Appendix 4.2: Generation return on capital employed

Contents

Introduction

1. The purpose of this appendix is to analyse the profitability of the electricity generation sector in accordance with the approach set out in Appendix 9.9: Approach to profitability and financial analysis. Appendix 9.9 explains why we undertook this analysis and sets out the generic approach we have adopted to analysing profitability in this market investigation. Interested parties should, therefore, read this appendix in conjunction with Appendix 9.9.

2. Most elements of our approach to analysing profitability, for example our chosen measure of profitability and the overarching approach to valuing a firm's asset base, are common across the energy supply value chain and are therefore set out once in Appendix 9.9. However, specific details on our approach to analysing generation profitability are set out in this appendix.

3. We consulted on our approach to analysing generation profitability and subsequently on the results of applying this approach, revised in certain respects to take account of the comments we received. This appendix sets out our response to the points raised by parties in response to these consultations.

4. The rest of the appendix is structured as follows:

   (a) scope of the analysis (paragraphs 6 to 30);

   (b) the asset valuation bases adopted to analyse profitability (paragraphs 31 to 88);

   (c) the extent of the refinement of the analysis (paragraphs 89 and 91); and

   (d) results (paragraphs 92 to 123).

5. In addition, this appendix includes material set out in three annexes:

(a) a comparison of the two basic generation business models adopted by the Six Large Energy Firms (Annex A);

(b) a brief summary of (a) the economics of electricity generation and (b) the various developments that have had an impact on the profitability of the firms over the relevant period (Annex B); and

(c) the detail of our methodology to estimate the replacement costs of power generation assets (Annex C).

Scope of the analysis

The scope set out in the profitability approach appendix

6. In Appendix 9.9 we set out that:

   (a) the relevant geographic market was Great Britain, in line with the terms of reference for this phase 2 investigation;

   (b) the relevant firms were Centrica, EDF, E.ON, RWE, Scottish and Southern Energy (SSE) and Scottish Power; and

   (c) the relevant time period for our analysis was from 2007 to 2013 for the generation activities of the Six Large Energy Firms.[1]

Further specification of the scope of our analysis

Scope of generation activities

7. We also explained in Appendix 9.9 that one of the areas of our focus was the business operations engaged in the generation of electricity.[2] We observe that the vertically integrated operators adopt two basic business models in terms of how they delineate their generation and trading activities (see Annex A for further details of firms' business models).

8. Under the 'full-function generator' model, the generation business directly manages the selling of its output and the associated purchasing of direct inputs in house and therefore takes all hedging and operating decisions itself, with the trading arm executing instructions on its behalf. In contrast, the 'toll-

[1] We have extended the timeframe for our ROCE analysis for the retail supply activities of the Six Large Energy Firms to cover the period between 2007 and 2014. We have not extended our generation ROCE analysis to 2014 as we considered that this would not provide additional insight in light of the pattern of results for the 2007 to 2013 period.
[2] Appendix 9.9, paragraph 13.

generator model',[3] takes away the responsibility of selling output and purchasing inputs from the generation business and places these activities with the trading function. The trading function is therefore responsible for 'optimising' the use of the plant, most notably by deciding when it should run. As a result, the trading function, rather than the generation, reaps the benefit of any individual plant being 'in merit' and suffers the loss of the plant not being 'in merit'. The impact of these different models is that the variability in returns to the firm from owing generation assets are reflected in the generation division in one firm and in the trading division in another firm.

9. The firms have chosen which business model to adopt based on their view of how best to organise their operations. We consider that there are strengths in each model and do not have a view on which may be optimal from the perspective of running an energy generation and trading business. For the purposes of this profitability analysis, these two business models give rise to two potential approaches: one approach would be to categorise asset optimisation as an intrinsic part of the generation business; while the other approach would be to view it as an activity that is logically separate from the ownership and operation of generation assets.

10. Based on detail of the business models set out in Annex A we considered that the relevant activities for generation comprised all the activities that a full-function generator would need to undertake to compete in the market on a stand-alone basis. In other words this generator would own and operate the generation assets, buy its own fuel and sell its output on the wholesale market using standard traded products. The main implication of defining 'generation' in this way was that any internal tolling arrangements would be unwound. As a result, all of the value realised from operating a power station would be caught within our definition of 'generation'.

Comments on scope of generation activities

11. The definition of generation activities set out in paragraph 10 differed from the scope of activities undertaken by the generation divisions of four of the Six Large Energy Firms (Centrica, E.ON, RWE and SSE), at least for some of the period of review.

12. SSE told us that, while it was reasonable to analyse the profits or losses arising from the optimisation of generation assets, we should do so only

[3] A toll is essentially an arrangement by which a firm rents out the use of its plant to another firm for a fee. In this sector tolling arrangements take the form of generation (here the firm's generation division) granting an option on the use of the power plant by another party (here the trading division). The trading division then decides when to run the plant and to whom and when to sell the resulting power. These arrangements are further explained in Annex A to this appendix.

where the firms themselves adopt this approach to their own business organisation and financial reporting. However, where firms, such as SSE, operate an internal toll generator model,[4] then any other approach would not provide a robust comparable analysis from which reliable conclusions could be drawn. It stated that it was simply not possible for SSE to analyse its generation transactions retrospectively on this basis.

13. RWE, E.ON and Scottish Power agreed that the profits or losses associated with asset optimisation should be considered part of overall generation activities for the purposes of our financial analysis. E.ON pointed out this was sensible in order to attempt to achieve comparability. RWE added that any trading costs and capital employed associated with such activities that might currently be captured within its trading division's results should likewise be captured within generation, the former by way of a market-based fee.

14. Both RWE and E.ON, however, pointed out the practical difficulties in isolating these optimisation profits. [✂].

15. E.ON explained to us that it was not able to isolate trading profits that specifically related to its generation activities as we defined them from an analysis of its accounting data. However, it explained that, given how its other divisions transacted with its trading division and how the generation division did so, E.ON was of the view that an assumption could be made that the majority of the profit or loss its trading business made as a result of its provision of services to other E.ON businesses in the UK was likely to arise from its tolling contract with its generation division. On this basis, it included all trading profits related to non-proprietary UK activities within the returns to its generation division.

16. However, because E.ON's trading division managed its own [✂] position, E.ON was not able to apportion its trading profits either between supply and generation or across the different generation technologies.

17. Citizens Advice[5] agreed with our proposal to include portfolio optimisation, adding that our characterisation of the toll generator model (as set out in Annex A to this appendix) matched its understanding and that this highlighted that significant parts of the value associated with generation assets would be transferred to the trading arm of those businesses that adopted this business model.

[4] That is, where generation is sold on a capacity basis to the trading division.
[5] Formally, the National Association of Citizens Advice Bureaux.

Our view

18. Our view is that the full-function generator business model reflects the economic substance of the generation activities of the Six Large Energy Firms. In practice they all seek to sell the output from their generation assets on their own account, albeit in some cases with some generation activities sitting within their trading divisions. As a result it was necessary for any internal toll transaction between their generation and trading divisions to be removed so that the full exposure from owing the generation assets was reflected in the generation business.

19. We agreed that this definition of generation should capture the full costs of transacting trades. Ideally this should be done by reflecting the underlying operating costs and any associated capital employed within generation. However, a reasonable alternative approach would be to include market-based fees in the generation profit and loss statement to reflect these transaction costs.

20. We appreciate that for certain firms it has not been possible to prepare financial information on this basis due to limitations in their financial reporting systems.[6] In Table 1 we set out a brief summary of the financial information that the relevant firms have been able to provide, highlighting areas where the basis upon which information has been prepared departs from the full-function model.

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[6] We emphasise that no criticism is intended in our observation of these 'limitations'. Firms design the financial reporting systems they require in order to manage their businesses and we recognise that these will not always reflect the needs of a competition authority which may seek to analyse markets in a different way from the firms.

Table 1: The Six Large Energy Firms' ability to report generation on a full-function basis[7]

Firm	*Ability to report on a full-function basis*
EDF	EDF's generation division outsources its fuel purchasing and sales on wholesale commodities markets to its trading division for a fee designed to recover transaction costs, but otherwise it operates on a full-function basis. Generation financial information therefore requires little adjustment. However, EDF noted that, due to the way their legal entities are structured, significant assumptions have had to be made in allocating certain assets and liabilities into the requested segmental format.
Scottish Power	Scottish Power operates on a similar basis to EDF but it is unable, without making assumptions, to split its total generation revenues by technology.
Centrica	Up to 2009 Centrica's generation division undertook all the functions of a generation business, including buying and selling on wholesale commodity markets. Thereafter it set up a trading division to centralise this buying and selling. [✂]. Centrica, however, has been able to re-present its financial information on the basis we specified across the whole period.
RWE	[✂]
E.ON	E.ON operates a toll between its generation and trading divisions. It has isolated the GB trading results from its group-wide trading activities, removed results from proprietary trading, and included the remainder within generation on the premise that almost all the profits/losses are assumed to be likely to relate to the toll. E.ON is, however, unable to analyse the profits from using the toll across technologies.
SSE	SSE operates a toll between its generation division and its integrated trading and retail supply division, all of the activities of which relate to GB and Ireland. Although SSE was able to analyse almost all of its costs by technology, it was not able retrospectively to isolate trading profits arising from the toll, nor identify generation revenues by technology as a full-function generator. This means that generation profits analysed here remain a reflection of the profits of its generation division. SSE's overall trading profits/losses have been in the low millions since 2010. Between 2007 and 2009 trading profits ranged between £110 million and £160 million per year.

Source: CMA analysis.

21. We concluded it was important that the firms' generation activities were analysed on a comparable basis where possible. Regardless of the business model adopted, we decided that the optimisation of generation assets and choosing how and when to purchase inputs and sell outputs were relevant to our analysis of generation profitability and should be included in our analysis.

Analysis of profitability by generation technology type

22. For the purpose of this profitability analysis we were more interested in measuring the profitability of each type of generation technology (ie nuclear, coal, combined-cycle gas turbine (CCGT), wind), rather than focusing on the profitability of the generation activities of individual firms as a whole. The reason for this was that we observed that a variety of factors were likely to have affected profitability over the relevant period, including the imposition of a carbon tax, changes in the (relative and absolute) prices levels of coal and gas and a reduction in demand, and that these factors were likely to have had a significantly different impact on the profitability of each of the generation

[7] We observe that the differences between the firms relate mainly to how they distribute their activities across divisions and, therefore, how they report their activities, rather than to the nature of activities undertaken.

technologies analysed. For example, where CCGT had been the marginal plant, the imposition of a carbon tax was likely to have increased the profitability of nuclear plants and have reduced the profitability of coal plants.

23. RWE told us that we should also present return on capital employed (ROCE) on a current value basis for the generation business as a whole, rather than just by technology. We however considered that the results of such an analysis would have been primarily driven by the portfolio of assets by technology type that the individual firm had held at the outset of the period of review. And this analysis would not have been as directly informative as the analysis by technology type. In addition, we had no ready means to revalue the full range of generation asset types on a deprival value basis, which is required by such an analysis, with hydroelectric assets particularly difficult to revalue in such a way.

24. As a result, we decided to present the results of our profitability analysis (assessed on current asset values) for each individual firm by the principal generation technologies they had deployed over the period of review.

Extent of period of review

25. All the Six Large Energy Firms argued on the lines that the proposed period of review, the seven years from 2007 to 2013 was too short to yield useful conclusions.

26. Centrica, for example, highlighted that returns assessed over such a short period were unlikely to be a good proxy for lifetime economic returns as would be calculated by the internal rate of return (IRR) because asset lives greatly exceeded the proposed period of review. Scottish Power suggested that it would be appropriate for the CMA to look at profitability over a ten-year time horizon in order to reflect conditions over a full business cycle. Similarly, E.ON argued that a longer period would better represent the long-run profitability of its generation assets. By way of illustration, it noted that the estimated useful lives of generating assets per the statutory accounts of E.ON UK plc Group for the year ending 31 December 2011 range from 25 to 45 years.

27. Centrica also pointed out that we had seen a number of significant changes that have had an impact on the normal cycles of the UK power generation market, many of which have had an effect on investment signals and profitability. Examples included changes to the mix of price-setting plant (from mainly coal to mainly CCGTs); changes in policy or regulation that had encouraged investment in intermittent generation, and the effect that has had on the operation of other plant in the system; and the extra revenue for thermal plant afforded by the award of free carbon allowances, which ended

in 2012. This would mean that the historic profitability of generators could not be used to represent the profitability that might be expected in the future.

Our consideration of these points regarding the extent of the period of review

28. We recognised that the returns earned by long-lived assets over a portion of their lifetimes may or may not be representative of the returns earned over the whole of their lifetimes. This was a factor that we considered carefully when interpreting the results of our analysis. As discussed in Appendix 9.9, we sought to analyse the profitability of the relevant firms over the longest period for which they were able to provide financial information. However, we noted that the competitive dynamics of an industry and the returns that operators were able to earn could, and did, change over time and we did not agree that whole-lifetime returns as would be reflected in an IRR calculation were pertinent to an assessment of the current competitive conditions in the industry, where assets have very long lives. For example, a significant proportion of the generation assets currently in use were built in the 1970s and 1980s as part of a nationalised and state-run energy industry. The returns earned by these plants during that period were clearly not relevant to the question of whether competitive conditions allowed firms to earn normal or super-normal profits over the period of review.

29. We appreciate that the period of review has been characterised by significant developments (such as those outlined by Centrica) that may or may not be expected to persist in the future. However, we considered that the most logical approach was to assess economic profitability over the period of review and then interpret that in light of both the prevailing circumstances and the results of all the other analysis we undertook as part of the market investigation.

Conclusion on scope of our analysis

30. We therefore concluded that the scope of our analysis should relate to the Great Britain generation activities of the Six Large Energy Firms (on the basis of a full-function generators business model as concluded in paragraph 10) and be analysed by generation technology type for the period from FY09 to FY13.[8] We therefore asked the Six Large Energy Firms to prepare and submit financial information to us in accordance with this scope.

[8] We requested this information for a five-year period rather than the full seven-year period in the first instance in order to reduce the burden of information preparation and expedite responses. We considered that we could request the additional years' information if we determined that it was necessary, having reviewed the data for FY09 to FY13.

The asset valuation bases adopted to analyse profitability

Introduction

31. As explained in Appendix 9.9 when analysing profitability on a ROCE basis we seek to value and depreciate assets measured on a deprival value basis. The Six Large Energy Firms, however, typically adopt the historical cost valuation basis to value assets when preparing their own financial information. We therefore sought to present generation profitability on the following three asset valuation bases for the reasons set out below:

    (a) *Carrying value basis* – which often in practice means historical cost basis. However, there are occasions where certain assets have been revalued to a current value basis and subsequently depreciated on that basis. This basis would be used as a starting point for our analysis before making adjustments to make the information more economically meaningful.

    (b) *Replacement cost basis* – which can be thought of as an intermediate valuation basis between the carrying value basis and full deprival valuation basis. We considered two alternative ways of valuing the replacement cost, one using the replacement cost of the technology currently being employed (*'replacement cost assessed on a like-for-like basis'*), and the other, for conventional generation only, using the modern equivalent asset (MEA) technology which we considered would have been deployed in its place had new investment in such generation occurred over the period of review.

    (c) *Deprival value basis* – where assets would be revalued to reflect their opportunity cost or value to the business in a competitive market. This would typically be the depreciated cost of the modern equivalent asset in the case where the asset would be worth replacing. However were the asset considered to be not worth replacing, as would be the case if the asset had been impaired, it would be downwardly re-valued to its recoverable amount as further explained in Appendix 9.9 paragraphs 41 to 49.

32. The calculation of replacement cost should take into account the cost of financing the construction of the asset at the firm's cost of capital. This cost can be substantial where the upfront investment is large and incurred over a number of accounting periods during which the firm does not earn any cash income. Such an approach however ensures that the firm, from an economic profitability perspective, earns its cost of capital on its investment before it is commissioned. This economic approach to profitability effectively shifts an

element of profit expected to be realised (in terms of cash) in future accounting periods into the current period.

Determining replacement values on the premise of a single modern equivalent technology

33. Because there are a number of distinct technologies currently deployed in GB to generate electricity, we considered revaluing coal and nuclear conventional power generation assets on the assumption that a new entrant would have chosen to replace these assets with an investment in a CCGT plant. We would then have depreciated this gross value to take account of the age of the assets actually owned. We would have taken account of the fact that the plant actually operated was of a different technology by adjusting the operating costs of the coal and nuclear plants to reflect those associated with CCGT plants (*'replacement cost with CCGT as the MEA for conventional power stations'*).

Consideration of the comments received on asset valuation bases

Use of carrying value basis to estimate the return on capital employed

34. We considered that the carrying value basis, which in most cases reflects historical costs, was important as a starting point for our analysis because it used the information that the firms themselves use to manage their businesses and which they report to the capital markets. This information was also audited. We noted however that information prepared on such a basis may not be comparable across the firms.

Comments on replacement cost assessed on a like-for-like basis

35. This attracted many comments, particularly in relation to coal and nuclear plants.

Coal as the MEA for coal

36. We proposed to determine the replacement cost of coal-fired power stations, which had largely been constructed in the 1960s and 1970s, on the premise that over the period of review all these coal assets would have been replaced with CCGT assets, had the need arisen. Hence the MEA for these assets would have been a CCGT power station, not a coal power station. The replacement cost of these assets would therefore have been determined with reference to the cost of a new CCGT power station.

37. RWE suggested that the cost of its recent investments in coal in Germany and the Netherlands would provide a better estimate of a coal plant's MEA value, relative to assessing coal's MEA value using a CCGT plant.[9]

38. E.ON also pointed to international comparisons available for replacement costs of technologies not currently popular or prohibited by legislation in GB. These international comparisons might need some adjustments to local GB market circumstances, including not least differing environmental standards and planning regimes.

39. Drax also said that that a technology-specific approach to asset valuation would represent a more robust approach and that there were a number of potential new-build hard-coal plant comparators that had been constructed over the analysis time period across continental Europe. These could be used to benchmark investment costs.

Our view

40. We decided it was worthwhile exploring using the cost of recently built European coal fired generation assets to provide an estimate of the replacement cost of the coal-fired GB generation assets.

41. Over the period of review firms had been prevented from building new coal plant in GB – without the inclusion of costly carbon capture and storage (CCS) technology – by environmental regulations. As a result, we considered whether the appropriate 'like-for-like' replacement asset would be an unabated coal-fired power station or rather one with CCS technology. We observed that the fleet of coal power stations in GB was largely coming towards the end of its useful economic life for both age and technological reasons.[10]

42. Whichever coal technology were to be considered to be the 'like for like' replacement, the actual value applied to coal-fired power stations would be heavily depreciated to reflect this age. We took into account the fact that CCS technology was still being developed and had not been brought into use on a widespread, commercial basis. In contrast, a number of unabated (although significantly less polluting) coal-fired power stations had been built in recent years in Germany and the Netherlands.[11]

43. On balance, therefore, while we recognised that an entrant could not have built a coal-fired power station in GB without CCS over the relevant period

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[9] See paragraph 55 for RWE arguments in the context of MEA II.
[10] Figure 4 in Annex A shows the age of the current GB fleet of energy generation assets.
[11] Pöyry report to DECC (April 2013), *Report on New Coal-fired Power Stations in Germany and the Netherlands*.

due to UK-specific regulations had it not already obtained permission to do so by 2009, we considered this rather than coal CCS to be the like for like replacement asset. As set out in paragraphs 6 to 8 in Annex C, we have estimated the replacement cost of coal-fired power stations with reference to the new-build costs of German and Dutch stations.[12]

Nuclear as the MEA for nuclear

44. The GB fleet of nuclear power stations was largely built in the 1970s and 1980s, with the large majority of this fleet (eight out of nine stations) expected to close by 2023.[13] Our view was that a new entrant wishing to provide base load electricity over the period of review would have chosen between constructing a new nuclear power station (using significantly different technology to the existing fleet) or possibly building a CCGT.

45. We proposed to determine the MEA, and therefore the estimation of the replacement cost of nuclear assets, on two different bases. The first was to assume that the MEA would be the type of nuclear power station that would be built now. The second basis, using the same logic set out in paragraph 36, was to assume that the MEA for these assets would have been a CCGT power station, not a nuclear power station.

46. EDF told us that, of the two options, the more reliable approximation of the MEA value of its nuclear fleet would be on the basis of new nuclear technology (rather than CCGT). EDF also questioned how we planned to treat long-term liabilities arising from the substantial future costs for nuclear decommissioning within our analysis.

47. Ecotricity told us that our benchmark for the replacement cost of a new power station should take account of the life-cycle cost of nuclear power, from the mining of uranium to decommissioning, safety considerations and waste management. Where these costs were borne by the state or another third party, it argued that this should be counted separately and noted as costs of nuclear that are not borne by the developer.

Our views

48. We considered this issue from the perspective of the value to the business or deprival value of the assets actually in place. Given the specific characteristics of nuclear power, there was a good case for assessing the

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[12] We note that the costs of building a coal-fired power station in Germany or the Netherlands may differ from the costs of doing so in the UK for a number of reasons. However, we consider these countries to be sufficiently similar for these build costs to offer a reasonable approximation.
[13] See EDF's website.

deprival value by reference to the cost of a new nuclear plant in the first instance. A firm, however, would only consider replacing its existing nuclear plant with another nuclear plant if it were to expect to earn at least a return on the full cost of its investment. Its expected returns from a replacement investment would factor in any subsidies that the government, or anybody else, provided. There will be different subsidies on offer for nuclear in the future than those currently provided to previous nuclear investment. As we sought to value the assets that existed over the period of review, it was the subsidy regime in force over that period that was relevant to assessing whether the asset would have been worth replacing.

49. EDF told us that in its view that there was no subsidy of its existing nuclear operations due to both past and ongoing contributions towards decommissioning and nuclear waste processing costs. We noted that, whether or not the terms agreed during the previous restructuring of British Energy and the sale of the business to EDF had created a subsidy to nuclear power, EDF's financial statements over the relevant period did not reflect the costs of decommissioning the power stations at the end of their lives and may not reflect the full costs of processing nuclear waste.[14] However, as explained in paragraph 48, we considered that it was appropriate to take the subsidy regime in force into account when assessing the profitability of the nuclear fleet rather than the full costs that might be incurred under a different regime. Therefore, we did not adjust our analysis to reflect these decommissioning costs or a different level of nuclear waste processing costs.

50. Based on our estimate of the depreciated replacement cost of a modern nuclear asset excluding decommissioning costs,[15] we considered it likely that a firm would not have chosen to replace the asset. This is because the firm would have earned returns well below its cost of capital based on prevailing wholesale energy prices. This strongly suggested to us that, in deprival value terms, the nuclear fleet was impaired at the outset of the period of review, and therefore which technology was the MEA did not affect the assessment of deprival value. In such circumstances, the value to the business can be regarded as the recoverable amount, which in this case would be its value in use – ie the net present value (NPV) of expected future returns. EDF told us that, on acquisition of the assets from British Energy, it valued them on a discounted cash flow (DCF) basis for the purposes of its accounts. We

[14] We reviewed two documents in particular: National Audit Office (22 January 2010), *The Sale of the Government's Interest in British Energy: Report by the Comptroller and Auditor General, HC 215 Session 2009–2010;* and Professor Gordon MacKerron (University of Sussex), SPRU – Science and Technology Policy Research (March 2012), *Evaluation of Nuclear Decommissioning and Waste Management: A Report Commissioned by the Department of Energy and Climate Change*.

[15] This estimate was based on the planned costs of building Hinkley Point C. See Annex B for full details of this estimate.

considered, therefore, that this carrying value represented a reasonable approximation of the value in use, and therefore the asset's deprival value at the beginning of the period of review.

51. In relation to Ecotricity's view that we should take account of all the costs of nuclear, not just the costs that EDF bears, we took for the purposes of this analysis the policy energy framework in force, including that related to subsidies and emissions, as a given. Were we to assess the life-cycle costs of the various generation technologies – including, for example, factoring in the cost of emissions – then this would be a different piece of analysis from this profitability analysis. The former takes the perspective of cost to society as a whole whereas we are investigating the competitive process where it is the profitability of the firms that was relevant.

Approach adopted in relation to valuing nuclear plant

52. We based our analysis of nuclear economic profitability by valuing nuclear plant at the outset of the period of review based on EDF's estimate of its value in use. We noted that this valuation was significantly below the depreciated replacement cost and provides a reasonable estimate of the opportunity cost or deprival value to EDF at this point in time. We emphasise that we would not have considered this valuation basis appropriate if it were higher than the replacement cost as it could then have been seen to capitalise some expectation of future profits. However, in this case, it appeared to reflect the reality that the economic returns to nuclear were below those required to incentivise new entry.

53. We adopted EDF's accounting treatment by which this value-in-use estimate (ie the fair value EDF ascribed to its acquisition in 2009), together with the cost of subsequent fixed asset additions to its nuclear fleet, was depreciated in the normal way – ie using straight-line depreciation.

Comments on assessing replacement cost with CCGT as the MEA for conventional power stations

54. RWE, EDF, Centrica, E.ON and Drax questioned whether the CCGT power stations should be considered equivalent to either coal or nuclear power stations. SSE agreed that CCGT power stations should be considered the MEA to coal-fired power stations but considered that the MEA for nuclear power stations should be new nuclear generation plant.

55. In the first instance, RWE challenged our contention that all coal assets would have been replaced with CCGT power stations. It highlighted that both it and other GB generators had seriously considered constructing new coal stations

early in the extended period of review. It suspended its own project in 2009. In addition, RWE said that coal power stations had significantly more volatile exposure to commodity spreads[16] ('clean dark spread') than a CCGT power station ('clean spark spread'). Investors would therefore require different rates of return from such investments. RWE also pointed to the need to consider the technical parameters, variable and fixed costs and different ongoing capital costs between CCGT and coal, which would make the adjustments to both capital and operating costs complex and therefore could result in misleading analysis.

56. EDF highlighted a number of technology-specific factors that needed to be considered in relation to its nuclear plant, including:

- its returns are far less sensitive to fuel input costs compared with gas and coal plant;
- its plant had higher ramp-up and ramp-down costs than gas and coal plant and could not easily vary their output in response to changes in demand and supply;
- its plant had higher costs at the end of their lives, due to the significantly higher costs of decommissioning, when compared with other generation technologies;
- its plant had a much higher fixed cost base than any other generation technology and faced stricter regulatory requirements and security arrangements;
- it was a low-carbon technology and therefore had no carbon emissions costs to factor in its operations;
- the plant construction time was considerably longer than that of other technologies and the costs of obtaining the various permissions to build a station were far higher than for other types of generation; and
- its low marginal costs of a nuclear plant meant that it would, in contrast to gas and coal plant, be expected to be in merit over its entire operational life and consequently run as a baseload plant throughout its life.

57. EDF stated that it would expect an MEA to possess the same productive capacity and have a similar economic profile to a given asset. Due to the significant differences between CCGT and nuclear capital, operating and fuel

[16] In other words that there is more variability around the difference between wholesale electricity prices and the cost of coal, than between the wholesale electricity price and the cost of gas.

cost profiles, however, the two technologies had very different risk profiles. The challenge for the CMA was for it to adjust the costs of the comparator CCGT plant in such a way as to recreate nuclear's risk profile; for instance, it should consider adding the cost of a gas storage facility to the extent necessary and also consider a fixed-price one-off fuel take or pay contract (with the operator having only a very limited ability to resell the fuel) to cover the remaining life of the asset.[17] This would in effect create some similarities in the level of sunk costs for CCGTs with nuclear and make the CCGT a price-taking asset as it would lose the partial natural hedge between underlying gas and electricity prices, and it would be run as a baseload plant regardless of the prevailing market price of gas.

58. EDF further pointed out that we should also consider the cost of creating an equivalent low-carbon generator; for CCGTs, this would entail installing CCS plant and associated infrastructure.

59. Centrica pointed to the many differences between new CCGTs and coal or nuclear plants such that it believed it was not possible for one to approximate the other. Some examples of the many differences which would have to be accommodated are the very different asset lives, operating modes, revenue earning potential (dark spread versus spark spread) and operating and maintenance costs structures. The adjustment process would require such a large number of approximations and simplifications that Centrica doubted that the results would be meaningful.

60. SSE explained that using CCGT as the MEA for coal-fired plant, and assuming a running pattern that followed that of coal, led to the situation that the coal plant would be generating when the CCGT plant, on which its valuation and associated operating cost adjustments would be based, had not been in merit. Such an approach would result in coal plants showing a loss in these periods.

61. E.ON also questioned our assertion that all coal plant would have been replaced with CCGTs by pointing to the following developments over the period of review:

- certain coal plants had been converted to biomass;
- substantial sums had been spent in upgrading certain existing coal and nuclear plant; and

[17] Nuclear plants are able to store a large quantity of their future fuel requirements, which a gas storage facility and one-off fuel procurement would replicate.

- although a number of coal and nuclear plant had closed during the period, in some cases this had been driven by safety and environmental legislation.

62. E.ON also pointed out that such an approach ran the risk of treating all assets of differing technology types as homogeneous although their technical characteristics and competitive advantages varied.

63. Scottish Power observed that the MEA of a coal plant could, in principle, be estimated based on the cost of a CCGT plant, on the basis that a company investing in new thermal capacity would be more likely to adopt CCGT than coal-fired technology. However, it noted that coal and CCGT generation units are also potentially subject to different policy risks, which could have some bearing on the valuation.

64. Drax recognised that a new CCGT was likely to be the new-build marginal plant of choice, and that if existing conventional plant could all be valued on this basis it might provide greater comparability between different generation asset types. It doubted, however, that, given the difficulty in particular of factoring in the differential impacts associated with technology-specific environmental/social government interventions across different generation technologies, any conclusions drawn from this analysis would be robust.

65. Citizens Advice, in contrast, doubted whether a nuclear plant could be considered an MEA asset. It was not aware of any fully merchant (ie subsidy-free) nuclear power station having been developed anywhere in the world during the period of review. It pointed out that nuclear projects could not be brought forward without subsidy as further evidenced by the government's decision to offer considerable subsidy to the new project at Hinkley Point C (HPC), where the agreed strike price was roughly twice the current wholesale power price. While the incoming Contract for Difference (CfD) regime allowed for subsidies to be offered to nuclear projects, the outgoing Renewables Obligation (RO) regime – which was the one in place during the period of review – did not.

Our views on assessing replacement cost with CCGT as the MEA for conventional power stations

66. We considered all the comments made as summarised in paragraphs 54 to 65, above. We also explored how we might implement the approach in practice by doing some initial calculations. As a result, we came to the view that adopting this basis to estimate profitability would not have given us additional insight beyond that to be gained from basing any replacement cost valuations needed for the profitability assessment on the premise that the

MEA would be the latest proven technology of the same type currently deployed (ie like-for-like basis). This was for both conceptual and practical implementation reasons, as explained below.

67. The conceptual issue was that a CCGT plant was not equivalent to a coal or nuclear plant since these different means of production had different bundles of risks and opportunities (or real options)[18] associated with them. In practice the flexibility offered by a diverse portfolio of generating technologies was a virtue that many of the Six Large Energy Firms have told us they have, at times, sought to attain.

68. In theory it might be possible to ascribe a value to each of the different real options associated with the asset actually owned – for example, that arising from the expected variability of fuel input costs for coal, or its expected longer asset life compared with CCGT, or the expectation about the path of future emissions regulation – and reflect this within our asset valuations and the associated depreciation profile. Such an approach, however, would be very complicated and would give results that were largely a function of our assumptions or estimates of likely future developments in the market. Our view was that this would have significantly limited the reliance that we could place on any such results.

69. The practical issue was that assessing the replacement cost with CCGT as the MEA for coal and nuclear assets effectively involves estimating the returns that a CCGT would have made over the relevant period if it had operated according to the same schedule as coal and nuclear plants. During periods when coal and nuclear had been in merit but CCGTs had not, this would have meant that the plant would have made a loss as the wholesale price had been below the marginal costs of operating. We observed that returns estimated on this basis would not have provided any insight into the actual returns earned by coal and nuclear plants over the period.[19]

[18] A real option is a way of characterising opportunities or risks to a firm which are not captured in financial statements. It is analogous to a financial option and can be valued on similar lines.
[19] We noted that this thought experiment does imply that, had the GB fleet of coal and nuclear plants actually been replaced by CCGT over the 2009 to 2013 period, the wholesale price of power would have been higher at those points in time when coal (or nuclear) was, in fact, the marginal plant and had a lower marginal cost than a CCGT. Conversely, at those times when coal had been the marginal plant (ie when CCGTs had a lower marginal cost), wholesale prices would in fact have been lower if coal had actually been replaced by CCGTs. We note that our decision not to pursue this line of analysis does not change our view that a new entrant entering the market by investing in a conventional power generation plant would have chosen to invest in a CCGT. This reflects the view that CCGT plant, under the current energy policy framework, provides investors over the long run the least-cost option to generate baseload electricity. This was the case before the period of review when decisions were made by Centrica and others to invest in CCGT plants, which were subsequently constructed and commissioned during the period of review.

Approach adopted in relation to specifying the MEA

70. We therefore decided not to analyse profitability using estimates for the replacement cost of assets with reference to technologies other than the latest evolution of the technology actually deployed (ie the like-for-like basis).

Initial comments on depreciation profile

71. Our approach to depreciation was to apply depreciation to our gross asset valuations according to the expected useful economic life of the existing assets. This is often described as straight-line depreciation, whereby the depreciated cost is an inverse function of the age of the asset. This is the approach typically adopted by firms when depreciating their assets in their financial statements.

72. There were a number of comments on the depreciation profile, with many firms noting that they themselves adopt straight-line depreciation for external reporting purposes.

73. Centrica pointed to the considerable amount of highly depreciated older generating capacity in the system and suggested that we may well observe high ROCE at the tail end of a plant's life. It noted that attempting to adjust the capital base by using an MEA basis would not necessarily resolve this distortion. RWE, in a similar vein, argued that depreciated replacement cost based on the age of the assets under use is likely to overstate the profitability of firms that operate older assets[20] when only part of the lifetime of the investment is considered and hence could discriminate against firms that happen to operate older assets. It suggested that one way for us to address this issue might be to assume an average age for all assets over the period of review.

74. E.ON argued that straight-line deprecation was unlikely to match the true economic returns of E.ON's generation assets and was likely to result in unrepresentative ROCE figures. It pointed to a wide range of alternative systematic methods, independent of the asset's actual usage, over which to depreciate assets for the purpose of assessing ROCE. In its view flat annuity seemed the most appropriate for the nature of long-lived assets, although conceptually inferior to a units of production method based on running hours or output.

[20] RWE pointed to DUKES data suggests an average age of around 25 years for the coal, gas and nuclear fleets.

Our further thinking on appropriate depreciation profile

- *Expected depreciation*

75. We sought to value firms' generation assets on their value to the business or deprival value at each balance sheet date. Where the assets are worth replacing, this value will be the depreciated replacement cost of the MEA. The appropriate level of depreciation should be such that a new entrant would be indifferent between buying a new MEA asset or an older version of the asset that has been depreciated to take account of its economic obsolescence.

76. In practice there are five factors which affect the value that such a new entrant would place on a partly used asset, all of which would be reflected in the price that such an asset would fetch in a well-informed, liquid and competitive second-hand market. The first four factors reflect expectations about the future – namely, the profile of expected future usage, expected rises in running costs as the asset ages, the expected development in real input costs, such as the prospect of development of even lower-cost technology, and the cost of capital the firm expects to earn from deploying that asset.

77. The precise shape and the expected useful life of an asset is an empirical issue. Straight-line depreciation is a useful compromise between declining returns and the discounting effect of factoring in the costs of capital, with the former suggesting accelerated (reducing balance) depreciation and the latter a rising (annuity depreciation) pattern. However, although we recognised that the two effects are unlikely to offset one another exactly, we considered straight line was a pragmatic way of estimating the depreciated replacement cost of the MEA, not an exact result.[21]

- *Impairment losses*

78. The fifth factor arises from unexpected negative developments in the operating environment, such as shocks or a fire that would lead to a one-off downward valuation. These losses in value are normally referred to as 'impairment losses'. In the case of a fire this would be the result from the physical damage to the asset. However, where a shock results in such a change in output (ie sales) that the firm (or new entrant) would not choose to replace that asset because it would not be expected to earn an economic return, then the asset is also impaired.

[21] This point is made in Annex 4 of HM Treasury (1986), *Accounting for economic costs and prices: a report to HM Treasury by an advisory group* ('the Byatt Report') (London: HMSO), Volume II, p133, paragraph 14.ii.

79. In this situation the value of the impaired asset to the business would be its recoverable amount. This is the higher of its value in use (essentially a DCF calculation) or its net realisable value. While valuing on a DCF basis might at first sight seem circular, in these circumstances market forces are determining the valuation of the asset. This contrasts with the situation where the firm's market power itself would affect the DCF valuation because it would incorporate the capitalised value of expected future excess profits. Reflecting these expected future profits within an asset valuation would indeed be circular for our purposes and in any case would not reflect the deprival value of the asset in a competitive second-hand market.

80. Where the recoverable amount falls below the depreciated replacement cost, this leads to a break in the previously expected depreciation profile pattern. Once the asset is valued taking into account the impairment loss, then a revised depreciation profile would be applied in the normal way, taking into account all the factors set out in paragraphs 76 to 77. Again, we sought to apply a straight-line depreciation profile for the reasons set out in paragraph 76.

81. We used the values that firms themselves had attributed to their impaired assets.[22] Accounting standards effectively require the firms to assess their values at their recoverable amounts, which in most instances were estimates based on expected net cash flows discounted at the firms' cost of capital. The firms' auditors are required to review these calculations when auditing the firms' balance sheets. We therefore considered that these estimates of the value of impaired assets were likely to be sufficiently robust for our purposes.

Our view on comments received

82. As set out in paragraph 73, Centrica and RWE both expressed concern that ROCE based on highly depreciated asset values might be distorted and therefore unrepresentative of returns over the lifetime of the asset.

83. Our response to the first point was that while this may well have been a concern where historic carrying values were used, especially where the assumed economic life was considerably shorter than the asset's actual economic life, this was not per se a concern with the depreciated MEA values. This is because the depreciation profile is the *net* result of the first four factors as set out in paragraph 76, which *together* influence the expected loss in

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[22] For financial reporting purposes an impairment is recognised only when recoverable amount is below book value. This means that the approach adopted here will not include those impairments against the MEA value where the MEA value is above book value *and* the recoverable amount is below MEA but above book value. This may result in an overstatement of asset values and an underestimate of impairment losses with an unclear overall effect on the ROCE estimates.

value over time. And we also used in our calculations the estimated economic useful life based on actual experience of the plants for each technology rather than necessarily their accounting lives. Therefore, any relatively low asset valuations would reflect the asset's relatively low value to its owner at that point in time.

84. In advocating flat annuity depreciation it seemed to us that E.ON was highlighting only one – albeit important – factor influencing expected depreciation, namely the opportunity cost of capital. The opportunity cost of capital's influence on the depreciation profile is significant for long-lived assets such as most power stations. A units of production methodology might likewise factor another (expected future) usage, but not necessarily all the factors that influence an asset's loss in value over time. These factors may work in opposite directions and thus offset one another to some extent.

85. Regarding Centrica's and RWE's second point, we did not seeking to estimate returns over the full lifetime of the asset. As explained in paragraph 28, we sought to estimate returns over the recent past, currently over the past five to seven years. It would also have been inappropriate to have substituted estimates of the depreciated MEA with some estimate of MEA values assuming that assets were half way through their expected useful life as we sought to estimate the ROCE on the assets actually held by specific firms. Only valuations relating to these assets represented the economic opportunities open to each firm over the period of review, not a notional portfolio of mid-life assets.

Approach adopted in relation to depreciation profile recognising impairment losses

86. In our analysis, therefore, we adopted a straight-line depreciation of an estimate of the gross replacement cost of the MEA, and where necessary supplemented this depreciation for any one period with an estimate of the impairment loss. The extent of the impairment loss was the difference between the depreciated replacement cost before the impairment loss and the firms' estimate of the recoverable amount as described in paragraph 81 after the impairment loss. The recoverable amount was subsequently depreciated in the normal way.

Summary of the asset valuation bases adopted to analyse profitability

87. In this appendix we prepared estimates of profitability for generation (scoped in line with the discussion in paragraphs 6 to 20) by comparing the ROCE with our estimate of the costs of capital. The ROCE has been computed using

asset values and associated depreciation charges determined on the following two bases:

(a) *carrying value basis* – as previously described in paragraph 24; and

(b) *deprival value basis* – initially assessed on the premise that the value of any replacement would be assessed in respect of the latest evolution of the technology currently deployed (ie like-for-like basis).

88. In both cases, we have applied straight-line depreciation to reflect an estimate of expected economic depreciation. In addition we reflected impairment losses in our analysis at a level that resulted in the impaired assets reflecting their recoverable amount as reported in the firms' own financial statements.

The extent of the refinement of the analysis

89. RWE suggested a number of refinements to our analysis, in particular to the way the level of profit and capital employed had been determined for each period used to compute ROCE. These included:

(a) taking into account subsequent investment in the replacement of components of existing power stations where these components had a shorter life than the power station as a whole;

(b) testing whether the factors which had influenced the depreciation profile over the period of review had in fact offset each other in such a way to produce a straight-line depreciation profile; and

(c) assessing the validity of the fair values ascribed to impaired assets by each firm.

90. RWE stated that, in its view, taking into account its points would most likely have led to a lower level of profitability being analysed for it than we had shown.

91. We considered all of RWE's detailed points and concluded, given the nature of the approximations inevitably involved when estimating economic profitability and the findings from the analysis we had performed across all the firms analysed, that we would not seek to refine our analysis further.

Results

92. In this section, we set out the results of our ROCE analysis using both the carrying value basis and the deprival value basis.

Return on capital employed – carrying values

93. As explained in paragraph 18, the starting point for our analysis was to consider the returns made by the Six Large Energy Firms using their profits and capital employed reflecting a full-function generator but otherwise prepared in accordance with their normal accounting policies used for external reporting. All operating revenues and costs incurred have been included in this analysis, including any impairment losses suffered, not least to maintain internal consistency between the measure of profits and capital employed. Table 2 gives a summary of the returns earned by each firm on its generation activities as a whole.

Table 2: Generation ROCE by firm, based on balance sheet carrying values*

							ROCE (%)
Energy firm	*2007*	*2008*	*2009*	*2010*	*2011*	*2012*	*2013*
Centrica	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
EDF	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
E.ON	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
RWE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
SSE	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Scottish Power	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.
*For 2007 and 2008, the ROCE relates to each firm's generation *division*, which might be a subset of its generation activities as we define them.

94. This table shows that the results were mixed, with a number of years of negative returns, as well as a few years of returns above the weighted average cost of capital (WACC). Returns appeared to have been higher in 2007 and 2008, declining over the period.

95. We next considered the returns earned by Centrica, EDF, RWE and Scottish Power by generation technology. This more detailed breakdown was not available for 2007 or 2008, or for either E.ON[23] or SSE. We noted that Scottish Power had to make a number of assumptions in order to present its results on a by-technology basis (see Table 1). While we did not consider that these were likely to have had an impact on the overall level of generation profits earned by the firm, we considered that the 'by-technology' results for Scottish Power should be treated as indicative only.

Centrica

96. Centrica's generation fleet is comprised of CCGT and wind assets as well as a 20% equity stake in EDF's nuclear fleet. While Centrica developed and operated a number of wind farms over the relevant period, we did not analyse its returns on these assets separately. This was because Centrica has

[23] This data was not available for E.ON due to the absence of technology-specific trading data.

developed and then sold on a number of its wind farms (or stakes in them) once operational.[24] The returns earned on the nuclear assets are shown within EDF's results, although 20% of these are attributable to Centrica. Table 3 shows Centrica's results for its CCGT assets only.

Table 3: Centrica ROCE by technology

					£m
CCGT	*2009*	*2010*	*2011*	*2012*	*2013*
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (%)	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis of Centrica financial information.

97. Centrica's results showed a decline in profitability over the period as a result of both a decline in operational performance, which can be seen in the earnings before interest, taxes, depreciation and amortisation (EBITDA) figures, and a significant asset impairment in 2011.[25] The overall level of ROCE was relatively low, remaining below the WACC for the entire period.

EDF

98. EDF has a diversified fleet of power generation assets, covering all the major technologies. It controls substantially all of the GB nuclear fleet and operates these assets on its own behalf as well as that of the 20% minority shareholder in the nuclear fleet, Centrica. These results reflected all of the profits earned on the nuclear fleet and associated capital employed, so as to match profits to the assets which generated them.

[24] This made it more difficult to match the returns earned on assets with the capital base as the latter is only reflected in the balance sheet of the business at the year end.
[25] Centrica made a number of other, smaller, asset impairments in 2009, 2012 and 2013.

Table 4: EDF ROCE by technology

					£m
	2009	*2010*	*2011*	*2012*	*2013*
Nuclear					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (%)	[✂]	[✂]	[✂]	[✂]	[✂]
Coal					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (%)	[✂]	[✂]	[✂]	[✂]	[✂]
CCGT					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (%)	[✂]	[✂]	[✂]	[✂]	[✂]
Wind					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (%)	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis of EDF financial information.

99. Over the relevant period, EDF saw a marked improvement in the performance of its nuclear assets. We understood that this was driven by the improved operational reliability of the fleet (as a result of significant investment in the fleet), which increased the volume of power generated by these assets, and, to a lesser extent, by the introduction of the carbon price floor (in 2013).[26] However, in spite of the positive trend, for three out of the five years reviewed, EDF (and Centrica) earned less than the weighted average cost of capital on the nuclear fleet.

100. The returns earned by EDF on its coal assets fluctuated significantly over the period, with a mixture of high double-digit returns in 2009, 2011 and 2012 and a negative return in 2010, which was driven by a significant impairment of its coal assets in that year. EDF earned persistently low or negative returns on its CCGT and wind assets.

RWE

101. RWE owned and operated a range of conventional (coal and CCGT) and renewable generation (wind and other) assets over the relevant period.

[26] The introduction of a carbon price floor increased the marginal cost of both coal and (to a lesser extent) CCGT. As these were the marginal assets, this increased the wholesale price for electricity, increasing returns to the owners of generation assets that did not produce carbon, such as nuclear.

Table 5: RWE ROCE by technology

					£m
	2009	2010	2011	2012	2013
Coal					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (as a toll generator) (%)	[✂]	[✂]	[✂]	[✂]	[✂]
CCGT					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (as a toll generator) (%)	[✂]	[✂]	[✂]	[✂]	[✂]
Asset-backed trading & other conventional					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
Wind					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (%)	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis of RWE financial information.

102. The EBITDA earned by RWE on its coal assets declined significantly between 2009 and 2013. These assets were also impaired materially in 2010, creating a negative return in that year. In most years over the period, RWE’s coal assets earned relatively high returns on capital. On CCGT and wind, RWE consistently earned returns that were below the WACC, with no particular trend evident in its results.

Scottish Power

103. Scottish Power owned and operated a range of power generation assets, including coal, CCGT, onshore and offshore wind and hydroelectric/pumped storage facilities. Table 6 sets out the returns earned by technology. (See paragraph 79 on the reliability of Scottish Power’s technology splits.)

Table 6: Scottish Power ROCE by technology

					£m
	2009	*2010*	*2011*	*2012*	*2013*
Coal					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (%)	[✂]	[✂]	[✂]	[✂]	[✂]
CCGT					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (%)	[✂]	[✂]	[✂]	[✂]	[✂]
Wind					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (%)	[✂]	[✂]	[✂]	[✂]	[✂]
Hydro/pumped storage					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (%)	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis of Scottish Power financial information.

104. The profits (EBITDA) earned by Scottish Power on its coal and CCGT assets fell substantially over the period due to the impact of lower market spreads and environmental cost pressures. We note that Scottish Power impaired its coal assets twice over the period (in 2009 and 2010) and its CCGT assets in 2013. As a result, the returns earned on both coal and CCGTs have fallen substantially and were significantly negative at the end of the period.

105. Scottish Power's hydroelectric and pumped storage facilities were constructed between the 1920s and 1960s and have very long asset lives.[27] We did not believe that a ROCE estimated based on carrying values, which may have been affected to a great extent by inflation and/or be largely depreciated, was likely to provide a reliable view of economic returns. Therefore, while the ROCE on these assets appeared to be high, we did not consider that this necessarily suggested the firm had been making excess returns.

Discussion of results by technology

CCGT

106. The profitability of CCGT assets between 2009 and 2013, set out in Figure 1, was reasonably consistently low/negative and declining over the period. In

[27] Scottish Power (nd) *Galloway and Lanark hydro schemes*.

2013, all firms made losses on their CCGTs due to a combination of relatively low load factors and asset impairments.

Figure 1: ROCE (carrying value basis) on CCGTs by firm

[✄]

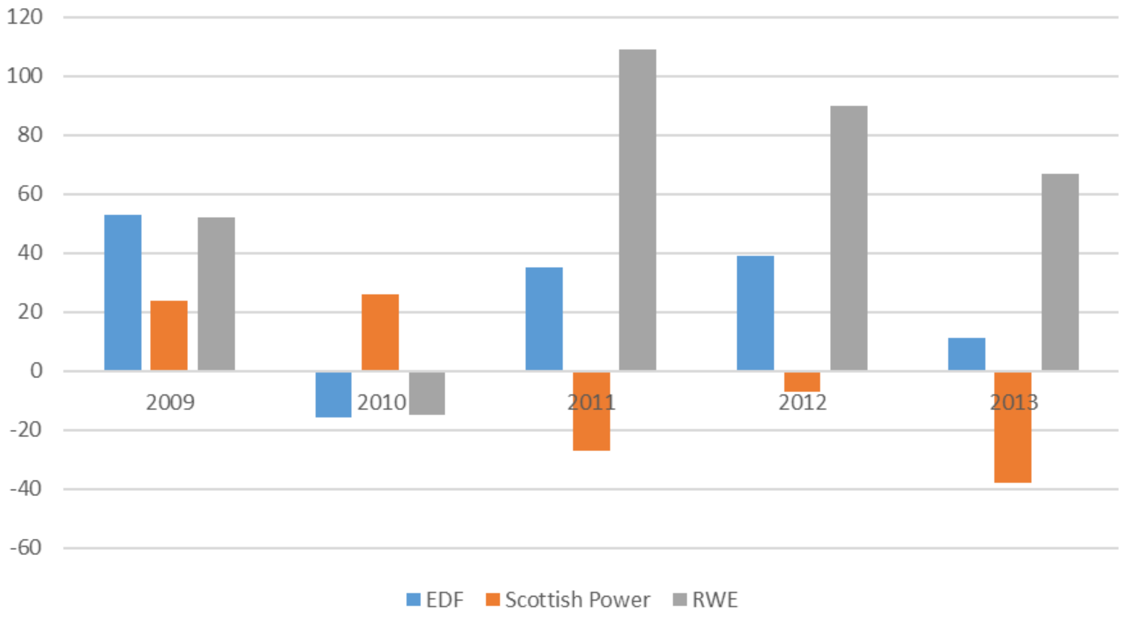
Source: CMA analysis.

107. While CCGTs have generally been built over the last 20 years, their useful economic life is around 25 years, hence there may be significant differences in the measured level of profitability due to the impact of inflation and depreciation. We took this into account in the next section when we revalue the CCGT assets on a consistent basis.

Coal

108. The returns earned on coal assets between 2009 and 2013, set out in Figure 2, show significant differences across firms and over time. For all firms, there had been a clear downward trend in EBITDA, with returns also affected by numerous impairment charges resulting from the introduction of environmental regulations that have shortened the operating lives of many of the coal-fired power stations in GB.

Figure 2: ROCE (carrying value basis) on coal-fired power stations by firm



Source: CMA analysis.

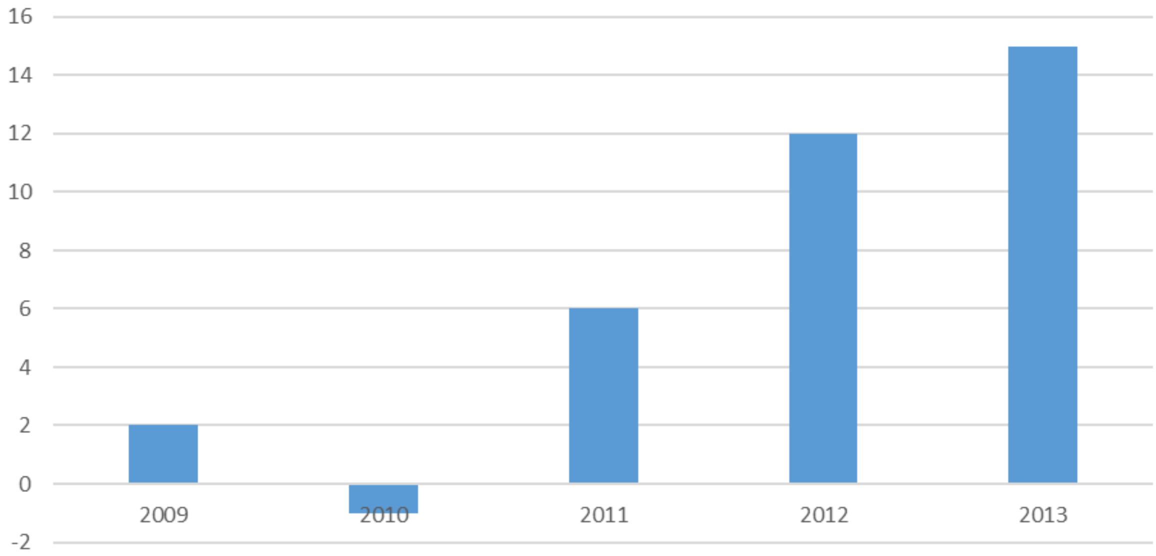
109. While the overall level of ROCE was significantly above the WACC in many cases, we note that the age of the coal assets raises issues of the relevance

of these returns figures. In the next section, we revalue the coal assets on an MEA basis, which we considered to be more appropriate.[28]

Nuclear

110. While the returns earned between 2009 and 2013 showed a strong increasing trend, they were below the WACC for three of the five years. We observed that EDF had made operational improvements to the nuclear power stations, improving their reliability and therefore output over time. EDF told us that, on acquisition of the assets from British Energy, they had been fair valued using a DCF basis for the purposes of its accounts (in line with accounting standards). We considered the relevance of this approach, as compared with a replacement cost approach, in the next section.

Figure 3: ROCE (carrying value basis) on nuclear power stations



Source: CMA analysis.

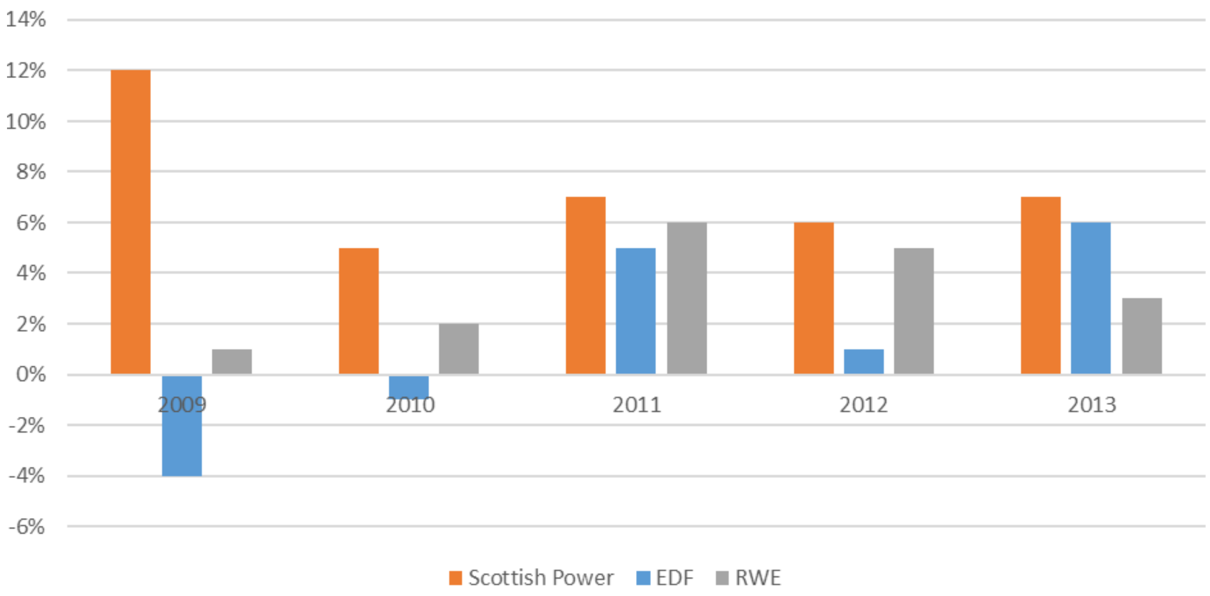
Wind

111. The returns earned on wind assets between 2009 and 2013, set out in Figure 4, are relatively low and generally below the WACC. We observed that a large proportion of the wind farms currently in operation were built during the period, with the capital employed reflecting a large proportion of assets in the course of construction but not yet operational. We do not consider,

[28] We also noted that the returns earned by RWE on its coal-fired power stations may be overstated by the exclusion of asset-back trading profits. RWE operates an internal toll model and was not able to separate its trading results by technology type. Overall, asset-backed trading profits were negative in 2010, 2011 and 2013 (and negligible in 2012).

therefore, that these returns were necessarily indicative of those that these assets are likely to earn once they were fully operational.

Figure 4: ROCE (carrying value basis) on wind assets by firm



Source: CMA analysis.

Return on capital employed – deprival value

112. As explained in paragraphs 48 to 53, we estimated the ROCE earned by several of the firms having revalued their CCGT, coal and nuclear assets on a value-to-the-business (or deprival) basis. Our approach was to estimate the depreciated replacement cost for each type of asset, with depreciation charged on a straight-line basis, and then to assess whether the value in use of these assets was below this replacement cost at any point during the relevant period. In order to make this assessment, we identified all impairments charged against generation assets and compared the carrying value of each asset following its impairment with our estimate of the depreciated replacement cost of the asset. Where the carrying value was lower, we applied a one-off impairment such that the asset's value was reduced to the level at which it was recorded in the firm's accounts.[29] In Annex C we set out in detail how we have estimated the (depreciated) replacement costs for each type of asset.

[29] We did not make any adjustments where the carrying value was higher in order to avoid capitalising any expected excess returns. We considered the post-impairment carrying value of an asset was likely to have been a reasonable estimate of its value in use as firms are required to value an impaired asset based on expected future cash flows discounted by their cost of capital. The logical implication of this approach is that, once an asset has been impaired (below its depreciated replacement cost), it should make a return equal to its cost of capital over its remaining lifetime provided that the firm's expectations are fulfilled.

113. We considered that the carrying value of wind assets would reflect a reasonable estimate of the deprival value of these assets, given that the majority of these had been constructed in the last decade and hence should not have been materially affected by inflation and/or technological obsolescence.[30] In the case of the other generation technologies, we noted that these were relatively minor sources of power generation in GB and we did not consider that a more detailed consideration of their asset values would have a material impact on the overall profitability assessment.

114. In this section, we first set out the ROCE using the depreciated replacement cost of assets, without applying additional impairments. We then considered the impact of impairments on the returns to each category of assets for each firm.

Centrica

115. Tables 7 and 8 show the returns earned by Centrica on a replacement cost and deprival value basis, respectively. The overall level of returns was similar in these two cases but the pattern over the period differed due to the impact of impairments reflected under the deprival value basis. These adjustments gave a view of profitability that was similar to that set out in Table 3.

Table 7: Centrica ROCE on CCGT assets (replacement cost basis)

					£m
CCGT	*2009*	*2010*	*2011*	*2012*	*2013*
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (%)	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

Table 8: Centrica ROCE on CCGT assets (deprival value basis)

					£m
CCGT	*2009*	*2010*	*2011*	*2012*	*2013*
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (%)	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

EDF

116. Tables 9 and 10 show the returns earned by EDF on a replacement cost and deprival value basis, respectively. The returns on nuclear assets were lower

[30] Subject to the proviso about the capitalisation of financing costs. See paragraph 32.

on a replacement cost basis as our estimate of capital employed was significantly higher than the carrying value in EDF's accounts. EDF did not impair its nuclear assets over the relevant period but these returns suggested that the actual recoverable value of these assets had been significantly below the depreciated replacement cost throughout (ie the assets were effectively impaired). We did not seek to estimate the extent of the impairment but noted that EDF's own estimate of the assets' value (as shown in its accounts) appeared reasonable in this context (ie valuing the assets on a deprival basis would give approximately the returns shown in Table 4).

Table 9: EDF ROCE by technology (replacement cost basis)

					£m
	2009	*2010*	*2011*	*2012*	*2013*
Nuclear					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (%)	[✂]	[✂]	[✂]	[✂]	[✂]
Coal					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (%)	[✂]	[✂]	[✂]	[✂]	[✂]
CCGT					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (%)	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

117. The returns earned on coal assets were reduced once the assets were revalued on a replacement cost basis. By taking into account impairments, the pattern of returns was changed and the average ROCE for the period as a whole was reduced further (to approximately [✂]%).

Table 10: EDF ROCE by technology (deprival value basis)

					£m
Coal	*2009*	*2010*	*2011*	*2012*	*2013*
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (%)	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

118. In the information it supplied to us, EDF did not impair its CCGT assets such that the ROCE estimated on the replacement cost basis and on the deprival value basis were the same.

RWE

119. Tables 11 and 12 show the returns earned by RWE on a replacement cost and deprival value basis, respectively. For coal, the pattern of returns was different between the two cases due to the impact of impairments. Average returns are also lower (and are, in fact, negative) on the deprival value basis as a result of these significant write-offs.

Table 11: RWE ROCE by technology (replacement cost basis)

					£m
	2009	*2010*	*2011*	*2012*	*2013*
Coal					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (as a toll generator) (%)	[✂]	[✂]	[✂]	[✂]	[✂]
CCGT					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (as a toll generator) (%)	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

Table 12: RWE ROCE by technology (deprival value basis)

					£m
	2009	*2010*	*2011*	*2012*	*2013*
Coal					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (as a toll generator) (%)	[✂]	[✂]	[✂]	[✂]	[✂]
CCGT					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (as a toll generator) (%)	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

120. The returns on CCGT assets were low on both bases throughout the period.

Scottish Power

121. Table 13 and Table 14 show the returns earned by Scottish Power on a replacement cost and deprival value basis, respectively. For coal, the pattern of returns was different between the two cases due to the impact of impairments. Average returns were also lower (and were, in fact, negative) on the deprival basis as a result of these significant write-offs.

Table 13: Scottish Power ROCE by technology (replacement cost basis)

£m

	2009	*2010*	*2011*	*2012*	*2013*
Coal					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (%)	[✂]	[✂]	[✂]	[✂]	[✂]
CCGT					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (%)	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

122. Scottish Power's CCGT ROCE was similar on the replacement cost and deprival value bases. In both cases, average returns were relatively low over the period, at around [✂]%.

Table 14: Scottish Power ROCE by technology (deprival value basis)

£m

	2009	*2010*	*2011*	*2012*	*2013*
Coal					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (%)	[✂]	[✂]	[✂]	[✂]	[✂]
CCGT					
EBITDA	[✂]	[✂]	[✂]	[✂]	[✂]
Net profits before interest and tax	[✂]	[✂]	[✂]	[✂]	[✂]
Capital employed	[✂]	[✂]	[✂]	[✂]	[✂]
ROCE (%)	[✂]	[✂]	[✂]	[✂]	[✂]

Source: CMA analysis.

E.ON and SSE

123. We were unable to prepare ROCE estimates on these bases for E.ON and SSE as we did not have sufficient data to do so. However, we noted that the replacement cost and deprival value basis had not generally shown a significantly different level of returns on CCGT assets and had shown a lower level of returns on coal assets over the period. We would expect a similar effect on the results of both E.ON and SSE.

Annex A: Business models (tolling)/hedging

1. The Six Large Energy Firms adopt different business models to delineate generation and trading businesses, which can have a significant effect on the amount of risk faced by the generation business and the trading business.[31]

2. In essence, a 'toll-generator model' removes the financial consequences of a plant not being in merit, and therefore not being in a position to make a profit from running the plant, from the generation business and places that risk with the trading function. The trading function therefore decides when to run the plant. Under this model, the trading function also gains when it is able to sell its output at a higher margin than expected. A 'full-function generator' takes on these risks and rewards in-house and takes all hedging and operating decisions, with the trading arm executing instructions on its behalf.

3. Table 1 below spells out the key aspects of the two models in further detail.

4. The revenues and costs of toll generation are not comparable to those of full service generators, not least because the fuel costs are typically not recorded on the toll generators P&L and the revenue line is significantly lower as a result.

[31] In practice the distinction between the full-service and toll-generator business models are not as sharp as portrayed in the table as some of the Big 6 do a combination of the two and/or specify the respective responsibilities between for generation and trading somewhere in between the two.

Table 1: Key aspects of the full-function generator and toll generator business models

Aspect	*Business*	*Full-function generator*	*Toll generator*
Activities	Generation	• Constructs & maintains power plant • Decides when it is worthwhile to run plant • Buys fuel • Produces electricity • Sells electricity	• Constructs & maintains power plant • Sells an option • Produces electricity as instructed • Charges a usage fee for electricity produced
	Trading	• Executes the transaction of buying fuel and selling electricity as instructed	• Pays option fee • Decides when it is worthwhile to run plant • Buys fuel • Incurs usage fees • Sells electricity
Turnover represents	Generation	• The sale of electricity	• The sale of an option over the capacity of the power plant (a fixed fee) plus usage fees that vary with the volume of electricity produced
Margin represents	Trading	• Brokerage fees for providing a dealing service, ie acting as an agent for Generation	• Gross margin is the revenue from the sale of electricity less the cost of fuel needed to produce it. • Net margin is gross margin less option and usage fees.
Main operational risks	Generation	• Margins (ie the difference between the selling price for output and the cost of variable inputs) move unexpectedly (it might not be worthwhile to run your plant or not as worthwhile as you thought it would be) • Plant breakdowns (you cannot run your plant even if it is worthwhile to do so)	• Plant breakdowns (you pay a penalty to the owner of the option)
	Trading	• None (trades on an execution-only basis in the market place)	• Margins move unexpectedly (it might not be as often worthwhile to instruct the plant to run as you envisaged when negotiating the option contract, or, when it is worthwhile running the plant, it is not as worthwhile as you envisaged)
Volatility of profitability (with economic cycle)	Generation	• High	• Low to medium
	Trading	• Low	• Medium to high
	Combined	• Weighted average of above (same as for toll generator)	• Weighted average of above (same as full-function generator)

Source: CMA analysis.

Annex B: The economics of electricity generation

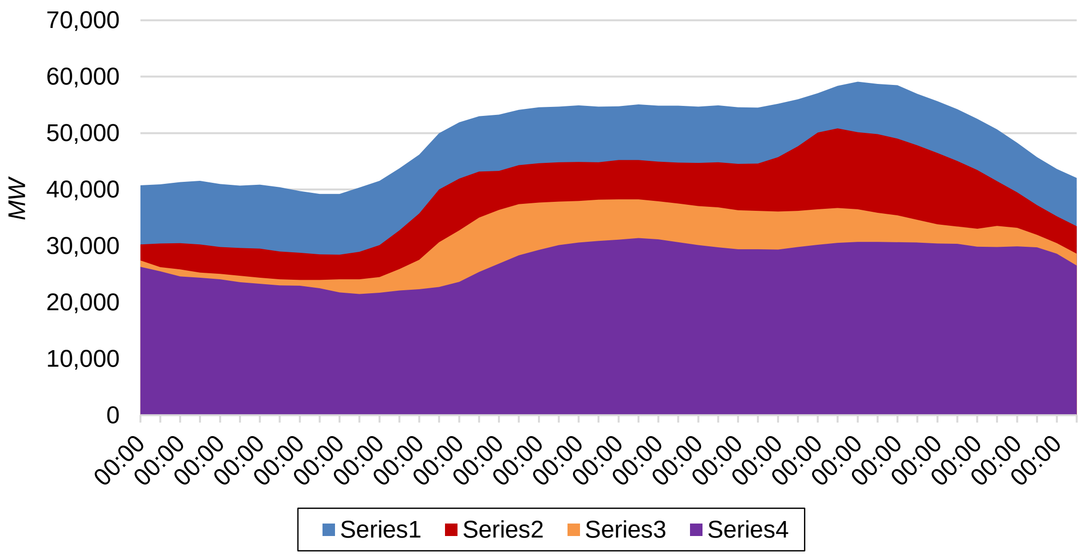
1. In this annex we provide a brief overview of those features of the electricity generation industry that drive commercial decision-making and that are, therefore, of direct relevance to the interpretation of our profitability analysis.

Basics of demand and supply of electricity

2. At any one point in time the electricity network needs to be balanced such that the total quantity of electricity supplied by generators across GB at any one point in time is equal to the total quantity being demanded by consumers.[32,33]

3. The quantity of electricity demanded varies across the day, as well as from season to season, and is especially dependent on the extent of daylight. Demand from industrial and commercial consumers is concentrated in working hours, whereas demand from domestic consumers is much more shaped, peaking between 5 and 7pm especially during the darker months. The combined effect is illustrated in Figure 1 below.

Figure 1: Intra-day electricity consumption



Source: Elexon.

4. This variability in demand, combined with the non-storability of electricity, means that more generation capacity will be required to produce electricity during some periods than at other periods. The lowest level of demand in any

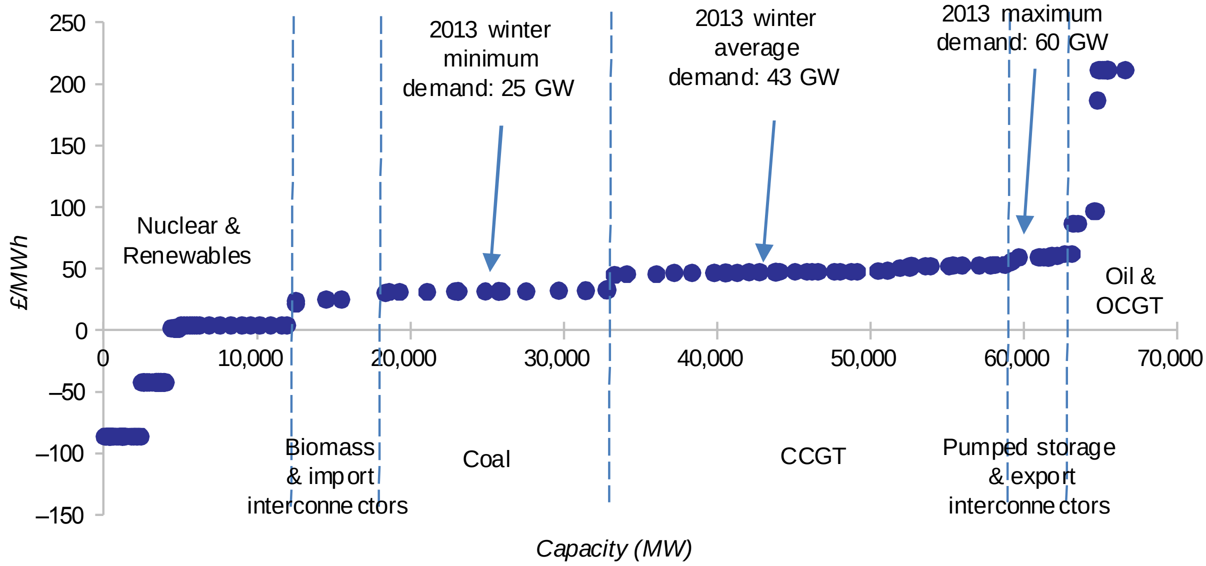
[32] Furthermore, as it is not economic to store electricity in any significant quantity, the electricity supplied to customers must broadly be generated contemporaneously with demand.
[33] Demand in this context would also include the losses associated with transmission and distribution of power.

one day can be thought of as the baseload level of demand, whereas the excess over this level is described as peak demand.

5. Electricity can be generated using a range of different technologies, which have wide variations in terms of capital and operating costs. On the one hand, nuclear power stations are very expensive to build (up-front costs) but have relatively low operating costs in terms of fuel inputs. On the other hand, CCGTs have substantially lower build costs but higher operating costs in terms of fuel inputs. There are also differences in terms of the speed with which the plants can ramp up and down in terms of production, such that some technologies are more flexible than others. Typically, technologies that can vary their output most flexibly have high marginal costs of production, while the less flexible technologies have lower marginal costs.

6. Figure 2 illustrates the short-run marginal costs (excluding starting costs) of production for each electricity generating plant in Great Britain. In a perfectly competitive market, one would expect this graph to represent the short-run supply curve for electricity with the marginal cost of the marginal plant to set the market clearing price for any half-hour period.

Figure 2: Merit order of GB generators (31 October 2013)



Source: CMA unilateral market power model

7. This graph shows that certain types of plant, as a result of their low (or even negative) marginal costs, will always run (breakdowns and planned outages for maintenance excepted), while other types of plant will run only if total demand across all consumers is sufficiently high that that plant will be able to earn sufficient money to cover at least that plant’s short-run costs of production.

8. In the longer run, however, the return earned by any individual plant will depend on the extent to which and the frequency of periods in which prices exceed the marginal cost of that plant. A certain level of such ‘rents’ is required to provide a return on the significant capital costs associated with constructing power stations.

9. Because the prices for key inputs into the production of electricity can and do vary over time, sometimes very substantially, the merit order for the plants of different technologies is not static.[34] For example, it has not always been the case in the recent past that producing electricity from coal-fired power stations was cheaper (in terms of short-run costs) than producing it from gas-fired power stations. However, it is generally the case that nuclear and renewables will always be in merit when they are available to operate.

Developments over the relevant period

10. There have been a number of developments over the period of review that have had an impact on the profitability of power stations. Some of these have had a similar impact on all technologies, while others have benefited some technologies and disadvantaged others. In this section, we briefly set out the main changes that have taken place and the impact that they have had.

Declining demand for electricity

11. There has been a long-term downward trend in the demand for electricity in the UK. Between 2006 and 2014, total demand for electricity in the first three quarters of the year fell by just over 12%. Several factors appear to have contributed to this decline, including a long-term decrease in industrial demand as the economy moves away from heavy industry and towards services, growth in the prevalence of solar panels,[35] the increased energy efficiency of many household appliances, the recession (starting in 2008/09), as well as rising electricity prices (in recent years), which may have encouraged customers to reduce their electricity use. The impact of this decline has been to move some plants from operating as baseload towards being marginal, peaking plants.

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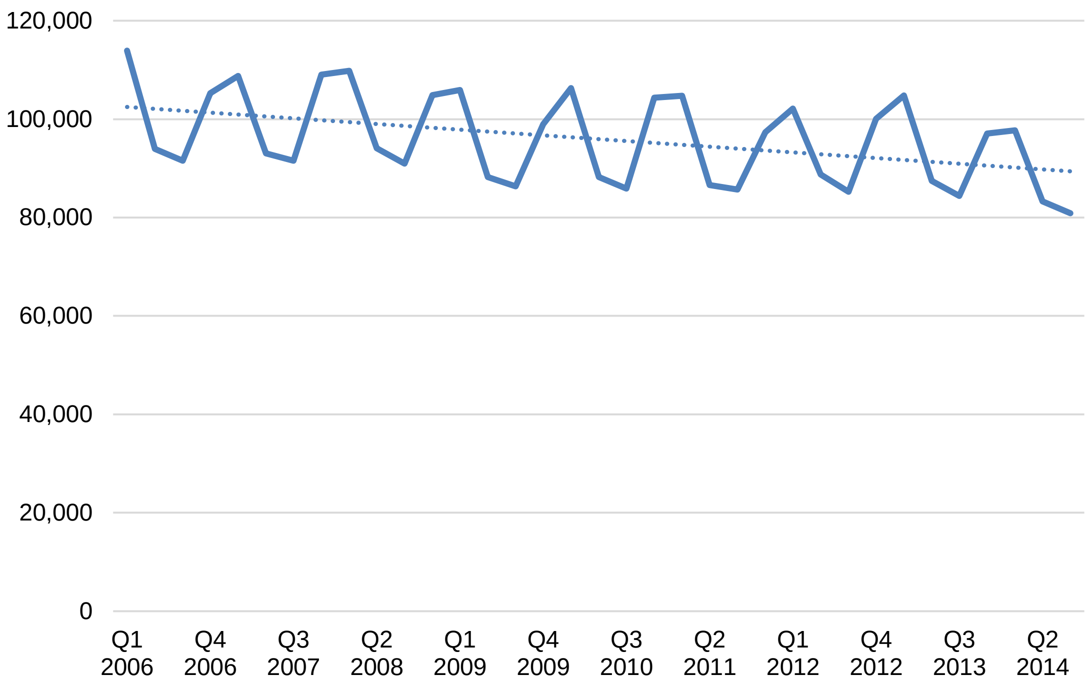
[34] Within a given technology, there is also a merit order depending on the relative efficiency of the plants. In general, newer plants will be more efficient, and therefore have lower marginal costs, than older plants.
[35] This is not strictly a reduction in energy demand but the sourcing of electricity from an alternative generation technology, which is owned by customers themselves rather than generated by power stations.

Figure 3: Total UK electricity demand (GW), 2006 to 2014



Source: DUKES data, 2014.

The promotion of lower carbon technologies

12. This policy objective has been supported by a number of measures that impact the period of review most notably:

(a) The EU Emissions Trading Scheme (ETS) puts a price on emissions of carbon, making electricity produced using fossil fuel technologies more costly to produce. This incentive to minimise carbon production was reinforced by the UK government's introduction of a carbon floor price in 2013.

(b) Two EU directives – the Large Combustion Plant Directive (LCPD) and the Industrial Emissions Directive (IED) – have had a significant impact on coal-fired power stations in the UK. The LCPD set reduced emission limits (from 1 January 2008) for sulphur dioxide, oxides of nitrogen (NOx) and dust. In order to meet these limits, firms had to install flue gas desulphurisation (FGD) abatement equipment.[36] A derogation from the new limit was available to plants, subject to a maximum of 20,000 hours' remaining operating life after 1 January 2008 and closure by 31 December 2015 at the latest. The IED was issued in 2011 (and required transposition into UK law by January 2013). Like the LCPD, it gives coal plants a choice: from 2016 they must either become even cleaner or opt

[36] This is very expensive; installation costs can be more than £50 million per GW of capacity.

to limit their running hours while still closing by the early 2020s. The IED therefore requires retrofitting of pollution abatement equipment by 2023 or closure.

(c) The Renewables Obligation (RO) is a mechanism to provide additional revenue for renewable sources of energy (in addition to the prevailing wholesale market price). It places an obligation on UK electricity suppliers to source an increasing proportion of the electricity they supply from renewables.

13. The EU ETS and the carbon floor price have increased the marginal cost of all generation technologies based on fossil fuels. The impact has been more significant for coal, which produces more carbon per unit of electricity, than for gas. Given that fossil fuels have been the marginal plant for the large majority of the period, this has increased the wholesale price of electricity, increasing returns to non-fossil fuel technologies.

14. The various directives designed to reduce polluting emissions have generally shortened the lives of UK coal plants. Some 8GW of coal-fired plant in GB agreed to close by 2015 (or after 20,000 operating hours) under the LCPD. Given the age of most GB coal plants, in practice most are likely to close by 2023 as a result of the IED rather than invest significant sums in installing abatement equipment.

15. The RO has not had an impact on the wholesale price of electricity (as it operates outside the wholesale market), but it has increased total electricity costs to suppliers and encouraged significant additional investment in renewable technologies, such as wind. This has had two main effects. The first has been to push all other technologies down the merit order, with some plant, such as CCGT, moving from operating as baseload to operating as peaking plant. The second has been to make the pattern of operation of peaking plant more volatile due to the intermittent nature of wind power. As marginal plants need to switch on and off more frequently, this raises their operating costs.

The decline in the price of coal relative to gas

16. Between 2009 and 2013, there was a significant shift in the relative prices of coal and gas, with the former becoming relatively cheaper. As a result, coal plant moved ahead of CCGTs in the merit order, increasing the returns on coal and reducing those on CCGTs.

17. This shift took place as the result of two main factors:

(a) In response to concerns over the Fukushima accident, Japan turned off a number of its nuclear power stations and sought to increase electricity output from CCGTs. This resulted in a significant increase in Japanese demand for gas (liquefied natural gas (LNG)), pushing up the world price.

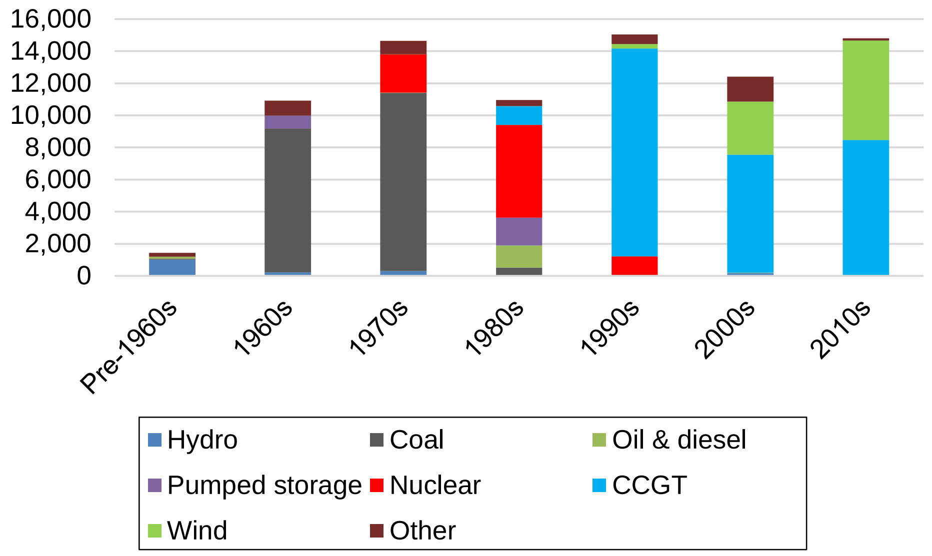
(b) In the US, the discovery of shale gas, combined with restrictions on the export of LNG, resulted in a falling gas price. This encouraged the development of CCGT generation within the US, displacing coal generation. As a result, the price of coal on the world market declined.

Overview of the GB generation fleet

18. Figure 4 shows the composition of the GB generation fleet, by decade of construction. It highlights the move from the construction of coal power stations in the 1960s and 1970s, to nuclear in the 1970s and 1980s, and then CCGTs in the 1990s, 2000s and 2010s. Since 2000 there has also been significant investment in both onshore and offshore wind.[37]

19. Coal-fired power stations tend to have a useful economic life of around 50 years, while CCGTs last for around 25 years. Taking into account upgrades, the existing nuclear fleet is expected to have a useful life of around 45 to 50 years, while Hinkley Point C is expected to have a life of around 60 years.

Figure 4: GB generation mix by technology and year built



Source: CMA analysis of DUKES data.

[37] The graph does not show the recent investment in solar power as this category of energy generation is 'embedded', which means that it forms part of the distribution rather than the transmission network.

Annex C: Replacement costs of power generation assets

1. In order to come to a view on the modern equivalent asset value of various types of generation plant, we examined a range of sources of evidence on the costs of building new CCGT, coal and nuclear power stations. In this annex, we set out the evidence that we collected and how we interpreted this data in the context of our profitability analysis.

CCGT replacement costs

2. We collected evidence on the cost of building new CCGTs from two main sources: *(a)* the Department of Energy and Climate Change (DECC)/Parsons Brinckerhoff data on average capital costs; and *(b)* the firms' information on the total capital costs of recently constructed (ie latest technology) CCGTs. This information is summarised in Figure 1. The red section of the DECC/PB bar indicates the range of estimates given by DECC.

Figure 1: Capital costs of new CCGT (per MW capacity)

[✂]

Source: CMA analysis of DECC/PB and firms' data in DECC (2013), *Electricity generation costs*, Annex 3.

3. We noted that the evidence showed a relatively broad range of construction cost estimates. The DECC figures gave a range of between £505,000 and £720,000 per MW of capacity, excluding financing costs.[38] The information on construction costs ranges from just over £370,000 per MW to almost £770,000 per MW, with a weighted average across the five projects of just over £500,000 per MW.[39] These estimates were based on the gross book value of the assets in the firms' balance sheets and were, therefore, likely to reflect the capitalised interest costs associated with financing the construction of the assets.[40]

4. For the purposes of our analysis, we considered it appropriate to include the full opportunity cost of financing the construction of assets which is calculated using the WACC of the business rather than the interest cost (cost of debt). Our estimate of the (pre-tax, nominal) WACC of a generation business was approximately 9%. On the basis that a CCGT takes approximately two years to plan and three years to construct, and that most of the capital is committed only during the construction phase, we estimated that the opportunity cost of

[38] DECC (2013), *Electricity generation costs*, pp21–22.
[39] The weighted average has been calculated by adding up the total build costs of all the plants and dividing them by the total capacity constructed over this period.
[40] International Accounting standard 23 (IAS23) permits the capitalisation of the interest costs incurred in financing the construction of assets but does not permit the capitalisation of the opportunity cost of capital, which is measured by a firm's WACC (rather than its interest costs).

financing would add approximately 13.5% to the total cost of a new CCGT.[41] Increasing all of the above costs by 13.5% gave a DECC range of £575,000 to £815,000 and a weighted average of the actual construction costs of £570,000. We observed that the latter calculation may have included some element of double-counting as the figures used were likely to include some capitalised interest costs. On this basis, we considered that a 'new' replacement cost of approximately £600,000 per MW of CCGT capacity provided a relatively conservative estimate. This placed more weight on the lower end of the DECC range as this was supported by the evidence of actual build costs.

5. In order to estimate the depreciated replacement cost of the firms' CCGTs, we took this estimate of £600,000 and multiplied it by the capacity of each of the firms' CCGT assets. We then depreciated the 'new' replacement cost on a straight-line basis over the life of the asset. For modelling purposes, we took the latter to be the plant's actual life (where it closed during the period) or 25 years.[42]

Coal replacement costs

6. There was more limited information available on the cost of building new, coal-fired power stations without CCS. The DECC report does not provide any such cost estimates and no new coal-fired power stations were constructed in GB during the relevant period. However, we observed that a number of coal-fired power stations have been built in recent years in Germany and the Netherlands and that these might be used to estimate the replacement cost of the GB coal fleet. These costs are summarised in Figure 2.

Figure 2: Capital costs of new (non-CCS) coal-fired power stations (per MW capacity)

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Source: CMA analysis of company information.

7. The weighted average construction cost per MW for these seven plants was £1.27 million.[43] These figures are not on a consistent basis, with E.ON's figures excluding capitalised interest costs, while those of GDF included capitalised interest.[44] We have taken the conservative approach of assuming

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[41] DECC (2013) *Electricity generation costs*, p55, provides these estimates of the development and construction timeframes for a CCGT plant. In the same report, on p57, DECC's cost estimates indicate that the large majority of capital is committed during the construction rather than the pre-development stage. The 13.5% figure assumes that the capital is committed evenly over a three-year build period, ie 3 years × 50% of total capital × 9% = 13.5% of total capital cost.
[42] This assumption of a 25-year useful economic life (UEL) was based on the views of the energy firms as to the UEL.
[43] We based this on a €:£ exchange rate of 1.25:1.
[44] It was not clear whether RWE's figures included or excluded capitalised interest costs.

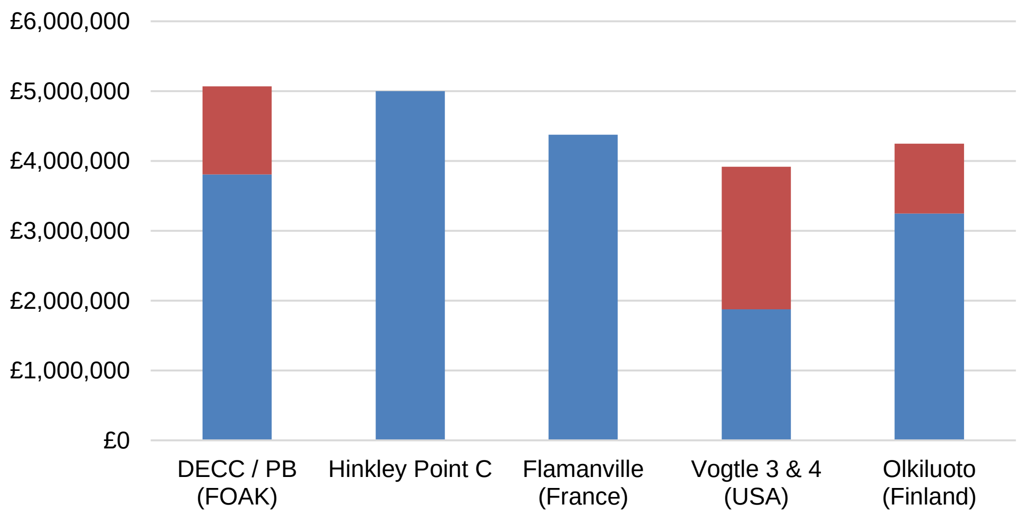
that these figures are quoted excluding capitalised interest and sought to reflect the opportunity cost of financing in the same way as for CCGTs. The DECC report indicated that new-build coal power stations (albeit with CCS) generally had a construction period of between five and six years. On this basis, we increased average build costs by 22.5% to reflect financing costs to give a total 'new' replacement cost of £1.56 million per MW of capacity.[45]

8. In order to estimate the depreciated replacement cost of the firms' coal-fired power stations, we took this estimate of £1.56 million and multiplied it by the capacity of each of the firms' (coal) power stations. We then depreciated the 'new' replacement cost on a straight-line basis over the life of the asset. For modelling purposes, we took the latter to be either the plant's actual life (where it closed during the period) or 50 years.[46]

Nuclear replacement costs

9. We collected two types of evidence on the cost of building new nuclear power stations: *(a)* DECC estimates of total construction costs; and *(b)* the estimated build costs of a number of nuclear power stations which are either currently under construction or on which construction will start shortly. These costs are summarised in Figure 3. The red segments of the bars indicate where a range of estimates is provided.

Figure 3: Capital costs of new nuclear power stations (per MW capacity)



Source: CMA analysis.

[45] This was calculated as half the total build cost being employed over the five years of construction multiplied by the WACC of approximately 9%. In effect, this assumed that the capital employed in a plant is built up from zero to the full construction cost evenly over the period of construction.
[46] This 50-year assumption was based on the firms' own estimates of the UEL of a coal-fired power station. These ranged from around 43 years to over 60 years (where upgrades have been put in place). We considered that a 50-year life span was a reasonable 'average' estimate.

10. In the first instance, we noted that the information collected on build costs was less reliable than that collected for CCGT and coal since it was based on forecast costs rather than those actually incurred, with the potential for actual costs to be higher or lower than these estimates. In this respect, the Flamanville information appeared to be the most reliable as this site was at the time close to completion and was expected to be operational from 2016. Second, we noted that the DECC, Hinkley Point C and Flamanville figures did not include any financing costs (capitalised interest). The European Commission estimates that these costs may increase the total capital employed at Hinkley Point C from £16 billion to £24.5 billion.[47] As explained above, we did not consider that capitalised interest costs fully capture the opportunity cost of financing the construction of an asset for the purposes of our profitability analysis. However, applying a similar approach as for coal and CCGT indicated that total build costs would be increased by approximately 24% once the opportunity cost of capital is taken into account, giving a total capital employed of £20 billion.[48] Given the significant uncertainty over total build costs and the length of time required to complete the project, our view was that the £20 billion figure represented a reasonable estimate and was consistent with the approach that we took to estimating the replacement costs of CCGT and coal assets. On the basis that Hinkley Point C would have a capacity of 3,200 MW, this equated to a replacement cost per MW of capacity of £6.25 million.[49]

11. In order to estimate the depreciated replacement cost of the nuclear fleet, we took this estimate of £6.25 million and multiplied it by the capacity of each of the existing nuclear power stations. We then depreciated the 'new' replacement cost on a straight-line basis over the life of the asset. For modelling purposes, we took the latter to be 45 years.

[47] European Commission (8 October 2014), *State Aid: Commission Concludes Modified UK Measures for Hinkley Point Nuclear Power Plant are Compatible with EU Rules*.
[48] This was calculated as half the total build cost being employed over the six years of construction (DECC (2013), *Electricity Generation Costs* estimate) multiplied by the WACC of approximately 8%.
[49] EDF Energy, *Hinkley Point C*.