Appendix 10.5: Assessment of the competitive benchmark in retail energy supply

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Introduction

1. This appendix sets out our analysis to inform our view of the level of prices that suppliers would have required in order to cover reasonably efficient levels of costs and earn a fair rate of return on their capital employed. We refer to this as the competitive benchmark revenue (or unit revenue when expressed in £ per MWh). We controlled for differences in wholesale energy costs, indirect costs and the levels of capital employed, which (among others) contributed to the observed differences in profitability between suppliers (see Appendix 10.3: Analysis of retail supply profitability).

2. This appendix first sets out a discussion of our methodology and the issues we considered in benchmarking costs and harmonising capital employed

levels across the Six Large Energy Firms. A summary of our key preliminary results and findings can be found in paragraphs 69 to 93 below.

3. This analysis forms part of our wider assessment of profitability in retail energy supply and therefore should be considered in conjunction with our other strands of analysis in this area.

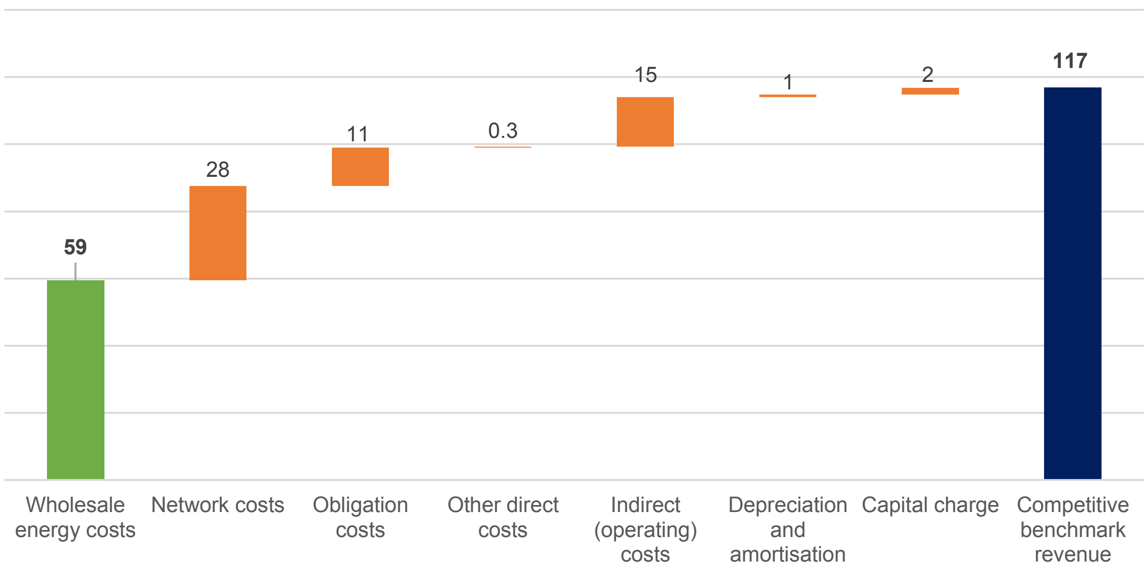
Methodology

Section overview

4. We calculate competitive benchmark revenue as equal to the sum of the direct and indirect costs which have been efficiently incurred plus a rate of return based on a weighted average cost of capital (WACC) on the capital employed in the business.

5. We illustrate how the individual cost components build up to a measure for a competitive benchmark unit revenue in Figure 1.

Figure 1: Illustrative derivation of the competitive benchmark unit revenue (£ per MWh)



Source: CMA illustration based on our results for the Six Large Energy Firms combined, and for domestic electricity in FY13.
Notes:
1. Unit cost figures were based on adopting the appropriate benchmark levels (which are discussed in more detail under our methodology section in this appendix), in particular the figures above were based on the lower quartile cost ratio relating to wholesale energy costs and indirect costs.
2. The bar representing the competitive benchmark unit revenue is the sum of the individual unit cost components listed on its left. The unit for the vertical axis could be expressed either as a ratio (eg £ per MWh or £ per customer account) or in absolute terms (eg in £ millions).

6. In order to estimate what level of costs might represent an efficiently-incurred level, we benchmarked the cost ratios of the Six Large Energy Firms' retail supply businesses over the period FY07 to FY13.

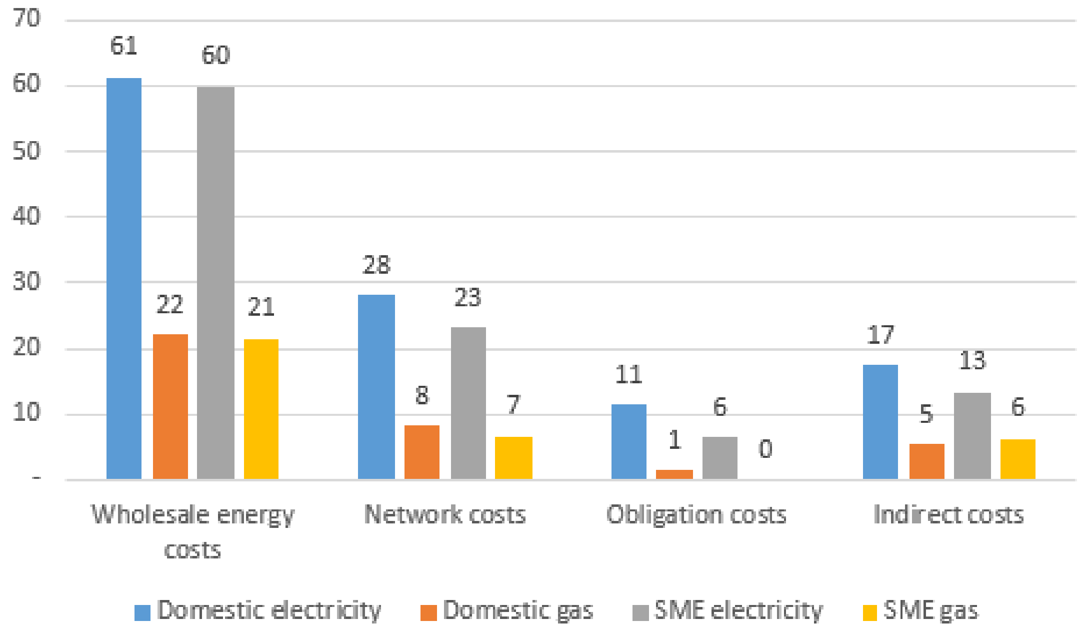
7. Before setting out in more detail how we benchmarked each cost category, we discuss how we controlled for cost differences between fuel type and retail customer segments.

Controlling for cost differences between fuel and retail customer segments

8. We sought to determine a competitive benchmark price separately for domestic customers on the one hand, and small and medium-sized enterprise (SME) customers on the other.[1]

9. In Appendix 10.2: Retail energy supply profit margin analysis, we found that there were considerable differences in unit costs (ie £ per MWh) between fuel types, as well as between different retail customer segments. We illustrate these unit cost differences again in Figure 2 where we compare unit costs between electricity and gas supply for domestic and SME customers.

Figure 2: Differences in unit costs between fuel type and retail segment. Five-year period total unit cost ratios (£ per MWh)



Source: CMA analysis of the profit and loss (P&L) information of the Six Large Energy Firms.
Note: figures are based on simple annual averages generated over a five-year period (FY09 to FY13) for the Six Large Energy Firms combined, and split by fuel type and by domestic and SME retail customer segments.

10. Figure 2 shows that differences in unit costs are particularly significant between fuel types, eg unit wholesale costs are around £60 per MWh for electricity and around a third of this for gas. There are also differences between domestic and SME unit costs, particularly in obligation costs, where

[1] We adopted SME customers as a proxy group for the smaller business customers covered by our terms of reference.

levels are relatively significant for domestic supply, but negligible in SME supply.

11. Given these differences in unit costs, and our objective of determining a competitive benchmark for our reference markets, we benchmarked costs for each fuel and retail customer segment type separately, to determine the competitive benchmark revenue (and price) for domestic and SME supply by each fuel type.

12. Whilst the annual segmental profit and loss (P&L) account information of the Six Large Energy Firms provided a breakdown by domestic, SME and industrial and commercial (I&C) customers, as well as by fuel type, the Six Large Energy Firms were unable to provide us with balance sheets segmented on this basis. We describe later how we apportioned their balance sheet information by fuel type and retail customer segment when we set out our determination of the appropriate capital charge.

Cost benchmarking overview

13. We set out below our methodology for determining the appropriate benchmark level for each of the main cost categories shown in Figure 1. For some cost categories, we considered a range of potential benchmarks, and by implication, this has resulted in a range for our estimates of the competitive benchmark.

14. In Table 1, we provide a high-level summary of our benchmarking approach for each cost item. We discuss each of these in further detail below.

Table 1: Cost benchmarking overview

Cost item	*Adopted benchmark(s)*
Direct costs	
Wholesale energy costs*	Benchmarking based on £ per MWh (unit wholesale energy costs) We have calculated the competitive benchmark revenue based on the average of the following two benchmark levels: (a) Lower quartile unit wholesale energy costs for each year across the Six Large Energy Firms (b) Average unit wholesale energy costs of two firms for each year† For illustrative purposes, a third scenario for unit wholesale energy costs based on spot market prices (only for domestic and SME electricity supply for FY09 to FY13)
Network costs	Not benchmarked, actual reported costs adopted (passed through)
Obligation costs	Not benchmarked, actual reported costs adopted (passed through)
Other direct costs	Not benchmarked, each firm has been allowed extra direct costs equal to 0.5% of its lower quartile total wholesale costs
Indirect costs	
Indirect (operating) costs	Benchmarking based on £ per customer account Lower quartile of total indirect cost ratios across the Six Large Energy Firms
Depreciation and amortisation	Based on the benchmarked balance sheet figures (discussed in Table 3)
Amortised customer acquisition costs	Based on the benchmarked balance sheet figures (discussed in Table 3)

Source: CMA analysis.
*We added a [✂] to wholesale electricity and gas costs (as per our retail supply ROCE analysis, see Appendix 10.3: Analysis of retail supply profitability) to reflect an appropriate market price for accessing the wholesale markets through a trading intermediary and for access to a significant credit facility.
†We explain why we adopted the average unit wholesale energy costs of two of the Six Large Energy Firms as one of our benchmarks in Annex A.
Note: We calculated and compared the annual direct and indirect cost ratios for each of the Six Large Energy Firms over the relevant period. In determining the appropriate cost ratios, we adopted what we considered to be the primary cost driver (eg volumes or customer account numbers), noting that there would be no single cost driver that would fully account for every change in costs, eg whilst volumes (measured by MWh) may be a key driver of the variable element of network costs, volumes would be less appropriate for their fixed element.

15. Given that we have passed through network and obligation costs, this results in a competitive benchmark revenue (and price) specific to each of the Six Large Energy Firms.

16. We first discuss our benchmarking exercise for each direct cost item, before turning to indirect costs and then the appropriate capital charge.

Direct cost benchmarking

17. There are three main direct cost items: wholesale energy costs, network costs and obligation costs. Some of the Six Large Energy Firms also reported a fourth ‘other direct costs’ item, although this was relatively immaterial in absolute terms. We turn to each direct cost item in turn below.

Wholesale energy costs

18. We calculated and compared annual unit wholesale energy costs (£ per MWh) for each of the Six Large Energy Firms, split by fuel type and retail customer segment.

19. As shown in Figure 2 above, wholesale energy costs account for the largest component of an energy retailer’s total costs. Energy retailers have some

control over the level of these costs because they can choose which products to buy and when, and can choose their purchasing strategy. They can also differ because of differences in how transfer charges between the retail supply and trading divisions are determined. We discuss this below when we consider the impact of transfer charges and hedging on reported wholesale energy costs below. We also discuss whether the wholesale energy costs of the mid-tier suppliers might provide another possible benchmark level for the Six Large Energy Firms.

Impact of transfer charges on reported wholesale energy costs

20. In Annex A to this appendix, we reviewed how each of the Six Large Energy Firms reported their wholesale energy costs in their P&L information. Based on our review set out in Annex A, we found that:

(a) All of the Six Large Energy Firms purchased almost the entirety of their wholesale energy requirements through their respective trading divisions, and therefore almost the entirety of their wholesale energy costs (as reported to us) comprised of transfer charges into their retail supply division;

(b) The approach adopted by [✄] in relation to their wholesale energy costs was likely to most closely match that of an equivalent stand-alone supplier that had adopted the same hedging strategy (ie the same timing and mix of products purchased) as [✄] and purchased all of its wholesale energy requirement on the open traded market. Therefore, in our view, we considered that the costs of [✄] were more likely, all other things being the same, to be the most informative when considering the competitive benchmark for wholesale energy in retail energy supply;

(c) The levies on wholesale energy purchases by [✄] during the relevant period had the effect of increasing their reported wholesale energy costs above the level of other suppliers. As a result, their reported wholesale energy costs (which included these levies) did not appear to relate to costs than an equivalent stand-alone supplier would have incurred.

21. Based on the above, we considered that one possible benchmark level may be the unit wholesale energy costs for either [✄], or both. We have for the purpose of this exercise, taken the average of these two firms' unit wholesale energy costs (for each year) as one benchmark level.

22. Given the variability of unit wholesale energy costs across the Six Large Energy Firms, we were also keen not to rely solely on a single point estimate

for our wholesale energy cost benchmark. We therefore considered others, which we discuss below.

Impact of hedging on reported wholesale energy costs

23. We mentioned above that differences in unit wholesale costs between energy retailers and from year to year, could be driven by differences in their individual hedging strategies. We therefore considered the impact of hedging on reported wholesale costs to understand whether looking at unit wholesale energy costs on a spot market price basis (ie where no hedging took place) would reveal a meaningful benchmark.

24. To do this, we first compared the reported unit wholesale energy costs of the Six Large Energy Firms with spot market prices. The details and preliminary results of this analysis are set out in Annex B to this appendix. Based on this analysis, we found that:

(a) for much of the five-year period from FY09 to FY13, reported unit wholesale energy costs for each of the Six Large Energy Firms were higher than the relevant spot market price for both electricity and gas, although this gap narrowed towards the latter part of the period; and

(b) based on market price data from 2011 to 2014, the further ahead of the delivery date a purchase was made, the higher the forward cost compared with shorter-dated or spot purchases for the same delivery date.

25. As we set out in Annex B, many of the Six Large Energy Firms argued that forward costs were likely to be higher than spot market prices given that this was a cost of giving customers price certainty. Parties also argued that the time period covered by our analysis was too short to make any meaningful conclusions, and that any spot market prices we observed would not be the prices they would actually pay if they were to purchase all of their wholesale energy requirements on the spot market, citing for example, the lack of liquidity and depth of the wholesale markets to supply all of the volumes they would require.

26. We considered whether the spot market price could be adopted as one of our relevant benchmarks for unit wholesale costs. Our analysis shows that using spot market prices would result in lower wholesale energy costs for all of the Six Large Energy Firms, all of whom hedge their wholesale energy prices not only for their fixed tariff customers, but also for their variable tariff customers.

27. In Annex B, we said that the main reasons given for hedging were: *(a)* to avoid the greater volatility of prompt prices; *(b)* to lock in the cost of energy for

fixed priced tariffs and; *(c)* to reduce the frequency of price changes for other tariffs.

28. In our view, the rationale for hedging variable tariff customers was initially less clear cut (although it is a commonly pursued strategy across the Six Large Energy Firms and other retailers). Absent other features of the market identified, it might be difficult to understand the reasons for doing so given that standard variable tariff (SVT) customers can in theory leave at any time. The decision to hedge so far in advance for these customers is however consistent with our provisional findings as regards customer behaviour, and further therefore indicates that, in practice, these customers are unlikely to leave (see Appendix 8.4: Price discrimination).

29. On balance, we considered that spot market prices would provide a useful benchmark minimum, or lower band, for our range of unit wholesale energy costs, as spot market prices represent a measure of the opportunity cost. We therefore illustrate in our preliminary results section the potential impact on the competitive benchmark revenue of adopting spot market prices as a possible benchmark (for electricity supply only (and for FY09 to FY13) given the data issues we faced for gas, see Annex B).

Mid-tier suppliers' wholesale energy costs

30. In addition to the issues surrounding the impact of transfer charges (which, in particular shows that [✂] and [✂] may not provide an appropriate benchmark level), and hedging decisions (where spot market prices that represent the opportunity cost might form one possible benchmark level), we also considered whether the unit wholesale energy costs of the mid-tier suppliers might be informative in this regard. Based on the P&L data we received from First Utility, Ovo Energy and Co-operative Energy (Co-op Energy) (predominantly domestic retailers),[2] we calculated their annual unit wholesale energy costs for domestic electricity and domestic gas.

31. In Table 2, we compare the mid-tier suppliers' unit wholesale energy cost figures with those of the Six Large Energy Firms.

[2] Given its supply agreement with RWE, Utility Warehouse did not separately report its wholesale energy costs, as these costs form part of a wider payment comprising other services provided by RWE.

Table 2: Mid-tier suppliers' unit wholesale energy costs (domestic electricity and domestic gas)

Domestic electricity

£ per MWh

Six Large Energy Firms	*2009*	*2010*	*2011*	*2012*	*2013*	*5YP Avg**
Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Six Large Energy Firms (all) avg	61	60	63	62	61	61
Six Large Energy Firms (all) lower quartile	60	58	58	60	59	59
Six Large Energy Firms ex Scottish Power/SSE avg	61	57	59	61	60	60
Six Large Energy Firms ex Scottish Power /SSE lower quartile	60	57	58	60	60	59
Mid-tier suppliers	*2009*	*2010*	*2011*	*2012*	*2013*	*Average†*
Co-op Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
First Utility	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Ovo Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Mid-tiers' Average (where available)	49	46	53	58	58	56

Domestic gas

£ per MWh

Six Large Energy Firms	*2009*	*2010*	*2011*	*2012*	*2013*	*5YP Avg**
Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Six Large Energy Firms (all) avg	22	19	20	23	25	22
Six Large Energy Firms (all) lower quartile	21	19	20	22	24	21
Six Large Energy Firms ex Scottish Power/SSE avg	22	19	21	23	25	22
Six Large Energy Firms ex Scottish Power/SSE lower quartile	21	18	20	23	25	21
Mid-tier suppliers	*2009*	*2010*	*2011*	*2012*	*2013*	*Average†*
Co-op Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
First Utility	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Ovo Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Mid-tiers' avg (where available)	16	16	21	23	24	22

Source: CMA analysis.
*Based on a simple average of the annual unit wholesale costs over the period FY09 to FY13.
†Based on the average of annual unit wholesale energy costs for the period over which data was available given that not all of the three mid-tier suppliers were operating for the full five-year period.

32. Based on Table 2:

(a) For domestic electricity, for each year over the period for which data was available, [✂] each had unit wholesale electricity costs that were lower than the lower quartile level for the Six Large Energy Firms combined. [✂] however, was significantly below the Six Large Energy Firms' lower quartile level from FY09 to FY11, but was slightly above the average of the Six Large Energy in FY12 and FY13.

(b) For domestic gas, the relative position of the mid-tier suppliers to the Six Large Energy Firms (combined) was less clear cut on an individual mid-tier supplier by supplier basis. For [✂] for example, its unit wholesale gas costs were significantly below the lower quartile level for the Six Large Energy Firms in FY09 and FY10; in line with the lower quartile level in FY11; between the lower quartile and average levels in FY12; and at the lower quartile level in FY13.

33. The reported energy costs of some mid-tier suppliers ([✂] in particular) are not directly comparable to those of the Six Large Energy Firms due to the inclusion of fees payable to wholesale market intermediaries. The Six Large Energy Firms do not incur such fees. However, if we control for trading intermediary fees(as described in Appendix 10.3), the mid-tier suppliers' unit wholesale gas costs either fall below the lower quartile level of the Six Large Energy Firms, or between their lower quartile and average levels. We therefore considered that the lower quartile unit wholesale energy costs (for both electricity and gas) of the Six Large Energy Firms could be another reasonable benchmark (in addition to that provided by the average of [✂]), given that the mid-tier suppliers have been able to achieve these levels for their own retail supply business.

- *Preliminary conclusions on benchmark unit wholesale energy costs*

34. As we set out in Annex A to this appendix, and as we discussed earlier in relation to the impact of transfer pricing on out-turn costs, there are reasons why reported costs may not be appropriate levels to adopt as our benchmark. In particular, we point to some of the issues we found from our analysis in Annex A, concerning the reported wholesale energy cost figures for [✂] and [✂] over the relevant period.

35. Based on the above, we adopted the following as our benchmark levels for unit wholesale energy costs:

    (a) the lower quartile across the Six Large Energy Firms;

    (b) the average of [✂] unit wholesale energy costs; and

    (c) (to illustrate the impact of taking the opportunity cost into account) the spot market price as the unit wholesale energy cost for each of the Six Large Energy Firms. However, given limitations in the data available, we were only able to perform this scenario for domestic and SME electricity, and for FY09 to FY13 only.

36. For the first two benchmark levels (ie *(a)* and *(b)*), we applied a small trading fee uplift to wholesale energy costs in line with our retail ROCE analysis (see Appendix 10.3). We assumed that this small trading fee uplift would not be

required under a spot market purchasing strategy. As set out in Appendix 10.3, we considered that for an efficient supplier, the trading intermediary fee approach represented a more efficient route than the costs (based on its WACC) of holding additional capital required to trade directly on the wholesale markets.

Network and obligation costs

37. We treated network and obligation costs as 'pass through' costs on the basis that suppliers exercised limited control over them. These costs are heavily regulated and suppliers have little ability to influence them, other than at the margin. We therefore adopted the reported out-turn levels of network and obligation costs as our benchmark levels.

38. We also noted that network charges do vary by region (or more specifically by network operator), and therefore adopting each of the Six Large Energy Firms' reported out-turn network charges would result in a competitive benchmark revenue for each firm that took into account these regional network cost differences.

Other direct costs

39. Some of the Six Large Energy Firms reported an 'other direct cost' item. However, whilst these costs were immaterial, and did not apply to all of the Six Large Energy Firms, we have allowed all of the Six Large Energy Firms an additional direct cost amount, which we have labelled as 'other direct costs', equal to 0.5% of their respective total wholesale energy costs (based on the lower quartile unit wholesale energy cost ratio across the Six Large Energy Firms).

Indirect cost benchmarking

40. We calculated indirect cost per customer account (£ per customer) ratios for each of the Six Large Energy Firms, for each fuel and for each retail customer segment. We examined depreciation and amortisation (D&A) separately.

Operating costs

41. Our detailed consideration of indirect costs are set out in Annex C to this appendix, where we set out the supporting analysis to our consideration of the benchmark level of indirect costs. In this annex, we examined the relevant firms' indirect cost per customer account ratios for their respective total supply businesses, ie domestic, SME and I&C supply combined, and their domestic and SME retail segments.

42. Whilst we had a breakdown of indirect costs by certain cost categories, eg sales and marketing costs, we considered that there were a number of factors which would suggest that we should benchmark indirect costs in their totality, rather than benchmark each individual cost component:

(a) there may be differences in definitions and allocations across different indirect cost categories across the Six Large Energy Firms; and

(b) higher costs in one cost category may yield efficiency benefits in another category.

43. Based on Annex C, our indirect cost ratio analysis showed that the gap between the best and worst performers was wide and persistent (mainly driven by [✂]), although two suppliers (namely [✂]) made significant improvements over the period.

44. We also noted that many of the parties indicated that there were further areas to improve efficiencies in their retail businesses. For example:

(a) EDF Energy told us that it had made continued efforts to get costs under control over the last five years, but had recently stepped up its efforts in this regard. It added that to be in the middle of the 'pack', it would have to reduce its costs by 20 to 30%.

(b) E.ON told us that its indirect costs were higher than those of some independents due to legacy IT systems and because it served the full spectrum of customers, and not just those who served themselves online and paid by direct debit.

(c) [✂].

(d) We also acknowledged that there may be reasons why indirect costs are higher for some energy retailers, including differences in the costs to serve certain types of customers. However, we noted that the Six Large Energy Firms all have a mixture of customer types (eg prepayment, standard credit, direct debit.

45. One benchmark we considered was the cost ratios of some of the mid-tier suppliers, eg First Utility, Ovo Energy and Co-op Energy. However, given that these mid-tier suppliers had invested into their business to grow their customer base, we noted that their out-turn cost ratios might be distorted upwards and thus be higher than the efficient level.

46. The Six Large Energy Firms argued that the independent domestic suppliers targeted customers with lower costs to serve, eg customers who opt for direct

debit, and therefore would not provide us with a relevant comparator. However, whilst we agree that the mid-tier suppliers have a higher proportion of direct debit customers, we would note that the Six Large Energy Firms could encourage more of their customers to move on to direct debit payment methods or improve their online services, to influence their costs to serve in other ways.

47. Therefore, the indirect costs (as measured on a per customer account basis) of some of these mid-tier suppliers support the use of the lower quartile indirect cost ratio across the Six Large Energy Firms as a benchmark level. Further support for adopting the lower quartile as the benchmark for indirect costs came from the mid-tier suppliers. As shown in Annex C, whilst Ovo Energy and Co-op Energy ranked better than the average for the Six Large Energy Firms, they told us that as their retail businesses expand, they would expect their indirect cost ratios to improve still further. This is of particular probative value given they are more likely to face acquisition and other costs relating to switching that the Six Large Energy Firms do not face to the same degree (notably in respect of the unengaged customer based identified in Sections 7 and 8).

48. For the purpose of our benchmarking exercise, we considered the lower quartile ratio to be a reasonable estimate for our benchmark level, noting that this is above the lowest indirect cost ratio exhibited by the mid-tier suppliers (notwithstanding that mid-tier cost ratios may be distorted upwards by high growth levels).

Depreciation and amortisation and the capital charge

49. D&A costs were derived from our estimate of the benchmark level of tangible and intangible fixed assets (including capitalised customer acquisition costs in the latter category), whilst the capital charge was based on the results of our determination of the benchmark capital employed level and the WACC. We discuss these two cost items below.

Determining the appropriate capital charge

50. In order to calculate the appropriate capital charge, we first apportioned the capital employed base by fuel type for the domestic and SME retail segments.

51. A summary of our approach is set out in Table 3. We discuss how we apportioned the capital employed and then determined the benchmark level by examining the main components of capital employed principally: working capital, capitalised customer acquisition costs, cash balances and tangible fixed assets.

Table 3: Balance Sheet benchmarking overview

Balance sheet item	*Adopted benchmark(s)*	*Fuel and retail segment apportionment assumptions*
Debtors	Benchmarking based on debtor days for the total supply business Two benchmark levels adopted: (a) Lower quartile across the Six Large Energy Firms (b) Average across the Six Large Energy Firms	Benchmarked debtor balances apportioned by actual segmental revenues
Creditors	Benchmarking based on creditor days for the total supply business Two benchmark levels adopted: (a) Upper quartile across the Six Large Energy Firms (b) Average across the Six Large Energy Firms	Benchmarked creditor balances apportioned by actual segmental direct costs
Capitalised customer acquisition costs	Not benchmarked. Figures used in our ROCE analysis adopted	Apportioned by actual segmental customer account numbers
Cash balances	Not benchmarked. Figures used in our ROCE analysis adopted	Apportioned by actual segmental volumes
Total fixed assets	Benchmarking based on Centrica's total fixed assets and segmental D&A by fuel and retail segment type*	See*
Stock	Not benchmarked. Figures used in our ROCE analysis adopted	Apportioned by actual segmental volumes
Quarterly working capital adjustment	Not benchmarked. Figures used in our ROCE analysis adopted	Apportioned by actual segmental volumes

Source: CMA analysis.
*For total fixed assets, we: (a) apportioned Centrica's total fixed assets to each fuel and retail segment based on the segmentation of its actual D&A costs; (b) adopted Centrica's fixed asset per customer account for each segment as the benchmarked level; and (c) applied this benchmarked level to the other Six Large Energy Firms' customer account numbers to determine their total fixed assets.

52. As set out in Table 3, we benchmarked working capital and total fixed assets, whilst assuming other categories remained as reported. We also note that working capital and total fixed assets in particular, were two balance sheet items which were subject to significant variations between the Six Large Energy Firms (even when relative size was controlled for, ie on a £ per customer basis).

53. We therefore discuss our benchmarking approach in relation to working capital and total fixed assets below.

Working capital (debtors and creditors)

54. In relation to determining a benchmark level for debtors, we calculated debtor days (for each year and for each of the Six Large Energy Firms) based on total supply business debtor balances and revenues. We adopted two benchmarks based on:

(a) the lower quartile debtor days; and

(b) the average debtor days.

55. Based on each of these benchmark ratios, we applied these to each firm's out-turn segmental revenues to derive debtor balances by the relevant segments.[3]

56. For creditors, we applied a similar approach, but calculated creditor days, and then adopted the upper quartile and average creditor days as our relevant benchmarks. We applied these benchmark creditor days to each individual firm's total direct costs figure, as segmented by fuel type and retail segment.

Fixed assets (and D&A)

57. For total fixed assets, we adopted Centrica's total fixed asset per customer account as a relevant benchmark, noting that, in our view, Centrica appeared to have invested consistently into their systems over the relevant period, and had encountered less major implementation issues with their new systems than some of the other Six Large Energy Firms.

58. We apportioned Centrica's total fixed assets to each retail segment (by fuel type) based on how it had apportioned its annual D&A costs across these segments. We then calculated for each of Centrica's segment (and fuel type), the total fixed asset per customer account, which we adopted as the benchmark to apply to the customer account figures of the other Six Large Energy Firms.

59. Having determined the apportioned level of benchmarked total fixed assets for all of the Six Large Energy Firms by fuel type and retail segment, in order to derive the D&A costs associated with their revised benchmarked total fixed assets, we first calculated for Centrica, the percentage of its total fixed assets accounted for by D&A (based on out-turn figures). We calculated these percentages for each fuel type and retail segment. We then applied these percentages to the corresponding benchmarked total fixed assets of each of the Six Large Energy Firms to arrive at the revised D&A costs estimate.

Capital charge

60. Based on the above, we were able to derive a capital employed figure for each of the Six Large Energy Firms, segmented by fuel type and retail segment. The capital charge was then calculated by multiplying the relevant

[3] We noted the circularity of applying benchmarked debtor days on a yet-to-be-determined competitive benchmark revenue figure. We have therefore applied benchmarked working capital ratios to actual revenues as a simplifying assumption.

capital employed figure by the WACC to provide us with the appropriate capital charge.

61. In Appendix 10.4: Cost of capital, we considered that a range of 9.3 to 11.5% would be an appropriate range for the WACC that a retail energy supply business operating in GB would face. For the purpose of our analysis, we adopted a WACC of 10%, approximately the mid-point of our range.

Outputs of our benchmarking exercise

62. Since we adopted more than one benchmark level, eg lower quartile and average cost ratios, for certain cost or balance sheet items, we calculated the competitive benchmark revenue based on five scenarios. When presenting our preliminary results however, we specify our minimum, maximum and average competitive benchmark price based on the first four benchmarking scenarios. For the reasons given in paragraph 35*(c)* above, we present the fifth (wholesale spot) scenario separately. The five benchmarking scenarios are:

(a) Scenario 1: for cost and balance sheet items, where the lower quartile was one of the benchmark levels, this scenario always adopted the lower quartile level (or upper quartile for creditor days).

(b) Scenario 2: this was based on scenario 1 above, but we changed the unit wholesale energy cost from being the lower quartile to the average of unit wholesale energy costs for two firms [✂].

(c) Scenario 3: this was based on scenario 1, but adjusting only the benchmark debtor and creditor days to their average levels.

(d) Scenario 4: this was scenario 1, but adopting the average as the benchmark level for both unit wholesale energy costs and debtor and creditor days.

(e) Scenario 5: this was based on scenario 1 above, but we adopted the spot market price as the relevant benchmark. As mentioned in paragraph 35*(c)* above, we ran this scenario on domestic and SME electricity only, and for the period FY09 to FY13.

63. Based on the four scenarios above, we were able to derive a range for the competitive benchmark revenue, from which we could derive an average figure. Therefore references to the minimum, maximum and average benchmark price or revenue, relate to the range we derived from the four scenarios described above.

64. The impact of adopting the benchmark on a firm's out-turn costs depended on the relative position of its cost ratios to the other Six Large Energy Firms. We found that the cost category most affected by our benchmark varied for each firm, by year, by customer segment (ie domestic and SME supply) and by fuel type. A high-level summary of the impact of our analysis can be seen in Annex G.

65. For some cost categories, the materiality of the impact of adopting benchmarked levels was broadly in line with our understanding of their costs. For example, in relation to domestic supply:

(a) For [✂] and [✂], as we note in Annex A, out-turn wholesale electricity costs in FY10 were relatively higher than other firms' costs due to the impact of transfer charging levies. [✂] and [✂] were most impacted by adopting our benchmark levels for domestic electricity costs.

(b) Similarly, we note in Annex B, that [✂] and [✂] indirect cost ratios were significantly higher than their peers. Therefore adopting the lower quartile indirect cost ratio had a significant impact on [✂] and [✂] out-turn indirect costs.

66. We now turn to the preliminary results of our analysis.

Preliminary results

Section overview

67. Based on our analysis, we carried out the following analysis:

(a) for domestic and SME supply, we compared actual unit revenues (a proxy for average realised revenues) with the competitive benchmark unit revenues (a proxy for the competitive benchmark price) for each fuel type (ie electricity and gas);

(b) we also compared actual out-turn revenues with the revenues implied by our estimates of the competitive benchmark unit revenue; and

(c) finally, we undertook a sensitivity analysis on economic profits, applying our benchmarked costs and capital employed assumptions to our calculations of out-turn economic profits (ie earnings before interest and tax (EBIT) less capital charge) set out in Appendix 10.3.

68. We first set out the key preliminary findings from our analysis, before concluding this section with our interpretation of our preliminary results.

Summary of key preliminary results

69. For reference, we use the term ‘out-turn’ to refer to the actual reported results achieved by the Six Large Energy Firms, and the competitive benchmark (or benchmark) to describe the adjusted figures that take into account the benchmarked costs and capital employed figures that we have derived.

Out-turn vs the competitive benchmark for the Six Large Energy Firms combined

70. Table 4 sets out:

(a) our comparisons of the average realised prices for the Six Large Energy Firms combined (ie based on a simple average of their actual unit revenues) against the competitive benchmark unit revenues based on the average of the four benchmarking scenarios described in paragraph 62 above;

(b) the difference between actual out-turn total revenues (ie volumes times unit revenues) and the total revenues implied by our benchmark unit revenues; and

(c) the difference between out-turn annual revenues per customer account and the benchmark annual revenues per customer account.

Table 4: Comparisons against the competitive benchmark for the Six Large Energy Firms combined

								*Average price differential (%)**	
Supply type	*FY07*	*FY08*	*FY09*	*FY10*	*FY11*	*FY12*	*FY13*	*5YP Avg*	*7YP Avg*
Domestic electricity	7	6	2	1	5	4	5	3	4
Domestic gas	–13	–5	–3	7	4	5	3	3	0
SME electricity	N/A	N/A	13	16	17	15	15	15	15
SME gas	N/A	N/A	9	22	21	15	7	15	15

								Implied total revenue differential (£m)†	
Supply type	*FY07*	*FY08*	*FY09*	*FY10*	*FY11*	*FY12*	*FY13*	*5YP*	*7YP*
Domestic electricity	686	785	209	155	634	513	665	2,176	3,647
Domestic gas	–1,051	–324	–97	1,120	696	1,067	855	3,640	2,265
SME electricity	N/A	N/A	381	400	414	347	388	1,930	N/A
SME gas	N/A	N/A	125	201	154	152	88	720	N/A

								Implied revenue per customer differential (£)‡	
Supply type	*FY07*	*FY08*	*FY09*	*FY10*	*FY11*	*FY12*	*FY13*	*5YP*	*7YP*
Domestic electricity	27	30	8	6	24	19	25	16	20
Domestic gas	–49	–15	–4	51	31	48	39	33	15
SME electricity	N/A	N/A	222	244	259	231	265	244	N/A
SME gas	N/A	N/A	235	402	317	329	200	298	N/A

Source: CMA analysis.

*The average price differential (%) equals the percentage difference between the simple average of the Six Large Energy Firms' actual unit revenues and the average competitive benchmark unit revenue. A positive percentage figure means that the average realised price is higher than the average competitive benchmark price.

†The implied total revenue differential (in £ millions) equals the difference between the actual out-turn revenues of the Six Large Energy Firms and the revenues implied by their respective average competitive benchmark price. A positive figure means that the actual revenues are higher than the implied competitive benchmark revenues.

‡Implied revenue per customer differential (in £ per customer terms) equals the implied total revenue differential figure divided by the number of customers (measured by accounts for domestic and by customer number for SME).
Note: actual unit revenues are used as a proxy for average realised prices, and the average competitive benchmark unit revenue is used as a proxy for the competitive benchmark price. The average competitive benchmark unit revenue was the average across the four benchmarking scenarios we undertook. A positive figure implies a higher out-turn revenue or price figure than our competitive benchmark.

71. Based on Table 4, our analysis showed that for domestic supply:

(a) Domestic electricity*:* average realised prices for the Six Large Energy Firms combined were between 1 and 7% higher than their respective benchmark figures over the period (or 1 to 5% over the last five years). In period total terms, actual out-turn revenues of the Six Large Energy Firms over the seven-year period) were £3.6 billion higher than the competitive benchmark level (or £2.2 billion over a five-year period). In per customer account terms, out-turn revenues per customer account were between £6 (FY10) and £30 (FY08) per customer account higher than our benchmark.

(b) Domestic gas: average realised prices were below the benchmark from FY07 to FY09 by between –3 and –13%. Since FY10, average realised prices have been higher by between 3 and 7%. Out-turn total revenues on a three-year period total basis (for FY07 to FY09) were £1.5 billion below benchmark levels, whilst for the subsequent four-year period (from FY10 to FY13), out-turn revenues on a period total basis were £3.7 billion higher than the benchmark level. In all, out-turn period total revenues were £2.3 billion over our benchmark over the seven-year period (but higher at £3.6 billion over a shorter five-year period).

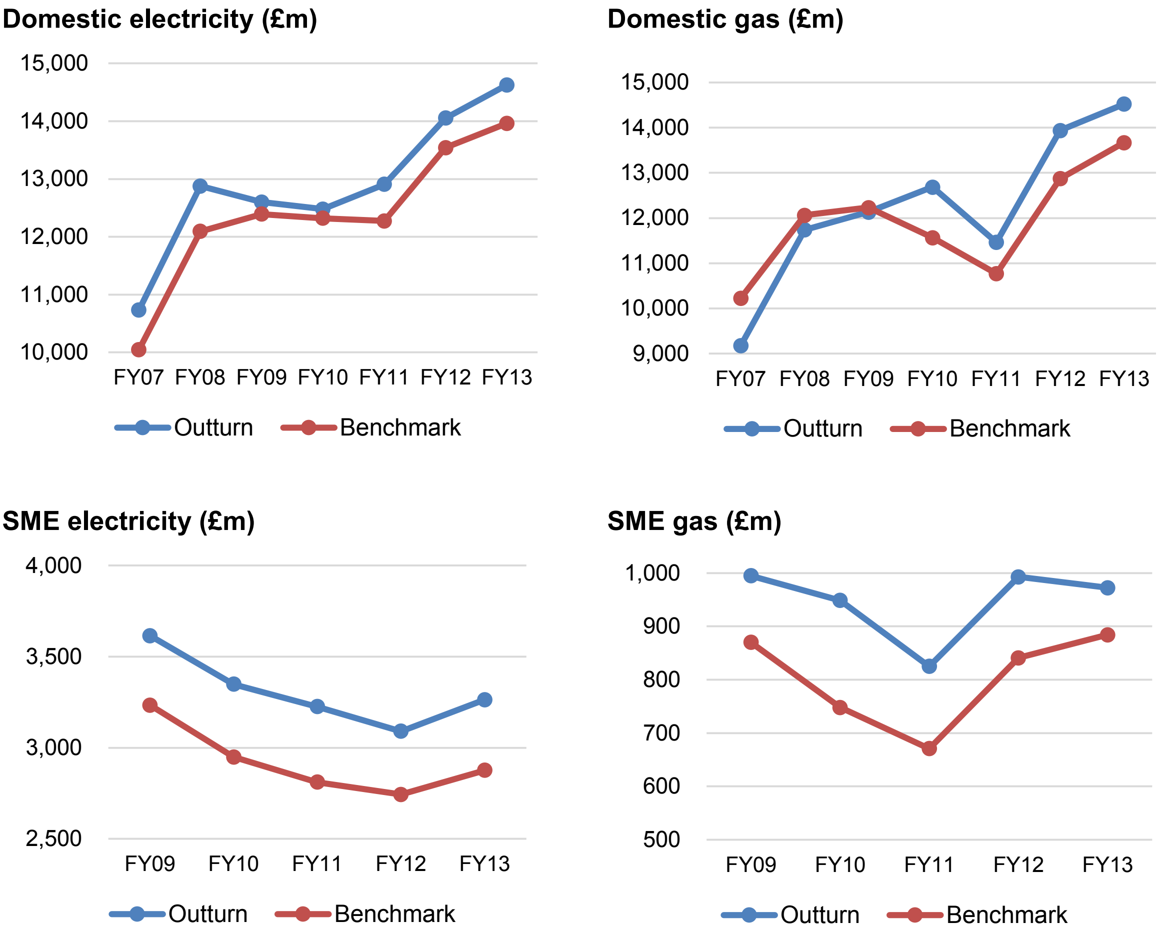
72. In relation to SME supply, Table 4 shows that the difference between out-turn and benchmark unit revenues were relatively greater in SME than domestic supply:

(a) SME electricity*:* we found that out-turn average realised prices were between 13 and 17% higher than our benchmark over the period FY09 to FY13, which in period total revenue terms (ie where each firm's relative share of total volumes are taken into account), were around £1.9 billion higher than the benchmark over the last five years.

(b) SME gas*:* out-turn average realised prices were between 7 and 22% higher than our benchmark over the five-year period, which amounted to out-turn period total revenues being £0.7 billion higher than our benchmark over the five years.

73. The trends in total annual revenues based on out-turn and our benchmark estimates are also illustrated in Figure 3, where we set out the total annual out-turn revenues for the Six Large Energy Firms combined for domestic electricity and gas, and SME electricity and gas (separately) and compare these with the relevant total annual benchmark revenues (based on the average of our four benchmarking scenarios described under our methodology section above). The underlying data tables for these charts can be seen in Annex D to this appendix.

Figure 3: Total out-turn revenues vs total competitive benchmark revenues (£m) for the Six Large Energy Firms combined



Source: CMA analysis of the Six Large Energy Firms' P&L and balance sheet information.
Note: Benchmark revenues based on the average of the four benchmarking scenarios we carried out as described under our methodology section.

74. Figure 3 shows that based on the Six Large Energy Firms combined, the out-turn was higher than our benchmark for all years during the relevant period for all segments, except for domestic gas, where out-turn revenues were below the benchmark between FY07 and FY09. However, examining these figures for all of the Six Large Energy Firms combined, disguises how differently each of the Six Large Energy Firms are affected.

Out-turn period total revenues vs competitive benchmark by individual firm

75. In Table 5, we present the percentage and absolute differences between each firm's five-year period total out-turn and benchmark revenues for each of the domestic and SME segments.

Table 5: Period total differences between actual and competitive benchmark revenues (% difference and absolute (£m) difference

% difference (five-year period out-turn revenues vs benchmark revenues)

	Outturn revenues (£bn)			*Benchmark revenues (£bn)*			*Outturn vs. benchmark (% difference)*		
Energy firm	*5YP*	*5YP*	*5YP*	*5YP*	*5YP*	*5YP*	*5YP*	*5YP*	*5YP*
	Dom	*SME*	*Sum*	*Dom*	*SME*	*Sum*	*Dom*	*SME*	*Combined*
Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Combined	131.4	21.3	152.7	125.6	18.6	144.2	5%	14%	6%

Absolute difference (based on five- and seven-year period out-turn revenues less benchmark revenues)

£m

Energy firm	*Domestic electricity*		*Domestic gas*		*SME electricity*	*SME gas*	*5YP sum total*
	5YP	*7YP*	*5YP*	*7YP*	*5YP*	*5YP*	
Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Combined	2,176	3,647	3,640	2,265	1,930	720	8,465

Source: CMA analysis.
Notes:
1. Note that we did not have FY07 and FY08 P&L information for SSE's SME retail segment. In presenting comparable results for the Six Large Energy Firms as a whole, we have focused on the five-year period from FY09 to FY13 when presenting our SME results.
2. The figures represent the differences between the period total (five or seven years) actual revenues (by firm) and the competitive benchmark revenues (ie the revenues implied by the competitive benchmark). We have adopted the average of the competitive benchmarks based on the four benchmarking scenarios we ran.

76. Table 5 shows that for domestic and SME gas, the relatively higher market share of Centrica, gives the difference between its own average realised prices and our benchmark, greater weighting when we look at these differences in total revenue terms (ie prices x volumes). Based on this table:

(a) *Domestic and SME combined:* when comparing out-turn and benchmark revenues generated in both the domestic and SME segments over the last five years, two firms' [✂] revenues had exceeded benchmark levels by around 9 and 7% respectively. Three other firms' [✂] revenues had exceeded benchmark levels by between 3 and 5%. One firm [✂] had priced around the competitive benchmark level. Based on Table 5, domestic customers paid around £1.2 billion and SME customers paid around £0.5 billion more on an annual basis than would have been the case had competition functioned more effectively, or 5% and 14% above the relevant benchmarks respectively.

(b) *Domestic electricity*: on both a five- and seven-year period total basis, all of the Six Large Energy Firms' out-turn revenues were higher than our benchmark. Over the seven-year period, [✂] generated the highest difference between its period total out-turn revenues and our benchmark ([✂]), closely followed by [✂] and [✂] ([✂]). On a five-year period basis, [✂] generated the highest differential ([✂]), followed by [✂] ([✂]).

(c) *Domestic gas*: [✂] accounted for the vast majority of the difference we found between period total out-turn revenues and our benchmark, eg on a seven-year period total basis, for the Six Large Energy Firms, out-turn period total revenue were [✂] than the benchmark – of this, [✂] period total revenues were [✂] than the benchmark. This was offset by [✂], whose period total out-turn revenues were below our benchmark. On a shorter five-year period total basis, out-turn domestic gas revenues were around [✂] than the benchmark, of which [✂] accounted for [✂].

(d) *SME electricity*: out-turn period total revenues in SME electricity were £1.9 billion higher than our benchmark for the Six Large Energy Firms, a significant proportion of which was accounted for by [✂], whose out-turn period total revenues were around [✂] higher than the benchmark, with the next highest accounted for by [✂] with its out-turn period total revenues being [✂] higher than the benchmark.

(e) *SME gas:* for the Six Large Energy Firms, out-turn period total revenues were £720 million higher than the benchmark, of which around [✂] was accounted for by [✂].

77. We note that the absolute size of the revenue differential relates both to the size of each firm's market share and the extent to which its prices are above the benchmark. We now turn to comparisons between individual firms' average realised prices and our competitive benchmark prices.

Comparison of individual firm out-turn prices vs the competitive benchmark range

78. We assessed how the average realised prices generated by the Six Large Firms over the seven-year period (or FY09 to FY13 for SME supply) compared with our range (ie minimum and maximum) for the competitive benchmark price (ie based on the four benchmarking scenarios we ran to determine the competitive benchmark revenue).

79. In the charts that follow, for domestic electricity and gas, and for SME electricity and gas, we plotted the average realised price for each year over the period, generated by each of the Six Large Energy Firms. We then overlaid the minimum and maximum bounds for our estimated competitive

benchmark unit revenue. The underlying data tables for these charts can be seen in Annex E to this appendix.

Domestic prices

80. Figure 4 shows for domestic electricity and gas (separately), the maximum and minimum competitive benchmark unit revenues as dashed lines, and the spot markers represent the average unit revenues for each of the Six Large Energy Firms.

Figure 4: Average realised prices vs competitive benchmark price (£ per MWh) by firm

Domestic electricity

[✂]

Domestic gas

[✂]

Source: CMA analysis of the Six Large Energy Firms' financial information.
Note: As mentioned under our methodology section, for domestic and SME electricity, we illustrate what unit prices would have been if we assumed spot market prices (overlaid on to scenario 1, where we adopted lower quartile ratios as our benchmark). The underlying data tables for this chart can be seen in Annex E to this appendix.

81. Based on Figure 4, Table 6 sets out the percentage difference between each firm's average realised price and the benchmark (for domestic electricity and gas separately).

Table 6: Domestic supply: difference between average realised price by firm and the benchmark price (%)

%

Domestic electricity

Energy firm	*Financial year*							*Average*	
	FY07	*FY08*	*FY09*	*FY10*	*FY11*	*FY12*	*FY13*	*5YP*	*7YP*
Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Domestic gas

Energy firm	*Financial year*							*Average*	
	FY07	*FY08*	*FY09*	*FY10*	*FY11*	*FY12*	*FY13*	*5YP*	*7YP*
Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.
Notes:
1. Benchmark price based on the average of the four benchmarking scenarios we undertook.
2. Average percentage difference figure represents a simple average of the percentage differences in each year.

82. Based on Table 6:

(a) Domestic electricity: the difference between average realised prices and the benchmark price was greatest for [✄], whose average unit revenues were respectively around [✄]% higher than our competitive benchmark over the seven-year period. We also noted that [✄] unit revenues were broadly in line with our competitive benchmark levels over the seven-year period.

(b) Domestic gas: we noted that some of the Six Large Energy Firms' unit revenues were broadly in line or below our benchmark for a large part of the period. However, [✄] have seen the difference between their average realised prices and our benchmark increase over the period, with this gap significantly higher than their other competitors. For example, in FY09, whilst [✄] average realised price was [✄] higher than the competitive benchmark, between FY10 and FY13 this gap had increased to up to [✄]. For SSE, a similar pattern emerged whereby in FY09, its average realised price was [✄] below the benchmark, but since then increased to between [✄] and [✄] above the benchmark.

83. Table 7 sets out our calculation of a typical household dual fuel energy bill (ex VAT) based on out-turn unit revenues and our benchmark unit revenues for each of the Six Large Energy Firms.

Table 7: Domestic annual dual fuel bill based on realised vs competitive benchmark prices by firm

							£
Energy firm	*FY07*	*FY08*	*FY09*	*FY10*	*FY11*	*FY12*	*FY13*
Centrica	[✄]	[✄]	[✄]	[✄]	[✄]	[✄]	[✄]
SSE	[✄]	[✄]	[✄]	[✄]	[✄]	[✄]	[✄]
E.ON	[✄]	[✄]	[✄]	[✄]	[✄]	[✄]	[✄]
RWE	[✄]	[✄]	[✄]	[✄]	[✄]	[✄]	[✄]
EDF Energy	[✄]	[✄]	[✄]	[✄]	[✄]	[✄]	[✄]
Scottish Power	[✄]	[✄]	[✄]	[✄]	[✄]	[✄]	[✄]
Average realised	740	894	961	928	1,040	1,126	1,202
Benchmark dual fuel bill							
Max benchmark	836	925	991	900	1,009	1,085	1,168
Min benchmark	724	875	953	875	987	1,073	1,149
Avg benchmark	780	900	972	887	998	1,079	1,159
							%
	FY07	*FY08*	*FY09*	*FY10*	*FY11*	*FY12*	*FY13*
Out-turn vs benchmark	–5	–1	–1	5	4	4	4

Source: CMA analysis.
Notes:
1. Mean annual consumption based on Ofgem.
2. For greater comparability, we have held consumption volumes constant for each year over this period.

84. Based on Table 7 and on the simple average of the Six Large Energy Firms combined, between FY07 and FY09, the typical household dual fuel energy bill was between –1 and –5% below our benchmark. Since then, each year, the typical annual dual fuel bill was around 4 to 5% higher than the benchmark level. However this trend varied when examined by individual firm, eg [✄] dual fuel bill was higher than the upper bound of our benchmark energy bill for five of the seven years, whilst for [✄] dual fuel was lower than the lower bound of our benchmark energy bill for all of the seven years.

SME prices

85. Figure 5 shows for SME electricity and gas separately, the maximum and minimum competitive benchmark unit revenues as dashed lines, and the spot markers represent the average unit revenues for each of the Six Large Energy Firms.

Figure 5: Average realised prices vs competitive benchmark price (£ per MWh) by firm

SME electricity

[✄]

SME gas

[✄]

Source: CMA analysis of the Six Large Energy Firms' financial information.
Note: As mentioned under our methodology section, for domestic and SME electricity, we illustrate what unit prices would have been if we assumed spot market prices (overlaid on to scenario 1, where we adopted lower quartile ratios as our benchmark). The underlying data tables for this chart can be seen in Annex E to this appendix.

86. Based on Figure 5, Table 8 sets out the percentage difference between each firm's average realised price and the benchmark (for SME electricity and gas separately).

Table 8: SME supply: difference between average realised price by firm and the benchmark price (%)

%

SME electricity

Energy firm	*Financial year*					*Average*
	FY09	*FY10*	*FY11*	*FY12*	*FY13*	
Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

SME gas

Energy firm	*Financial year*					*Average*
	FY09	*FY10*	*FY11*	*FY12*	*FY13*	
Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.
Notes:
1. Benchmark price based on the four benchmarking scenarios we undertook.
2. Average percentage difference figure represents a simple average of the percentage differences in each year.

87. Based on Table 8, the gap between average realised prices in SME and the benchmark level was greater than for domestic supply, with all of the Six Large Energy Firms' average realised prices exceeding the benchmark level. We note that in Appendix 10.2, we also found that EBIT margins generated on SME customers were higher than those generated on domestic customers over the relevant period.

Comparison of electricity prices and the wholesale spot benchmark scenario

88. In paragraph 35*(c)* above, we said that we would run a scenario analysis for the competitive benchmark price for domestic and SME electricity based on adopting spot market prices as the benchmark for unit wholesale energy costs. Table 9 below shows the percentage difference between out-turn and benchmark unit revenues for domestic and SME electricity for the period FY09 to FY13.

Table 9: Domestic and SME electricity: out-turn vs wholesale spot scenario benchmark prices (% differences)

%

Domestic electricity

Energy firm	*Financial year*					*Average*
	FY09	*FY10*	*FY11*	*FY12*	*FY13*	
Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Combined avg	24	11	9	10	6	12

SME electricity

Energy firm	*Financial year*					*Average*
	FY09	*FY10*	*FY11*	*FY12*	*FY13*	
Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Combined avg	45	30	21	24	15	27

Source: CMA analysis.
Notes:
1. Due to data limitations, the wholesale spot benchmark scenario was limited to domestic and SME electricity supply, and for the period FY09 to FY13.
2. Figures show percentage differences between out-turn and benchmark prices (based on adopting wholesale spot market prices as the benchmark).
3. Combined average figures for the Six Large Energy Firms were calculated based on a simple average of each firm's unit revenues in a given year.

89. Adopting spot market prices as the benchmark for unit wholesale energy costs has the effect of reducing the competitive benchmark price below the four benchmark prices arising from our other benchmarking scenarios. Based on Table 9:

(a) *Domestic electricity*: we found that over the FY09 to FY13 period, the percentage difference between out-turn and benchmark prices (based on spot market prices) was highest in FY09, when the difference ranged from 22 to 23% ([✂]) to 27% ([✂]). This percentage difference continued to narrow towards the later years, eg for Scottish Power and SSE, the percentage difference between out-turn and benchmark prices (based on spot market prices) was [✂] and [✂] respectively in FY13. The narrowing of this gap is consistent with the narrowing of the out-turn unit wholesale costs and the spot market prices over this period shown in Annex B to this appendix.

(b) *SME electricity:* the percentage difference between out-turn and benchmark prices for SME electricity was greater than for domestic electricity. The difference between out-turn and benchmark prices (based on spot market prices) narrows in more recent years, eg for the Six Large Energy Firms combined, the percentage difference was 45% in FY07 and 15% by FY13.

Analysis of economic profits adjusted for benchmarked costs and capital employed

90. Based on our benchmarked costs and capital employed levels which we determined as part of our analysis, we applied these to our calculation of out-turn economic profits (as set out in Appendix 10.3) to calculate adjusted economic profits.

91. In Table 10, we set out the five-year period totals for economic profits prepared on two bases:

(a) firstly, based on out-turn revenues, costs and capital employed (as set out in our economic profit and ROCE calculations for retail energy supply in Appendix 10.3); and

(b) secondly, overlaying our benchmarked costs and capital employed assumptions (adopting the lower quartile as the relevant benchmark) and running a scenario analysis on our economic profit figures based on these adjusted figures.

Table 10: Five-year period total economic profits: out-turn vs benchmarked costs (£m)

Economic profit

Energy firm	*5YP (£m)*	*Per year (£m)*
Centrica	[✂]	[✂]
E.ON	[✂]	[✂]
RWE	[✂]	[✂]
EDF Energy	[✂]	[✂]
SSE	[✂]	[✂]
Scottish Power	[✂]	[✂]
Combined	4,355	871

Adjusted economic profit

Energy firm	*5YP (£m)*	*Per year (£m)*
Centrica	[✂]	[✂]
E.ON	[✂]	[✂]
RWE	[✂]	[✂]
EDF Energy	[✂]	[✂]
SSE	[✂]	[✂]
Scottish Power	[✂]	[✂]
Combined	8,850	1,770

Source: CMA analysis.
Note: We note that our calculation of economic profits relate to the total supply business, and therefore includes domestic, SME and I&C customers. In relation to I&C wholesale energy costs, we assumed these to be fully 'passed through' and adopted each firm's reported (out-turn) figures – we considered this to be a reasonable assumption given that the Six Large Energy Firms told us that I&C customers could exercise greater control over their wholesale energy prices (see Appendix 10.6: Retail profit margin comparators. Economic profits quantify the amount of revenues which exceed the competitive level. For example, in Figure 1, the competitive benchmark revenue equals the sum of total costs and the capital charge. Since revenues less total costs equal EBIT, the capital charge represents the EBIT component of the competitive benchmark revenue. Therefore if EBIT less the capital charge is greater than zero (ie the economic profit formula), then the implication is that revenues or EBIT is higher than the competitive level.
*Our calculations of the out-turn economic profit figures are set out separately in Appendix 10.3.
†Our calculations of the adjusted economic profit was based on assuming benchmarked costs and capital employed (based on the average of the two wholesale energy cost scenarios).

92. We noted that given the volatility in EBIT and capital employed over the relevant period, we considered that it would be more appropriate to focus on period averages over the last five years.

93. Based on Table 10 (the underlying data tables for this table can be seen in Annex F to this appendix):

(a) *Out-turn economic profit:* the five-year period total economic profit figure for the Six Large Energy Firms' total supply business was £4.4 billion, of which [✂] accounted for a significant proportion [✂]). This equated to an average annual economic profit of around £870 million a year for the Six Large Energy Firms combined.

(b) *Adjusted economic profit:* when we applied our cost and balance sheet benchmark levels, the five-year period total economic profit for the Six Large Energy Firms combined increases from £4.4 billion to around £8.9 billion. This equates to an average annual economic profit of £1.8 billion (up from £870 million based on the out-turn figures of the Six Large Energy Firms).

Annex A: Review of wholesale energy costs

Introduction

1. As part of our financial data request, the CMA asked the Six Large Energy Firms to provide details of wholesale energy purchase costs over the period 2009 to 2013. In this annex we assess whether these costs accorded with the costs (measured on a historical cost accounting (HCA) basis) that would have been incurred by an equivalent stand-alone retail supplier making its purchases on traded markets.

2. We sought to do this because almost the entirety of the wholesale energy costs (as reported to us) comprised of transfer charges from energy firms' trading divisions into their retail supply divisions. We wanted to assess the extent to which such firms' transfer charging practices resulted in a cost base that would have been incurred by a stand-alone retail supplier that had made all its purchases on traded markets.

3. We took the view that, for the purposes of this analysis, such a stand-alone retail supplier would not purchase any wholesale energy products apart from those that were traded on the open wholesale market. We provisionally consider the demarcation line between retail supply and trading should be determined by reference to products sold on the open wholesale market.[4] Therefore, the purchase of any other energy products by retail supply would include the results of what we would consider a trading activity, namely buying (or selling) bespoke and selling (or buying) products on the open wholesale market.

4. We also note that products bought and sold on traded markets replicate the sourcing options open to a stand-alone retail supplier where:

   (a) the pricing of transactions unambiguously reflects the outcome of a competitive market process; and

   (b) transaction prices are subsequently made publicly available and are therefore capable of being independently verified after the event as market prices.

5. The rest of this annex is structured as follows:

[4] See Section 7: Nature of retail competition, paragraph 7.20 (a).

(a) approach taken to assessing wholesale energy costs (paragraphs 6 to 12 below;

(b) description of wholesale energy costs by firm (paragraphs 13 to 75 below); and

(c) assessment of basis of wholesale energy cost by firm (paragraphs 76 to 94 below).

Approach taken to assessing wholesale energy costs

6. We used the responses we had received from the Six Large Energy Firms, to a number of requests for information, to help us assess the wholesale energy costs across the period of our review (2009 to 2013 inclusive) against the benchmark set out in paragraph 1 of this annex including:

(a) the analysis of wholesale electricity and gas costs for their retail supply business by channel and component part;

(b) the analysis of wholesale energy costs by broad customer segment (domestic, SME and industrial and commercial); and

(c) the narrative responses to a number of questions on transfer pricing and trading practices.

7. We also held discussions with the Six Large Energy Firms on this subject.

8. We were not only interested in the transfer charges for the underlying wholesale energy products but also any other elements reflected in the total costs given for wholesale energy. For example, recharges to recover the operating costs of the trading division (eg the cost of employing traders to purchase or sell energy and working capital to support that activity). However it was important to us that these sorts of costs were separately identified as some firms might report these costs within wholesale energy and others elsewhere within other direct costs or indirect costs, or in another division. We wanted to establish the scale of any recharges of this nature within wholesale energy costs.

The benchmark implied by an 'equivalent stand-alone retail supplier' [5]

9. We are seeking to assess whether the wholesale energy costs for each of the Six Large Energy Firms reflected the costs that a stand-alone retail supplier of the same size and pursuing the same wholesale energy purchasing strategy,

[5] See paragraphs 35 and 37 of Appendix 10.1: Approach to profitability and financial analysis.

in terms of hedging timescales, would have incurred transacting on traded markets. This had important implications for our assessment of the profitability of retail supply.

10. First, where some purchases were made using bespoke products not available on traded markets, the costs of these products would reflect the results of individual negotiations, often between two divisions of the same firm.[6] Therefore these costs would not necessarily reflect open market prices.

11. Second, we understand that the Six Large Energy Firms start purchasing their energy requirements for their retail customers up to three years ahead of delivery.[7] We also understand that liquidity in wholesale traded markets, both for electricity and gas, was restricted three years out to basic seasonal products, and that such products were subject to wider bid/offer spreads than the same products traded closer to delivery. Only when it became much closer to delivery was it possible to trade in more granular products. Therefore the implication was that any charges for shaped products ahead of these becoming available in the open market were by definition not based on market products.

12. This caused us to question energy purchases that were sourced on a bespoke basis either because they didn’t reflect products traded on open markets or because the products in question were not at the time available to be purchased.

Description of wholesale energy costs by firm

13. In this section we describe for the Six Large Energy Firms the approach each had used to determine its wholesale energy costs, most notably the basis of the transfer charging from its trading division into retail supply. We start with the firms whose approach is the more straightforward to describe and then move on to the firms whose approach is more complicated.

14. The following text refers to ‘purchases’. In this context ‘purchases’ is intended to refer to net purchases and so may include sales of energy surplus to requirements.

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[6] Some of the Six Large Energy Firms purchased wholesale energy from third parties on a bespoke basis. In these circumstances whilst transfer charging might well reflect the outcome of individual commercial negotiations, the effective pricing of an individual transaction could not be observed and therefore could not be readily verified. Such pricing might have also have reflected market conditions at the time of negotiation which might have been many years earlier, and before the period of our review.
[7] See Appendix 6.1: Liquidity.

[Firm A]'s approach

Purchases of wholesale energy

15. [Firm A] told us that its transfer charges into retail supply for wholesale energy (both electricity and gas), throughout the period of our review, comprised entirely of the purchase of standard products traded on wholesale markets. These products were always priced at the prevailing market price for that product at the time the trading division was instructed. The vast majority of retail supply's orders led to an external purchase by the trading division in the wholesale market, although in some cases the external purchase would not be immediate.

16. [Firm A] also explained that retail supply didn't necessarily accept the 'offer' prices prevailing in the wholesale market at the time. Its retail supply division was able (via its trading division) to 'bid' (lower) prices at which it would like to buy energy in the market to find out if a counterparty would be forthcoming to sell at that price. If such a counterparty came forward, it would transact at that lower price.

17. [Firm A] told us that [✂] upstream exploration and production division for gas and this [✂] the source of some of its wholesale gas requirements. Nevertheless the basis on which retail supply had procured its wholesale gas requirements over the period of review had been on the basis of wholesale traded products at the prevailing market prices.

Internal supply

18. [Firm A] told us that it didn't tag the trades that its trading division transacted on behalf of its other operating divisions including retail supply. However it had estimated that about 10 to 15% of the total annual volumes of its wholesale electricity requirements had been sourced from its own Great Britain generation, the rest coming from external wholesale traded markets.

Financial hedges

19. [Firm A] told us that it had entered into weather hedges for both power and gas to manage the financial impact of unexpected variations in weather. What it had done over the years had varied, however in each case the trading division had recharged to retail supply the cost of the hedge on a back-to-back basis. These transactions were included within wholesale energy costs.

Imbalance charges ('cash out')

20. Like all retail suppliers, [Firm A] incurred these costs whereby National Grid supplied and charged for any gap between what it had contracted to buy on behalf of its retail customers over each and every half hour period and what these customers had actually used in each half hour period. [Firm A] told us that it had included these (relatively minor amounts) in 'other costs of sales'. National Grid also charged firms for any shortfall in the volumes of wholesale gas purchased, and these costs were likewise included in 'other cost of sales'.

Recharges to recover the costs of operating a trading division

21. [Firm A] told us that its trading division charged its retail supply division under an umbrella service level agreement (SLA) to recover these sort of costs. There were a variety of charging mechanisms, some based on the gross volumes traded, others on the net volume traded and there was a separate fee for the provision of short-term position management that was required close to the point of delivery.

22. [Firm A] told us that these costs had been included within indirect costs under the subheading of 'other costs'. The total cost for these recharges had ranged from £[✄] million to £[✄] million per year.

[Firm B]'s approach

Purchases of wholesale energy

23. For the purposes of this review [Firm B] had two trading divisions, one whose role was to focus on managing [Firm B]'s overall portfolio of GB interests (its GB trading division[8]), the other, a transnational operating unit, with the role of managing the global [Firm B] position (its global trading division) and executing the vast majority of any trading required on wholesale energy markets. What we describe below are the transfer charges into retail supply that [Firm B]'s GB trading division levies. (There are separate transfer charges between its GB trading division and its global trading division.)

24. As with [Firm A], [Firm B] told us that its transfer charges into retail supply for underlying wholesale energy (both electricity and gas), throughout the period of our review, were based entirely on products traded on wholesale markets. These products were always priced at the prevailing market price for that product at the time the order was placed with trading.

[8] [Firm B] refers to this division as its [✄] Division.

25. In practice [Firm B]'s GB trading division saved up (typically until the end of the trading day but the period could be longer) all the orders to buy and sell received from each of its GB operating units, including retail supply, before placing the net purchase or sell order with its global trading division. However the transfer price for the product purchased would be determined when the order was placed by retail supply, rather than when [Firm B]' global trading division transacted the net order, which was potentially a few days later.

26. Regarding wholesale gas, [Firm B] told us that [✂] long-term gas supply contracts. [✂] bought the use of wholesale gas storage [✂], or the equivalent financial trades, which enabled cheaper summer gas to be stored for supply in the subsequent winter.

Internal supply

27. [Firm B] told us that it routinely tagged all trades that its GB trading division handled on behalf of the other GB operating divisions including retail supply. This tagging enabled the identification of the netting of purchases and sales (ie internal supply) undertaken by the GB trading division across each pair of GB operating divisions. However this tagging couldn't be used to reliably identify the extent of *overall* internal trading between, for example, generation and retail supply. Internal transfers were transacted at mid-market prices.[9]

Financial hedges

28. [Firm B] told us that it had had a small amount of financial hedges for weather (mainly gas) and it had recorded the costs of these within 'other direct costs'.

Imbalance charges ('cash out')

29. [Firm B] had included these (relatively minor amounts for both electricity and gas) within its analysis of wholesale energy costs.

Recharges to recover the costs of operating a trading division

30. [Firm B] told us that it had included the recharge of brokerage costs within the transfer charges for traded product purchases. [Firm B] estimated these to amount to less than £[✂] million a year for retail supply.

[9] Trades at mid-market prices result in there being no bid-offer spread (ie same transaction price for generation and retail supply).

31. [Firm B] told us that it also recharged a relevant portion of the costs of running its GB but not its global trading division within 'other indirect costs staff'.

[Firm C]'s approach

Purchases of wholesale energy

32. [Firm C] told us that its transfer charges into retail supply for underlying wholesale energy (both electricity and gas) throughout the period of our review comprised entirely of the purchase of products based on, but not always exactly the same as, those traded on wholesale markets. When [Firm C] had set up the basis of its trading division's interaction with its retail supply businesses in the UK, [✂] and [✂] it had decided that these businesses would buy shaped products, rather than the standard 'flat' products available in the wholesale market throughout the hedging window (up to 3 years out until the start of the delivery period[10]).

33. [Firm C] told us that, while there had been no market prices for these shaped products, it had been able to price them using the market prices for the (unshaped) products that had been available at the time of transfer as a starting point.

34. [Firm C] explained that it could have implemented a policy to base transfer prices on unshaped products and then add shape later, but had instead put in place a transfer charging mechanism which incorporated shape right from the beginning. Such a mechanism meant that its trading division, rather than retail supply, took on the responsibility for managing any risks arising from selling a shaped profile (to retail supply) but only being able to buy unshaped products on the open market until shortly before delivery.

35. When it came to pricing its shaped product, [Firm C] had sought to reflect full bid/offer pricing within the transfer charges since June 2011. In other words, retail supply would pay the higher (ie 'offer') price if it was buying and receive the lower ('bid') price if it was selling back energy surplus to its needs. Previously the basis for transfer pricing of purchases had been at the offer price less a 20% discount on the bid-offer spread[11]. [Firm C] explained that the change in policy had been prompted by a desire to more closely align transfer charges between its divisions to the open market prices for traded products.

[10] The end of the delivery window for a product can be up to 41 months out.
[11] For any sell-back transactions the price would be the (unadjusted) bid price.

Internal supply

36. [Firm C] told us that its trading division, subject to the overall constraints imposed on it by [Firm C] management, had the flexibility to either back out a purchase request into the wholesale market, net it against an opposite request from another division, or hold an open position. This flexibility meant that [Firm C] was in practice unable to quantify the extent of internal supply between, for example, GB generation and retail supply that might have been able to be inferred had each individual purchase or sale transaction been tagged.

Financial hedges

37. [Firm C] told us that its trading division entered into weather derivatives on behalf of its retail supply business and it included these costs within its wholesale energy costs.

Imbalance charges ('cash out')

38. [Firm C] had identified these costs (relatively minor amounts for both electricity and gas) as the only item additional to its transfer charges for its shaped products within its analysis of wholesale energy costs.

Recharges to recover the costs of operating a trading division

39. [Firm C] told us that, since June 2011 when its trading division had moved to full bid/offer pricing, its trading division no longer levied transfer charges to recover such costs. Previously the trading division had also levied a service charge based on volumes delivered to recover the trading division's operating costs. These costs had been reflected in the transfer charges for the shaped product but they were small.

[Firm D]'s approach

Purchases of wholesale energy

Electricity

40. [Firm D] told us that its transfer charges into retail supply throughout the period of our review reflected a wider mix of purchases than simply the purchase of products traded on wholesale markets. In relation to the latter it told us that these products were always priced at the prevailing market price for that product at the time the purchase was agreed.

41. [Firm D] also reflected in its transfer charges bespoke purchases of electricity, most notably:

(a) purchase of [✂] from [Firm [✂]] under a [✂]. The pricing under this long term agreement was [✂]. See paragraph 46 below for an explanation of this formulation;

(b) purchase of a certain quantity of the output from a [✂]-fired plant owned by [✂]. The purchase price of this output reflected a unit 'fixed clean [✂] spread' fee, the cost of the [✂] and carbon allowances, and any associated foreign exchange costs;

(c) purchase of the output of wind farms, primarily those owned by third parties but also some from its own or plant in which it had a minority stake. The purchase price of this output was generally specified at a discount to the prevailing day or month ahead market price to reflect wind's intermittency.[12]

42. These bespoke purchases in total comprised [✂] [Firm D]'s total purchases in any one period.

Internal supply

43. [Firm D] provided us with a split of its transfer charges for traded products between internal and external purchases. It explained that internal supply only arose in those situations where date of trade, product, volume and duration matched between one division and another. [Firm D] told us its calculation for 2013 showed 14%[13] of total supply volumes (including bespoke purchases) had been sourced internally.

Gas

44. [Firm D] provided us with an analysis showing that over the period of review [✂] of its transfer charges related to the purchase of physical gas from third parties on long-term supply contracts. [✂] of its transfer charges into retail supply comprised purchase of products traded on wholesale markets. [Firm D] told us these latter products were always priced at the prevailing market price for that product at the time the purchase was agreed.

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[12] The discount reflected in the pricing of such wind reflects an implicit fee for trading the intermittent output of the wind farm (ie route to market) *and* forecasting/managing the wind farm's exposure to the balancing market as part of the purchaser's own overall balancing market position.

[13] Part matches reflected in this calculation eg a 50 MW power generation sale could be part-matched with a 100 MW order.

45. [Firm D] provided us with an analysis of the transfer charges for each of these long-term gas supply contracts, which it told us fully reflected the terms of each contract, the principal details for which (including identity of counterparty and pricing formula) it provided alongside.

46. Most of these long-term gas supply contracts specified the pricing in terms of the following structure:

(a) a ‘pricing-in period’, defined as the length of the time over which a contract priced in;

(b) a ‘lag period’, defined as the time offset between the pricing-in period and the delivery period; and

(c) a ‘delivery period’, defined as the length of time during which the price is effective.

47. For example, where the contract price was specified as ‘6, 0, 6’, this meant that the price for gas supplied under the contract over a particular season of 6 months (the ‘c’) would be priced at the average of the daily market prices prevailing over the 6 month period (the ‘a’) preceding a 0 month lag (the ‘b’) between the end of the pricing-in period and the actual period of physical supply.

48. Such pricing formulae mimic the phasing-in of price that the Six Large Energy Firms have sought to implement when executing their purchasing strategy.

Financial hedges

49. [Firm D] told us it had entered into weather swaps for gas and electricity (although small when compared to gas) over the period of review and these costs had been included in its wholesale energy transfer charges for retail supply.

Imbalance charges (‘cash out’)

50. [Firm D] had identified this item (relatively minor amounts for both electricity and gas) as one of the items comprising its wholesale energy costs.

Recharges to recover costs of operating a trading division

51. [Firm D] had a policy of recharging the costs of running its trading division to each of its operating divisions which benefitted from its services. In its analysis of its wholesale energy costs, [Firm D] separately identified its apportionment to retail supply of the general running costs of the trading

division from the incremental costs of transacting trades (such as brokerage fees) in the external wholesale market. For both electricity and gas, both items were a very small element of total wholesale energy costs (around [✂] out of nearly [✂] per year).

[Firm E]'s approach

Purchases of wholesale energy

Electricity (both externally sourced and internal supply)

52. [Firm E] had distinct approaches to the basis of transfer charging for the supply of electricity to, on the one hand, its domestic and SME customers and, on the other, its larger industrial and commercial customers. The distinction between the two groups arose because the latter's consumption of electricity was measured on a half-hourly basis.

- *Domestic and SME customers*

53. Like [Firm D], [Firm E] told us that its transfer charges into retail supply for wholesale electricity, throughout the period of our review, reflected a wider mix of purchases than simply the purchase of products traded on wholesale markets. In relation to the latter it told us that these products were always priced at the prevailing market price for that product at the time the purchase was agreed.

54. However, in contrast to [Firm D], [Firm E]'s bespoke purchases of electricity mostly comprised of self-supply, rather than being sourced from third parties. The most notable elements of the bespoke mix were:

    (a) purchases of output of coal- and gas-fired generation plants. The purchase price of this output reflected fees for the right to use the plants (capacity fees), the HCA cost of the fuel and carbon allowances plus any associated foreign exchange and financial hedging costs. Almost all of these plants were either owned by [Firm E] or, in the case of the [✂] gas-fired plant, deemed for statutory reporting purposes to be owned by [Firm E];[14]

    (b) purchases of the output of wind farms, primarily those owned by [Firm E] but some from plants owned by third parties;

[14] [Firm E] has an offtake agreement similar to [✂] for the [✂] gas-fired plant. This latter plant is not deemed for statutory reporting purposes to be owned by [Firm E].

(c) purchases of conventional ('run-of-river') and pumped storage electricity from its own hydroelectric plant.

- *Larger industrial and commercial customers*

55. The approach to transfer charging for these customers significantly differed to that for domestic and SMEs. [Firm E] used the average market price on the day that a supply contract was agreed adjusted for shape of demand on the day to determine the level of transfer charges.

Gas (both externally sourced and internal supply)

56. [Firm E] had a single approach to transfer charging for the supply of gas to its retail gas customers and its gas-fired generation business as described below.

57. [Firm E] provided us with an analysis that showed over the period of review that most, if not all, of its transfer charges into retail supply reflected the purchase of products traded on wholesale markets. It told us that these products were always priced at the prevailing market price for that product at the time the purchase was agreed.

58. [Firm E]'s analysis also showed some transfer charges related to the purchase of physical gas on long-term supply contracts both from third parties and its upstream exploration and production division. The pricing for these long-term contracts varied from referencing to day-ahead pricing to long-term indexation to oil or other commodity indices. This same analysis also showed transfer charges for the use of its [✂] gas storage facilities.

Financial hedges

59. [Firm E]'s analysis showed that for both electricity and gas it had, to a limited extent, entered into option contracts over the period of review. For example to hedge its generation fuel costs and these costs had been included in its wholesale energy transfer charges for retail supply.

Levies on wholesale energy purchases

60. [Firm E] levied a charge of [✂] in relation to all purchases and financial hedges for retail supply (but not for supply to its generation business) to reflect that its trading division had assumed responsibility from it for the following:

(a) marked-to-market volume risk;

(b) volatility;[15]

(c) shape risk; and

(d) imbalance charges.

[Firm E] told us out that whilst imbalance charges were a clearly measurable cost, the other three items related to other, difficult-to-measure, real costs borne by its trading division.

Imbalance charges ('cash out')

61. Because these charges were in principle recovered through the levy on wholesale energy purchases, [Firm E] had not included imbalance charges in its analysis of wholesale energy costs for retail supply. The costs had instead been included in the costs of its trading division.

Recharges to recover costs of operating a trading division

62. [Firm E] had not included any other recharges within its wholesale energy costs to recover these costs.

[Firm F]'s approach

Purchases of wholesale energy

Electricity

63. [Firm F] told us that since April 2011, after it introduced a new transfer pricing methodology, its transfer charges into retail supply had, in form, comprised entirely of the purchase of products traded on wholesale markets. These products were always priced at the prevailing market price for that product at the time the purchase was agreed.

64. [Firm F] further explained that the only difference between the products on which its transfer charges were based and the products available on the open market were their clip sizes (ie quantity of power supplied at each moment during the period of supply).

65. [Firm F] told us that prior to April 2011 it had based its transfer pricing on buying forward the entirety of the expected energy requirement for an

[15] [Firm E] did not provide us with a detailed explanation of what it meant by risks a) and b). However [Firm F] has, for what appears to be broadly the same risks – see paragraph 73 below.

individual customer at the point in time [Firm F] judged that the customer had committed to buy it. [Firm F] would then buy or sell incremental volumes to reflect changes in its expectation of these requirements on a daily basis using a forward price which was recalculated every month using the average of daily forward market prices for the prior month.

66. This approach had meant that between 2008 and 2011 a significant proportion of purchases had had a relatively flat profile (ie close to 100% of forecast demand had been purchased at the outset from its generation division) rather than the more typical phased purchase profile. [Firm F] told us that, although the internal transfer price had been based on the then published market prices, it was doubtful whether there would have been sufficient depth of liquidity for a stand-alone retail supplier to have purchased this volume of power in the market. [Firm F] also told us that, although this 'long' strategy had been initially successful, wholesale prices fell sharply in the aftermath of the 2009 financial crisis, and thereafter it would have been cheaper for its retail supply division not to have acquired power on that basis.

67. [Firm F]'s wholesale energy costs also reflected a range of bespoke purchases, in particular from generators embedded in its retail distribution network and from wind farms, both those owned by [Firm F] and by third parties. Prior to April 2011, these purchases formed part of retail supply's wholesale energy costs, but from April 2011, these purchases had then been sold on to its generation division at cost, so [Firm F] made no profit or less on these purchases.

68. [Firm F]'s analysis of its purchases (both pre- and post-April 2011) also showed that a small proportion of its trades had been negotiated directly between it and the counterparty using the product structure and pricing available on the over-the-counter (OTC) market.

Internal supply

69. [Firm F] told us that its approach to netting generation requests to sell forward against retail supply requests to buy forward (see paragraph 64 above) resulted in a very significant proportion of its electricity for retail supply being supplied internally. This ranged from 30% (in 2011) to 63% (in 2013) of total purchases by volume.[16]

[16] 25% and 62% by value in 2011 and 2013 respectively.

Gas

70. The same picture also broadly applied to gas. In other words, post-April 2011 transfer charges into retail supply had largely comprised of the purchase of products traded on wholesale markets. These products were always priced at the prevailing market price for that product at the time the purchase was agreed. Pre-April 2011 the transfer charges in relation to traded products had been determined as described in paragraph 65 above.

71. In addition to the transfer charges based on products traded on the open market, there was also a [✂] proportion throughout the period (for example, [✂] of total retail supply volumes for 2013) which reflected purchases of gas acquired by [Firm F] on the basis of long-term contracts from third parties. These transfer charges were based on the contract price plus a premium, which had been retained by its trading division. This premium reflected the amortisation of the upward revaluation of these contracts to market value in [✂].

Financial hedges

72. [Firm F] told us that it had not carried any financial hedges over the period of review.

Levies on wholesale energy purchases

73. Prior to June 2011 [Firm F] levied a varying charge of between £[✂] million and £[✂] million in relation to all purchases to reflect that its trading division had assumed responsibility from it for the following:

(a) *Volume variability*: unexpected changes in weather, for example, could change the forecast of total retail demand in the final month before delivery. [Firm F]'s then approach to determining the transfer price for changes in volume would however not have taken account of any changes in market prices in the final month before delivery.

(b) *Market movement*: the daily forward market price had been based on an external view of the closing prices of the previous day. A factor had been used to reflect that market prices would have changed between the previous day's closing price and when an actual trade had been carried out; and

(c) *Shape (electricity only)*: a levy had been added to reflect that electricity was traded for each half hour to reflect the shape of customer demand. As the transfer price had been based on 'unshaped' market prices for each prior month, there had been a need to add 'shape' to take account of the half hourly demand shape.

Imbalance charges ('cash out')

74. [Firm F] had identified this item (relatively minor amounts for both electricity and gas) as one of the items comprising wholesale energy costs.

Recharges to recover costs of operating a trading division

75. [Firm F] told us that it had not recharged any of the costs of running its trading division over the period of review [✂].

Assessment of the basis of wholesale energy costs by firm

76. In this section we evaluate how well each of the Six Large Energy Firms' approach to determining its wholesale energy costs accorded with the basis set out in paragraph 1 – the 'equivalent stand-alone retail supplier' test. We do this first by answering the basic question of whether wholesale purchases reflected products traded on open market at the time of purchase for each of the Six Large Energy Firms in turn. We then consider the question of whether prices for these traded purchases reflected market prices. We then finally consider the other costs that some of the Six Large Energy Firms included in their analysis of wholesale energy costs.

77. We then provisionally conclude on the implications this has for our assessment of the competitive benchmark for wholesale energy in retail energy supply.

78. As explained in paragraph 6 and 7 above, this assessment is based on what firms have told us as summarised in paragraphs 15 to 75 above, the numerical analyses provided and our subsequent investigation.

Underlying wholesale energy costs

79. These comprise the transfer charges for traded and bespoke products, any associated financial hedges plus imbalance charges. They would (in theory) exclude any recoveries for the cost of running a trading division or dealing in external markets.

80. In Table 1 below we set out our provisional assessment of the answer to whether in principle the Six Large Energy Firms are purchasing the same open market products that an equivalent stand-alone retail suppler could have bought over the period of our review.

Table 1: Provisional assessment of whether wholesale energy transfer charges accord with those that would have been incurred by an equivalent stand-alone retail supplier

Energy firm	***CMA questions***	
	Do wholesale electricity purchases reflect ***in form*** *products traded on open market at time of purchase?*	*Do wholesale gas purchases reflect* ***in form*** *products traded on open markets at time of purchase?*
[Firm A]	Yes	Yes
[Firm B]	Yes	Yes
[Firm C]	No, not all of the time: all of its purchases are for shaped products, which are only available in prompt timescales	No, not all of the time (as per electricity)
[Firm D]	No, in addition to its purchase of traded products, it purchased power on a bespoke basis mainly from third parties, primarily [Firm [✂]], [✂] and renewable firms	No, it has [✂] bespoke gas contracts
[Firm E]	No, much of the cost base comprises bespoke purchases of power, primarily from internal sources	Mostly, but not entirely. There are some bespoke purchases which are a mix of internal and external purchases
[Firm F]	A qualified 'yes' post-April 2011 (ie for FY12 onwards)* No, pre-April 2011 (ie for FY11 and before)	No, there is a [✂] proportion of bespoke contracts, (which were revalued post-[✂])

Source: CMA analysis.
* Throughout the period of review [Firm F] had a much higher proportion of internal trades (30 to 60%) with its generation division than was the case for the other Six Large Energy Firms that were able to provide this information – [Firm A] (10 to 15%) and [Firm D](14% in 2013).

81. The next question we considered was whether purchases based on traded products had been priced at open market prices. The Six Large Energy Firms had told us that this had invariably been the case.

82. There were some subtleties as to how the actual open market prices had been determined. Please see the explanations in paragraphs 15 and 16 ([Firm A]), 25 ([Firm B]) and 36 and 39 ([Firm C]) above. These demonstrate that, at the margin, there might have some differences between the Six Large Energy Firms around how the bid/offer spread had been treated.

Levies on wholesale energy purchases

83. As explained in paragraphs 60 ([Firm F]) and 73 ([Firm E]) above, [✂] firms had imposed a levy on underlying wholesale energy transfer charges. We considered their explanations for what these levies related to.

84. [Firm E] explained that the levy in part was due to the fact that its retail supply division did not bear the cost of imbalance charges. Based on our review of the analyses provided by the other Six Large Energy Firms which all had included these imbalance costs within wholesale energy costs, we concluded that these costs would have been small compared with size of [Firm E]'s levies.

85. Regarding the other eventualities these levies were designed to cover, we considered that these were likely to be small in extent, and therefore that these levies were unlikely to be cost-justified. [✂].

86. We therefore provisionally concluded that we would exclude these costs from our assessment of their wholesale energy costs on the basis that they did not appear to relate to costs that an equivalent standalone supplier would have incurred.

Recharges to recover costs of a trading division

87. There was a variety of practice across the Six Large Energy Firms as to whether these costs were recovered through wholesale energy transfer charges or not. Based on our review of the amounts analysed by the firms that had been able to isolate these costs[17], we concluded that the amounts were so small compared with underlying wholesale energy costs that, for the purposes of our analysis, these differences were unlikely to matter.

Other observations

88. [Firm F]'s forward purchase of almost the entirety of its electricity requirement over the period 2008 to 2011 when [Firm F] judged them to have been committed (see paragraph 66 above) was, in particular, unlikely to have resulted in the costs that an equivalent stand-alone retailer supplier would have incurred. Such a firm would not have bought ahead to such extent because there would not have been sufficient liquidity in the market, and, to the extent there would have been liquidity, on account of the unattractive bid-offer spreads.

89. The extent of [Firm F]'s internal supply of traded electricity products post-April 2011, compared with the other Six Large Energy Firms who also had based their transfer charges on purchasing traded products, was very marked.[18] This suggested there was some dialogue between its generation and retail divisions regarding internal transactions and / or the detail of [Firm F]'s

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[17] See paragraph 30 above concerning [Firm B] and paragraph 51 concerning [Firm D].
[18] See paragraph 69 above.

approach to netting transactions across operating divisions was different from either that of, for example, [Firm A] or [Firm D].

90. [Firm E] purchased wholesale electricity for its larger industrial and commercial customers (see description at paragraph 55 above) in the form of standard traded products at the point of the contract was signed, whereas it largely took a different approach for its other retail customers.

91. The fact that not all the Six Large Energy Firms' transfer charges comprised in form exclusively of purchases of traded products has implications for the recognition of profits or losses across the energy value chain. For example, whilst [Firm D] sourced some of its electricity from [Firm [✂]] on a bespoke [✂] basis ([✂]) [19], [Firm [✂]] sourced all of its electricity for retail supply using traded products. The implication of this is that any difference in costs between these two firms would have been reflected in retail supply in the case of [Firm D] and elsewhere in the case of [Firm [✂]].

92. The Six Large Energy Firms' retail supply divisions in general did not purchase intermittent energy.[20] Although in layman's terms there is an obligation for them to purchase electricity from renewable resources, strictly speaking they are only obliged to buy renewable obligation certificates (ROCs) from renewable energy providers.[21] As intermittent energy cannot be used to implement a forward purchasing strategy, the Six Large Energy Firms tend instead to channel purchases of renewable elsewhere, typically either to their generation or trading divisions. For example, [Firm F] pre-April 2011 initially included the purchase of wind (and embedded power) within its wholesale energy costs, but post-April 2011these were then sold on at a no profit/no loss basis to its generation division. Due to its intermittency[22], there is the scope for a wider diversity of accounting treatment across the energy value chain than for other sources of energy. This in turn makes it more likely that the Six Large Energy Firms will have taken a variety of approaches to accounting for this source of energy, including into their retail supply businesses.

Provisional conclusion

93. Based on our review of how each of the Six Large Energy Firms had approached determining their wholesale energy costs, we provisionally

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[19] See paragraph 41(a) above.
[20] All the Six Large Energy Firms own wind generation assets and/or have agreements to purchase the output of independently-owned wind farms.
[21] Or pay the buy-out price for ROCs.
[22] See also paragraph 41(c) above including its footnote 12.

concluded that both [Firm A] and [Firm B]'s approach for both electricity and gas was likely to most closely match that of an equivalent stand-alone supplier who had adopted the same hedging strategy (ie same timing and mix of products purchased) as [Firm A] or [Firm B] and purchased all its energy requirement on the open traded market. Therefore the costs for [Firm A] or [Firm B] were more likely, all other things being the same[23], to be the most informative when considering the competitive benchmark for wholesale energy in retail energy supply.

94. We also provisionally concluded to exclude both [Firm E] and [Firm F]'s levies on underlying wholesale energy transfer charges from our assessment of wholesale energy costs incurred by their retail supply businesses.

[23] For example, costs might have differed between [Firm B] and [Firm A] on account of differences in the timing and mix of traded product purchases.

Annex B: Wholesale spot scenario analysis

Introduction and summary

1. We compared the reported wholesale energy costs of the Six Large Energy Firms with a calculation of energy costs based on volumes consumed and spot market prices over the relevant period.[24]

2. In doing so, we sought to understand the extent to which reported wholesale energy costs, which account for the single largest cost item for energy retailers, have differed from spot market price in recent years and the reasons for any differences. This annex primarily focuses on electricity, unless otherwise stated due to data availability.

3. The reported energy costs of the six largest energy suppliers vary over time and between suppliers. In any given year the costs of individual suppliers can be materially different from each other, with variances in some years over 10%. In addition, suppliers report different average wholesale energy costs over time, with a difference of over 8% between the highest and lowest. There are several possible explanations for this.

4. One possible explanation is differences in hedging policy. The energy suppliers hedge (forward purchase) significant amounts of their energy needs in advance. There are a variety of reasons for hedging but the main reasons given are;

   (a) to avoid the greater volatility of prompt prices (trades two weeks prior to delivery);

   (b) to lock in the cost of energy for fixed-price tariffs and;

   (c) to reduce the frequency of price changes for other tariffs.

5. All things being equal, if wholesale costs are falling, any strategy that hedges further in advance would lead to a higher average cost of energy when compared to a strategy that hedges less far out. The converse of this is also true, that is, in a rising commodity market the further out a supplier hedges the average cost of energy should be lower than a supplier hedging shorter.

6. We would expect that over an appropriate period of time, the suppliers reported cost of energy (hedged cost) should broadly be equal to the average spot price. To investigate this, we compared the spot cost of electricity with

[24] Profitability approach working paper.

hedged cost from 2009 to 2013. We found that for all of the suppliers, over this period of time the reported cost of energy was higher, approximately 17% on average, than the spot cost.

7. In relation to our analysis the suppliers outlined a number of potential adjustments that would bring the overall difference down and outlined a number of practical difficulties with purchasing at spot and the increased risk thereof. However, none disagreed with the finding that reported costs had exceeded spot costs over the period of review.

8. The main reason for the observed difference appears to be due to forward purchasing and over this period there have been fewer price spikes such as those seen in 2004/05 and 2008.

9. The cost of wholesale electricity spiked in 2008 and then fell sharply in 2009. This created a large variance in our analysis in 2009 as firms forward purchased at 2008 prices. From 2009 to 2013 the wholesale cost steadily rose and the difference between the hedged cost and the spot cost reduced to a small difference in 2013. We discuss the hedging behaviour and the impacts of this behaviour in more detail in Appendix 8.4 and in Annex A to this appendix.

10. An alternative explanation for the observed differences in reported wholesale energy costs between suppliers is that they adopt different transfer pricing methodologies between the retail part of the business and the trading and/or generation part of the business. This is also explored in further detail in Annex A.

11. The remainder of this section sets out (a) an overview of the six large energy firms' reported energy costs and (b) a description of the methodology used to calculate the wholesale spot price scenario (c) the results of the analysis (d) parties comments on the analysis (e) our preliminary views on the results of the analysis.

Reported wholesale energy costs

Section overview

12. Energy suppliers purchase their energy through a wide variety of sources which will impact the cost. We describe in more detail the purchasing behaviour and impacts on reported wholesale costs in Annex A. A significant proportion of this energy is purchased in advance through forward deals with the majority of forward purchasing done within two years[25] prior to delivery.

13. Energy suppliers purchase the bulk of their energy needs ahead of delivery and use the prompt market to manage shape and imbalance risks. In their December 2014, Wholesale Electricity Market Report[26], Energy UK stated that:

> From the perspective of a supplier, forecasts that are closer to delivery are more accurate than the longer forecasts which entail greater risks. As a result, interest lessens in trades further out, although this has to be balanced against the need to hedge to meet consumer demand for fixed price products.

14. The above statement highlights the trade-off between locking in energy costs and therefore margins on certain products and the risks associated with and the uncertainty of forward prices.

15. We looked at how the spot price compared with the cost of purchased energy for the Six Large Energy Firms from 2009 to 2013 and explored reasons for differences.

16. First, we looked at how reported wholesale costs varied between the suppliers from 2009 to 2013.

Six Large Energy Firms' reported wholesale energy costs

17. Figure 1 profiles the cost of electricity (£/MWh) as reported in P&L accounts[27] for domestic and SME customers from 2009 to 2013 split by supplier. It shows that the unit cost of wholesale electricity varied substantially across the Six Large Energy Firms in any year.

[25] See Appendix 6.1: Liquidity.
[26] Energy UK (December 2014), *Wholesale Electricity Market Report*.
[27] The P&L information was provided to us by each of the parties as part of our investigation covering the GB energy market.

Figure 1: Six Large Energy Firms' combined domestic and SME electricity costs £/MWh (2009 to 2013)

[✂]

Source: CMA Analysis of P&L information provided by the parties.
Note: For ease of comparability, SSE year end 31 March 2010 is deemed financial year 2009 with the same assumption being applied in subsequent years.

18. Based on Figure 1, [✂] in financial years 2010 and 2011 had a very high £/MWh cost compared to the other suppliers as did [✂] in 2011 to 2013. We explore the reasons for these differences in further detail in Annex A to this appendix.

19. Table 1 shows the average reported cost of domestic and SME energy over the five year period from 2009–2013 for each of the six large energy suppliers. We note that although the in-year variations are quite large, across the period four of the suppliers have very similar costs (see Table 1 below) with [✂] and [✂]both higher as noted in paragraph 18 above. There is an 8.5% differential between the lowest and highest reported average costs.

Table 1: Average cost of domestic and SME electricity £/MWh (2009–2013)

Energy firm	*£/MWh*
Centrica	[✂]
Scottish Power	[✂]
SSE	[✂]
E.ON	[✂]
EDF Energy	[✂]
RWE	[✂]

Source: CMA analysis.

20. We then looked at gas costs on a combined domestic and SME basis (£/Thm). Figure 2 shows that over the same period, as with electricity there are significant intra-year variances between the firms.[28] We note that, although there are large intra-year variances in the cost of gas between the suppliers, they follow a similar trend with costs falling and rising in a relatively similar fashion.

Figure 2: Six Large Energy Firms combined domestic and SME gas costs £/Thm (2009 to 2013)

[✂]

Source: CMA analysis.
Note: EDF Energy figures represent their domestic gas customers only as they do not have an SME gas business.

21. Table 2 sets out average reported costs of gas over the period from 2009–2013 for each of the Six Large Energy Firms. This shows a variation in average reported costs of gas of 10% between the highest and lowest. We

[28] The cost of gas is compiled from the same P&L account information as electricity.

explore the reasons for these differences in further detail in Annex A of this appendix.

Table 2: Average cost of domestic and SME gas £/Thm (2009 to 2013)

Energy firm	*£/Thm*
Centrica	[✄]
Scottish Power	[✄]
SSE	[✄]
E.ON	[✄]
EDF Energy	[✄]
RWE	[✄]

Source: CMA analysis.

22. From Table 2, taking the average over the period RWE, Scottish Power and EDF Energy have the lowest cost £/Thm, although their relative positioning changes year on year.

23. We now outline our methodology for calculating electricity costs by supplier using the spot price.

Wholesale spot scenario

Background

24. Energy prices are volatile for both gas and electricity, with prices affected by weather, international events such as Fukishima and the prevailing geopolitical landscape. This volatility, in terms of price fluctuations, is greatest for within-day and day-ahead prices. Day-ahead volatility can be seen graphically in Figure 6.

25. Forward purchasing is a key reason why the spot price at any given time may not be reflective of the cost of energy purchased by the suppliers. Each supplier adopts a different hedging strategy that will impact each firms specific cost and there is no simple equation that describes the relationship between spot prices and forward prices.

26. Another reason each firms cost of energy might differ is due to their customer and tariff mix. The energy suppliers will hedge differently depending on customer type and fuel type, which will impact their overall cost. The volume information is not available to allow an analysis of the spot cost by tariff type.

27. Though in any given time period, the procured cost (hedged cost) of energy would be expected to differ from the spot price, we would not expect to see persistent differences in one direction. Any differences seen should, over a suitable time horizon, expect to approximately even out.

28. In the *Methodology* section below, we set out how we recalculated the cost of electricity for each supplier using day-ahead prices. The focus of this paper is on electricity, however with gas being the marginal fuel in recent years the electricity market will to a certain degree mirror the gas market.

Methodology

29. Recalculating the cost of energy was done by multiplying volumes delivered over the year by the in-day spot price. This was done using company specific volume data for each supplier.

30. This paper focuses on electricity but a high level assessment of gas was also undertaken and shared with the parties. Gas volume data does not allow us to look at our reference markets of domestic and SME[29] customers therefore we do not include the results of gas in this paper but the result was broadly the same as our electricity analysis.

Volumes data

31. In order to restate each firm's reported wholesale energy costs based on spot market prices, we sought to maintain the granular profile and shape of each firm's energy volumes it supplied to its customers over the Relevant Period[30]. The suppliers could only provide total volumes delivered over the year, therefore we requested Elexon to provide us with half-hourly electricity volumes supplied by each of the Six Large Energy Firms for the whole of the Relevant Period.[31]

32. *A* Gas volumes data request was sent to Xoserve to provide us with daily gas volumes supplied by each of the Six Large Energy Firms for the whole of the Relevant Period.[32] As noted, gas end user volume categories did not allow us to segment the volumes into our reference markets.

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[29] SME customers taken to approximate our actual reference market of microbusinesses.
[30] Electricity is traded in half-hourly settlement periods, with settlement period 1 equivalent to 00:00 to 00:30, settlement period 2 to 00:30 to 01:00, and so on. Therefore, each day is split into 48 settlement periods (source: Elexon guidance document *The Electricity Trading Arrangements*, p9).
[31] Elexon provided us with reported settlements volumes data at a purchase volume level, ie including transmission and distribution losses. The volumes data was based on the latest available settlement data flow by PC type, based on industry settlement data flows. Elexon made all of the necessary adjustments to these volumes, namely those relating to the Group Correction Factor, Distribution Line Loss Factor and the Transmission Loss Multiplier.
[32] Xoserve provided us with daily deemed gas volumes. Xoserve told us that daily deemed volumes represented the daily allocated volumes adjusted by weather and seasonality factors and any other adjustments that took place 5 days after gate closure (ie D+5). Xoserve also told us that we should not use 'Reconciliation and Settled Volumes' for the purposes of our analysis, given that these reconciliation runs could last up to four or five years after gate closure, and any adjustment would not be retrospectively allocated. Xoserve told us that these reconciliation adjustments did not have a material impact on the daily deemed volumes (ie up to 3–4% overall) .

33. Given that the Elexon data was split by electricity meter profile class (PC),[33] we considered that this provided us with potential scope to map each firm's granular electricity volume data on to its domestic and SME volumes.

Electricity volume segmentation

34. We consulted with the Six Large Energy Firms and Elexon on how PCs might be used to segment each firm's volume data by domestic, SME and I&C customers. Based on these discussions, there was a general consensus across the different parties that grouping certain PC volumes would give reasonable approximations for volumes by retail segment, where: (i) PC1 and PC2 could be used to approximate domestic electricity volumes; (ii) PC3 to PC8 for SME volumes;[34] and (iii) PC0 for I&C volumes. Most parties agreed that the scope for misclassification was largely limited to SME and I&C volumes.[35]

35. Based on the volume categories and responses from parties, we concluded that we would be able to recalculate the cost of energy for domestic electricity customers and SME electricity customers. Below we outline how this volume data was used to calculate domestic and SME electricity costs:

Domestic electricity spot calculation

36. We used the profile of the Elexon half-hourly data for PC1–2 to profile the total volumes that each supplier reported that they delivered to their domestic customers in year.[36] This new company specific half-hourly profile was multiplied by APX in-day market index prices in each half hourly period. The aggregate of this gives a total cost of energy if all was purchased at the spot price. The only adjustment that was made to this calculation was an uplift of 8% to account for transmission and distribution losses[37] as these were not factored into the delivered volumes the suppliers provided us.

[33] There are nine PCs for electricity volumes data, denoted by PC0 to PC8, and nine EUCs for gas volumes data, denoted by EUC1 to EUC9. PC1 to PC8 apply to non-half hourly meters whilst PC0 apply to half-hourly higher consuming.
[34] PC1 and PC2 meters apply to domestic premises and PC3 to PC8 apply to non-domestic premises (source: Elexon guidance document *The Electricity Trading Arrangements*, pp18-20).
[35] For example, Centrica told us that whilst it could classify PC3 and PC4 as SME volumes with absolute certainty, PC5 to PC8 may include some I&C volumes.
[36] The data provided by Elexon was firm specific.
[37] DECC, *Digest of United Kingdom Energy Statistics 2013*. Losses constitute distribution losses, transmission losses, fraud and theft (7.7%).

SME electricity spot calculation

37. We used the profile of the Elexon half-hourly data for PC3–8 to profile the total volumes that each supplier reported that they delivered to their SME customers in year.

38. As with the domestic customers, the SME profiles were multiplied by APX in-day prices and an 8% uplift also applied to give a total recalculated cost of SME electricity by firm.

39. The recalculated cost measured on a per-unit of output was compared with the reported historic cost in each suppliers P&L account. No adjustments were made to the historic cost of energy reported in the P&L accounts.

40. We recognise that there are other price series that could be used that may yield a different result. There are also other industry and company specific adjustments that could be made. However, we believe that the methodology, even when taking its limitations into account provides a reasonable basis with which to compare reported costs with the spot price in recent years. The parties' views on the methodology and results of the analysis are set out in Supplement A. In the next section we set out our results.

Results

Domestic electricity

41. In Table 3 below we set out the differences between the average reported cost of electricity £/MWh and the cost based on our spot price recalculation. A year on year breakdown can be found in Supplement B. When we compared our recalculated cost (spot cost) for domestic electricity customers we found significant variances in any given year between each of the suppliers.

Table 3: Domestic electricity costs (£/MWh) reported costs against CMA recalculated cost

Energy firm	*Average domestic WSE costs 09–13 £/MWh (P&L)*	*Average domestic WSE costs 09–13 £/MWh (spot)*	*Variance (£)*	*%*
Centrica	59	51	8	13
EDF Energy	60	50	10	16
E.ON	60	50	10	16
RWE	60	51	10	16
Scottish Power	64	50	14	22
SSE	64	50	15	23

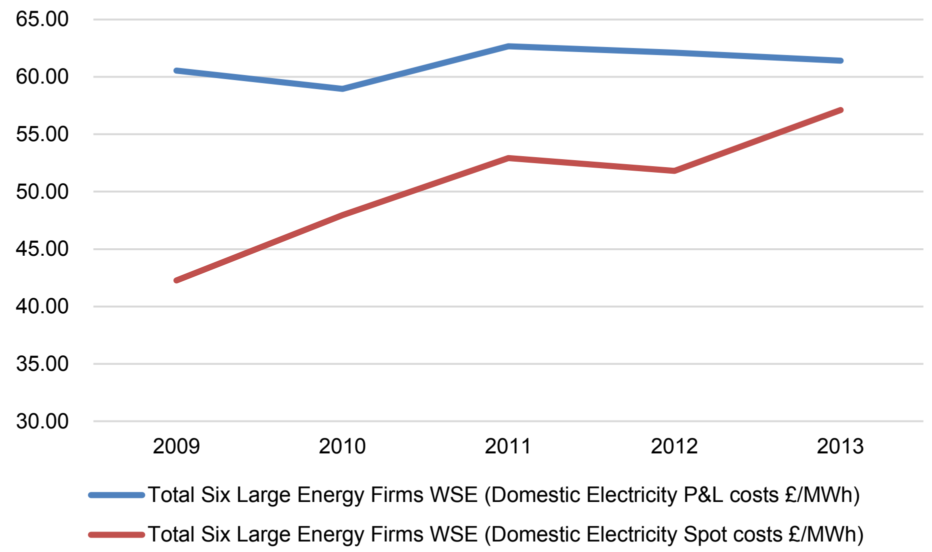
Source: CMA analysis.
Note: Figures rounded to nearest £.

42. We found that from 2009 to 2013 in all cases our recalculated cost based on in-day spot prices was lower than the reported costs. The lowest average

difference was Centrica with their reported costs being 13% higher. Scottish Power and SSE had the highest aggregate difference of 22% and 23% respectively, reasons for this are discussed in further detail in Annex A to this appendix. The other three suppliers all had a difference of 16%.

43. There was also a clear trend over time. From Figure 3 below you can see that the gap is at its greatest in 2009, the difference being approximately 30% and the gap narrows to its lowest point by 2013, approximately 7%. These figures can be seen in Supplement C.

Figure 3: Six Large Energy Firms' combined domestic electricity costs in £/MWh (2009 to 2013)



Source: CMA analysis.

44. If we exclude Scottish Power and SSE, who as noted have a slightly higher cost for domestic electricity the gap is lower. In 2013 the difference is only 4%, please see Supplement B.

45. In the *Further Analysis* section we outline and explore possible reasons for the differences seen above. First, to explore to what extent this trend relates only to domestic electricity customers, we set out our findings for the same analysis on the Six Large Energy Firms' SME electricity businesses.

SME electricity

46. We recalculated the cost of electricity for the larger suppliers SME customers in the same way that we did for their domestic customers. By comparing this cost to the reported cost for SME customers we found similar differences to those found on the domestic side of their business. Please see Table 4 below.

Table 4: SME electricity costs (£/MWh) reported costs against CMA recalculated cost

Energy firm	*Average SME electricity costs 09–13 £/MWh (P&L)*	*Average SME electricity costs 09–13 £/MWh (spot)*	*Variance (£)*	*Variance (%)*
Centrica	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]
RWE	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

47. The lowest differences noted were among [✂] who on average had their reported costs all being 14% higher than the recalculated cost. [✂] had the highest differences with reported costs being 21% and 22% higher respectively. Again in all cases and in every year the reported cost of SME electricity was higher than our recalculated cost based on in-day spot prices.

48. Below in Figure 4 we outline the trend in reported costs against the recalculated cost from 2009 to 2013.

Figure 4: Six Large Energy Firms' combined SME electricity costs (£/Mwh)

[✂]

Source: CMA analysis.

49. The trend seen on the SME business segment shows some similarities with the trend seen in domestic electricity. With the gap across the Six Large Energy Firms at its greatest in 2009, approximately 31% and falling to its lowest difference in 2013, approximately 4%.

50. To identify whether this may be an electricity only difference or the result of cost allocation we need to look at reported gas costs, this is set out below.

51. Our recalculated cost of energy and the reported costs are not a like for like comparison. There are other costs of energy, hedging, shaping and forward purchasing that could explain the differences we have seen.

52. We provided our workings to each of the largest suppliers and below we set out the key responses.

Parties' responses

53. The parties' responses to these results are set out in Supplement A. The main comments were as follows:

(a) the analysis was done over a too short a time period to draw any conclusions from;

(b) company specific adjustments, such as company specific losses would need to be made;

(c) there is not enough depth to purchase total volumes at spot prices and this would possibly have an effect on the price; and

(d) purchasing closer to delivery entails greater risk, which consumers would not want.

54. The parties do not dispute that there is a gap over the period we have looked at and many point out the benefits of hedging for consumers.

Results interpretation and preliminary views

55. There are a number of small adjustments that would reduce the total difference but not materially, these are set out in Supplement D. The point that the spot cost is lower than reported costs over the period of 2009 to 2013 remains valid and the parties do not dispute this.

The forward cost of electricity

56. The forward cost of electricity or gas may differ from the spot price during any static point in time, be it higher or lower. We would expect, all things being equal that the forward cost over an appropriate length of time would be broadly similar to the spot cost of energy, perhaps as some suppliers suggest at a small premium.

57. To assess any impact from this over the period of our review we looked at the spot cost and the forward costs over time. Below in Figure 6 we profile the day ahead cost of energy (green line) against what one and two year forward products are trading at.[38]

Figure 6: Electricity day-ahead cost of energy against the forward cost (£/MWh)

[✂]

Source: CMA analysis.

58. This chart indicates market expectations against current day-ahead prices. We note:

[38] Forward prices taken from Appendix 7.2: Cost pass-through.

(a) Firstly, that the year where the gap between the forward cost and the day-ahead cost is at its lowest is in late 2012 through into 2013. This may correspond to the narrowing of the gap our analysis showed in 2013.

(b) Secondly, the gap is at its widest in 2014, indicating that after 2013 the gap is likely to have widened again.

59. Figure 6 does not precisely match the day-ahead cost with the forward cost was for that period because the forward costs used are a stylised version of a block of energy being delivered in equal amounts over a one or two year period. To more accurately compare the forward cost of electricity with the out-turn price at delivery, it is necessary to look at individual products.

60. Below in Table 6 we show the average traded value[39] of forward summer and winter products[40] against the average day-ahead price during the delivery period of those products.

Table 6: Average price of seasonal products (£/MWh) and spot price during that delivery period

Season/year	Average of cost product £/MWh	Average spot price during period £/MWh	Variance (£)	Variance %
Summer 2011	46	51	–5	–11
Winter 2011	55	47	8	14
Summer 2012	52	45	7	13
Winter 2012	56	54	2	3
Summer 2013	51	51	1	1
Winter 2013	56	50	6	11
Summer 2014	52	40	12	23
Average	53	48	4	8

Source: CMA analysis.

61. From the table above only in one season was the forward product cheaper than the out-turn cost during that period. On average the forward cost over the period was 8% higher than the prevailing spot prices. We also note that in 2013 the difference between the two is minimal, again showing a possible symmetry with our preliminary findings.

62. We believe the parties are correct in that the main reason for the difference is due to the forward cost of energy. Our analysis suggests that the primary driver in our electricity results are due to the difference in the forward cost of electricity and the prevailing spot prices. The large disparity in 2009 is therefore driven by the wholesale cost rises in 2008.

[39] The average price is taken as the average price of all trades 18 months prior to delivery. These products can be purchased over three years in advance.
[40] Summer and winter products are forward traded products of 6 months' worth of energy.

Preliminary views

63. The reported costs of the energy suppliers are higher than prompt prices over the last five years. One main reason for this is that suppliers forward purchase (hedge) significant volumes and over this period the forward cost has been higher than the spot price.

64. The forward curve is an inherently uncertain but is less volatile than prompt prices so there is a trade-off between securing energy and balancing this with the risk over the uncertainty of forward prices.

65. Spot price tariffs are not common in Europe. However they are prevalent and popular in the energy markets of Norway, Sweden and Finland.[41] In these countries, consumers typically pay the average monthly spot price on the NordPool power exchange plus a mark-up. The VaasaETT European Residential Energy Price Report 2013 states that academic research in the Nordic markets shows that retail prices tend to adjust to long term (year) trends in wholesale prices in these markets. The Retail Market Review (RMR) four tariff rule may limit suppliers' ability to offer certain tariffs.

66. We further examine the reasons for and impacts of hedging forward for all customers in Appendix 8.4.

[41] *VaasaETT European Residential Energy Prices Report 2013*, p14.

Supplement A: Parties' responses

The Six Large Energy Firms

Below we outline the main responses we received from the parties in relation to the electricity spot analysis.

E.ON

1. In E.ON's response, we were told:

> At a high level, E.ON believes that the analysis that the CMA has completed demonstrates the difference between forward electricity prices and the spot electricity prices.

2. E.ON's response set out their thoughts on the limitations of our work and the benefits of hedging. From their perspective, additional to those previously highlighted in this paper were, the primary limitations of this analysis were:

   (a) The volumes traded at APX were relatively low and therefore could not be necessarily relied upon to be indicative of prices achieved for the entirety of the volume requirement.

   (b) Wind and solar feed-in generation have a substantial and specific effect on the spot market price that could not necessarily be indicative of overall prices achievable across all generation technologies.

   (c) N2EX might be a better price series to use as opposed to the APX used.

   (d) The reported wholesale cost included the costs and benefits of overall volume forecasting inaccuracies and imbalance.

   (e) The study of an extended period prior to the periods looked at would likely reveal greater volatility.

   They outlined the benefits of hedging as:

   (f) It protected suppliers and generators from exposure to commodity price risk, which may have contributed to the collapse of Bizz Energy and E4B in Q4 2008 for not being sufficiently hedged.

   (g) Customers did not like direct exposure to the volatility of wholesale price fluctuations. Therefore hedging was essential to protect consumers from 'bill shock'. It provided protection to consumers and suppliers so has value.

(h) A lack of storage, the technical risks associated with generation and volumetric risks associated with a portfolio of customers would crystallise and be perceived in differing timescales and would therefore manifest themselves differently across forward and spot products.

(i) Forward products reflected the uncertainty in the wholesale market given the wide range of drivers of price such as capacity margins, environmental, regulatory and political impacts as well as the underlying commodity price. Nearer to delivery risks, might or might not have been realised.

(j) Past prices were not necessarily indicative of future prices given the significant change in the wholesale market. For example, the drive towards 2020 renewables and carbon targets, the introduction of electricity market reform, industrial emissions directive, the electricity balancing significant code review, supplemental balancing reserve and demand-side balancing.

(k) If suppliers did not hedge they could take on the risk of spot price volatility but would require a risk premium, or transfer the risk to consumers leading to more frequent price changes and 'bill shocks'.

(l) Even if the risk was passed on to consumers, the incentive to aim for a 'cheap' cost base, which spot pricing may give in a falling wholesale market, would be lessened because suppliers would be exposed to asymmetric competitive risk (customer number loss when pricing was out of the market being much greater than customer number gain when in the market).

RWE

3. In their response RWE stated that:

> We believe that the main fundamental driver for the difference is that global energy markets have fallen over the period and thus we would expect out-turn prices on average to be below forward prices for these historic periods.

Importantly RWE stated that this analysis only represented an ex-poste, ie looking at costs in recent years with the benefit of hindsight.

4. RWE set out a number of limitations of this analysis and also outlined the benefits of hedging. The limitations of this analysis in RWE's view were:

(a) The consumption data used did not provide any information as to the supplier-specific mix and resulting risks of customer product characteristics. The distinction between ‘fixed’ and ‘variable’ customers was lost in this analysis. For example [✂].

(b) Under the implied spot scenario there would be significant extra risk for suppliers. If they were unable to absorb this, and such exposure could pose a threat to a supplier’s viability, greater risk would need to be transferred to customers.

(c) RWE considered [✂].

(d) The domestic and SME profiles of PC1–2 and PC3–8 respectively did not perfectly align with RWE’s customers. This was more pronounced with the SME analysis.

(e) At a theoretical level you might also expect an element of premium in forward prices compared to spot prices as there is a cost of holding fuel in store – known as the ‘cost of carry’.

On the benefits of hedging, RWE said:

(f) Forward purchasing reduced volatility. It was likely that averaging over a daily electricity spot cost would lead to more volatile wholesale costs than a longer-term forward purchase.

(g) It would not be an attractive proposition for customers to take on most or all of the risk of price volatility.

EDF Energy

5. EDF Energy stated that:

> the data used has been from a period of largely falling forward markets, meaning that spot prices are lower than the prices traded a year or two earlier, purely because the market as a whole has moved during the intervening period. In particular, both forward and spot prices were very high in the mid-2008, falling by nearly half over the six month period from July 2008, which would have increased EDF Energy’s costs for 2009, 2010 and to a lesser extent 2011.

6. EDF Energy set out a number of limitations in our analysis and the benefits of hedging:

(a) Hedging strategies inputted into the pricing process and therefore, if EDF Energy were not to hedge, the products would be different.

(b) If EDF Energy and other market participants followed a spot purchasing strategy the dynamics of both the spot and retail market would be very different, which limits any conclusions that can be drawn from this analysis.

(c) EDF Energy had not seen any evidence that there was any demand for a product that was indexed to the spot price.

(d) If all market participants adopted this strategy it would be likely to impact on the liquidity available in the curve and therefore also affect the ability of generators to hedge, potentially increasing their earnings volatility and therefore their cost of capital.

(e) EDF Energy did not believe the dataset was large enough to draw any general conclusions about the relative levels of spot and forward prices. If this analysis were extended prior to 2009 then it would show a number of years where the spot prices were higher than the forward products.

(f) There were significant overlaps between PC1–8, meaning that the assumed profile classes are not an accurate reflection of EDF's customers.

(g) EDF Energy did not use raw APX data for prompt benchmarking, EDF used their own internally generated index. The reason for this was that APX data does not include the true cost of shape.

(h) The analysis assumed that all volume is purchased at the mid-price, which is not always the reality.

(i) There were enough market participants that it was reasonable to expect that the market would self-correct if a bias existed. Forward prices, in general terms, should be an un-biased opinion of forward costs.

On the benefits of hedging:

(j) EDF Energy said it hedged to reduce the variability of its cost base and to shield its customers from the volatility of the wholesale markets. Hedging did not increase or decrease costs on average.

Scottish Power

7. Whilst in their response Scottish Power did not explicitly state that the gap in our analysis is due to the difference in the forward cost of energy, they did give a number of reasons for why forward prices would differ from spot prices.

8. Scottish Power set out a number of reasons for why our analysis may not be comparing on a fair basis and why the cost of forward energy might be expected to vary.

9. They said that the reasons that our analysis may not be an accurate reflection were:

(a) The CMA analysis assumed 100% forecast accuracy and a single trade for each half hourly period. This took no account of changes in demand affected by things like temperature, customer behaviour and number of customers supplied. Each of these would change over time leading to purchases or sales required to balance change in customer demand. This would impact on costs.

(b) In relation to liquidity costs, our methodology assumed the APX price wouldn't change if all volumes were purchased at the day ahead price. Scottish Power said this was not true: a liquidity premium would need to be added to the APX price.

On the differences between the APX price and the forward price, Scottish Power said:

(c) The risk involved in spot price formation generated a counteracting premium in the forward price.

(d) Forward pricing would factor in an expectation of system margin, the difference between supply and demand and a measure of scarcity. A perceived decreasing margin might cause spot prices, and therefore forward prices and corresponding premiums, to increase.

(i) Demand-side risk had an impact. A slower than expected recovery coupled with energy efficiency measures had had the effect of reducing demand in the UK at delivery. As a result, the UK electricity system had been oversupplied at delivery over the past few years and this is reflected in the lower APX prices that we observed.

(ii) Supply side risk had an impact. Due to the unreliability of older conventional plant, the uncertainty of intermittent generation and the limitations of grid capacity there was a risk of unplanned cuts in the face of severe weather driving up peak demand. This was a further risk, likely to be factored into forward pricing. As the system has been oversupplied, these risks have not been observed at delivery in recent years.

(e) Global commodity risk would influence both spot and forward prices.

(f) Wind generation had delivered an intermittent supply of electricity to the oversupplied market over the past few years. It was questionable whether this was explicitly factored into the forward pricing given the uncertainty of when new wind generation would come online and the intermittency of the generation. This was a further factor contributing to the lower prices that had been observed in the spot market.

SSE

10. SSE had concerns with the length of time and the methodology that we have used in this analysis. However, SSE did state that:

> Over the last five years, purchasing at spot prices may have been cheaper than forward hedging but there is no guarantee this will be the case going forward.

11. In their response, SSE's concerns fell broadly into two categories: concerns over the methodology and the reasons for hedging. In relation to concerns with the methodology SSE said that:

(a) Our analysis uses a spot price that never would have been paid in practice if all retailer were purchasing at spot. No supplier operating on the scale of the large vertically integrated company could operate solely on purchasing at spot.

(b) Such a cost benchmark would not reflect the realities of the market over the longer term since it takes no account of the capacity payments sought by power producers.

(c) In an industry where the assets have lives in excess of 30 years looking at a five year time frame was too short to draw any conclusions. In particular over the last three years the annual temperatures had been above the long-term average, leading to lower demand and less peaky prices.

(d) The impact of incidents such as Fukishima, Ukraine, South Ossetia and others had increased the risk premium on forward prices and, in addition, regulatory uncertainty around the carbon floor price and the introduction of EMR had also pushed up forward prices.

(e) In a downward trending market, forward prices would tend to be consistently higher than the out-turn spot price.

(f) If we conducted this analysis from 2005 to 2008 the opposite observation would have been observed. Over the long term, forward prices were equally likely to be lower than spot prices as they were to be higher.

In terms of the benefits of hedging and why suppliers entered into forward purchasing arrangements, SSE said:

(g) Over the longer term there were incentives for power producers and suppliers to enter into long-term contractual arrangements reflecting the risks inherent in the market. Purchasing Power Agreements (PPAs) were required to secure investment in new plant and entering into a PPA was part of a prudent commercial policy to have a proportion of generation locked in for consumers.

(h) Forward hedging also includes long-term commitments to power plants through tolling agreements and the long-term purchases of coal and gas entered into to generate power. SSE said it entered into these forward hedges to provide price stability to customers.

(i) Unusually cold weather or supply shocks related to market response to geopolitical or geological hazards could result in spot prices spiking.

Centrica

12. In its response, Centrica stated that:

> The vast bulk of the difference between the [spot price] and the reported electricity costs are attributable to hedging.

Centrica set out a number of concerns with the analysis and how it might be interpreted.

13. In relation to the analysis Centrica stated that:

(a) There was typically a small premium built into forward price curves. Buyers were willing to pay a small forward curve premium to avoid some exposure to greater prompt price volatility. The premium was fairly modest, with Centrica estimating that from 2008 to 2013 the forward price was on average 2% more than the day-ahead price.

(b) In a rising or falling commodity market, there could be much more significant price deltas between spot and curve pricing. Recently for example, spot prices had fallen below the prior level of the forward curve but there had been earlier periods where the reverse has been true.

(c) Without a sufficient time period our analysis risks being misconstrued. The analysis should be conducted from 2005 where the opposite pattern would be observed.

(d) Spot prices had historically been more volatile than forward curve pricing, as seen with other physical commodity markets. This volatility had increased over the last two years as the market has had to respond to the growing amount of intermittent electricity available, which could not be forecasted with any accuracy.

(e) There were differences between spot and forward curve prices due to ‘shape’ which was not factored into our analysis. It is important to recognise that a residential demand-weighted average day-ahead price (as used in this appendix’s analysis) would be at a significant premium to the time-weighted average (baseload) day-ahead price.

(f) Centrica estimated that its transport and distribution losses were higher than the 8% allocated and that these were likely to vary between different time periods across the year.

(g) If all electricity supplies were bought at the [spot price], then the prices could well be different from those actually recorded and used in this analysis. Therefore our analysis could not be considered a robust counterfactual in the absence of forward hedging.

(h) The day-ahead market was typically used by suppliers for (relatively) marginal hedging adjustments, eg to manage shape and imbalance risks. The amount of prompt trading generally fell well short of the total volume being supplied to customers on any given day.

(i) The relationship between forward and day-ahead prices was strongly influenced by underlying commodities.

In terms of the benefits to consumers, Centrica said:

(j) Forward purchasing helped to support pricing propositions which sheltered residential customers from prompt wholesale price volatility which suppliers would otherwise have to seek to pass through to consumers by way of more frequent price changes. Centrica also highlighted that this forward purchasing met their customers’ desire to avoid ‘bill shocks’ and allowed them to budget for their energy bills.

(k) Hedging strategies were typically designed to support residential customer propositions, which in effect, sheltered those customers from short-term volatility in prompt wholesale prices and smoothed out long-term fluctuations in wholesale costs.

14. Customers on standard variable tariffs were subject to infrequent price adjustments (relative to the regularity of wholesale price fluctuations) and did

not face the full impact of short-term volatility in prompt wholesale prices because of hedging.

Supplement B: Domestic electricity

Domestic electricity costs (2009 to 2013)

1. The table below outlines the results from our analysis of reported energy costs against a recalculated spot cost of energy and the resulting variance between the two.

Table 1: Domestic electricity reported energy costs and spot priced energy costs

Year	*Energy firm*	*Volumes (TWh)*	*Volumes (MWh)*	*Cost per P&L account (£m)*	*Recalculated spot cost (£) (including 8% losses)*	*Variance (£m)*	*Variance (%)*	*Average variance (%)*	*Excluding Scottish Power & SSE (%)*
2009	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	30	[✂]
	EDF	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
2010	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	19	[✂]
	EDF	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
2011	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	16	[✂]
	EDF	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
2012	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	17	[✂]
	EDF	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
2013	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	7	[✂]
	EDF	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]		

Source: CMA analysis.

Supplement C: SME electricity

SME electricity costs (2009 to 2013)

1. The table below outlines the results from our analysis of reported energy costs against a recalculated spot cost of energy and the resulting variance between the two.

Table 2: SME electricity reported energy costs and spot priced energy costs

Year	*Energy firm*	*Volumes (Twh)*	*Cost per P&L account (£m)*	*Spot cost (£m) (plus 8% for losses)*	*Variance (£m)*	*Variance (%)*	*Average variance (%)*
2009	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	31
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	
2010	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	17
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	
2011	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	8
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	
2012	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	15
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	
2013	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	4
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	

Source: CMA analysis.

Supplement D: Other factors

Other factors that will influence the result

1. Below we outline the main possible explanations that could explain the difference between the reported cost of energy and our recalculated spot cost.

   (a) *Ancillary hedging costs* – such as transaction costs and brokerage fees. We believe that these costs are minimal.

   (b) *Imbalance costs* – the charge for being out of balance in each half hourly period. To account for this, half hourly imbalance information would need to be identified. Our analysis assumes 100% forecast accuracy, ie imbalance costs are valued at spot price. This would add extra cost to the recalculated spot cost base but based on reported information we believe this to be minimal.

   (c) *Shaping costs* – the costs of near-term shaping of energy volumes.

   (d) *Transmission and distribution losses*[42] – line losses, eg through heat, theft and fraud. We have accounted for 8% based on DECC findings and we believe is a reasonable assumption. Losses will vary from firm to firm and within year but it is not possible to identify these.

   (e) *Accounting treatment* – such an adding internally generated premiums or transfer charges between trading and retail arms. These are discussed in Annex A to this appendix.

   (f) *Forward cost of energy* – the forward cost of purchased energy may be higher (or lower) than the out-turn price over any given period. This is the main reason for the difference and is discussed in detail in the main body of this annex.

[42] Unaccounted for Gas (UAG) charges are acquired by network operators and recovered via transmission and distribution charges but this is not the case for electricity.

Annex C: Analysis of energy retailers' indirect costs

Introduction

1. This annex, and its accompanying supplements, sets out our assessment of the Six Large Energy Firms indirect costs.

2. Past studies have suggested that indirect costs had not been falling for the Six Large Energy Firms, and that the gap between the best and worst performers in this regard was significant:

   (a) In its 2008 Probe, Ofgem noted that operational costs were rising faster than the rate of inflation, and that the gap between the best and worst operational costs on a per customer account basis was around 90%. Ofgem noted in its report at the time that some of the Six Large Energy Firms had programmes in the pipeline to reduce these costs going forward.[43]

   (b) In its 2012 report, the Institute for Public Policy Research (IPPR) stated that in a competitive market it would not be unreasonable to expect operational cost savings of at least 2.5% a year. It found that the differential between the best and worst operational costs was over 100%, and concluded that competition did not appear to be driving down costs, or forcing their convergence.[44]

3. In a well-functioning market, all things being equal, we would expect competition to drive market participants to improve services and seek efficiencies. These efficiency gains should, at least in part, manifest themselves in reduced costs. Over time a significant and persistent gap between the highest and lowest cost suppliers, given that the product is homogenous, would be unlikely to be sustainable. In this section, we considered, at a high level, whether there was any evidence of the Six Large Energy Firms generating efficiency savings in indirect costs over the period of review, from FY07 to FY13.

4. This annex is structured under the following headings:

   (a) Methodology: in paragraphs 5 to 8 below, we discuss how we measured indirect cost savings.

[43] Ofgem (October 2008), *Energy Supply Probe – Initial Findings Report*, pp95–96.
[44] IPPR (April 2012), *The True Cost of Energy*, pp26–28.

(b) Preliminary results: in paragraphs 9 to 31 below, we set out the preliminary results of our analysis.

Methodology

5. We focused our analysis on the indirect cost base, which is largely comprised of the operational costs of meeting customers' day-to-day needs. These costs can be controlled by energy suppliers more so than their direct costs. Our analysis was predominantly focused on the indirect cost base of the Six Large Energy Firms. However, for comparability purposes, we have also considered the indirect costs of the four mid-tier suppliers.

6. Given that all the relevant firms vary in size, an analysis of their total indirect costs in absolute terms would not provide us with an indication of their relative cost efficiency. To take into account the effect of a firm's size, we sought to adopt a suitable metric against which to calculate and compare indirect cost ratios between the Six Large Energy Firms. Most of the Six Large Energy Firms told us that the number of customer accounts was a key metric for looking at indirect costs, although when looking at individual cost categories the appropriate metric may change.

7. We considered that the number of customer accounts represented the most appropriate measure, given that it closely corresponded with the number of customer contracts held by a supplier, and was therefore a key driver (but not the only driver) of indirect costs. The number of customer accounts would also be closely aligned with the number of bills generated and therefore was likely to be a good indicator for the level of customer contact and any associated costs. For the purposes of this analysis, we therefore adopted indirect costs per customer account as our indirect cost ratio measure.[45] We also converted indirect costs into real terms based on taking FY07 as the base year (see Supplement 1 to this annex for the details of these adjustments).

8. For the purposes of our analysis, we looked at indirect cost ratios at a total supply business level, as well as by retail segment split by fuel and by indirect cost component (ie the individual elements of a supplier's indirect cost base).

[45] While we acknowledge that the number of customer accounts may not a perfect metric against which to measure all indirect costs, we considered that this measure benefited from being measured reasonably consistently across each of the Six Large Energy Firms, and therefore enables greater consistency and comparability across the relevant firms.

Preliminary results

Total supply business indirect cost ratios for the Six Large Energy Firms combined

9. In Table 1, we set out the indirect cost ratios at a total supply business level for the Six Large Energy Firms on a combined basis from FY07 to FY13.

Table 1: Total supply business indirect cost ratios over the relevant period for the Six Large Energy Firms combined

Financial year	*Total indirect cost ratios (£)* (average of the firms FY07–FY13)*	*Year-on-year movement (%)*
FY07	81	N/A
FY08	83	4
FY09	83	–1
FY10	81	–2
FY11	76	–7
FY12	75	–1
FY13	74	–2

Source: CMA analysis of P&L information submitted by the Six Large Energy Firms.
*We calculated indirect cost per customer account by dividing total indirect costs in real-terms divided by total customer accounts across the total supply business. The averages for each year is a simple average of the six ratios for each firm.
Notes:
1. For the purposes of restating indirect costs into real terms, we adopted FY07 as the base year.
2. ‘N/A’ means ‘not available’.
3. RWE’s indirect costs and account figures include Telecom Plus figures.
4. Figures have been rounded.

10. Based on Table 1, indirect costs fell by around £6 per customer account between FY07 and FY13. We found that from a peak of around £83 per customer account in FY08, costs had fallen year-on-year by around 2% each year on average, to around £74 per customer account by the end of FY13.

11. The above comparison, however, masks the underlying trends in each individual firm’s performance, and we consider these below.

Total supply business indirect cost ratios for each of the Six Large Energy Firms

12. Table 2 shows the indirect cost ratios at a total supply business level for each of the Six Large Energy Firms from FY07 to FY13 (see also Supplement 2 for further details for each of the Six Large Energy Firms).

Table 2: Total supply business indirect cost ratios* over the relevant period for each of the Six Large Energy Firms

Energy firm	*FY07*	*FY08*	*FY09*	*FY10*	*FY11*	*FY12*	*FY13*	*Average*	*Rank of average*	*Comments*
Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis of P&L information submitted by the Six Large Energy Firms.
*We calculated indirect cost per customer account by dividing total indirect costs in real terms divided by total customer accounts across the total supply business. The averages for each supplier is a simple average of the six ratios for each year.
Note: For the purposes of restating indirect costs into real terms, we adopted FY07 as the base year.

13. Based on Table 2, we found that:

(a) both [✂] and [✂] had each made relatively large improvements over the relevant period to their individual indirect cost base; in particular, we found that these two firms were the primary drivers for the cost reductions seen for the Six Large Energy Firms on a combined basis;

(b) the average gap between [✂] (with the lowest indirect cost ratios) and [✂] (with the highest) was around [✂] per customer account, or a percentage difference of [✂]; and

(c) in considering the impact of higher indirect costs on [✂] profitability – and based on *(b)* above – we calculated that, if [✂]had generated indirect cost ratios in line with [✂], this would have the effect in most cases of turning [✂] EBIT losses into an EBIT profit for its total supply business.

14. We noted that an analysis of total indirect costs per customer account at a total supply business level would not make a distinction between customers in different retail segments, eg between a domestic customer account and a SME customer account. Below, we carried out our indirect cost analysis on a retail segmental basis, focusing on the two retail segments that formed part of our reference markets, namely domestic and SME supply.

Retail segmental indirect cost ratios for domestic and SME supply by fuel type

15. Table 3 shows the average segmental indirect cost ratios for domestic supply (split by fuel type) for each of the Six Large Energy Firms for the period FY09 to FY13. The detailed figures behind this table are set out in Supplement 3 to this annex.

Table 3: Average* domestic indirect costs per account for each of the Six Large Energy Firms (FY09 to FY13)†

Energy firm	*Average indirect cost ratios (domestic electricity)*	*Rank*	*Average indirect cost ratios (domestic gas)*	*Rank*	*Average indirect cost ratios (total domestic)*	*Comments*
Centrica	£54	2	£64	2	£60	Both fuel types show a flat trend from FY09 to FY13
E.ON	£64	4	£72	4	£67	Improvements in both fuel types
EDF Energy	£82	6	£91	6	£85	Both fuel types show a flat trend from FY09 to FY13
RWE	£75	5	£89	5	£81	Improvements in electricity supply and flat trend for gas supply from FY09 to FY13
Scottish Power	£57	3	£66	3	£60	Improvements in both fuel types
SSE	£45	1	£53	1	£48	Both fuel types show a flat trend from FY09 to FY13

Source: CMA analysis of P&L information submitted by the Six Large Energy Firms.
*Average indirect cost ratios have not been weighted.
†This analysis focuses on FY09 to FY13 as there was no split for SME for FY07 and FY08 for SSE.
Note: For the purposes of restating indirect costs into real terms, we adopted FY07 as the base year.

16. Based on Table 3 and Supplement 3 to this annex, we found that, while there were peaks and troughs in their respective indirect cost ratios with some firms demonstrating no significant cost reductions, there appeared to be no consistent trend of increasing costs. We also found that:

(a) both [✂] and [✂] demonstrated the strongest trends in cost reductions over the relevant period, as was the case for their respective total supply business indirect cost ratios; and

(b) the ranking of the indirect cost ratios for each of the Six Large Energy Firms' domestic retail segments was broadly consistent with the ranking we found for their respective total supply businesses above, eg with [✂] generating the lowest indirect cost ratio, and [✂] generating the highest.

17. Table 4 shows the segmental average indirect cost ratios for SME supply (split by fuel type) for each of the Six Large Energy Firms for the period FY09 to FY13 (see also Supplement 3 to this annex for further details).

Table 4: Average SME indirect costs per customer account for each of the Six Large Energy Firms (FY09 to FY13)

Energy firm	*Average indirect cost ratios (SME electricity)*	*Rank*	*Average indirect cost ratios (SME Gas)* *	*Rank*	*Average indirect cost ratios (Total SME)*
Centrica	[✂]	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]
RWE	[✂]	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis of P&L information submitted by the Six Large Energy Firms.
*Average indirect cost ratios have not been weighted.
Note: For the purposes of restating indirect costs into real terms, we adopted FY07 as the base year. This analysis focuses on FY09 to FY13 as there was no split for SME for FY07 and FY08 for SSE.

18. Based on Table 4 above, in conjunction with Supplement 3 to this annex, we found that:

(a) year-on-year movements in indirect cost ratios were more volatile for the SME retail segment than for the domestic retail segment;

(b) the rankings for SME indirect cost ratios were slightly different from the similar rankings we found for the domestic retail segment and total supply business levels for the Six Large Energy Firms; for SME indirect cost ratios, [✂] generated the lowest ratio while [✂] generated the highest; and

(c) only [✂] indirect cost ratios showed significant reductions in indirect cost ratios over the period.

19. We considered that the reason for the more varied picture for indirect cost ratios in the SME retail segment was likely to depend to some extent on the relative significance of the SME retail segment for each of the Six Large Energy Firms. For example, [✂].

20. We now consider the components of indirect costs on a more granular basis to look at trends in different cost categories.

Total supply business indirect costs by cost category

21. In relation to our analysis of the individual components of indirect costs, we categorised indirect costs into six broad 'standardised' categories, namely the costs relating to: *(a)* bad debts; *(b)* metering; *(c)* sales and marketing; *(d)* customer service; *(e)* central services; and *(f)* other costs.[46] We then

[46] We defined each indirect cost category as follows: *(a) bad debts:* comprising in-year bad debt write-offs and movements in bad debt provision; and their debt collection, legal costs, debt reminders and other associated debt

requested each of the Six Large Energy Firms to allocate their total indirect costs to each of these six categories. This analysis was conducted at the total supply business level.

22. Table 5 sets out the average indirect cost ratios at a total supply business level for each of the Six Large Energy Firms over the relevant period.

Table 5: Total supply business average indirect cost ratios* for the Six Large Energy Firms by category (FY07 to FY13)

Energy firm	*Average bad debt cost ratio*	*Average metering cost ratio*	*Average sales and marketing cost ratio*	*Average customer service cost ratio*	*Average central service cost ratio*	*Average other cost ratio*
Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis of P&L information submitted by the Six Large Energy Firms.
*Indirect cost item per customer account. The average was based on a simple average of the annual indirect cost item ratios over the period FY09 to FY13.
Note: For the purposes of restating indirect costs into real terms, we adopted FY07 as the base year.

23. In Supplement 4 to this annex, we describe the trends we saw in each of these indirect cost categories. Based on Table 5 and Supplement 4 to this annex, we found that:

(a) [✂] generated the lowest indirect cost ratios across most of the indirect cost categories, and significantly outperformed its peers in relation [✂];

(b) [✂] and [✂] both had significantly higher sales and marketing cost ratios relative to their peers; [✂] sales and marketing costs were over [✂] higher than the lowest cost per account supplier with [✂] being over [✂] higher; [✂] also generated a significantly higher central service cost ratio than the other suppliers, being almost [✂] higher than the next highest ratio; and

(c) both [✂] and [✂] generated the lowest customer service cost ratios, while [✂] had significantly higher customer service cost ratios than all the other Six Large Energy Firms, with a cost ratio almost [✂] higher than the next highest supplier.

collection costs; *(b) metering:* comprising meter asset charges, transaction charges, meter reading costs and other associated costs; *(c) sales and marketing:* comprising costs associated with customer acquisition and retention, as well as the costs associated with white label arrangements; *(d) customer service:* comprising their costs for billing, credit management, call centres, customer relations (including complaints handling), cash control and other costs associated with customer service provision; *(e) central services:* comprising their central office recharges, IT and property costs and those costs associated with each of these; and *(f) other items:* comprising any other indirect cost items that may not on their own be material and do not fit into the above categories.

Indirect cost ratio comparison with the mid-tier suppliers

24. As noted in our methodology above, we compared the indirect cost ratios of the Six Large Energy Firms with those of the four mid-tier suppliers.

25. The financial information that could be provided by the mid-tier suppliers was not as detailed as that provided by the Six Large Energy Firms, and therefore our analysis was limited to calculating their indirect cost ratios at a total supply business level rather than on a retail segmental basis, although we would note that the mid-tier suppliers predominantly supply the domestic retail segment.

26. Table 6 shows the indirect cost ratios for each of the four mid-tier suppliers (see also Supplement 5 to this annex for further details).

Table 6: Total supply business indirect costs per customer account for the mid-tier suppliers

	FY09	*FY10*	*FY11*	*FY12*	*FY13*	*Average**
Co-op Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
First Utility	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Ovo Energy†	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Utility Warehouse	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis of P&L information submitted by the mid-tier suppliers.
*We calculated the period average indirect cost per customer account by calculating a simple average of each year's indirect costs per account.
†For the purpose of our indirect cost ratio analysis, we used Ovo Energy's P&L information that reported to different financial year-ends for FY09 to FY11. Therefore, FY09 and FY10 are reported to 30 June year-ends, while FY11 represents a six-month accounting period, and FY12 and FY13 are reported to 31 December year-ends. Given that FY11 represented a partial year, we did not include FY11 indirect cost ratios for Ovo Energy in its average calculation.
Note: For the purposes of restating indirect costs into real terms, we adopted FY07 as the base year.

27. Based on Table 6, we found that [✂] indirect cost ratios were significantly higher than any of the other relevant firms, including both the mid-tier suppliers and the Six Large Energy Firms. This represents one of the areas of further investigation in relation to our indirect cost analysis.

28. Turning to the other three mid-tier suppliers in turn, we noted that [✂] generated the lowest indirect cost ratios, and that this was lower than the ratios of the Six Large Energy Firms.[47] Based on our analysis, [✂] would be ranked joint first with [✂] over the period under consideration, with [✂] ranking third, ahead of [✂], [✂], [✂] and [✂]. This comparison is represented graphically in Figure 1.

[47] Utility Warehouse has an operating relationship with RWE that means some typical energy supply costs are borne by RWE.

Figure 1: Comparison of total supply business average indirect cost ratios between the mid-tier suppliers and the Six Large Energy Firms

[✂]

Source: CMA analysis of P&L information submitted by the Six Large Energy Firms and mid-tier suppliers.
Note:
1. For the purposes of restating indirect costs into real terms, we adopted FY07 as the base year.
2. We calculated the average indirect cost ratio based on a simple average of the annual ratios for each firm.

29. Based on Figure 1, the mid-tier suppliers compared relatively favourably against the Six Large Energy Firms.

Summary of our indirect cost analysis

30. It is important to acknowledge that all of the suppliers are at different stages in their development, in particular in relation to their levels of investment in IT systems and new technologies such as SMART metering. Given our preliminary findings, the incremental benefit of trying to adjust for these was not deemed necessary. Indirect costs alone cannot prove or disprove efficiency. This indirect cost work sits alongside our other quantitative and qualitative work on the performance of the six largest energy suppliers.

31. Based on our analysis we found some signs of improvement over the period of review, specifically we found that overall:

(a) [✂];

(b) [✂];

(c) [✂]; and

(d) [✂].

Supplement 1: Indirect cost information

Introduction

1. This supplement sets out the limited number of adjustments we made to the indirect costs of the Six Large Energy Firms.

Adjustment for inflation

2. To eliminate the effects of inflation on indirect costs, we calculated the indirect cost ratios in 'real terms', using the Consumer Price Index (CPI) as our deflator and FY07 as our base year.[1]

3. Using the annual CPI movement taken from the Office for National Statistics, we deflated the costs of years FY08 to FY13 to make them comparable to 2007 prices. The annual CPI change used for each of the Six Large Energy Firms and the deflator applied to FY08 to FY13 can be seen in Table 1:

Table 1: Annual CPI and associated deflator

Deemed Financial Year	*Financial Accounts Year End*	*Firm*	*Annual CPI index*	*Deflator (Costs x %)*
FY 2007	31 December 2007	Centrica, E.ON, EDF Energy, RWE and Scottish Power.	2.1%	100.0%
	31 March 2008	SSE	2.5%	100.0%
FY 2008	December 2008	As above	3.1%	96.9%
	March 2009		2.9%	97.1%
FY 2009	December 2009		2.9%	94.1%
	March 2010		3.4%	93.8%
FY 2010	December 2010		3.7%	90.6%
	March 2011		4.0%	90.0%
FY 2011	December 2011		4.2%	86.8%
	March 2012		3.5%	86.9%
FY 2012	December 2012		2.7%	84.5%
	March 2013		2.8%	84.5%
FY 2013	December 2013		2.0%	82.8%
	March 2014		1.6%	83.1%

Source: Office for National Statistics. CPI dataset used – last updated 16 December 2014.
*Simple average gross margins (by tariff type) based on all the years for which we could assess its tariff profitability.

Additional adjustments to indirect costs

4. We describe some of the other minor adjustments we made to the indirect costs for each of the Six Large Energy Firms (when applicable):

   (a) Centrica had included some metering costs as direct costs above the gross profit line. These have been brought into indirect costs in this analysis and mapped to 'metering costs'.

[1] Office for National Statistics. CPI dataset used – last updated 16 December 2014.

(b) EDF Energy had included some commission costs as direct costs above the gross profit line. We have included these costs within indirect costs within our analysis and mapped them to ‘sales and marketing costs’.

(c) SSE had some third-party intermediary costs recorded as direct costs above the gross profit line. We have included these within indirect costs and mapped them to ‘sales and marketing costs’.

Supplement 2: Total indirect cost ratios for the Six Large Energy Firms

Introduction

1. This supplement sets out the total indirect cost ratios for each of the Six Large Energy Firms over the relevant period.

Total supply business indirect cost ratios

2. Table 2 sets out the total customer accounts, the nominal and real total indirect costs and the indirect cost ratio (ie £ per customer account). The table is split by firm and by year with a simple average of the seven years shown at the foot of the table.

Table 2: Annual total supply business indirect costs and ratios (FY07 to FY13) and average ratios

Financial year	Energy firm	Total customer accounts	Total indirect costs (nominal) £'000	Total indirect costs (adjusted for CPI) £'000	£/account
	SSE	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]
FY07	Centrica	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]
FY08	Centrica	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]
FY09	Centrica	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]
FY10	Centrica	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]
FY11	Centrica	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]
FY12	Centrica	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]
FY13	Centrica	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]
	SSE				[✂]
	RWE				[✂]
Average	Centrica				[✂]
	E.ON				[✂]
	EDF Energy				[✂]
	Scottish Power				[✂]

Source: CMA analysis of P&L information of Six Large Energy Firms.
Notes:
1. Simple average of the seven years shown at the foot of the table.
2. SSE FY07 and FY08 customer account figures omit industrial customers so will be marginally overstated.

Supplement 3: Segmental indirect cost ratios for the Six Large Energy Firms

Introduction

1. This supplement sets out the indirect cost ratios for each of the Six Large Energy Firms' domestic and SME retail segments (split by fuel type) over the period FY09 to FY13.

Retail segmental indirect cost ratios

2. Table 3 sets out the indirect cost ratios (ie £ per customer account) in real terms for domestic and SME supply, split by fuel type.

Table 3: Domestic and SME indirect cost ratios in real terms (FY09 to FY13) and average ratios (£/account)

£/account

FY	*Energy firm*	*Domestic electricity*	*Domestic gas*	*SME electricity*	*SME gas*	*Total domestic*	*Total SME*
FY09	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
FY10	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
FY11	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
FY12	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
FY13	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

FY	*Energy firm*	*Domestic electricity*	*Domestic gas*	*SME electricity*	*SME gas*	*Total domestic*	*Total SME*
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Average	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis of P&L information of Six Large Energy Firms.
Notes:
1. Simple average of the five years shown at the foot of the table.
2. All costs are reported in real terms with 2007 as the base year to make the figures comparable to others in the indirect cost analysis.

Supplement 4: Indirect cost categories for the Six Large Energy Firms

Introduction

1. This supplement sets out the indirect cost ratios for each of the Six Large Energy Firms based on the six broad indirect cost categories we used for the purpose of our analysis.

Indirect cost ratios split by category

2. Table 4 shows for each of the Six Large Energy Firms the indirect cost per customer account for each of their indirect cost categories.

Table 4: Total supply business indirect cost ratios by cost category for the Six Large Energy Firms

Financial year	*Energy firm*	*Bad debt costs*	*Metering costs*	*Sales and marketing costs*	*Customer service costs*	*Central service costs*	*Other costs*
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
FY07	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
FY08	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
FY09	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
FY10	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
FY11	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
FY12	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
FY13	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Average	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis of P&L information of Six Large Energy Firms.
Notes:
1. All costs are reported in real terms with 2007 as the base year to make the figures comparable to others in the indirect cost analysis.
2. Simple average of the seven years shown at the foot of the table.

Commentary on indirect cost ratios by cost category

3. Based on Table 4:

   (a) *Bad debt cost ratios*: each firm showed a similar trend, with all the Six Large Energy Firms showing a spike in bad debt costs from the impact of the financial crash and subsequent recession. The biggest peaks in bad debt cost ratios were seen for [✄] and [✄], with [✄] showing the smallest peak. After this peak, the cost ratios fell to similar levels seen in FY07. We note that this trend did not significantly alter when looking at bad debts as a percentage of revenues.

   (b) *Metering cost ratios*: over the period, this cost ratio remained relatively flat for most of the Six Large Energy Firms. The gap between the highest ([✄]) and lowest ([✄]) ratios narrowed over the period.

   (c) *Sales and marketing cost ratios*: we note that this cost ratio would be heavily influenced by each firm's business and customer acquisition strategy. We found that over the period of review all the Six Large Energy Firms reduced their sales and marketing cost ratios on a per customer account basis. The firms that had spent the most in sales and marketing (ie [✄] and [✄]) reduced their costs the most and the firm that spent the least, [✄], reduced its costs the least. Over the period of review, on average [✄] had the lowest cost ratio and [✄] the highest.

   (d) *Customer service cost ratios*: these ratios were significantly higher for [✄] than for all the other Six Large Energy Firms. Over the period, while these ratios fell for [✄], they remained significantly high relative to the other suppliers. [✄], although significantly lower in its cost ratios than [✄], showed year-on-year increases in its customer service cost ratio. [✄] showed the strongest signs of cost reductions over this period.

   (e) *Central service cost ratios*: were significantly higher for [✄] than the other Six Large Energy Firms. [✄] central service costs also increased over the period, while [✄] incurred the lowest average central service cost ratio.

Supplement 5: Mid-tier suppliers' indirect cost ratios

Introduction

1. This Supplement sets out the indirect cost ratios for the mid-tier suppliers.

Mid-tier suppliers' indirect cost ratios

2. Based on the indirect cost information provided by the four mid-tier suppliers, we calculated total indirect costs per customer account. These results are set out in Table 5. In calculating their indirect cost ratios, we would highlight that:

   (a) to make these figures comparable to the other parts of our indirect cost ratio analysis, all figures were adjusted for inflation based on CPI using 2007 as the base year; the adjustment made is reported in the table below; and

   (b) the average provided at the bottom of the table is a simple average; for Ovo Energy, it excludes FY10 because this was a six-month accounting period as a result of a year-end change during 2011. In the table below, for Ovo Energy, FY09 relates to the period ending 30 June 2010, FY10 is for the 12 months to 30 June 2011, FY11 is for the six months to 31 December 2011, and for both FY12 and FY13 the financial year matches the calendar year.

Table 5: Total supply business indirect cost ratios for the mid-tier suppliers

FY	*Types of indirect costs*	*Ovo Energy*	*Utility Warehouse*	*Co-op Energy**	*First Utility*
FY09	Customer numbers	[✂]	[✂]	[✂]	[✂]
	Meters	[✂]	[✂]	[✂]	[✂]
	Customer accounts	[✂]	[✂]	[✂]	[✂]
	Total indirect costs	[✂]	[✂]	[✂]	[✂]
	CPI adjustment made:	[✂]	[✂]	[✂]	[✂]
	Total indirect costs per customer	[✂]	[✂]	[✂]	[✂]
	CPI adjusted:	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]
FY10	Customer numbers	[✂]	[✂]	[✂]	[✂]
	Meters	[✂]	[✂]	[✂]	[✂]
	Customer accounts	[✂]	[✂]	[✂]	[✂]
	Total indirect costs	[✂]	[✂]	[✂]	[✂]
	CPI adjustment made:	[✂]	[✂]	[✂]	[✂]
	Total indirect costs per customer	[✂]	[✂]	[✂]	[✂]
	CPI adjusted:	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]
FY11	Customer numbers	[✂]	[✂]	[✂]	[✂]
	Meters	[✂]	[✂]	[✂]	[✂]
	Customer accounts	[✂]	[✂]	[✂]	[✂]
	Total indirect costs	[✂]	[✂]	[✂]	[✂]
	CPI adjustment made:	[✂]	[✂]	[✂]	[✂]
	Total indirect costs per customer	[✂]	[✂]	[✂]	[✂]
	CPI adjusted:	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]
FY12	Customer numbers	[✂]	[✂]	[✂]	[✂]
	Meters	[✂]	[✂]	[✂]	[✂]
	Customer Accounts	[✂]	[✂]	[✂]	[✂]
	Total Indirect Costs	[✂]	[✂]	[✂]	[✂]
	CPI adjustment made:	[✂]	[✂]	[✂]	[✂]
	Total indirect costs per customer	[✂]	[✂]	[✂]	[✂]
	CPI adjusted:	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]
FY13	Customer numbers	[✂]	[✂]	[✂]	[✂]
	Meters	[✂]	[✂]	[✂]	[✂]
	Customer accounts	[✂]	[✂]	[✂]	[✂]
	Total indirect costs	[✂]	[✂]	[✂]	[✂]
	CPI adjustment made:	[✂]	[✂]	[✂]	[✂]
	Total indirect costs per customer	[✂]	[✂]	[✂]	[✂]
	CPI adjusted:	[✂]	[✂]	[✂]	[✂]
	Simple average	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis of P&L information of four mid-tier suppliers.
*Co-op Energy commenced trading in December 2010.
Note: All costs are reported in real terms with 2007 as the base year to make the figures comparable to others in the indirect cost analysis.

Annex D: Actual revenues vs the competitive benchmark

Introduction

1. This annex contains the data tables for each of the Six Large Energy Firms' out-turn revenues compared with the total revenues implied by the average of the competitive benchmark price scenarios. We do this separately for domestic electricity and gas, and SME electricity and gas.

Domestic electricity

Table 1: Domestic electricity – out-turn revenues vs competitive benchmark by firm (FY09 to FY13)

£m

	Energy firm	*Financial year*							*7YP*
		FY07	*FY08*	*FY09*	*FY10*	*FY11*	*FY12*	*FY13*	
Out-turn revenues	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Out-turn	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Competitive benchmark revenues	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Benchmark	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Difference*	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Combined	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.
*The difference equals the total out-turn (actual) revenues less the total competitive benchmark revenues implied by the average competitive benchmark unit revenues from our different benchmarking scenarios.

Domestic gas

Table 2: Domestic gas – out-turn revenues vs competitive benchmark by firm (FY09 to FY13)

£m

	Energy firm				*Financial year*				*7YP*
		FY07	*FY08*	*FY09*	*FY10*	*FY11*	*FY12*	*FY13*	
Out-turn revenues	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Out-turn	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Competitive benchmark revenues	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Benchmark	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Difference*	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RW	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Combined	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.
*The difference equals the total out-turn (actual) revenues less the total competitive benchmark revenues implied by the average competitive benchmark unit revenues from our different benchmarking scenarios.

SME electricity

Table 3: SME electricity – out-turn revenues vs competitive benchmark by firm (FY09 to FY13)

£m

	Energy firm	*Financial year*					*5YP*
		FY09	*FY10*	*FY11*	*FY12*	*FY13*	
Out-turn revenues	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Out-turn	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Competitive benchmark revenues	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Benchmark	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Difference*	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Combined	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.
*The difference equals the total out-turn (actual) revenues less the total competitive benchmark revenues implied by the average competitive benchmark unit revenues from our different benchmarking scenarios.

SME gas

Table 4: SME gas – out-turn revenues vs competitive benchmark by firm (FY09 to FY13)

£m

	Energy firm	*Financial year*					*5YP*
		FY09	*FY10*	*FY11*	*FY12*	*FY13*	
Out-turn revenues	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Out-turn	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Competitive benchmark revenues	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Benchmark	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
		[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Difference*	Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	Combined	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.
*The difference equals the total out-turn (actual) revenues less the total competitive benchmark revenues implied by the average competitive benchmark unit revenues from our different benchmarking scenarios.

Annex E: Average prices vs the competitive benchmark

Introduction

1. This annex contains the data tables for each of the Six Large Energy Firms' average realised prices compared with the maximum, minimum and average competitive benchmark price (based on the range resulting from our four benchmarking scenarios).

Domestic electricity

Table 1: Domestic electricity – average realised prices vs competitive benchmark by firm (FY07 to FY13) (£/MWh)

£/MWh

	Financial year						
	FY07	*FY08*	*FY09*	*FY10*	*FY11*	*FY12*	*FY13*
Avg realised price (all firms)	92	108	110	108	119	129	137
Avg benchmark price	86	102	109	107	113	124	131
Max benchmark price	89	104	111	108	114	125	132
Min benchmark price	84	100	106	106	112	124	130
Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Spot cost*			89	97	109	117	129
Avg price difference (%)†	**7%**	**6%**	**2%**	**1%**	**5%**	**4%**	**5%**

Source: CMA analysis.
Notes:
*For illustrative purposes, we present the implied unit revenue based on spot market prices.
†The average price difference equals the percentage difference between the average realised price for all of the Six Large Energy Firms (calculated as a simple average of each firm's average unit revenue) and the average of the competitive benchmarked unit revenue (a proxy for the competitive benchmark price) based on our different benchmarking scenarios.

Domestic gas

Table 2: Domestic gas – average realised prices vs competitive benchmark by firm (FY07 to FY13) (£/MWh)

£/MWh

	Financial year						
	FY07	*FY08*	*FY09*	*FY10*	*FY11*	*FY12*	*FY13*
Avg realised price (all firms)	25	31	34	33	37	40	43
Avg benchmark price	29	33	36	31	36	39	42
Max benchmark price	32	34	36	31	37	39	42
Min benchmark price	26	31	35	30	36	38	42
Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Avg price difference (%)*	**–13%**	**–5%**	**–3%**	**7%**	**4%**	**5%**	**3%**

Source: CMA analysis.
*The average price difference equals the percentage difference between the average realised price for all of the Six Large Energy Firms (calculated as a simple average of each firm's average unit revenue) and the average of the competitive benchmarked unit revenue (a proxy for the competitive benchmark price) based on our different benchmarking scenarios.

SME electricity

Table 3: SME electricity – average realised prices vs competitive benchmark by firm (FY09 to FY13) (£/MWh)

£/MWh

	Financial year				
	FY09	*FY10*	*FY11*	*FY12*	*FY13*
Avg realised price (all firms)	113	105	110	118	123
Avg benchmark price	100	91	93	102	107
Max benchmark price	104	95	94	104	107
Min benchmark price	96	87	92	101	106
Centrica	[✂]	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]	[✂]
RWE	[✂]	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]
Spot cost*	78	81	91	95	107
Avg price difference (%)†	**13%**	**16%**	**17%**	**15%**	**15%**

Source: CMA analysis.
*For illustrative purposes, we present the implied unit revenue based on spot market prices.
†The average price difference equals the percentage difference between the average realised price for all of the Six Large Energy Firms (calculated as a simple average of each firm's average unit revenue) and the average of the competitive benchmarked unit revenue (a proxy for the competitive benchmark price) based on our different benchmarking scenarios.

SME gas

Table 4: SME gas: average realised prices vs competitive benchmark by firm (FY09 to FY13) (£/MWh)

£/MWh

	Financial year				
	FY09	*FY10*	*FY11*	*FY12*	*FY13*
Avg realised price (all firms)	36	33	36	40	41
Avg benchmark price	33	27	30	35	38
Max benchmark price	34	28	31	36	39
Min benchmark price	32	27	29	34	37
Centrica	[✂]	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]	[✂]
RWE	[✂]	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]
Avg price difference (%)*	**9%**	**22%**	**21%**	**15%**	**7%**

Source: CMA analysis.
*The average price difference equals the percentage difference between the average realised price for all of the Six Large Energy Firms (calculated as a simple average of each firm's average unit revenue) and the average of the competitive benchmarked unit revenue (a proxy for the competitive benchmark price) based on our different benchmarking scenarios.

Annex F: Out-turn vs benchmark adjusted economic profits

Introduction

1. This annex contains the data tables for each of the Six Large Energy Firms' out-turn economic profits compared with the adjusted economic profits based on benchmarked costs and capital employed. This is shown in Table 1.

Table 1: Total supply business out-turn vs benchmarked cost scenario economic profit by firm (£m)

Economic profits

£m

	2009	*2010*	*2011*	*2012*	*2013*	*5YP*
Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Excess profits	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Economic losses	(362)	(162)	(205)	(142)	(131)	(1,001)
Total	**617**	**1,355**	**721**	**919**	**743**	**4,355**

Adjusted economic profits

£m

	2009	*2010*	*2011*	*2012*	*2013*	*5YP*
Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
EDF Energy	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Total	**688**	**2,259**	**1,894**	**2,085**	**1,924**	**8,850**

Source: CMA analysis of the P&L information of the Six Large Energy Firms.
Notes:
1. The above figures set out the annual and scenario economic profits for each of the Six Large Energy Firms on a total supply business basis.
2. The adjusted economic profit figure was based on the lower quartile ratio across various cost and balance sheet items, as explained under our methodology in the main body of this appendix.

Annex G: Out-turn vs benchmark sensitivity

Introduction

1. This annex contains a summary of the Six Large Energy Firms' combined actual revenue per MWh from a cost build perspective. The combined Six Large Energy Firms' actuals are compared to the benchmarked costs (£ per MWh). The actual and percentage difference between the two is also shown.

Table 1: Domestic electricity and gas actuals revenue build-up (£/MWh) vs competitive benchmark (FY09 to FY13 average) by firm

Centrica

	Domestic electricity				*Domestic gas*			
	Actual	*Benchmark*	*Difference*	*%*	*Actual*	*Benchmark*	*Difference*	*%*
Volumes (TWh)	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Capital charge	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Dep/Amort	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Indirect costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Other direct costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Obligation costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Network costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Trading fee	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Energy costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Revenue	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

RWE

	Domestic electricity				*Domestic gas*			
	Actual	*Benchmark*	*Difference*	*%*	*Actual*	*Benchmark*	*Difference*	*%*
Volumes (TWh)	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Capital charge	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Dep/Amort	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Indirect costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Other direct costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Obligation costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Network costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Trading fee	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Energy costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Revenue	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

EDF Energy

	Domestic electricity				*Domestic gas*			
	Actual	*Benchmark*	*Difference*	*%*	*Actual*	*Benchmark*	*Difference*	*%*
Volumes (TWh)	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Capital charge	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Dep/Amort	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Indirect costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Other direct costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Obligation costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Network costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Trading fee	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Energy costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Revenue	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Scottish Power

	Domestic electricity				*Domestic gas*			
	Actual	*Benchmark*	*Difference*	*%*	*Actual*	*Benchmark*	*Difference*	*%*
Volumes (TWh)	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Capital charge	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Dep/Amort	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Indirect costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Other direct costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Obligation costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Network costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Trading fee	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Energy costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Revenue	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

SSE

	Domestic electricity				*Domestic gas*			
	Actual	*Benchmark*	*Difference*	*%*	*Actual*	*Benchmark*	*Difference*	*%*
Volumes (TWh)	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Capital charge	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Dep/Amort	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Indirect costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Other direct costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Obligation costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Network costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Trading fee	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Energy costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Revenue	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

E.ON

	Domestic electricity				*Domestic gas*			
	Actual	*Benchmark*	*Difference*	*%*	*Actual*	*Benchmark*	*Difference*	*%*
Volumes (TWh)	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Capital charge	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Dep/Amort	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Indirect costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Other direct costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Obligation costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Network costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Trading fee	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Energy costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Revenue	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis of the P&L information of the Six Large Energy Firms.

Table 2: SME electricity and gas actuals revenue build-up (£/MWh) vs competitive benchmark (FY 2009 to 2013 average) by firm

Centrica

	SME electricity				*SME gas*			
	Actual	*Benchmark*	*Difference*	*%*	*Actual*	*Benchmark*	*Difference*	*%*
Volumes (TWh)	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Capital charge	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Dep/Amort	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Indirect costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Other direct costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Obligation costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Network costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Trading fee	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Energy costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Revenue	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

RWE

	SME electricity				*SME gas*			
	Actual	*Benchmark*	*Difference*	*%*	*Actual*	*Benchmark*	*Difference*	*%*
Volumes (TWh)	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Capital charge	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Dep/Amort	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Indirect costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Other direct costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Obligation costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Network costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Trading fee	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Energy costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Revenue	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

EDF Energy

	SME electricity				*SME gas*			
	Actual	*Benchmark*	*Difference*	*%*	*Actual*	*Benchmark*	*Difference*	*%*
Volumes (TWh)	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Capital charge	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Dep/Amort	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Indirect costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Other direct costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Obligation costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Network costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Trading fee	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Energy costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Revenue	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Scottish Power

	SME electricity				*SME gas*			
	Actual	*Benchmark*	*Difference*	*%*	*Actual*	*Benchmark*	*Difference*	*%*
Volumes (TWh)	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Capital charge	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Dep/Amort	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Indirect costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Other direct costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Obligation costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Network costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Trading fee	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Energy costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Revenue	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

SSE

	SME electricity				SME gas			
	Actual	*Benchmark*	*Difference*	*%*	*Actual*	*Benchmark*	*Difference*	*%*
Volumes (TWh)	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Capital charge	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Dep/Amort	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Indirect costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Other direct costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Obligation costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Network costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Trading fee	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Energy costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Revenue	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

E.ON

	SME electricity				SME gas			
	Actual	*Benchmark*	*Difference*	*%*	*Actual*	*Benchmark*	*Difference*	*%*
Volumes (TWh)	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Capital charge	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Dep/Amort	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Indirect costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Other direct costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Obligation costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Network costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Trading fee	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Energy costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Revenue	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis of the P&L information of the Six Large Energy Firms.