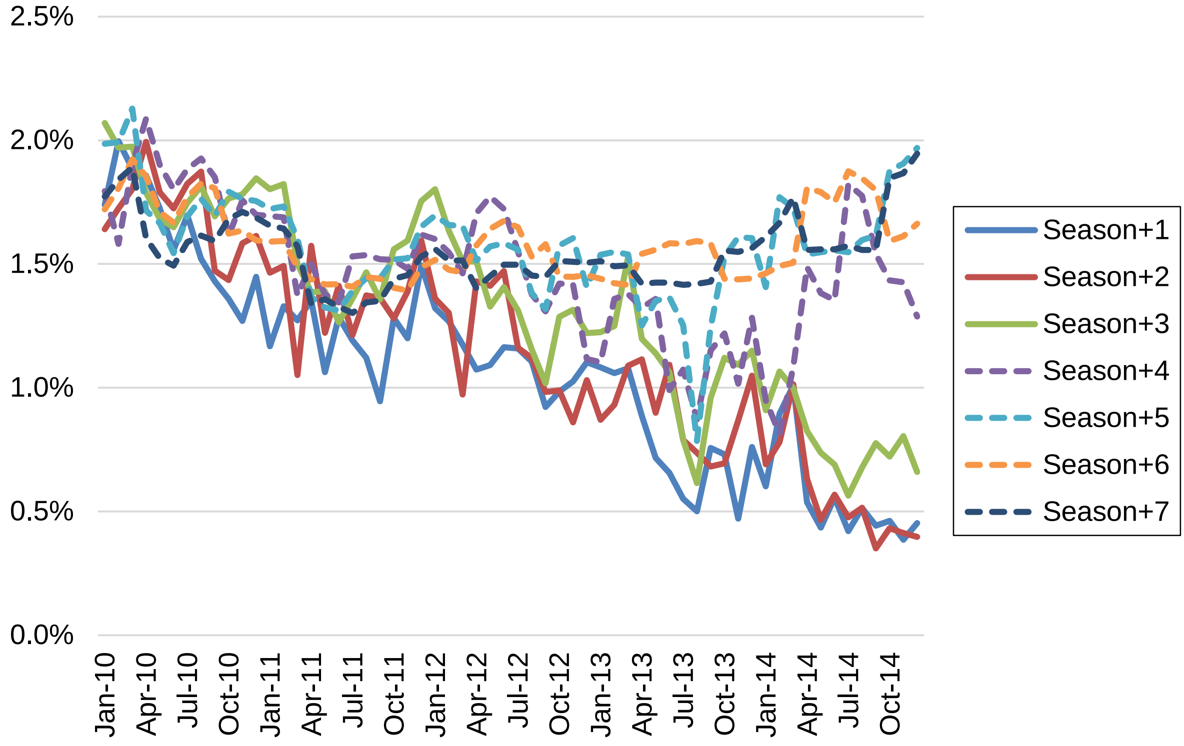
Source: CMA analysis, ICIS Heren data.
Note: Solid lines are products that are included in the S&P Market Making obligation (since 31 March 2014).

Figure 41: Monthly average spreads for Quarterly and Monthly Baseload products



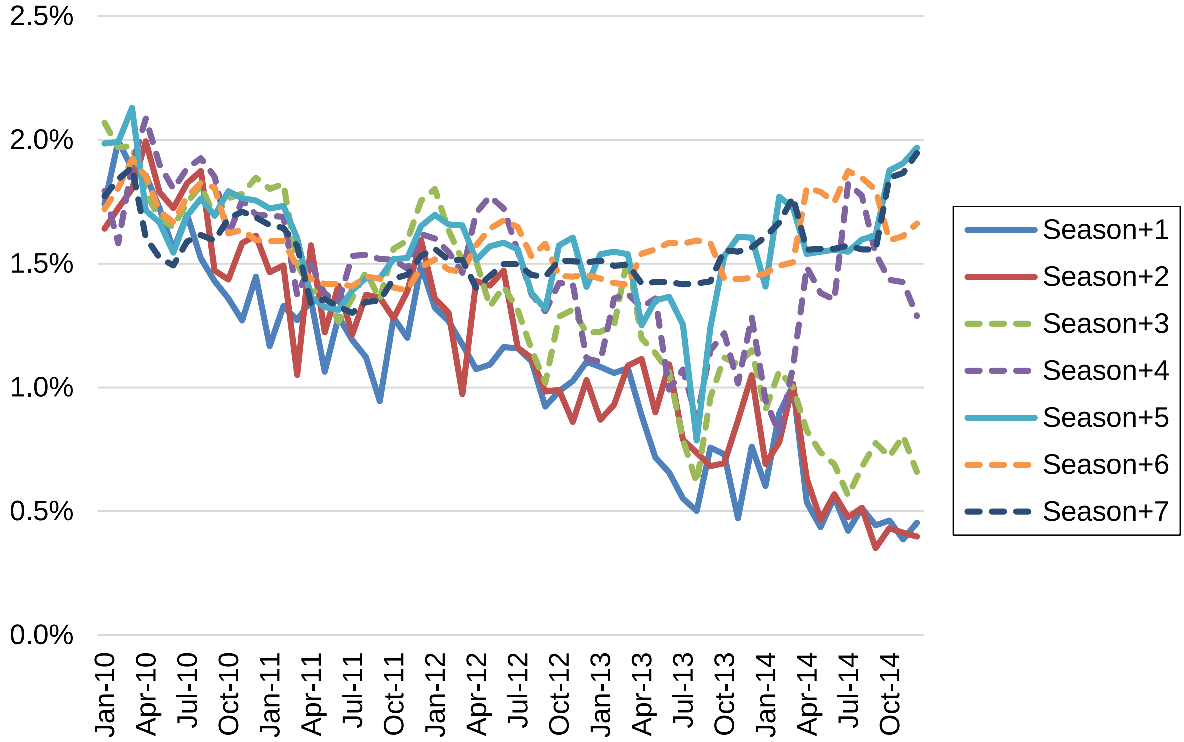
Source: CMA analysis, ICIS Heren data.
Note: Solid lines are products that are included in the S&P Market Making obligation (since 31 March 2014).

Figure 42: Monthly average spreads for Seasonal Peak products



Source: CMA analysis, ICIS Heren data.
Note: Solid lines are products that are included in the S&P Market Making obligation (since 31 March 2014).

Figure 43: Monthly average spreads for Quarterly and Monthly Peak products

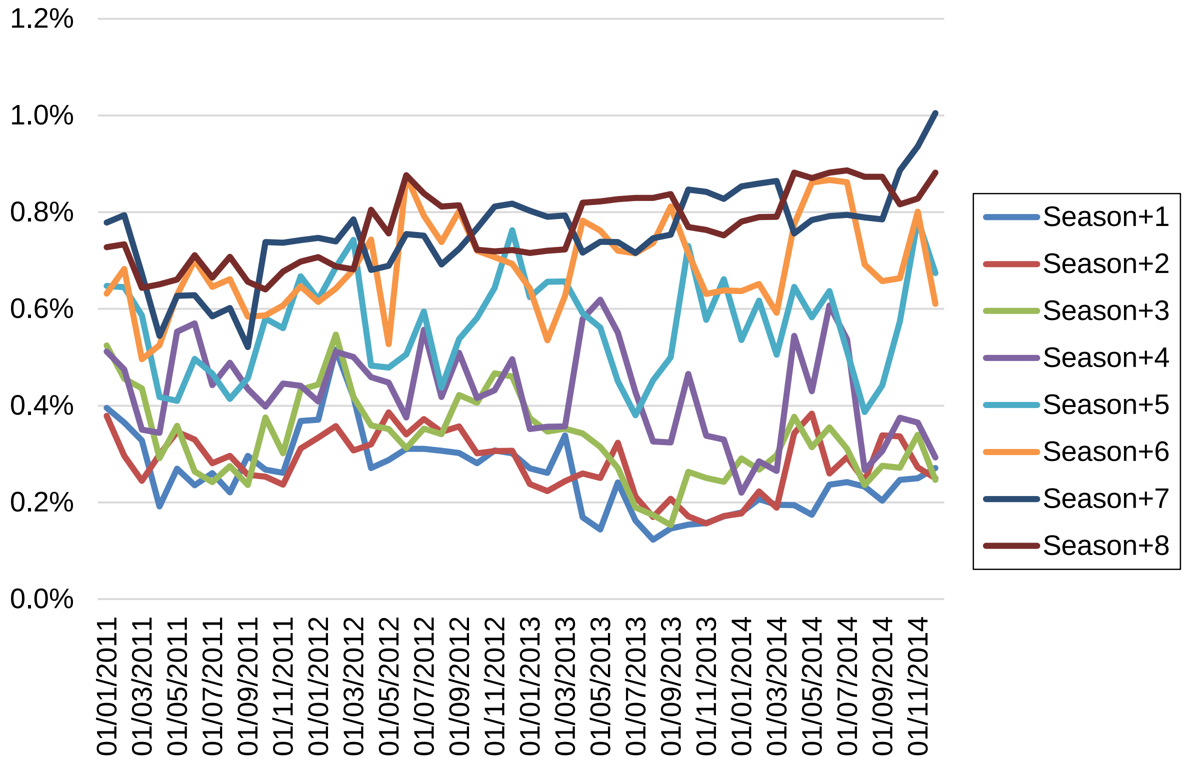


Source: CMA analysis, ICIS Heren data.
Note: Solid lines are products that are included in the S&P Market Making obligation (since 31 March 2014).

Gas

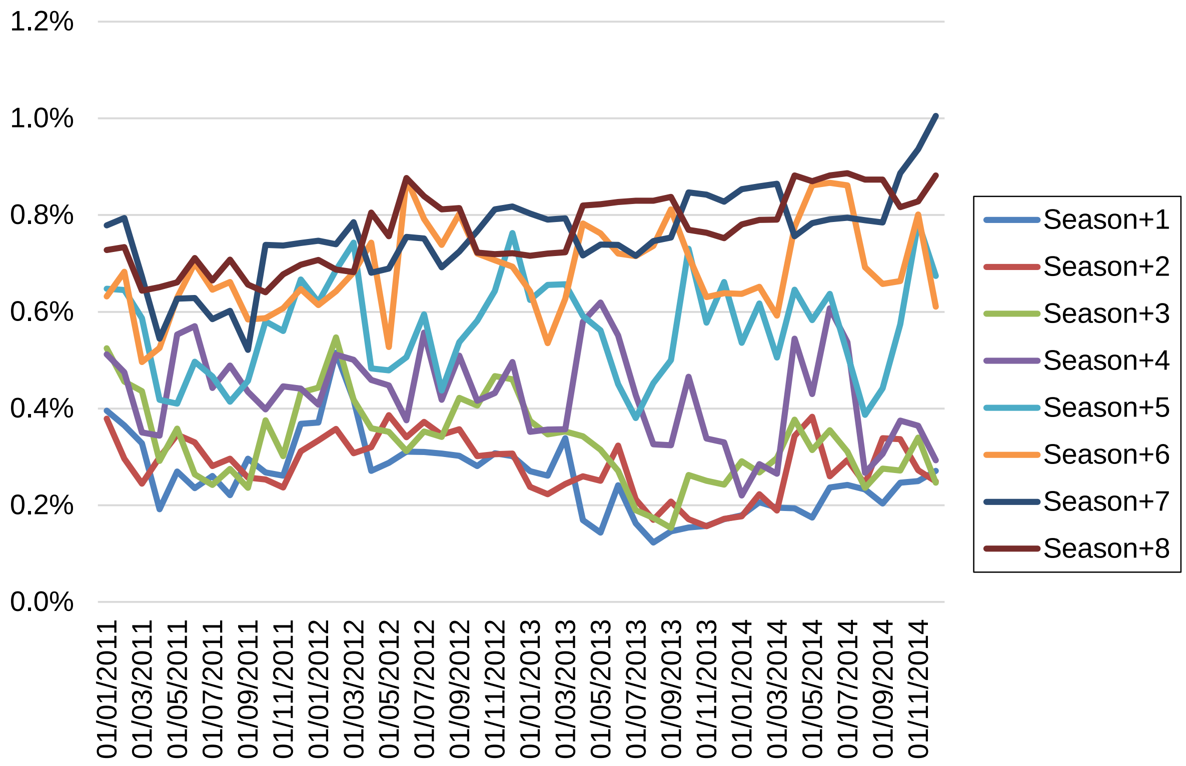
139. Gas products had tighter spreads than their electricity equivalents. There was also a larger number of products within a given spread – for example, the chart below shows eight Seasonal gas products with a spread of under 1%, compared to generally four or five Seasonal Baseload products for electricity. The main divergence in the pattern among products was that, for gas, Monthly spreads were tighter than equivalent Seasonal spreads.

Figure 44: Monthly average spreads for seasonal gas products



Source: CMA analysis, ICIS Heren data.

Figure 45: Monthly average spreads for Quarterly and Monthly gas products



Source: CMA analysis, ICIS Heren data.

140. ICIS Heren also recorded when its spread data was based on actual bids and offers in the market at their designated market close time, and when it had to default to other market data; this distinction could be used as an indicator of availability. Table 7 shows the results of our analysis of this. It suggests that availability is better for Baseload than Peak, better for Seasons than for Months than for Quarters, and better close to delivery – all of which is consistent with our other analysis. The same pattern is true of gas. We note that the figures for electricity cannot be compared with those for gas: ICIS Heren told us that because gas is more liquid than electricity, the standards for bid-offer confirmation are higher.

Table 7: Proportion of days on which actual spreads were observed rather than estimates

			%
Product	*Baseload*	*Peak*	*Gas*
Month+1	99	78	86
Month+2	97	54	74
Month+3	75	25	54
Month+4	26	7	23
Quarter+1	85	46	69
Quarter+2	50	16	46
Quarter+3	15	2	26
Quarter+4	6	1	13
Season+1	99	73	85
Season+2	98	61	78
Season+3	96	40	66
Season+4	90	25	43
Season+5	66	8	20
Season+6	27	1	8
Season+7	4	1	2
Season+8	0	0	1

Source: CMA analysis, ICIS Heren data.
Note: Gas figures are not directly comparable with electricity.

Hedging analysis

Our approach

141. Our quantitative hedging analysis looks at how parties hedge in practice. Some of the concerns raised about liquidity relate particularly to shaping, so we have ensured that our data is sufficiently granular to provide information on shape. We note that this data reflects how firms actually hedge, and that may be either because they ideally wish to hedge in this way, or because availability of products affects their hedging.

142. As with the trading data, this work focuses on electricity, although there is a later comparison with gas.

Data

143. We asked parties to complete templates describing their historical hedging positions. For practical reasons, we based this on sample delivery dates. These are the second Tuesday of each month,[68] between January 2011 and July 2014. (This is the same period as the trading data.)

144. For each of these delivery dates (second Tuesdays), our template asked for information on how the party built up its position over the previous years. We asked for information at set points before delivery.[69] We asked for the contracted and forecast volumes at each point ahead of delivery. We also

[68] Intended to be a representative weekday.
[69] The set points were: 36 months ahead, 24 months ahead, 18 months ahead, 12 months ahead, six months ahead, one month ahead, week ahead and day ahead.

asked for each firm's contracted volume and final output or demand at delivery.

145. As noted above, we want to understand whether there are issues about hedging shape. This means that we asked parties to provide the information above on a settlement period (half-hourly) basis.

146. We sent this questionnaire to the Six Large Energy Firms and to independent suppliers and generators. We asked these parties to complete separate templates for different business areas.[70] The number of templates completed by each party depended on:

(a) the scope of its activities – some parties do not participate in all business areas;

(b) the categories it uses to manage its hedging; and

(c) the extent to which data was available.

147. The responses received are mostly complete. SSE was unable to fill out our templates, because [✂].Some independent firms were unable to complete the templates, though they did send us qualitative information. Some other independent firms were unable to provide forecast volumes, or provided forecasts for usage of their existing customers but not a forecast of the set of customers they would have at the relevant point in the future, but were able to provide contracted and final volumes.

[70] For example, gas generation or domestic variable supply.

Table 8: Electricity hedging templates completed by each party (at most disaggregated level)*

Party	*Generation*	*Supply*
Centrica	Gas; Nuclear; Renewables	Domestic variable; Domestic fixed; Non-domestic fixed
[✂]	[✂]	[✂]
E.ON	Coal; Gas; Renewables; Unallocated	[✂]
RWE	Coal; Gas; Biomass; Oil; Lynemouth coal; Renewables; Cogeneration; Prompt embedded	Domestic; SME; I&C; Retail-generation netting
Scottish Power	All	All
Co-op Energy		Domestic variable; Domestic fixed
First Utility		All
Opus		Microbusiness; I&C
Utilita		All
Drax	Coal	
ESB	Gas	
ENGIE	Rugeley; Saltend; Deeside; First Hydro	
Intergen	Gas	
MPF	Baglan Bay; Sutton Bridge; Severn	

Source: Parties' responses.
*Some parties also provided summary templates at more aggregated levels.

Key measures

148. As with trading, we are interested in three areas:

(a) overall volumetric hedging;

(b) hedging of annual shape; and

(c) hedging of daily shape.

149. For overall volumetric hedging, we look at this on a percentage basis. Ideally we would look at contracted volumes as a percentage of forecast volumes.[71] However, as several independent firms were unable to provide forecast volumes, we instead use final volumes.[72] (See paragraph 152 for further discussion of this.) We also note that this gives us an aggregate picture when we look at an entire supply portfolio, but firms may hedge customers on fixed

[71] The forecast volume represents the information available to a firm at the time it made its hedging decision. It is therefore reasonable to suppose that a firm's hedging decisions are made in relation to this. The final volume may differ from the forecast volume for a variety of reasons, such as growth, changes in plant profitability, or deviations from seasonal normal weather. Another potential comparator would be contemporary actual demand. However, the construction of our data set means that we do not have information on this for all timeframes before the start of our delivery dates.
[72] We present results on the same basis for all firms to aid comparability.

term contracts different from customers on variable contracts. For example, we understand that some suppliers, for some types of customer, may hedge 'back to back', ie when a customer signed a fixed-term fixed-price contract, the supplier buys the expected volume of that customer's demand over the whole term of the contract.[73]

150. It is possible for the contracted volume to be greater than the final volume, meaning that the hedged percentage exceeds 100%. Suppliers sometimes buy more than they need for a period and sell back to the market later (or vice versa for generators). For example, this can happen at times of day with low demand (eg overnight), if a firm is hedging by buying Baseload products (which deliver the same volume throughout the day).

151. In order to summarise the volumetric hedge, we use the median hedged percentage to compare firms. This reduces the impact of outliers on the results, compared to using the mean. However, there can still be a large degree of variability around the median. For example, the chart below illustrates the overall supply hedge for [✂]. The interquartile range is up to 24 percentage points, and the range between the 95th percentile and the 5th percentile reaches a maximum of 70 percentage points.[74]

Figure 46: Example of hedge variability – contracted volume as a percentage of final demand for [✂]'s whole supply business

[✂]

Source: CMA analysis, party's data.
Note: 36m – 36 months ahead of delivery; 24m – 24 months ahead of delivery; 18m – 18 months ahead of delivery; 12m – 12 months ahead of delivery; 6m – six months ahead of delivery; 1m – one month ahead of delivery; wa – one week ahead of delivery; da – one day ahead of delivery; del – at delivery.

152. As noted above, our results use contracted volumes as a percentage of final output or demand. However, for the Six Large Energy Firms, we also have information about forecast output or demand. We can therefore compare contracted volumes as a percentage of final volume, and contracted volumes as a percentage of forecast volume. This allows us to see if there are any key differences between two measures. The table below shows the percentage

[73] This means that a portfolio of fixed-term customers, for a firm that was growing, would appear to be less than 100% hedged down the curve on our measure, even though it would consider itself to be fully hedged at any point in time. This was not a substantial issue for the Six Large Energy Firms since their customer volumes were generally not changing rapidly (in percentage terms) over this period. In any cases where we thought this may be an issue, we took it into consideration in interpreting the results.
[74] To some extent, this variability may be the result of firms deliberately applying flexibility. For example, an internal document from ENGIE showed proposed upper and lower bounds for hedging, with around 30 percentage points difference.

point difference between the median hedge percentages using the two metrics.[75] It covers the Six Large Energy Firms' supply businesses.

Table 9: Percentage point difference: median contracted volume as a percentage of final demand, minus median contracted volume as a percentage of forecast demand (based on the supply businesses of the Six Large Energy Firms)

					Percentage point
Time ahead of delivery	[✄]	[✄]	[✄]	[✄]	[✄]
36m	[✄]	[✄]	[✄]	[✄]	[✄]
24m	[✄]	[✄]	[✄]	[✄]	[✄]
18m	[✄]	[✄]	[✄]	[✄]	[✄]
12m	[✄]	[✄]	[✄]	[✄]	[✄]
6m	[✄]	[✄]	[✄]	[✄]	[✄]
1m	[✄]	[✄]	[✄]	[✄]	[✄]
wa	[✄]	[✄]	[✄]	[✄]	[✄]
da	[✄]	[✄]	[✄]	[✄]	[✄]
del	[✄]	[✄]	[✄]	[✄]	[✄]

Source: CMA analysis, parties' data.
Note: 36m – 36 months ahead of delivery; 24m – 24 months ahead of delivery; 18m – 18 months ahead of delivery; 12m – 12 months ahead of delivery; 6m – six months ahead of delivery; 1m – one month ahead of delivery; wa – one week ahead of delivery; da – one day ahead of delivery; del – at delivery.

153. The differences vary between firms: all of Scottish Power's differences are under [✄] percentage points, whereas E.ON's largest difference is [✄] percentage points. The largest differences belong to three parties where the percentage based on final demand is consistently smaller than the percentage based on forecast demand. (This implies that the final demand is larger than the forecast demand). In each case, we believe that these are due to parties' forecast volumes not including parts of I&C demand. We believe that this issue means our preferred approach is reasonable (especially when we look at hedges that do not include I&C supply).[76,77] We therefore proceed with using the percentage based on final demand, while accepting that this may have an effect on the hedged percentages of particular firms. (If anything, using final volumes will underplay the extent to which these three parties are hedged.)

154. For shaping, we present information on firms' hedges graphically. To make it easier to identify patterns in the graphs, we use the median contracted volume as our metric.

[75] This comparison is based on an identical set of observations for each metric. (We dropped any observations where final or forecast volumes were missing.) In the main body of the analysis, we have used only final volumes, and so we have not dropped observations where forecast volumes were missing.
[76] [✄]. [✄]. The cause therefore seems to be the same. Similarly, E.ON's large negative differences seem to result from its I&C portfolio. E.ON told us that it does not include a number of its I&C customer types in its forecasts until week ahead. These include customers on flexible contracts and customers who are out of contract.
[77] The two approaches would diverge more if a firm's volume of customers diverged significantly from forecast in percentage terms (eg unexpectedly fast growth).

Supply hedging

Volumetric supply hedging – Six Large Energy Firms

155. The graph below shows the overall supply hedges for five of the Six Large Energy Firms, based on their entire supply businesses.[78]

Figure 47: Median contracted volume as a percentage of final demand – Six Large Energy Firms – all supply

[✄]

Source: CMA analysis, parties' data.

156. The graph shows that all of the Six Large Energy Firms have forward hedges for their supply businesses which extend at least two years ahead. This is aligned with the qualitative information we received from them.[79] [✄] hedged [✄] of its supply volumes 24 months out, making it the firm with the largest median hedge at this point. There is a fairly similar pattern between these firms, especially within 18 months from delivery. This might suggest that they have a similar ability to hedge.

Volumetric supply hedging – comparing the Six Large Energy Firms and independent suppliers

157. The graph below takes the previous graph and adds hedging profiles for independent suppliers.

Figure 48: Median contracted volume as a percentage of final demand – Six Large Energy Firms and independent suppliers – all supply

[✄]

Source: CMA analysis, parties' data.

158. Independent suppliers generally have shorter hedges than the Six Large Energy Firms. Before a year ahead, all independent suppliers in our data have smaller hedged percentages than the Six Large Energy Firms. Co-op Energy, [✄] and Opus all carry out the bulk of their hedging [✄].[80]

159. The impression that independent suppliers have shorter hedges is also confirmed by qualitative responses from independent suppliers:

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[78] As noted above, SSE was unable to provide data in the same format as other firms.
[79] [✄]. E.ON described its variable hedge [✄]. RWE said that it the length of its hedging approach for SVT customers [✄]. However, it said that it would not hedge domestic variable customers beyond [✄]. [✄]. [✄]. [✄] SSE's data is not included in this graph. However, SSE told us that it hedges supply [✄].
[80] In the case of First Utility, we calculated results that may be misleading as to its normal behaviour because of the way it traded in this period (discussed above). In addition, [✄].

(a) BES Utilities (BES) said that it traded only up to six to nine months ahead.

(b) Ecotricity said that its hedging strategy covered up to a year ahead.

(c) OVO Energy provided information showing that its hedging extended around 18 months into the future.[81]

(d) Spark said that its hedging strategy covered 18 months ahead, and that it aimed to be fully hedged three to six months before delivery.

160. Despite this, the independent suppliers have similar hedged percentages to the Six Large Energy Firms at the month-ahead stage. This suggests that there is not a barrier to them achieving a volumetric hedge in this timeframe.

161. Independent suppliers have grown over the period. This means that the forecast demand of an independent supplier in forward timeframes may generally be smaller than its final demand. It is therefore possible that the percentage based on final demand may underestimate the extent to which growing independent suppliers were hedged. For example, Co-op Energy told us that [✂]. Our graph may therefore present an upper bound on the difference in hedged percentages between the Six Large Energy Firms and independent suppliers.

162. We also compared the hedged profiles of the Six Large Energy Firms and independent suppliers in domestic supply. Independents also had shorter hedges than the Six Large Energy Firms in this area. For example, [✂],[✂] and [✂] [✂]. Independent suppliers ([✂], [✂] and [✂]) had [✂].[82]

163. On its own, the picture of the Six Large Energy Firms hedging further out than independent suppliers has a number of potential interpretations. These could include liquidity, access to credit, or commercial choice. We therefore need to look at this in the context of other information. However, Figure 48 might suggest that the Six Large Energy Firms are not relying on the implicit hedge between their generation and supply arms; if they were, we would expect to see them having **shorter** hedges than independent suppliers.[83]

[81] For example, OVO Energy provided an internal document as part of its response to the trading questionnaire showing its hedged position for electricity in September 2014. At this stage, its longest hedge was until March 2016.
[82] In the case of First Utility, the results we calculated may be misleading because of the way it traded in this period (discussed above). See also footnote 80, which also applies here.
[83] As discussed in the main body of this appendix.

Annual shape

164. We looked at hedging for individual months in order to see whether firms' contracted volumes reflect the relative demand in each month. In forward timescales, this would be the case if firms were hedging using individual Monthly products, but would not be true if firms were hedging using Seasonal products (which deliver the same volume over six months).

The Six Large Energy Firms

165. The chart below shows contracted volumes for [✂] supply business. At six, 12, 18 and 24 months ahead, [✂] hedged volume increases over the summer Season.[84] In contrast, final consumption is lowest in July and August.[85] This appears to suggest that [✂] is using Seasonal products further ahead, and leaving its Monthly trading nearer to delivery.

Figure 49: Median contracted volume (per settlement period) by month in summer – [✂] supply

[✂]

Source: CMA analysis, party's data.

166. This picture is reasonably representative of the Six Large Energy Firms. Paragraph 229 below provides more information on others of these firms, in the context of comparing parties' hedging and trading data.

Independent suppliers

167. For independent suppliers, there is a mixed picture. The graph below shows the hedged position by month for Opus. Looking at 12 months and six months ahead, the contracted volume increases over the summer Season. We obtained a similar result for [✂].

[84] This occurs because Seasonal products start in specific months, and because we would expect the volume of trading in a product to increase over time. We would therefore expect to see a greater volume hedged for months towards the end of a season (eg September) than at the start (eg April).
To give a specific example, we think about Summer 2015 and look at each month from 12 months ahead. We assume that in April 2014 a firm has bought 50 MW of Summer 2015 product. It will continue to buy Summer 2015 over the following months – in each month, it might buy an extra 10 MW. By September 2014, the volume hedged for September 2015 will be 100 MW. By September 2014, it will also have hedged 100 MW for April 2015 – but our 12 month ahead chart looks at April 2015 only from the perspective of April 2014, not September 2014. So when the firm buys a Summer product, our 12 month ahead line slopes up. In contrast, if it were hedging using Monthly products, we would expect our 12 month ahead line to match the monthly shape of demand. Even if demand were flat across the summer, our 12 month ahead line would be flat.
[85] This is indicated by the shape of [✂] contracted volume at delivery.

Figure 50: Median contracted volume (per settlement period) by month in summer – Opus supply

[✂]

Source: CMA analysis, party's data.

168. However, [✂] contracted volumes 12 months and six months ahead show some signs of shaping by month. [✂].[86]

Figure 51: Median contracted volume (per settlement period) by month in summer – Utilita supply

[✂]

Source: CMA analysis, party's data.

Daily shape

The Six Large Energy Firms

169. We are interested in when suppliers shape their contracted positions to reflect the profile of their final demand over a day. First Utility suggested that the Six Large Energy Firms could do this through internal trading, stating that 'On a forward basis, VI generators could sell bespoke forward shaped products to their VI supply businesses.' If this were the case, we would expect to see each of the Six Large Energy Firms having a forward contracted profile that follows the shape of its demand.

170. The evidence suggests that this is not the case. Most of the Six Large Energy Firms seem to leave their shape trading to the near term,[87] as illustrated by the graph below for [✂]. This graph shows [✂] median contracted position for each settlement period, with each line representing a different time ahead of delivery. The flat lines on the graph until the week-ahead stage indicate that [✂] was trading only standard products, rather than a shape which looks like its final demand. The main product used appears to be Baseload (flat lines over the entire day), as well as small amounts of Peak (settlement periods 15–38). This is aligned with firms' qualitative responses – [✂] provided examples of their supply business placing orders for specific standard products with their trading business.

Figure 52: Median contracted volume by settlement period – [✂] supply

[✂]

Source: CMA analysis, party's data.

[86] See footnote 53 above.
[87] This is based on graphs similar to the one below for [✂]. [✂] also told us it generally starts to trade shape two to three months before delivery.

171. One of the Six Large Energy Firms displays a different pattern to the rest. E.ON's graph, below, shows that its contracted position exhibits daily shape from [✂]. This may be explained by its process –[✂] ([✂].)

Figure 53: Median contracted volume by settlement period – E.ON supply

[✂]

Source: CMA analysis, party's data.

172. [✂]. However, our trading analysis shows that E.ON's trading activity is not noticeably different to that of other large energy companies.[88] [✂], E.ON's position at a group level may be no different to that of other parties.

173. In general, there is no evidence that the Six Large Energy Firms (except E.ON) are trying to add significant daily shape to their forward contracted supply positions.

The Six Large Energy Firms – daily shape by portfolio

174. The Six Large Energy Firms each have domestic and non-domestic supply businesses. Domestic and non-domestic demands have different daily shapes, meaning that they offset each other – to some extent – when combined. A combined supply business therefore has a flatter daily demand shape than a domestic-only or non-domestic-only supplier. This may help to explain why the Six Large Energy Firms do not hedge daily shape along the curve.

175. To illustrate this, the charts below show RWE's domestic, non-domestic and combined supply businesses. The non-domestic business has its highest demand in the middle of the day, while the domestic business has its highest demand in the evening.[89]

Figure 54: Median contracted volume by settlement period – RWE domestic supply

[✂]

Source: CMA analysis, party's data.

Figure 55: Median contracted volume by settlement period – RWE non-domestic supply

[✂]

Source: CMA analysis, party's data.

[88] For example, E.ON traded [✂] of its volume as Baseload. This [✂] to the figure across the Six Large Energy Firms as a group (80%).
[89] In each case the shape of demand is represented by the contracted volume at delivery. (We would expect demand to be very similar to contracted volume, as otherwise the party would incur imbalance costs.) We saw a similar pattern for other firms (Centrica and EDF Energy) for whom we could perform this analysis.

Figure 56: Median contracted volume by settlement period – RWE supply (combined)

[✂]

Source: CMA analysis, party's data.

Independent suppliers

176. There is a mixed picture for whether independent suppliers hedge daily shape. [✂]'s daily profile is shown below. There is some sign of daily shape from six months out. [✂]'s trade data shows that it trades shape with [✂].

Figure 57: Median contracted volume by settlement period – [✂]

[✂]

Source: CMA analysis, party's data.
Note: [✂].

177. Several other independent suppliers also hedge shape. These firms all have contracts with intermediaries. (This implies that the question may not be whether independent suppliers can obtain shape, but rather the cost of the service provided by intermediaries.)

- The equivalent chart for First Utility shows that its contracted volume has daily shape from [✂] ahead. We understand that this was the case under its previous contract with Morgan Stanley, [✂]. Under First Utility's current contract with Shell, it trades [✂] and starts to take on daily shape [✂] before delivery. First Utility has a contract with Shell (and previously had one with Morgan Stanley).

- Similarly, the chart for Opus has daily shape throughout the period. Opus has a contract with ENGIE.

- Spark told us that it is able to trade hourly shape through its contract with Morgan Stanley.

178. [✂].

Figure 58: Median contracted volume by settlement period – Utilita

[✂]

Source: CMA analysis, party's data.

179. It is not straightforward to compare independent suppliers (some of which have contracts with intermediaries) and the Six Large Energy Firms (which do not). However, at least some independent suppliers are able to contract for daily shape and do so to a greater extent, and earlier, than the Six Large Energy Firms.

Generation hedging

Volumetric generation hedging

180. We now look at generation, starting with the overall hedges of the Six Large Energy Firms. The graph below shows that the percentage hedges varied more between firms in generation than in supply. For example, at 18 months out, [✂] had a median hedge of [✂]. In contrast, [✂] had a median hedge of [✂] 18 months ahead.

Figure 59: Median contracted volume as a percentage of final output – generation – Six Large Energy Firms

[✂]

Source: CMA analysis, parties' data.

181. Two firms hedged earlier than the others – [✂] and [✂] sold at least 30% of their final output 24 months ahead of delivery. The three other firms sold the majority of volume within 18 months from delivery.

182. [✂] operates on an integrated basis, [✂].If firms saw benefits in aligning their generation and supply hedges (eg due to collateral savings), then we might expect integrated firms to be better able to deliver this.[90] Some firms have suggested to us that generators would generally prefer to hedge further ahead than suppliers.[91] More integrated firms might therefore hedge their generation later or their supply earlier in order to align the two. In practice, this does not appear to be the case – [✂] had the shortest supply profile, and its generation profile was not an outlier.

183. More generally, there is some pattern of the Six Large Energy Firms hedging a greater proportion of their generation than their supply at a given point in time, as shown in the table below. [✂], [✂] and [✂] all had generation hedges which were significantly larger than their supply hedges in percentage points (eg 12 months ahead).

[90] As a centralised decision maker would be able to take into account the positive externalities.
[91] For example, Drax, Response to issues statement, p2.

Table 10: Percentage point difference between median generation hedge and median supply hedge

Percentage point

Time ahead of delivery	[✂]	[✂]	[✂]	[✂]	[✂]
36m	[✂]	[✂]	[✂]	[✂]	[✂]
24m	[✂]	[✂]	[✂]	[✂]	[✂]
18m	[✂]	[✂]	[✂]	[✂]	[✂]
12m	[✂]	[✂]	[✂]	[✂]	[✂]
6m	[✂]	[✂]	[✂]	[✂]	[✂]
1m	[✂]	[✂]	[✂]	[✂]	[✂]
wa	[✂]	[✂]	[✂]	[✂]	[✂]
da	[✂]	[✂]	[✂]	[✂]	[✂]
del	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis, parties' data.

184. The graph below includes independent generators. There are strong variations between independent generators, meaning that there is not a clear picture as to whether they hedge in a different way from the Six Large Energy Firms.

Figure 60: Median contracted volume as a percentage of final output – Six Large Energy Firms and independent generators

[✂]

Source: CMA analysis, parties' data.

185. At 36 months ahead Drax already had a median hedge of 22%.[92] This was larger than any of the Six Large Energy Firms. However, Drax then hedged only 15 percentage points more over the next 18 months. Drax told us that its hedging policy covers at least three years ahead.

186. On an overall basis, ENGIE was 12% hedged at 18 months out, and 34% hedged at 12 months out. This was slightly below the shortest hedges of the Six Large Energy Firms. There is a similar pattern when we look at particular generation technologies. ENGIE hedged its coal output within 18 months from delivery. This was the shortest hedge of all the firms in this sample.[93] For gas generation, ENGIE appears to have a similar hedging profile to some of the Six Large Energy Firms.

187. Some other independent generators traded more near-term:

- ESB's median hedge was zero a week ahead of delivery.[94]

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[92] This may result from its long-term agreements with Centrica. Drax had two structured agreements to sell baseload to Centrica – one expired in 2012, and the other expires in 2015.

[93] Eggborough (an independent generator with a coal-fired power station) told us in its qualitative response that its hedging policy covers three seasons ahead, which would also be around 18 months.

[94] ESB is currently only hedging its Corby power station (ESB, Response to trading questionnaire, pp1–4). This was built in 1993 (DECC (2014) Electricity: chapter 5, Digest of United Kingdom energy statistics (DUKES), 5.10:

- At six months ahead of delivery, Intergen's median hedge was zero.[95]
- We have limited data for MPF, because it bought its plants only in the last couple of years. [✂].

188. As noted in the main body of this appendix, there are several reasons why Drax and ENGIE may hedge differently from other independent generators.

Generation hedging – daily shape

189. We see a similar picture for the hedging of daily shape in generation as in supply. Most of the Six Large Energy Firms seem to hedge using only Baseload and Peak until close to delivery.[96] Many firms fully shape their positions only at the day-ahead stage, although some firms appear to do some hedging using forward blocks.[97] The graph below shows [✂] hedging – the flat lines suggest it trades only (or primarily) Baseload and Peak products until around a week before delivery.

Figure 61: Median contracted volume by settlement period – [✂]

[✂]

Source: CMA analysis, party's data.

190. Independent generators also seem to hedge primarily using Baseload and Peak in forward markets. This is shown in the graph below for ENGIE. We can also see that ENGIE hedged a small amount using Blocks six months ahead.

Figure 62: Median contracted volume by settlement period – ENGIE

[✂]

Source: CMA analysis, parties' data.

191. Overall, generators do not seem to be hedging using fully shaped products. Both the Six Large Energy Firms and independent generators appear to leave their shape hedging until near to delivery.

Power stations in the United Kingdom), meaning that it probably has low efficiency. It is therefore hard to predict whether it will run. ESB may therefore have little need to trade forward the output from this plant. ESB's data is consistent with its statement that it trades Corby's output only up to month ahead.

[95] Intergen's hedge increases significantly at delivery – this represents Centrica's nomination under its tolling agreement.

[96] E.ON's graph is different, as it includes some signs of shape. However, this seems to be the result of eight months (August 2011 to March 2012) of trading in its coal portfolio only.

[97] [✂].

Effects of vertical integration

192. Up to this point, our analysis has looked at the generation and supply arms of the Six Large Energy Firms separately. In this section, we consider these parts of their businesses together. In particular, this allows us to consider the potential effects of the natural hedge between generation and supply activities.

193. We asked each of the Six Large Energy Firms whether their supply arm considers their generation arm when hedging (and vice versa). Most of them said that their different arms make these decisions independently. [✂]. RWE stated that ‘When the Supply Business evaluates the extent to which it is hedged at various points ahead of delivery, no consideration is given to the Generation Business positions.’

194. Some of the Six Large Energy Firms did identify situations where they consider different arms together for the purposes of hedging, based on overarching risk assessments:

   (a) [✂];

   (b) [✂]; and

   (c) E.ON said that ‘The supply business has at times considered our generation position when considering the degree of strategic risk we face.’

195. We also have an example of wider considerations from [✂].

196. Taking the statements from the Six Large Energy Firms into account, we looked at the extent to which factoring in generation activities affects the degree to which these firms are hedged. We did this by constructing a measure we called total hedge, which applies to the firm’s supply business. This adds together the contracted volumes purchased by the supply business and the firm’s uncontracted generation. The total hedge is expressed as a percentage of the firm’s final volume supplied. This is only an indicative metric. (See the section titled ‘the Natural Hedge’ in the main body of this appendix.)

197. As the example chart below shows, the composition of the total hedge changes over time. At three years out, [✂]’s total hedge is dominated by uncontracted generation. Over time, there are more supply purchases, and there is less uncontracted generation.

Figure 63: Total hedge by source – [✂]

[✂]

Source: CMA analysis, party's data.

198. The chart below shows the median total hedge for the Six Large Energy Firms. The slope is fairly flat, meaning that each firm starts off with a significant total hedge. For example, at 24 months out, each firm has a total hedge of at least 49%, and three firms have a total hedge of over 92%.

Figure 64: Median total hedge (uncontracted final generation plus supply contracts, as a percentage of final demand) – Six Large Energy Firms

[✂]

Source: CMA analysis, parties' data.

199. Although this applies at the median, it would still be possible for there to be periods with a low total hedge. This could occur if the output profile from a firm's generation deviated significantly in places from the demand profile of its supply business. This does not appear to be the case. Even at the lower quartile, each firm still has a significant hedge in place. With the exception of [✂], each firm had a lower quartile total hedge of at least 40% at all timescales.

200. The total hedge metric helps us to remember that the supply hedge of the Six Large Energy Firms may look rather different if we consider the impact of uncontracted generation. It may be harder for a non-integrated supplier to achieve the same total hedge as a vertically integrated supplier, as this would require larger amounts of purchases along the curve.

Gas supply hedging

201. As a comparison, we can look at the hedging of firms in the gas market. As noted in the main section of this appendix, there are some key differences between gas and electricity that could affect firms' hedging in the two products.

Volumetric gas supply hedging

The Six Large Energy Firms

202. Four of the Six Large Energy Firms had very similar hedging profiles. Each was around 10% hedged 24 months ahead, and 40–45% hedged 12 months ahead. This means that these firms were buying the majority of their volumes within year.

Figure 65: Median contracted volume as a percentage of final demand – gas supply – Six Large Energy Firms

[✂]

Source: CMA analysis, parties' data.

203. The exception (for whom we had data) was [✂], which was over [✂] hedged [✂] months out. [✂] noted in its response to the supply questionnaire that its [✂].

204. The Six Large Energy Firms have smaller offsetting upstream positions in gas than in electricity, or in some cases none in gas.[98] If the 'natural hedge' were important for firms' hedging decisions in electricity, then we might expect them to react by explicitly hedging larger volumes in gas, so as to achieve the same overall effect. This does not appear to be the case.

205. Looking at the hedged percentages, apart from Scottish Power, firms generally had larger hedges for electricity than for gas. The only exceptions were [✂],[✂], and [✂].[99] This can be seen in the chart below, where the percentage point difference between electricity and gas is generally positive (meaning that the median percentage hedge is larger in electricity).

Figure 66: Percentage point difference: median contracted volume as a percentage of final demand in electricity, minus median contracted volume as a percentage of final demand in gas – Six Large Energy Firms

[✂]

Source: CMA analysis, parties' data.

Independent suppliers

206. The graph below adds the hedging profiles for independent suppliers. It appears that independent suppliers had somewhat shorter gas hedging profiles than the Six Large Energy Firms.

Figure 67: Median contracted volume as a percentage of final demand – gas supply – Six Large Energy Firms and independent suppliers

[✂]

Source: CMA analysis, parties' data.

207. Neither [✂] nor [✂] seemed to hedge a significant amount 24 months out relative to their actual supply.[100] In contrast, the Six Large Energy Firms all carried out some hedging at this stage. The percentage hedged by [✂] was

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[98] See Section 4: Nature of wholesale competition.
[99] However, making direct comparisons between the hedged percentages for gas and electricity is somewhat complicated because electricity has daily shape, while gas does not.
[100] [✂]

similar to or larger than those from the Six Large Energy Firms by the year-ahead stage, and the percentage hedged by [✂] was similar to those from the Six Large Energy Firms by six months ahead. From the data available, [✂] also seemed to have a similar or larger hedge than the Six Large Energy Firms from 12 months out. We do not have trading data for [✂]. However, from other information submitted, we understand that it carries out the majority of its hedging within a year from delivery.[101]

208. If liquidity were the key constraint preventing independent suppliers from trading forward in electricity, then we might expect to see independent suppliers trading further ahead in gas. However, there is a mixed picture on this. [✂]'s gas hedges were all larger than the equivalent electricity hedges. [✂] gas hedges were larger 18 months out [✂] and 12 months out [✂]. However, none of [✂]'s gas hedges was larger than its electricity equivalents. As with Figure 66, a bar above the axis indicates that the median percentage hedge is larger in electricity than gas.

Figure 68: Percentage point difference: median contracted volume as a percentage of final demand in electricity, minus median contracted volume as a percentage of final demand in gas – independent suppliers

[✂]

Source: CMA analysis, parties' data.

Gas supply hedging – annual shape

209. We also looked at how firms manage their annual shape in gas. We might expect this to be more significant in gas than electricity, given that season variation in gas demand is substantially greater than in electricity.

210. As in electricity, Centrica, [✂] and [✂] appear to be leaving their monthly shaping until closer to delivery. As the graph below shows, [✂]'s supply hedge started to mirror its monthly shape only between six months and one month before delivery. This would be consistent with [✂] hedging using mainly products longer than a month (ie Quarters and Seasons) before that point.

Figure 69: Median daily contracted volume by month in summer – [✂] gas supply

[✂]

Source: CMA analysis, party's data.

[101] Based on charts submitted as part of its response to our electricity questionnaire.

211. As with electricity, E.ON's graph had monthly shape from an early stage. E.ON is able to buy Monthly gas products from its trading business up to six seasons ahead. In the case of gas, [✂] also had a contracted monthly shape which followed the pattern of demand [✂].[102]

Figure 70: Median daily contracted volume by month in summer – Scottish Power gas supply

[✂]

Source: CMA analysis, party's data.

212. All three of the independent suppliers for which we have data ([✂]) also had profiles that exhibit some monthly shape. [✂]. These positions may result from independent suppliers being able to trade a more granular product range through their intermediaries.

Figure 71: [✂]

[✂]

Source: CMA analysis, party's data.

Trading in support of hedging

213. In this section we bring together information on trading and hedging to assess whether the external trading carried out by the Six Large Energy Firms is sufficient to construct their hedged positions. If this trading is sufficient, then it suggests that independent firms should be able to replicate these hedges in the market. If the Six Large Energy Firms' external trading is not sufficient, then this might indicate that internal trading plays an important role. This would be an option unavailable to independent firms (without either vertically integrating or entering into a long-term contract with a generator willing to trade shape well in advance of delivery).

Comparing hedging and trading – volumetric hedging

214. While our hedging and trading data cover similar timeframes, they are not immediately comparable. For example, our trading data includes all trades, whereas the hedging data looks only at snapshot days. We therefore converted the hedging data into an annual hedge volume requirement. This involves transforming the median hedged volume per settlement period into an annual purchase requirement.[103]

[102] [✂].
[103] Multiplying by 17,520 (number of half-hour settlement periods per year).

215. We then compared this against (for supply) the annual average volume bought and (for generation) the annual average volume sold, based on the trading data we collected. The graph below presents the volumes bought and sold on a cumulative basis. This is for comparability with the hedge profiles, which build up over time.

216. This analysis is necessarily approximate, with several caveats:

(a) The hedge volume requirement will be a slight overestimate. This is because the hedging data covered only Tuesdays, and weekends have lower demand.[104]

(b) 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.

(c) For the supply comparison, the traded volume is based on purchases. In reality the supply arm will sell as well as buying, but we cannot identify which trades were carried out for supply purposes. (Similarly, the generation arm will sometimes buy as well as selling.)

217. The question we ask is whether the traded volume meets (or exceeds) the hedge volume requirement. If not, then (subject to the caveats above) this would suggest that some of the hedge is being achieved through internal transfers. The caveats are largely conservative (ie they make the hedge volume requirement harder to meet).

218. We are able to complete this analysis for five of the Six Large Energy Firms.[105] For each company, we look at generation and supply separately, so we have ten graphs in total. We discuss the results in more detail below, but we summarise the results here:

(a) Two graphs ([✄] and [✄]) show traded volume exceeding the hedge volume requirement in every timeframe.

(b) Three graphs ([✄], [✄]) show traded volume exceeding the hedge volume requirement in all but one or two timeframes. In the cases where the traded volume is lower, this is only by small amounts (under 2 TWh).

[104] This may not be significant if most trading along the curve is Baseload.
[105] We cannot look at SSE in this way, because it was unable to complete our hedging templates.

(c) Three graphs ([✄]) have four instances where the traded volume is less than the hedge volume requirement. However, the differences are not particularly large.

(d) Two graphs ([✄]) show the traded volume exceeding the hedge volume requirement only from month ahead. The traded volume can also be significantly lower than the hedge volume requirement (by up to 18 TWh).

219. In general, this suggests that trading activity is sufficient to deliver parties' hedged positions, and even where it does not cover the complete hedged volume, there is substantial trading activity at each point in time where the firm takes a hedged position.

220. [✄]. This suggests that [✄] trading is generally consistent with its hedging.

Figure 72: Comparing cumulative volume bought and volume required to achieve hedge – Centrica supply

[✄]

Source: CMA analysis, party's data.

221. [✄].

Figure 73: Comparing cumulative volume sold and volume required to achieve hedge – Centrica generation

[✄]

Source: CMA analysis, party's data.

222. E.ON's supply hedge volume requirement [✄]. The largest difference is at [✄] out in volume terms (nearly [✄] of the hedge volume requirement).

Figure 74: Comparing cumulative volume bought and volume required to achieve hedge – E.ON supply

[✄]

Source: CMA analysis, party's data.

223. For E.ON's generation business, the volume it sold was also [✄]. However, the differences were fairly small (up to [✄] difference).[106]

Figure 75: Comparing cumulative volume sold and volume required to achieve hedge – E.ON generation

[✄]

Source: CMA analysis, party's data.

106 As with E.ON's supply business, the largest difference in percentage terms was 36 months out (91%). However, this was also based on very small volumes.

224. [✂].

Figure 76: Comparing cumulative volume bought and volume required to achieve hedge – EDF supply

[✂]

Source: CMA analysis, party's data.

Figure 77: Comparing cumulative volume sold and volume required to achieve hedge – EDF generation

[✂]

Source: CMA analysis, party's data.

225. The graph below shows that RWE [✂].

Figure 78: Comparing cumulative volume bought and volume required to achieve hedge – RWE supply

[✂]

Source: CMA analysis, party's data.

Figure 79: Comparing cumulative volume sold and volume required to achieve hedge – RWE generation

[✂]

Source: CMA analysis, party's data.

226. [✂] almost entirely met the hedge volume requirement for its supply business. [✂]. The difference was [✂], and arose because it had a [✂].

Figure 80: Comparing cumulative volume bought and volume required to achieve hedge – Scottish Power supply

[✂]

Source: CMA analysis, party's data.

227. [✂].

Figure 81: Comparing cumulative volume sold and volume required to achieve hedge – Scottish Power generation

[✂]

Source: CMA analysis, party's data.

Comparing hedging and trading – annual shape

228. Independent suppliers have suggested that there is limited liquidity in Monthly products further along the curve. The Six Large Energy Firms do not appear

to do much trading of Monthly products along the curve (as there is little volume traded beyond three months out).[107]

229. However, the Six Large Energy Firms also do not seem to be hedging using Monthly products along the curve. We have already looked at [✂] supply hedging of annual shape.[108] The charts below add to this by showing hedging by the supply businesses of [✂] and [✂] on a monthly basis during the summer.[109] In each case, the contracted volume in September is higher than the contracted volume in April in timescales up to six months ahead. This is in contrast to the profile of demand, which is higher in April.[110] This suggests that these parties are not hedging using monthly products until within six months from delivery, which is in line with their trading data. The picture for [✂] is generally similar (eg at 12 months ahead of delivery).

Figure 82: Median contracted volume per settlement period by month in summer – [✂] supply

[✂]

Source: CMA analysis, party's data.

Figure 83: Median contracted volume per settlement period by month in summer – [✂] supply

[✂]

Source: CMA analysis, party's data.

Figure 84: Median contracted volume per settlement period by month in summer – [✂] supply

[✂]

Source: CMA analysis, party's data.
[✂]

230. [✂]. This allows it to obtain [✂]. For example, its contracted monthly profile at [✂] before delivery is broadly similar to the shape of monthly demand.

Figure 85: Median contracted volume per settlement period by month in summer – [✂] supply

[✂]

Source: CMA analysis, party's data.

Comparing hedging and trading – daily shape

231. Our trading data showed that most Peak is traded within a year from delivery by the Six Large Energy Firms (although all of them trade small volumes further down the curve).

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107 See Figure 6 (Monthly Baseload) and Figure 9 (Monthly Peak).
108 See Figure 49.
109 As we do not have the full data for summer 2014, we exclude it from this analysis.
110 Approximated on the graph by the contracted volume at delivery.

Figure 86: Volume of trading by time ahead of delivery by the Six Large Energy Firms – Peak

[✂]

Source: CMA analysis, parties' data.

232. This is aligned with the charts below, which show the median contracted volume by settlement period at each stage ahead of delivery. From these, we can see when five[111] of the Six Large Energy Firms start to hedge their supply businesses' daily shape.

233. [✂] and [✂] both start to have evidence of Peak hedging only at 12 months ahead of delivery. This corresponds to their trading above – both companies traded some Peak between 12 and 18 months from delivery. Both firms also have Peak hedges that increase closer to delivery. This matches the build-up of traded volume over time.

Figure 87: Median contracted volume by settlement period – [✂] supply

[✂]

Source: CMA analysis, party's data.

Figure 88: Median contracted volume by settlement period – [✂] supply

[✂]

Source: CMA analysis, party's data.

234. Similarly, the chart below shows [✂]'s supply hedging. [✂]'s profile includes some [✂]. Figure 20 showed that [✂] traded some volume in 'other standard products' (a category including Extended peak and Overnights) between 18 and 24 months ahead, making it possible that [✂] achieved this shape in the market.

Figure 89: Median contracted volume by settlement period – [✂] supply

[✂]

Source: CMA analysis, party's data.

235. [✂] appears to add daily shape at a later stage [✂]. Its graph indicates that it is hedging shape only at [✂]. This is consistent with the trading graph, which suggests [✂] is trading only small volumes of Peak along the curve.

[111] As previously, we do not have this data for SSE.

Figure 90: Median contracted volume by settlement period – [✂] supply

[✂]

Source: CMA analysis, party's data.

236. As discussed above, [✂] obtains daily shape in a different way from the other Six Large Energy Firms. There are signs of [✂] ahead.

Figure 91: Median contracted volume by settlement period – [✂] sup**ply**

[✂]

Source: CMA analysis, party's data.