

## **Energy Market Investigation:**

# **Centrica's Non-confidential Response to the CMA's Provisional Findings and Notice of Possible Remedies**

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## Executive Summary

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1. We recognise and accept many of the CMA's Provisional Findings (PFs), including those on the adverse effect of regulation on competition in GB energy markets. We also support the provisional finding that competition in wholesale electricity and gas markets is generally effective and that vertical integration may create efficiencies that benefit consumers. However, as discussed at our Response Hearing, there are a number of important areas where we disagree with PFs and urge their reconsideration before the CMA's final conclusions and remedies are settled.
2. They include misconceptions regarding the state and level of customer engagement and the effectiveness of retail competition. We also consider a number of the assumptions underpinning the CMA's provisional findings on profitability to be unsound and not reflective of the market realities we and our competitors actually face.
3. That is not to say that retail market competition could not be improved. Indeed we support many of the CMA's proposed remedies, including the practical measures to improve customer engagement from its current level, and the removal of regulatory inhibitors of competition. But the Remedy 11 proposal to re-regulate by way of imposing a so-called "safeguard" tariff cap is unnecessary, would weaken incentives for customer engagement, and would contradict the CMA's competition objectives.
4. Instead, we propose that ending evergreen tariffs (in conjunction with other pro-competitive measures) would be a bold market-oriented remedy package that would address the issues identified by the CMA without the severe risk of unintended consequences associated with Remedy 11.

### ***Assessment of customer engagement***

5. Since liberalisation in 1998, competition in the GB retail energy market has evolved and continues to evolve in response to changes in the regulatory framework, technological innovation and customer preferences. The retail market has also adapted to periods of intense wholesale market volatility (e.g. in 2008 and early 2013).
6. Over this period, most indicators have suggested that competition has been effective. Retail energy prices have consistently been amongst the lowest in the EU<sup>1</sup>, consumers now have the widest ever range of suppliers from which to choose, with a total of 29 retail suppliers now competing in the domestic retail market, and with levels of switching rising. Indeed, in recent years the pace of change has significantly accelerated, with the advent of smart meters which are facilitating changes in energy consumption management and have the potential to transform the fabric of underlying industry systems and processes.
7. So while we support the CMA's principles of improving the framework for competition and facilitating wider and deeper customer engagement, we consider that any form of re-regulation (along the lines of candidate Remedy 11) is inappropriate and disproportionate and would slow down the current trajectory of competition, contrary to the interests of consumers and indeed of the competitive process that the CMA exists to protect and promote. A strength of the provisional findings is the CMA's analysis of

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<sup>1</sup> For example, GB domestic gas prices have been lower than the EU15 median over the last 15 years.

- how some regulatory intervention to date has had unintended adverse effects on competition; Remedy 11 risks repeating this error.
8. The CMA's PFs have identified weak customer response as being the primary area of concern. Customer engagement is therefore a central theme in the PFs. While we submit that many aspects of the PFs relating to the current state and level of customer engagement (including the CMA's interpretation of its own customer survey and gains from switching results) are flawed, we support practical measures to improve it further.
  9. However, we do not consider that we have – still less that we exploit – unilateral market power over our least active customers, or more generally through the pricing of our domestic Standard Variable Tariff (SVT). We face strong competition for all of our customers, many of whom are on SVT, and we gain and lose around two million customer accounts every year.
  10. There continues to be effective new entry with smaller and mid-tier market share increasing from around 2% to 10% in just two years.<sup>2</sup> This trend continues today, with 44% of the 1.1 million gas and 1.4 million electricity customers switching between January and June 2015 moving to small and mid-tier suppliers.<sup>3</sup> All of our products are open to all of our customers and are designed to facilitate both external and internal switching. In 2014, [3<] of our customers chose to switch tariffs within the British Gas brand. Customers are also able to choose from a wide and increasing range of price comparison websites (PCWs) to compare competitive deals, including 12 accredited PCWs.
  11. The interpretation of the CMA's customer survey is selective and does not provide evidence of notably weak customer engagement in the sample of customers surveyed (especially in comparison with other sectors of the retail economy). Awareness of switching was very high (89% of customers stated they knew they could switch), confidence in the switching process was good (89% of customers that chose to switch had no difficulty in switching) and customers had little difficulty in comparing tariffs (76% of customers found no difficulty when shopping around).
  12. More specifically, our experience is that customers positively value our SVT product. We recognise that under the current unusually benign and falling wholesale markets we have seen unusually large price differentials open up between SVT and products hedged on a shorter term basis. But as the CMA recognises, the relative pricing of SVT and non-standard tariffs naturally varies through the commodity cycle, with SVT terms sometimes appearing cheaper and at other times more expensive than other products offered in the market (which themselves will change in nature as the commodity curve moves and regulatory restrictions come and go).
  13. Therefore we do not accept that customers do not value the SVT and its implicit assumption that customers choosing SVT products are relatively unengaged. Our 2014 full year data shows this is not the case [3<]. We believe that the failure of the PFs to take proper account of this issue and the evidence relating to it, in particular the impact of dynamic commodity market conditions on pricing,<sup>4</sup> is a serious weakness that must be remedied before the CMA's final conclusions are reached.

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<sup>2</sup> <https://www.ofgem.gov.uk/publications-and-updates/infographic-bills-prices-and-profits>

<sup>3</sup> *Ibid.*

<sup>4</sup> Provisional Findings, p.27, para.115 (a).

## **Measures to improve engagement**

14. While we do not agree with the CMA's findings regarding the nature of customer engagement in the retail market, we do support practical measures that have the prospect of improving engagement further, and which promote the continued development of effective competition in the retail market. We believe that many of the CMA's proposed remedies could enhance and further accelerate the existing level of competition in this market. Indeed, some – such as the removal of licence conditions introduced following Ofgem's Retail Market Review (RMR) – could lead to a step-change in innovation and commercial creativity in the retail market.
15. We support the core principles the CMA has used to select possible remedies – namely providing the framework for effective competition and facilitating widespread customer engagement. However we also note the CMA has considered “whether it may be necessary” to provide transitional safeguards for disengaged customers. The need for such measures would reflect a partial failure of competition, and as described below, we do not believe such an intervention is necessary. We therefore believe the focus should be on the first two priorities, with safeguards only considered if and when the other measures introduced by the regulator fail.
16. Subject to that, we support many of the remedies set out in the Remedies Notice. In particular:
  - Removing the “simpler choices” component of the Retail Market Review (RMR) would be beneficial to competition.<sup>5</sup> It would allow suppliers to compete fully by developing ranges of products to target competitors' customers. To be fully effective this remedy should also include the removal of limits on what can be bundled with tariffs, and remove the ban on cash discounts to encourage greater innovation and differentiation.
  - Reducing informational barriers to engagement would also be a positive step. This could be achieved by removing the prescriptive regulations introduced through the “clearer” component of RMR. Instead, Ofgem's focus should be an outcomes-focused approach to regulation underpinned by the Standards of Conduct, enabling information provision to become a point of competitive differentiation. Specifically, we believe that bill design should be driven by customer research rather than detailed regulation. The regulatory requirements to provide Cheapest Tariff Messaging and explain Ofgem's Tariff Comparison Rate on sales calls are also unnecessary, restrictive and burdensome, and should be removed.
  - We support measures that facilitate greater competition between PCWs for the benefit of consumers. The removal from the Confidence Code of the requirement to show all tariffs would increase competition by enabling bilateral deals with specific suppliers. However it is important that the Code ensures that PCWs are transparent in the service they provide, specifically about whether they carry all tariffs in market and whether different levels of commission are earned for promoting different tariffs/suppliers. We strongly disagree with the proposal for Ofgem to provide a whole-of-market price comparison service, on the basis this would crowd out more effective market-driven services, may undermine customer trust in PCWs, and would

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<sup>5</sup> Ofgem introduced three packages of regulatory restrictions and requirements as a consequence of RMR; “simpler”, which related to tariffs, “clearer” which related to information provision and “fairer” which introduced Standards of Conduct as a licence obligation.

confuse Ofgem's proper market oversight role with that of central market player. The cost of such a service would also ultimately be borne by all customers through Ofgem's licence fee (rather than being paid for by consumers of the service, which would be the case if provision was left to the market). In principle, we do not consider it is appropriate for the Regulator to play such a role in a liberalised market.

- We very much agree with the CMA's views regarding smart meters as an enabler of greater engagement and ultimately customer satisfaction. This is demonstrated by the fact that smart customers are more likely to be on a FTC (when compared to customers with standard meters), benefit from reduced consumption and engage with smart tariffs. We are absolutely committed to meeting the Government's deadline for supplier roll out, and encourage the CMA to continue to seek assurance that this deadline will be enforced. As requested at our Response Hearing we have prepared a separate section in the Appendix that sets out details of the benefits of smart meters for energy consumers.
- While we support the principle of the CMA's possible remedy to prioritise smart meters to prepayment (PPM) customers, we do not support Remedy 5 as proposed. Instead a requirement to provide no further "dumb" prepayment meters would be more cost effective and feasible. This is largely due to smart PPM being a relatively immature technology, and commercial incentives to prioritise smart PPM already exist.
- Similarly the possible remedies for microbusinesses set out in Remedies 7 and 8 would be broadly helpful as they would improve transparency and enable greater engagement. In particular, we strongly support the need for a robust Third Party Intermediary (TPI) Code of Practice which explicitly mandates upfront commission transparency, as this will enable customers to engage in an informed way.

### ***Measures to prompt customers on default tariffs***

17. We believe the combined effect of the measures outlined above would have significant potential to increase engagement. However, our experience suggests that one of the most powerful triggers for engagement is the process customers go through when they come to the end of a fixed term contract. The power of this trigger is developed but not fully harnessed under the CMA's current proposals.
18. Although we do not recognise the existence of unilateral market power in SVT in the PFs, we believe the mandated withdrawal of evergreen tariffs from the market would be a bold measure that would improve customer engagement. By this we mean:
  - Introducing a ban on acquiring new customers onto evergreen contracts, from a specified date; and
  - The phased notification of contract end dates to customers currently on evergreen contracts.
19. This major change in the way the retail market functions would expose customers currently on evergreen contracts to a series of strong trigger points. Moreover, this remedy would create a constant dynamic in the market by changing customers' attitudes towards energy such that they see it as a product in which they should engage on a regular basis as is the case, for example, with insurance products. Suppliers would be required to inform affected customers that their current tariff was

- ending, and that they must review their choice of tariff. Other communication (e.g. regular prompts) would provide a further series of calls to action.
20. The termination of evergreen contracts would need to be phased, so as to create sufficient opportunity for the prompts and new “market pull” remedies to work and create a sustainable competitive market. In addition, a phased approach would help to prevent customer disruption and an associated increase in industry wide costs due to the increase in customer contact requirements (something which the CMA has already recognised should be minimised).
  21. We believe such an approach would have a material impact on the engagement of customers who are currently on evergreen contracts (typically SVT), by accelerating the improvement in engagement that is already occurring in the market (and that will be further enhanced by the other remedies). It will do so by exposing them to a series of escalating prompts to take action before mandatory migration onto a fixed-term tariff if the customer nevertheless makes no choice.
  22. Our analysis suggests that under this model, within three years no customers will be left on evergreen SVT, and the majority of current customers will have switched to another supplier or non-standard product, or else have made a deliberate, active choice to stay on SVT terms.
  23. We have based this assessment on our experience of levels of switching that we currently observe at the end of fixed term contracts, overlaid with our assessment of the impact of smart meters and a sustained period of high profile switching-related advertising and media activity during the transition period. Engagement may well be even higher in a market where there are fewer regulatory constraints, which currently limit product innovation and segmentation. Over time, this awareness would be further enhanced by the rollout of smart meters which, as the CMA notes, has the potential to increase customers’ awareness and interest in their ability to switch.<sup>6</sup>
  24. A residue of customers may still fail to take action even after multiple prompts. For those who do fail to respond, we recognise the need for provision of default tariffs onto which they automatically move. This is because, unlike other industries, customers do not have the option of stopping their consumption of energy.<sup>7</sup>
  25. We suggest that the form of the default should be a one-year variable price, fixed term contract, without exit fees. To minimise distortions to competition, this default tariff should be set by suppliers. Under our proposal, there will be public and regulatory scrutiny of the tenure of customers on the default tariffs and the level of pricing. Suppliers will therefore be strongly incentivised to encourage customers to switch away from the default tariff. Should these incentives need to be strengthened further, any customers who still remain on the default after a year – despite ongoing supplier prompting – could receive a further prompt from the regulator to switch to another tariff or supplier, or the regulator could request the supplier to make additional contact citing regulatory concern.
  26. We expect this transparency, combined with strong competition for the residue of customers who remain on this default as the other remedies take effect, to provide sufficient safeguard for pricing without the need for prescriptive regulation.

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<sup>6</sup> We set out further views on the positive impact of smart meters on customer engagement in the ‘smart’ section of our Appendix.

<sup>7</sup> Nor can they be disconnected, except in specific circumstances.

### ***The regulated 'safeguard' tariff proposal***

27. We consider the regulated safeguard tariff as proposed in Remedy 11 to be the wrong approach and fundamentally incompatible with the CMA's objective of stimulating competition in the market. Were the CMA to proceed with this remedy, we have serious concerns that the market distortions it would introduce would be counter-productive – damaging, rather than promoting, engagement.
28. Even though intended to be a transitory measure, we believe a regulated tariff is highly likely to become a permanent feature of the market. This is because this tariff will be viewed as being specifically protective of consumers. It will therefore blunt if not remove any incentive for them to shop around further, which could also weaken competitive pressure in the marketplace more widely. Once introduced, a cap will also be very difficult for a regulator to remove, not least due the risk of political interference.<sup>8</sup>
29. This risks an enduring and unnecessary shift towards regulation rather than the stimulation of further competition in the retail market, and would be a step backwards from the past 17 years of broadly successful liberalisation of retail as well as wholesale competition. The nature and scale of the intervention, potentially affecting a wide swathe of consumers due to the safe haven effect explained below, creates a major risk to the competitive market as it stands and its future development.
30. Setting the level of any tariff cap would prove extremely difficult as recognised by the CMA. Such a tariff is likely to reduce engagement and switching, with customers viewing the regulated tariff as a “safe haven” (if set at a “low”, or even at a “correct” level) as was observed in New South Wales<sup>9</sup>. If set at a relatively high level, a tariff cap may have limited impact on supplier pricing or even distort supplier pricing, potentially leading to tariff “bunching” at or very near to the cap. The difficulty of identifying the relevant baseline price level – and then going on to identify the appropriate level of “headroom” – is inextricable. This insolubility of the problem of how much “headroom” to create is an indication that such a remedy will be fraught with difficulties.
31. In summary, we believe any consideration of a safeguard tariff set by the regulator is held in abeyance until the consequences and functioning of other remedies, including supplier default tariffs, and the size of any ‘residue’ of inactive customers, are known. We believe in a well functioning competitive market, it is likely that the other remedies will function well and the residue will be small. In such a scenario, a regulated safeguard would not be necessary so avoiding price regulation, something the CMA has indicated it is not minded to pursue – and indeed which would undermine progress towards the CMA's desired outcome of increased customer engagement. Ending evergreen, in conjunction with other remedies to promote active choice, would go a long way to achieving the aims of Remedy 11 in a pro-competitive manner and without the clear risk of its unintended consequences.

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<sup>8</sup> See “Submission on Summary of Provisional Findings”, Littlechild et al, p.10, para.44 and “Penalty tariffs, open-ended regulation and embedding overcharging”, Helm, p.19, para.71.

<sup>9</sup> See our response to Remedy 11 below which includes a case study on New South Wales.

## **Profitability**

32. Ultimately, in a competitive and well-designed market, profitability will be an outcome of the competitive process. Therefore while we disagree with the CMA regarding important aspects of its profitability calculations, our primary focus is on competition and stimulating the market appropriately.
33. That being said, we wish to stress that we do not believe that the analysis of profitability and margins in the PFs is sufficiently robust to support a conclusion that excessive profits are being earned in retail markets. We have serious concerns about the validity of some of the assumptions that drive all three of the CMA's profitability analyses (ROCE, price benchmarking, and EBIT benchmarking). The analysis is highly sensitive to small and reasonable adjustments to assumptions - and a number of these assumptions are inconsistent with commercial reality. These concerns are so serious we do not believe the analysis would stand up to rigorous peer review.
34. In particular:
- Assuming a "scaled up" industry-wide intermediary fee model is not credible, and is not a reasonable proxy for the real level of risk capital that would be necessary to manage commodity market risk (whether that is done by an intermediary or the supplier itself);
  - The intermediary fee model also appears to make unrealistic assumptions about the extent to which such agreements would provide a credit facility that could be used to manage residual business risks;
  - The price benchmark analysis is based on an unrealistic depiction of an efficient market, e.g. assuming suppliers can benefit from commodity price hindsight in choosing their procurement strategy;
  - The ROCE and price benchmarking analyses and EBIT comparisons all fail to make necessary adjustments to take account of the ways in which risk and capital requirements vary between different customer groups (in particular domestic versus SME) and products (in particular gas versus electricity, but also e.g. fixed price versus variable price products); and
  - The analysis in many places excludes consideration of periods prior to 2009 when commodity costs reflected relative scarcity and volatility: the data and business model underlying the PFs therefore do not capture the full range of market conditions that suppliers need to be able to deal with across a normal commodity cycle.
35. Several of these assumptions affect more than one of the analytical approaches in the PFs. So the CMA cannot "gain assurance that different sources of evidence on profitability give broadly consistent results": the three methodologies employed are interrelated and rely on the same fundamentally flawed assumptions. We do not consider therefore that the CMA can place significant reliance on this analysis in its current form in coming to its final conclusions, in particular of any potential consumer detriment and consequences for the selection and design of remedies.

## **Regulatory framework**

36. We share the CMA's view that robust and transparent regulatory decision-making is necessary to avoid the risk of future policy decisions having an adverse effect on

competition. We therefore support a revision of Ofgem's Duties to clarify the primacy of competition as the best way of protecting consumers' interests.

37. Measures to improve the transparency of policy decision making by DECC and Ofgem would be similarly helpful. We believe impact assessments should be at the core of policy decision making, and are an essential part of a transparent consultation process. They should be quantified wherever possible. Such principles are already a feature of other regulatory processes.<sup>10</sup> We would therefore support the appointment by Ofgem of a Chief Economist, with specific responsibility for ensuring policy decisions are supported by robust impact assessments.
38. We believe the movement towards principles based regulation (and away from prescriptive regulation) has the potential to enhance competition – but only if implemented appropriately. In this regard, Ofgem's approach to the definition of fairness will be crucial. Specifically, we do not believe that a "fair" outcome is necessarily a "standardised" outcome. Customers who invest more time in trying to find a price or product that best suits their budget or needs should be able to choose products that suit those needs, even if that results in outcomes that differ from the average customer.

### **Wholesale Markets**

39. Finally, we support the CMA's provisional findings in respect of wholesale gas and electricity market competition. We find that the wholesale energy markets are generally effective, and agree there is no evidence to support a finding of unilateral market power. We also agree that vertical integration does not create an adverse effect on competition – and indeed that vertical integration may create efficiencies that benefit consumers. These findings represent an important marker for future reference.
40. In respect of wholesale electricity market rules and regulations, we agree that the GB self-dispatch system does not reduce price transparency, increase transaction costs or give rise to systematic technical inefficiency. We also support the principle of introducing locational prices for transmission losses. However, such a scheme must send appropriately cost-reflective price signals, and be sufficiently robust to market and network dynamics. We also agree with the CMA's provisional findings on the allocation of Contracts for Different (CfDs), as we are supportive of measures that will improve transparency in CfD allocation.
41. The remainder of this document sets out Centrica's more detailed views on the CMA's Provisional Findings, Notice of Possible Remedies and associated appendices. It is split into two main sections:
  - A Response to the Provisional Findings; and
  - A Response to the Notice of Possible Remedies.
42. In addition, more detailed responses to elements of the CMA's documents are provided in an Appendix. These are referred to in our response where appropriate.

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<sup>10</sup> For Ofcom's approach, see [http://stakeholders.ofcom.org.uk/binaries/consultations/better-policy-making/Better\\_Policy\\_Making.pdf](http://stakeholders.ofcom.org.uk/binaries/consultations/better-policy-making/Better_Policy_Making.pdf)

## Response to the Provisional Findings

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### Domestic retail competition

43. In this section we respond to the domestic retail section of the provisional findings. Specifically, we cover:
- The nature of retail competition;
  - Customer activity and engagement;
  - Gains from switching;
  - Price discrimination; and
  - Regulations.
44. Overall, Centrica recognises and accepts many of the CMA's provisional findings, including those on the effect of regulation on competition in GB energy markets. But we believe that some important provisional findings are based on a fundamental misconception of the nature of retail competition in the presence of wholesale price and demand volatility. In the PFs, the CMA sets out that it would expect competition in “a well-functioning retail market” to be largely focused on price, with competitive pressures forcing suppliers to focus on costs, and deliver a minimum standard of customer service. The suggestion is that the GB retail market is not competitive and does not function well.
45. This view contrasts sharply with our day-to-day experience of the retail market and in particular we fundamentally disagree with the hypothesis that we have unilateral market power over our SVT customers. Indeed, we believe the CMA's conclusions are driven by a number of fundamental mischaracterisations of the operation of the energy market. In particular:
- **Evidence of customer disengagement:** The CMA characterises its assessment of gains from switching as evidence that certain products *consistently* offer poor value. However, this fails to recognise that this rolling snapshot analysis cannot capture longer term outcomes for consumers (e.g. the fact that a consumer switching from an SVT that has not yet cut price to one that has already done so might save money by switching back to their initial product choice in the following quarter). Moreover, the failure to control for important product characteristics (e.g. online only or payment in advance) *in addition to* payment and tariff types means that the analysis in the PFs in fact only calculates gains from switching that can be obtained in return for switching to a product with *different characteristics*. This cannot be assumed to be evidence of disengagement: customers may simply value the characteristics of their current product more highly than the gains from switching. When truly like-for-like products are compared, gains from switching fall to around £60 in the most “like for like” comparison<sup>11</sup>.
  - **Interpreting price differences across products:** Despite characterising electricity and gas products as essentially homogeneous, the CMA does recognise that the SVT product offers consumers smoothed prices, and that the pricing of this product

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<sup>11</sup> See the Second Data Room Report submitted by CRA (our economic advisors).

reflects the costs incurred in using a hedged procurement strategy.<sup>12</sup> However, the PFs nonetheless go on to characterise a competitive market as one in which all products should be priced off the immediate forward curve (i.e. as if all commodity for that customer's expected needs over the next year were to be purchased in one shot), which fluctuates considerably.<sup>13</sup> The fact that SVT prices follow a smoother path than this would suggest (in particular that they have fallen less fast in the last 18 months) is then interpreted as a failure of competition. It is important to recognise that the 1 year forward purchase cost is more volatile than costs underlying SVTs not only because of the longer time horizon over which SVTs are typically hedged (buying up to 24 months or more ahead), but *also because those purchases are made on a rolling basis over a long period of time.*<sup>14</sup> The CMA therefore appears to promote a view of a competitive market as one in which prices should be significantly more volatile than has been seen to date. But this fails to recognise that many of our customers actively choose our SVT product: and we believe this price smoothing feature is one of its key attractions for consumers.

- **The importance of a full commodity-cycle view:** The analysis in the PFs is very heavily driven by experience of the last 2-5 years: a period of unusually benign (and recently falling) commodity prices – and uses evidence from these short recent periods to draw conclusions on pricing and profitability that its own data show do not apply over a longer period. For example, the apparent assumption that non standard tariffs (NSTs) are essentially discounted products fails to recognise that this is only the case at some points in the commodity cycle:<sup>15</sup> when commodity costs are increasing then hedged SVT products will often offer lower prices.<sup>16</sup> Basing conclusions on the competitiveness of current market conditions, rather than a full assessment of competitive dynamics over the course of the commodity cycle, risks creating “solutions” that worsen market outcomes when commodity market conditions change.
- **An unrealistic view of the costs of risk transformation:** We strongly disagree with the CMA's assessment of the costs of translating volatile commodity costs into a smooth price available to consumers for whatever volumes they choose to take on a given day. As we set out in our comments on profitability, in our view the assessment in the PFs fundamentally understates the working capital and risk capital required to support this price and volume risk transformation (whether such capital is held by the supplier itself or by an intermediary in return for a fee). Although we have not been provided with a clear description of the hypothetical service to be covered by this estimated fee, the CMA's findings appear to rely on an assumption that (a) the fee would be substantially lower than standard risk pricing models would suggest, and (b) that the intermediary would also provide (at no incremental cost) a large credit facility that the standalone supplier could use to manage residual business risks. As we set out below, these assumptions do not fit with standard approaches to risk pricing or our experience of the types of bespoke contracts that the PFs appears to be using as a benchmark (e.g. based on our experience of entering into similar arrangements ourselves in the US – both as a customer and a supplier).

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<sup>12</sup> Provisional Findings A7.2-26 paragraph 74.

<sup>13</sup> Provisional Findings 7.153.

<sup>14</sup> See Figure A on page 4 of Centrica's response to the CMA's Working Paper on Cost Pass Through for an illustration of the relative volatility of a 24 month rateable strategy versus a 12 month forward purchase.

<sup>15</sup> See for example Appendices 7.2 (Cost Pass Through) and 8.4 (Price Discrimination) to the Provisional Findings.

<sup>16</sup> See the Data Room Report for a year-by-year examination of the CMA's SVT versus NST price comparison.

46. We have a number of other concerns over the approach taken to the competitive assessment in the PFs, which are set out below. However, it is these themes that run throughout the PFs. We believe that each of them is based on a fundamental misreading of the market, and results in the CMA coming to an unduly pessimistic reading of the current competitiveness of the market and an over-interventionist approach to remedies (notably Remedy 11). We are concerned that, unless revised before the CMA settles its final conclusions, this may well result in interventions that stifle rather than promote competition.

### ***The nature of retail competition***

47. We face strong competition for our current customers, and consider our customer base to be generally dynamic and engaged. We gain and lose around two million customer accounts each year, and 70% of our current dual fuel customers joined British Gas subsequent to liberalisation. Our single fuel customers are served not only by us but also by one of our competitors; both we and the rival would like to win their dual fuel custom. Energy customers have never had a wider selection of energy suppliers from which to choose (29) or price comparison websites (14 of which 12 are accredited).
48. The structure of the market also continues to evolve rapidly. Smaller new entrants continue to gain a firm foothold in the market, and these suppliers (including small and “mid-tier” suppliers) are now a significant and increasing competitive force in the market. Latest data from Ofgem show that 1.1 million gas and 1.4 million electricity customers switched between January and June 2015, and 44% of these customers moved to a small or mid-tier supplier.<sup>17</sup>
49. Looking back over the 17 years since liberalisation, we also consider competition has worked well in the face of – at times – highly volatile commodity markets, a constantly changing regulatory framework and technological innovations. In our response to the Updated Issues Statement, we described this in terms of four phases of the evolution of the market. As the rollout of smart meters continues, we believe the market will continue to evolve rapidly, given the proven ability of smart meters to accelerate customer engagement and change the fabric of underlying industry systems and processes.
50. The CMA suggests that gas and electricity are “extreme examples of homogenous products”, that such products are unaffected by consumers’ choice of supplier, and that price should be the most important characteristic in supplier or tariff choice. We take a fundamentally different view to the CMA on this issue. We are in the business of providing retail energy packages to consumers in response to their diverse needs and preferences, not homogeneous gas and power. We constantly seek to differentiate ourselves from our competitors through providing our customers a combination of tariffs that manage price volatility while offering excellent customer service, a range of differentiated standard and innovative products (including a choice of different levels of price protection/smoothing), and competitive pricing across all our products. In particular we offer:
- A range of propositions (some of which are highly innovative, such as our Fix & Fall November 2013 tariff that attracted [3<] accounts, our Fix & Control tariff that

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<sup>17</sup> <https://www.ofgem.gov.uk/publications-and-updates/infographic-bills-prices-and-profits>

includes a free Hive thermostat and our Fix & Gift Card that includes a £50 high street voucher), including different customers' levels of willingness to take on the risks associated with volatile energy costs (with some products offering a more smoothed price profile over time than others);

- Effective control of their energy consumption, through online consumption analytical tools, 'Smart Energy Reports' (for our customers with smart meters) and devices such as Hive Active Heating;
- A range of payment options, from paying in arrears by cash or cheque, prepaying through a meter, or regular payment schemes such as Direct Debit; and
- Accurate information in formats which our exhaustive research demonstrates customers understand and prefer (although prescriptive regulation continues to be a material constraint in this aspect of competitive differentiation).

51. This is a view seemingly supported by the CMA's customer survey (covered in more detail in the next section). This shows that consumers' choice of supplier is not only driven by price, but by a range of factors which are also considered essential or very important to customers, such as good customer service (83%).
52. The existence of service differentiation in energy also calls seriously into question the CMA's view (in paragraph 7.153ff) that prices in a competitive energy market should reflect only forward-looking costs. If the CMA's assumption were correct, retail prices would continually be changing in response to expected cost movements in wholesale commodity markets. But most customers in reality place value on products that insulate them from volatile commodity markets without locking them into a long fixed term contract. We believe the apparent assumption that price smoothing is of little value to customers is incorrect, as evidenced by the number of customers who actively choose our SVT. Yet the cost of providing these smoothed price products is a rateable hedging strategy that requires significant working and risk capital, and the cost of that capital will be reflected in prices in a competitive market.
53. Finally, we note the CMA's finding that there is no evidence of tacit coordination amongst domestic retail energy suppliers. This is consistent with our view that the conditions in the market do not allow for tacit coordination and that suppliers' motives in relation to price announcements are unilateral.

### **Customer activity and engagement**

54. The CMA's provisional findings have identified weak customer response as being the primary area of concern. Customer engagement is therefore a central theme in the PFs, with many of the CMA's conclusions being based on its interpretation of the nature of customer engagement, in particular based on information from the customer survey. This is another area in which we have a very different perspective to that of the CMA, and again we wonder whether the CMA may be measuring commercial reality against an unduly theoretical benchmark.<sup>18</sup>
55. The CMA places significant weight on a number of data points drawn from the customer survey to support its finding of a general lack of engagement amongst retail customers. We accept that the customer survey provides a useful means by which to

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<sup>18</sup> Please see Paragraph 4 and Annex A to our response to the Survey Working Paper, which included a comparison of survey results from a range of somewhat similar industries and found that measures of customer engagement in relation to energy are in many cases similar or better compared with these other markets.

assess consumer searching and switching behaviours in the GB residential market. However, we believe that some important conclusions the CMA draws from it do not reflect the balance of evidence, and are not always supported by the results.

56. In particular, we consider that the customer survey supports a finding that level of engagement in the energy market is relatively high compared with how other relevant markets work in practice. There appears to be a high awareness of the ability to switch (89%), strong confidence among customers surveyed that they would make the correct decision when switching (70%) and satisfaction with current supplier (73%).
57. Nearly half of customers in the survey had either switched or considered switching in the past three years and, of those who did switch, 89% found no difficulty in doing so. Even if some consumers expect switching to be difficult, the experience of customers who have switched appears to suggest that in reality it usually goes smoothly.
58. We also have concerns that the survey underestimates the real level of switching as some customers appear to forget that they actually switched. For example, almost 4 in 10 of those reporting they had never switched in the survey were shown to have switched according to the underlying supplier data. Including these customers as having switched would raise the proportion of customers who had switched from 44% to 61%. Additionally, almost one third of the 54% of customers who said they had never shopped around had in fact switched supplier according to the underlying supplier data, while 42% of those who had not shopped around had been approached by another supplier. Indeed, as the CMA recognises, Ofgem has found similar disparities and suggested that “consumer recall is one part of the reason for this”.<sup>19</sup>
59. There are other ways to gain awareness of whether you are on a satisfactory tariff beyond formal “shopping around” or considering switching supplier (e.g. through media reports on typical bill levels). We would suggest that any competition concerns should be focused on those customers who are dissatisfied with their tariff, would like to shop around/switch, but find it difficult to do so. The March data room analysis conducted by our advisers suggests that the reason many customers do not switch is because they are satisfied with their current supplier (and a significant proportion of those who were not satisfied intend to switch in the next three years and are confident they will find a better deal if they do so). The balance of customers who appear “disengaged” on all these bases is a relatively small proportion of the total (at around 5%).<sup>20</sup>
60. Indeed we note that the customer group of most concern to the CMA (those who have been on an SVT tariff with their supplier for over five years and have never considered switching supplier) also account for around 7% of the survey sample.<sup>21</sup> Key reasons for these customers not to switch are said to be that they are “not interested” or that they are satisfied with their supplier. In particular, many of them place value on supplier reputation and service. Moreover, most of them (over 85%) cannot make large savings from switching (over £100) unless they were prepared to switch not only supplier, but also tariff and/or payment type, or to switch to tariffs that are only offered online and/or require payment in advance.<sup>22</sup> Their decision not to switch may therefore in many cases be driven by a sensible judgement of the value they place on their supplier and product characteristics, rather than a fundamental disengagement with

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<sup>19</sup> Provisional Findings Appendix 8.1 p.120, para.29.

<sup>20</sup> CRA's First Data Room Report, March 2015, slide 24.

<sup>21</sup> Provisional Findings, 8.3, p.291. See also CRA's Second Data Room Report.

<sup>22</sup> See CRA's Second Data Room Report.

the market process. This needs to be taken into account in considering what remedies are most likely to increase customer engagement, trust and satisfaction.

61. We also reiterate our view that engagement is about more than just switching. Our strategy is to build consumer engagement through initiatives such as Hive and Smart as this allows customers to manage their consumption more effectively, saving money as a consequence. We regret that the survey did not do more to gauge the potential impact on engagement of such propositions.

### **Gains from switching**

62. The CMA attaches “particular importance” to the existence of apparently large gains from switching in the retail market, as evidence of weak customer response, and a broader lack of engagement. While we have a number of concerns with the CMA’s analysis of gains from switching (set out below), we believe that the existence of modest gains from switching at any given moment is entirely consistent with effective competition over time. This is particularly the case in energy where there are different costs associated with different forms of supply, different products (embodying different levels of price assurance for example) and different levels of service and other non-price forms of product differentiation.
63. We set out a number of problematic features of the CMA’s gains from switching assessment in our response to the Updated Issues Statement.<sup>23</sup> While the CMA has partially recognised some of our concerns, in many cases our comments remain unaddressed.
64. Many of the CMA’s scenarios assume that price differences can be interpreted as “gains” from switching, even in cases where the products being switched between are very different (e.g. switching from a smoothed price product with cheque payment in arrears and call centre support available to a short fixed term fixed price product with advanced payment and online-only communication). Many customers care about these product characteristics, and so would not necessarily consider this switch a “gain” even if it results in a cost saving.
65. This problem is particularly acute for Scenarios 4b and 5, which are the scenarios discussed in detail in the main body of the Provisional Findings, and control only for payment method and no other tariff characteristic. However, even the CMA’s most “like for like” scenario (3b) fails to control for online tariffs and payment in advance. The gains from switching in the full sample fall from around £103 (9.4% of the bill) in Scenario 3b to £82 (7.6% of the bill) if we control for whether tariffs are online only or not, and to £60 (5.4% of the bill) if we also control for tariffs that require payment in advance<sup>24</sup>. We are concerned that the CMA’s findings on engagement may be based on fragile comparators that do not properly control for comparability of product characteristics that influence actual customer behaviour. This is particularly significant given that the CMA’s survey suggests that only 18% of customers would be prepared to switch for £99 or less and only 5% for a saving of £50 or less<sup>25</sup>.

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<sup>23</sup> See our response to CMA’s Working Paper on Gains to Switching and also CRA’s Second Data Room Report

<sup>24</sup> See CRA’s Second Data Room Report.

<sup>25</sup> See Figure 70 in the CMA’s “GfK NOP customer survey report (20.2.15)”

66. The CMA has recognised that these “gains” from switching are not a measure of a consumer welfare loss (as if customers all switched to the lowest priced tariffs this would affect the pricing decisions made by suppliers).<sup>26</sup> However, the results of the analysis – based on taking a quarterly snapshot of gains available from switching – continue to be characterised as a measure of “whether there are customers who are subscribing to tariffs that have *consistently* offered poor value compared to other tariffs offered by the same and other suppliers”.<sup>27</sup>
67. This approach fails to recognise that the CMA’s analysis will in some cases assume that customers are switched to products which offer only a temporary discount from SVT, or products which are quickly withdrawn from the market. Without understanding what happens to the prices paid by customers who switch to these products, the CMA cannot assume that they would be better off on a sustained basis. Even for customers who simply switch to a rival SVT, different timings of SVT price changes between suppliers will mean that the “snapshot” gains from switching at the time of the switch cannot be assumed to be consistent over time.
68. It is also important that discounts are fully taken into account in the analysis. The CMA has not shared with us its calculations (including on how the discounts we offer to our own customers are reflected), and we understand that the Warm Home Discount may not be included in the calculation.<sup>28</sup> However, the CMA has indicated it considers these discounts to be “small” on average across all customers. We believe this ignores the fact that the discounts are nonetheless material to those customers who receive them – often of the same order of magnitude (or in some cases higher) as the gains that the CMA suggests customers could achieve from switching.
69. Finally, we also have serious concerns over the CMA’s apparent comparison of findings across suppliers in light of the substantial levels of data that have been excluded from the CMA’s analysis for certain suppliers.<sup>29</sup> Without robust assurance that the excluded observations are a representative sample of customers then, given the very high proportion of customers dropped from certain supplier samples we do not believe that weight can be placed on cross-supplier comparisons. Further details of these concerns are set out in the Gains from Switching section of our Appendix and will also be set out in the Second Data Room Report by CRA (our economic advisors).

### **Price discrimination**

70. We also contest the CMA’s conclusion that there is a lack of evidence showing that energy costs for standard variable products are higher than energy costs for fixed term, fixed-price tariffs.<sup>30</sup>
71. We respond more fully to the analysis in the Price Discrimination section of our Appendix, but in summary we believe that the CMA has based its analysis on too limited a timeframe (from July 2013 to March 2015), resulting in an incomplete view. The CMA has relied on a time period in which commodity costs have been relatively benign, and generally falling. We consider it likely that a different conclusion would

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<sup>26</sup> Provisional Findings Appendix 7.4 p.1, para.3.

<sup>27</sup> Provisional Findings Appendix 7.4 p.13, para.39, 52.

<sup>28</sup> The Centrica column of Provisional Findings Appendix 7.4 p.34 Table 1 is also redacted.

<sup>29</sup> Provisional Findings Appendix 7.4 p.4, para.11.

<sup>30</sup> Provisional Findings Appendix, para.69

have been drawn if the CMA had considered pricing outcomes across the entire commodity cycle, including periods of higher volatility and increasing commodity prices.

72. Movements in wholesale energy markets materially affect the changes in the relative prices of SVT and FTC products over time. This is because there are different costs and risks associated with the ways energy is bought for different products. We described this in our response to the Updated Issues Statement,<sup>31</sup> but it has not been properly reflected in PFs.
73. More broadly, we cannot accept the CMA's view that only forward-looking costs should be reflected in prices in a competitive market.<sup>32</sup> This fails to recognise that much of the smoothness of SVT pricing stems from our rateable hedging strategy, purchasing commodity over time. If prices were always driven by the current forward market view (even taking e.g. a 24 month forward view) this would result in significantly more volatile pricing outcomes, which in our view would not be in consumers' best interests. Indeed, if in this hypothetical market customers dealt with this volatility by entering into FTCs, then at any point in time most of them would be midway through a contract, so the average price paid at any point in time would reflect past as well as current costs (as is the case today).
74. In reality, consumers tend to avoid the risk of such spikes, either explicitly through choosing fixed price contracts, or implicitly by opting for products such as SVT which smooth out such volatility.
75. Moreover, had competition operated on the basis suggested by the CMA, spot prices – both wholesale and retail – are likely to have followed a very different path (as in such a theoretical construct, most contracted volume could be expected to be bought / sold in short term / day-ahead markets), which we expect would have had profound implications for the CMA's findings.
76. CRA's Second Data Room Report also casts doubt on the CMA's conclusions. It is not correct to say that non-standard tariffs are not always priced below SVTs; a substantial number are priced above (around two thirds are priced below and one third above). Moreover, the proportion changes significantly over time, and appears to be strongly driven by the relative costs of different hedging strategies (with fewer non-standard tariffs sold at a discount to SVT at times when the SVT procurement strategy generates lower costs than the 1 year forward curve, for example).<sup>33</sup> This demonstrates that the retail market is not purely homogeneous: we use our hedging activities to provide a differentiated offer so that our customers can choose the product that suits them best (for example in relation to the degree of price smoothing offered).

## Regulations

77. In this section we provide our view on the following areas of regulation:
  - Retail Market Review reforms;
  - PCW Confidence Code;

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<sup>31</sup> Response to the CMA's Updated Issues Statement, Centrica, pp.9 - 16 and response to the Cost Pass Through Working Paper

<sup>32</sup> "In a competitive energy market, we would expect domestic retail prices to change in response to expected marginal costs rather than historical costs", Provisional Findings, para.7.153

<sup>33</sup> See the CRA Data Room Report for further details.

- Gas and electricity settlement and metering;
- Switching process and erroneous transfers;
- Uncertified meters;
- Must inspect; and
- Small supplier exemptions.

### **Retail Market Review reforms**

78. Regulation should be used to determine the minimum standards required to ensure competition best serves consumer interests. The Retail Market Review (RMR) goes much further than this by intervening in how specific outcomes are to be achieved. We believe the CMA is therefore right to look at removing elements of this, notably the ‘simpler’ and ‘clearer’ elements of the RMR<sup>34</sup>.
79. We are in a new phase of competition in the retail market. Changes being delivered through the smart metering program, new technologies and new entrants - plus engagement remedies considered elsewhere in the CMA report - are likely to accelerate the pace of change.
80. As a result of remedies 3, 4a, 9 and 10 for example, we believe it likely that more varied and tailored products will be brought forward, designed to meet more individual customer needs in an effort to gain customers. Prescriptive regulation is inconsistent with a changing market such as this. We are already seeing it inhibit competition today, and without change we believe the problem will only get worse.
81. The CMA is therefore correct to say that “some of the RMR measures restrict the behaviour of suppliers and constrain the choice set for customer in a way that may have an adverse effect on competition and consumer welfare”.<sup>35</sup> In particular, we believe that the tariff simplification rules have limited innovation and choice.
82. The same is true of the RMR rules which limit what (and how) products can be offered alongside an energy tariff<sup>36</sup> and the ban on cash discounts. Both have limited suppliers’ ability to create engaging products that can drive acquisitions, and prevented suppliers from developing exclusive deals with Price Comparison Websites (PCWs). We therefore also support the CMA’s provisional findings in this area.
83. We also see that the market would benefit from a relaxation of elements of the RMR information remedies. For example, we agree with the CMA that the proposed remedies will enable exclusive deals between PCWs and suppliers – improving competition in both markets. Information remedies such as the Cheapest Tariff Mechanism (CTM) act as a barrier to the increased segmentation envisioned here by the CMA.
84. Furthermore, we note that the CTM is incompatible with the more varied, tailored, product range that the CMA’s other remedies are likely to lead to, for example exclusive PCW products. Specifically, as non-price elements of products become more important, a customer recommendation based simply on the energy unit cost is likely to be both inaccurate and misleading.

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<sup>34</sup> Ofgem introduced three packages of regulatory restrictions and requirements as a consequence of RMR; “simpler”, which related to tariffs, “clearer” which related to information provision and “fairer” which introduced Standards of Conduct as a licence obligation.

<sup>35</sup> Provisional Findings Appendix 8.2, para.63.

<sup>36</sup> SLC22B.8 to SLC22B.29.

85. Similarly, whilst we support the intent of the Personal Projection (PP) and see its benefit as a cross-market comparison tool, we believe that the level of prescription on its presentation and delivery means it is ineffective and often results in customer confusion and dissatisfaction. The same applies to the requirements Ofgem have set out regarding the design, layout and content of the bill, and the requirement to remove offers of mitigation from any price rise notification. In removing elements of the RMR which act as a barrier to competition, the CMA should therefore remove the obligation to provide a CTM, and relax the level of prescription around the bill and the PP.
86. We also believe that the CMA should also remove the obligation to provide a Tariff Comparison Rate (TCR). The TCR was introduced as a way for customers to compare tariffs across the market 'at a glance', however it is inaccurate to customers with anything other than 'average' consumption. It is also a complicated artificial construct for customers to understand and in our view unengaging.
87. Notwithstanding these concerns about the 'simple' and 'clearer' elements of RMR, we support the shift towards principles based regulation and the focus on delivering specific customer outcomes introduced through the RMR's 'fairer' package. If implemented properly, this will both improve Ofgem's ability to efficiently regulate the market, and improve suppliers' ability to deliver products and services in a way that enables differentiation and supports competition.
88. More information on this, including our proposals about how the CMA could address these issues, is provided in our response to Remedies 3 and 9.

### **PCW Confidence Code**

89. We agree with the CMA's analysis of Price Comparison Websites (PCWs) and collective switching schemes. In particular, we agree that PCWs and collective switching schemes can reduce search costs and increase engagement across the market.
90. On reflection therefore, we agree with the CMA that the provisions within the Confidence Code requiring PCWs to provide a 'whole market view' by default risk distorting competition by, for example, allowing a 'free advertising' option for suppliers. We therefore agree that PCWs should be able to provide partial views of the market, provided it is also clear and transparent to customers about what market coverage is being offered.

### **Settlement and metering**

91. The CMA is correct to conclude that the current gas settlement system is likely to lead to inefficient cost allocation. The causes of this are both the infrequent nature of meter reading collection, the infrequent updating of Annual Quantity (AQ) values, and the allocation of unidentified gas.
92. We also agree with Ovo Energy<sup>37</sup> that this can distort supplier incentives, for example by disincentivising suppliers from measures which may reduce their customers' gas consumption. We agree that this gives rise to the risk of gaming, although importantly we are not aware of any evidence to suggest gaming actually occurs today.
93. We agree that the length of the electricity settlement and reconciliation process creates uncertainty of costs and revenues for suppliers.

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<sup>37</sup> Provisional Findings Appendix 8.6, para.12.

94. We also believe that half-hourly (HH) settlement will ultimately lead to improvements in the speed and accuracy of settlement, and also enable the development of future dynamic ToU tariffs. Both the costs and scale of a project to implement HH settlement are likely to be very large however, and before any decision can be taken to implement it, a full cost benefits analysis is required.
95. These concerns and our views more widely on the remedies the CMA has proposed in this area are set out below in our response to Remedy 4.

### **Switching process and erroneous transfers**

96. We agree with the CMA that the current change of supplier process is “very complex”, and can lead to “delays, errors and costs”.<sup>38</sup> This complexity reflects the current complexity of ‘as-is’ industry processes and procedures, and will be simplified as part of the smart meter programme.
97. The smart meter roll out is central to the industry’s efforts to improve this. For example, we believe that smart meters, and the introduction of the Data Communications Company (DCC) should enable faster (and ultimately next day) switching and reduce the frequency of erroneous transfers.

### **Uncertified meters**

98. We do not agree that the issue of uncertified meters is necessarily creating a barrier to switching. When a supplier acquires a site, they do not know the certification status of the meter they are switching, and as such it cannot be a factor in their decision about whether to acquire a site.
99. Furthermore, we believe this problem is relatively minor. Whilst other suppliers’ performance may differ, just [X] % of our electricity meter population is uncertified today.
100. Notwithstanding this, we recognise that the problem means that meter certification costs are not always properly allocated. The problem is in part being driven by the approaching smart meter roll out deadline, which means suppliers face strong financial disincentives to exchange an uncertified meter for a new traditional meter today, such as the stranding costs when the smart meter is due for installation.
101. This is particularly apparent for sites where a smart meter cannot yet be installed, for example where the enduring industry solution is yet to be agreed, as in the case of tall buildings where the meter and the property may be separated by several floors. The CMA may be able to alleviate the impacts of this issue, and any impacts of costs misallocation, by providing suppliers with temporary derogation from the meter certification rules until 2020.

### **Must Inspect**

102. The Must Inspect obligation is designed to ensure the safety of gas meter points. Ofgem allow any supplier to seek derogation from the obligation if they can show that safety can be maintained to the same or a higher level through another mechanism. Whilst no supplier has yet chosen to apply for the derogation apart from us, the option remains available to them. We also note that by 2020 this obligation will no longer apply due to the roll out of smart meters.

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<sup>38</sup> Provisional Findings Appendix 8.6, para.98.

103. As with uncertified electricity meters, an acquiring supplier is not aware of the Must Inspect status of a gas site before they apply for the site. It cannot therefore be creating a barrier to them acquiring the site.
104. Our views on the proposal to remove our derogation are set out below in our response to Remedy 4.

### **Small supplier exemptions**

105. Whilst we acknowledge that the majority of smaller suppliers agree that the policy exemptions are not creating a barrier to growth<sup>39</sup> we think that the CMA is wrong to conclude that they are not distorting competition.
106. For example, the CMA's own analysis of the DECC impact assessment show that the Energy Company Obligation (ECO) results in a £36 cost advantage per customer for exempt suppliers. Whilst we believe the DECC figures are too low, even if they were correct, the benefit conferred would far exceed the administration costs per account for ECO the CMA has estimated for small suppliers.<sup>40</sup> The current exemption therefore over-compensates smaller suppliers and thus distorts competition between large and small suppliers. We believe that the CMA should reconsider its provisional finding on this matter.
107. In particular, we note that the diseconomies of scale small suppliers would experience with the delivery and administration of energy policies could be managed in a more proportionate way. For example, the cost of delivery could be moved to general taxation, or failing that, the scheme could be amended such so that delivery can be achieved through either brokerage or a white certification scheme.<sup>41</sup> This would remove both the cost distortions of the current model and economies of scale benefit larger suppliers would gain in the absence of an exemption.

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<sup>39</sup> Provisional Findings Appendix 7.1, para.35 and 36.

<sup>40</sup> Provisional Findings Appendix 7.1, para.46.

<sup>41</sup> A 'white certification' scheme separates delivery and funding for energy efficiency. White certificates are tradable instruments proving the achievement of end-use energy savings through installed energy efficiency improvement measures. Obligated parties are required to have sufficient white certificates to meet a given obligation level – either by implementing qualifying energy efficiency projects or by buying them from other parties in the market. This model is currently used in Italy.

## Microbusinesses

108. This section responds to the following Provisional Findings relating to Microbusinesses:

- Engagement;
- Transparency;
- Margins;
- Outcomes; and
- Provisional conclusions.

109. We strongly disagree with the CMA's provisional finding that we have unilateral market power over our microbusiness customers on 'Default Tariffs'. We face strong competition for all of our microbusiness customers and we are seeing already high levels of customer engagement continuing to increase.

110. Findings from the survey of micro/small businesses published by Ofgem in March 2015<sup>42</sup> show a much higher proportion of customers switching year on year; this is clear evidence of increasing engagement.

111. In addition to this already competitive environment, we reiterate that in the wake of recent moves by most suppliers to stop auto-rollovers, the SME market is in a state of transition. The majority of the data and research that the CMA relies upon relates to a period before these changes were implemented, when there were markedly fewer customer prompts to engage and auto-rollovers led to large differentials between acquisition and renewal deals, creating unsustainably high profits.

112. As the market continues to move away from auto-rollovers, and with more transparency and effective competition in the provision of TPI services, the number of customers on default / replacement tariffs will rapidly diminish. That will leave only Deemed customers - where prices are already regulated obviating the need for further intervention - and customers who value the flexibility of short-term contracts or variable products remaining on these 'default' arrangements.

## Engagement

113. We believe that the CMA's provisional finding that a substantial minority of microbusiness customers did not arrive on their current tariff as a result of an active decision, and are consequently on Default Tariffs, is misleading because the data cited includes customers who were auto-renewed onto new contracts. Since this practice has largely ended, this is no longer an accurate reflection of the current market.

114. The CMA's analysis (Figure 9.40) shows that 26% of microbusinesses were on electricity rollover tariffs in April 2013. [X ]

115. Moreover, findings from the survey of micro/small businesses published by Ofgem in March 2015 provide further evidence of increasing engagement. It showed that 60% of businesses had switched supplier in the previous five years. Crucially, however, a much higher proportion had switched in 2014 (23%) than had switched in 2013 (13%); this is clear evidence of increasing engagement, especially given this is a very high

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<sup>42</sup> [https://www.ofgem.gov.uk/sites/default/files/docs/2015/03/non\\_dom\\_quant\\_final\\_v4\\_0.pdf](https://www.ofgem.gov.uk/sites/default/files/docs/2015/03/non_dom_quant_final_v4_0.pdf)

proportion of those customers actually available to switch in any given year, i.e. those coming to the end of, or not in, fixed term contracts.

116. The same Ofgem survey notes that 92% of businesses are on fixed-term contracts for one or more years with over 50% being on contracts of two years or more. This naturally limits the number of customers available to switch in any given year. The survey data also shows these fixed-term customers are now highly engaged, with 84% of them knowing (at least approximately) when their contracts end. This proportion has gone up very significantly from 63% in 2013. This shows a marked increase in engagement in recent years and confirms the potency of prompts.
117. Therefore, the fact there are far more customers able to switch (now that auto-rollovers are less prevalent) along with the marked increase in switching since 2013 (partly attributable to increased prompts on bills and renewal letters), must be considered when assessing current engagement levels and the possible number of customers on Default Tariffs in the future.
118. We agree with the CMA's view (paragraph 9.39) that there is a variety of reasons for the recent increase in switching and that increased broker activity targeting small businesses is one factor. We therefore think it is important for the CMA to consider the further positive effects on engagement and switching which are likely to be driven by greater TPI transparency (i.e. an Ofgem Code of Practice). This will have the dual effects of improving customer trust in, and therefore usage of, brokers and providing the right market and commercial conditions for PCWs to emerge (discussed in further detail below).
119. Finally, in respect of possible low visibility of energy consumption by microbusiness customers (paragraph 9.45), we believe that the roll-out of smart meters will increase engagement further. We are fully supportive of the smart meter programme and believe that it will reduce complexity as customers have more information available to them in a form which is more easily understood and actual (rather than estimated) consumption is used to produce accurate bills. Further detail on this is provided in the PF Appendix in the smart section.

## **Transparency**

### **Importance of transparency**

120. We agree with the CMA's view that transparency is important for microbusiness customers and that a new business may begin its energy supply with a deemed tariff (paragraph 9.48). We frequently contact our deemed customers to encourage them to save money by upgrading to a fixed-term contract and our online quoting tool allows customers to get a firm quote within two minutes. The messaging included on every monthly invoice prompts them to contact us and agree a new fixed term deal. It is in our interest to do this because it lowers the cashflow, hedging and bad-debt risk associated with deemed contracts. Bad debt as a percentage of revenue for our SME deemed customers is [X]. The figure is [X] for customers with fixed term contracts.

### **Information from suppliers**

121. Whilst we agree that it is beneficial for customers to be able to access and compare prices easily, we emphasise the importance to many microbusinesses of tailored pricing and contractual arrangements (paragraph 9.50). The CMA acknowledges the

substantial differences between microbusiness customers, both in terms of overall consumption, usage patterns and cost-to-serve, and it is these factors, amongst others, that give rise to the requirement and appetite for tailoring of contractual arrangements (both for customers and suppliers).

### **Information from third party intermediaries**

122. The CMA notes the proportion of microbusinesses that have used TPIs (paragraph 9.53). However, it is also important to note the proportion of all microbusinesses that have regular contact with or from TPIs. Findings from Ofgem's 2015 survey showed that only 15% of those surveyed weren't approached by a TPI in the previous 12 months and 38% reported more than 10 contacts. It is likely that the introduction of appropriate TPI regulation will increase customers' trust and prompt productive engagement between customers and TPIs, resulting in increased awareness of value and better outcomes for consumers.
123. We agree with the CMA's findings that there is a lack of trust in the broker market amongst microbusinesses and that commission payments are not well understood. We therefore support Ofgem's development of a Code of Practice for TPIs but do not think it is currently sufficiently robust. Based on our experience, it should include the requirement for TPIs to provide customers with clear details of:
- the extent to which they cover the markets, i.e. highlighting which suppliers they have agreements with and which they do not; and
  - the level of commission and how they are paid.
124. Moreover, the Code of Practice must operate within an appropriate governance and enforcement framework, managed either by Ofgem or by an appropriate independent party, and with the ability to impose proportionate sanctions. We know Ofgem has had powers under the Business Protection from Misleading Market Regulations since 2013. However, Ofgem has not openly used these powers and our own experience tells us that very few industry participants are aware of these Regulations (or their requirements) or Ofgem's powers. Consequently, they do not act as an effective deterrent. While we have no doubt these powers would be effective at punishing malpractice, we believe pre-emptively specifying a framework for good practice, rather than solely relying on the BPMMRs ex-post civil/criminal sanctions, would be more effective at engendering trust and confidence in TPIs.
125. Ofgem's survey found that only 5% of businesses that had used a broker said they were charged for the broker's services; the remainder believed the service to be free of charge.
126. The widely-held belief that a charge is not being levied by TPIs must be corrected. We believe that upfront transparency of TPI commission will allow customers to properly assess the value of the services they will receive in return. Indeed we believe that transparency will force TPIs to justify their commission levels which will create far greater and more immediate competitive pressure than multi-homing will do on its own.

### **Information from price comparison websites**

127. We agree with the CMA's view that PCWs may generally help to make customers more informed and agree that there are firms which could provide a commercial PCW (paragraph 9.62). We believe that the combined factors of the ending of auto-rollover contracts (which has removed the short window of opportunity for customers to find a

new contract) and the introduction of targeted TPI regulation will create the right conditions for commercial PCWs to emerge. It is reasonable to assume that some existing brokers, who have the requisite knowledge, will consider developing PCWs when the new greater transparency means it will be much harder to justify and thus earn the high commissions in the traditional brokered market.

128. We recognise the view (paragraph 9.63) that it is not necessarily simple to capture the full breadth of the more varied pricing required by some microbusiness customers but we do not believe this poses a barrier to the emergence of commercial PCWs. TPIs with the requisite industry knowledge and general spreadsheet skills perform price comparison services today. We already supply full price books to TPIs, including online TPIs, and welcome the opportunity to do the same for PCWs.

### **Margins**

129. The CMA's reliance on EBIT data from 2009 to 2013 (paragraph 9.66) has had the effect of excluding from the analysis the impact on suppliers' margins of the recent, substantial change of removing auto-rollovers in the SME market. Using 2009-13 data is therefore inappropriate when considering the eroded margin position in the present day. This will be increasingly the case in years to come as auto-rollovers become less prevalent and profit levels rebalance to a new lower competitive equilibrium. The market has been evolving at a rapid pace and any assessment of market dynamics needs to take into account the recent trends.

130. Furthermore, we disagree with the assertion (paragraph 9.68) that the differences between SME and domestic EBIT margins cannot be justified by the additional risks to suppliers. As outlined later in our discussion on the CMA's profitability analysis, it is our view that the supply of gas and electricity to SME customers represents a significantly higher risk and demands the investment of a greater level of capital than does the supply of domestic customers. These risks and increased capital requirements are the result of:

- A greater bad debt and consumption risk, particularly in the microbusiness market, as a result of changes in the economic cycle. Because these risks are correlated with broader economic conditions they are not diversifiable by shareholders, and therefore result in a higher cost of capital (via a higher beta);
- The need to maintain a greater level of working capital owing to the extended period over which SME customers settle their bills; and
- An increased exposure to margin calls as a result of commodity price volatility owing to the extended duration of contracts offered to SME customers compared to the domestic business, resulting in higher risk capital requirements.

131. The CMA has observed (paragraph 9.70) higher revenues and gross margins for smaller business customers compared with larger ones. We agree with paragraph 9.99 and 9.100 that these higher revenues and gross margins do not result in higher profits and that the level of indirect costs incurred by these customers is similar to the difference in gross margin.

132. We note the CMA has highlighted that there are higher revenues and gross margins on deemed and out of contract (OOC) tariffs. This is largely attributable to much higher levels of debt write-off. Bad debt accounts for [X] of revenue for our deemed

customers and [redacted] for OOC. The equivalent figure is [redacted] for customers on fixed-term contracts. The other key factors attributing to higher rates on these default products is shorter term cashflow certainty and hedging exposure because these customers can leave with little (if any) notice.

## **Outcomes**

### **Auto-rollovers**

133. The CMA observes that certain suppliers have responded to pressure to remove auto-rollover contracts (paragraph 9.80), but we note that this was predominantly competitive pressure imparted by customers rather than regulatory or political pressure. Indeed Ofgem has avoided a ban despite all non-domestic consumer groups and trade bodies supporting one, and our own move (along with those made by other suppliers) to stop auto-rollovers came before the Government set up its SME energy working group.
134. We ended the practice of auto-rollover as customer numbers were declining and it was clear that, due to dissatisfaction with the practice, the gap between acquisition and renewal pricing was unsustainable. We believe that effects of competition in the market would limit, if not prevent, the reintroduction of auto-rollover contracts. However, we accept that fundamentally there is actually nothing to prevent their reintroduction at some future time whether by an existing or new entrant supplier.
135. The CMA has noted that there is no evidence of customers who would previously have been moved onto an auto-rollover contract getting lower prices on the replacement tariffs now that this practice has largely been discontinued (paragraph 9.83). However, since the introduction of VPP, rates of switching and renegotiation have increased. We anticipate that the increased switching both at renewal and once on default/replacement tariffs will mean the differential between acquisitions and other products will reduce and will obviate the need for regulatory intervention.
136. Moreover, whilst the price of our replacement tariffs has not yet reduced significantly from auto-rollover levels, the fact those businesses are no longer locked-in and can switch or renegotiate at their own free-will is of great benefit, as indicated by our direct customer feedback and views expressed by business consumer groups. Indeed, as the CMA itself notes, not all customers on these Default Tariffs are disengaged (paragraph 9.81) and we highlight the fact that [redacted] of customers who first moved onto our VPP tariff in September 2014 have since actively engaged either by switching or by negotiating new fixed-term contracts. It is also clear from this that this default product is predominantly being used by customers as a transitory product rather than on an enduring basis.

### **Deemed and Out Of Contract**

137. The CMA has noted that not all suppliers write off the same amounts of debt from deemed customers (paragraph 9.93). A large number of those customers on the deemed tariff are low-consuming customers who have moved premises. The significant cost associated with tracking these very small consumers and attempting to recover their debt can often exceed the money owed, resulting in high levels of debt write off.

138. We acknowledge the CMA's provisional finding (paragraph 9.96) that there is a relatively small number of customers who remain on deemed and OOC tariffs when they could move onto cheaper tariffs and we actively engage with these customers to encourage them to move to fixed-term contracts. It is in our commercial interests to do this because it reduces our exposure to hedging risk and debt risk.

### **Customer size**

139. Although we acknowledge that there are slightly lower levels of switching among microbusinesses than larger SMEs (paragraph 9.97), we believe this is a relatively immaterial difference (findings from Ofgem's survey showed that 14% of microbusinesses reported switching in the previous 12 months compared to 18% for the rest of SME).

140. We agree with the CMA's view that there is no conclusive evidence to suggest that supplying medium microbusinesses may be more profitable than supplying larger SMEs. We also agree with the CMA's analysis that higher average revenues and gross margins from small microbusinesses does not translate into higher profits.

### **Provisional conclusions**

141. We disagree with the CMA's provisional conclusion that the homogeneous nature of gas and electricity may give rise to low levels of interest and engagement from microbusiness customers. Whilst it is true that the underlying commodities are homogeneous in nature, the contractual terms (e.g. payment terms, flexibility, credit provisions), the product (e.g. fixed, variable, price structure, payment type, or bundled with other services), and the overall customer service experience we provide, make the different 'packages' we provide heterogeneous between each other, and our products heterogeneous to other suppliers' products.

142. Our customers have varied requirements and this is expected to increase as smart meters and associated technologies advance. This drives differentiation and innovation in propositions and products as well as competition in non-price factors. Any intervention which may have the effect of stifling this, for example by limiting product variation, should be avoided and, in any event, is unnecessary.

143. The business supply market is evolving rapidly and in recent years has been increasingly competitive. This increased competitive pressure has led to the widespread withdrawal of auto-rollover contracts which in turn has boosted competition by allowing customers to switch more freely. We believe that this change, coupled with targeted and enforceable TPI regulation will create the right conditions for the emergence of commercial PCWs and these factors together will address the CMA's concerns regarding engagement among microbusinesses.

## Profitability

144. We have consistently highlighted our concerns with using Return on Capital Employed (ROCE) to assess the profitability of standalone retail energy supply businesses. In particular, we have been concerned by the large number of speculative assumptions needed to quantify the costs that such a supplier would incur, and capital it would need to deploy, in managing risk: either through holding sufficient cash reserves to manage margining and credit risk themselves, or the balance sheet capacity that would be used by an intermediary to do so on their behalf (and therefore the fee that would be charged). This is why we suggested that an Earnings before Interest and Tax (EBIT) benchmark might be more constructive: at least in placing broad bands around what an acceptable competitive EBIT could be.
145. The CMA acknowledges the difficulty in accurately measuring profits or estimating a fair return in this market, noting that it has “sought to make reasonable judgements and assumptions” in order to draw conclusions.<sup>43</sup> However, rather than responding to these challenges by estimating a reasonable range, the CMA has taken comfort by using three methodologies (ROCE, competitive benchmarks to measure cost efficiency and EBIT margin analysis) to reach a rather narrow view on profitability. From these, the CMA believes that it can “gain assurance that different sources of evidence on profitability give broadly consistent results”.
146. We believe this confidence is misplaced. This analysis relies heavily on a number of assumptions which are fundamentally flawed and inconsistent with commercial reality. Furthermore, the three methodologies are interrelated and rely on the same assumptions. So they do not provide the independent level of comfort suggested. We therefore remain of the view that this analysis is not sufficiently robust to support the CMA’s PF and, so, should not be relied upon by the CMA in its current form. These concerns are so serious we do not believe the analysis would stand up to rigorous peer review
147. Our fundamental concerns with the methodology used in this analysis have already been articulated in detail in our written responses to the CMA working papers on Weighted Average Cost of Capital (WACC), ROCE and EBIT benchmarking.<sup>44</sup> However, this new analysis on competitive price benchmarking raises additional concerns, as well as many of those previously set out.
148. At our Response Hearing we identified our key areas of concern with the assessment of profitability set out in the PFs. In this section, we expand on these areas and set out our response to the CMA’s specific request to comment on differences in the profitability of our gas and SME customer segments. These concerns are outlined in the following sub-sections, and further in the Profitability section of the Appendix to this document:
- Analysis of out-turn profits (using ROCE and comparing this to an estimated Cost of Capital - WACC);
  - Analysis of competitive benchmark prices and costs; and

<sup>43</sup> Provisional Findings, para.10.7.

<sup>44</sup> Centrica response to CMA working paper on Cost of Capital, submitted March 2015; Centrica response to CMA working paper on “Analysis of retail supply profitability – ROCE working paper”, submitted May 2015; Centrica response to CMA working paper on “Assessment of profit margin comparators for the competitive benchmark in retail energy supply”, submitted May 2015

- Margin benchmarking across markets and within energy retail.
149. In each of these areas we have found that relatively small and reasonable changes to assumptions virtually eliminate the £1.7bn of “excess industry profits” reported by the CMA. Such a significant reduction suggests that this analysis is not robust and requires thorough and careful reconsideration before any final recommendations on remedies are made.
150. First, let us respond to comments made by the Panel on the use by Centrica of Economic Profit (EP) at both of our hearings. We have used EP historically for executive compensation at British Gas, but only as one of a number of metrics. As risk capital requirements are primarily driven by wholesale market conditions, they are not a factor that managers can control and so no adjustment for this is made at a business unit level.
151. In each of the following sections the key points are given a reference (a to m) that correspond to our more detailed response in the Profitability section of our Appendix.

### ***Analysis of out-turn profits (using ROCE and comparing this to an estimated Cost of Capital - WACC)***

152. **a) The intermediary fee is not credible:** The analysis relies upon a hypothetical industry wide intermediary fee model rather than recognising the additional capital that a standalone supplier would require. This model relies on scaling up an approach used by only two small suppliers and applying it across the entire market including the Six Large Energy Firms (SLEF). We are concerned as:
- This fails to identify the real level of risk capital that would be necessary to support such an approach and the impact this would have on pricing.
  - We have not seen the full details upon which this analysis relies, but given the bespoke nature of these contracts and the important interrelationship between the level of fee charged and the risk transfer, which is particular to the two negotiated parties involved in the contracts, we do not accept that a simple scaling up of the terms of the contact is appropriate. Given the significance of this to this analysis, and as set out in various emails to the CMA, we do not consider that we are able to make appropriate submissions on this issue, instead having to rely in many cases on conjecture as to the assumptions made. There is insufficient information in the redacted version of Appendix 10.3 for us to consider whether these would indeed be scalable at the fee levels the CMA suggests. We understand that in the less redacted version of 10.3 made available in the data room our advisors have only been provided with details of the CMA’s fee assumption, but without further detail or evidence underlying the assertions and propositions contained in the Appendix regarding the fee arrangement. In the absence of fuller disclosure, we do not believe we have had a fair opportunity to make a proper response on this crucial issue.
  - It is most doubtful that this model would be available at scale: it isn’t in practice in the US or UK. Such large additional demand would significantly increase the cost in a market where we have seen a reduction in the number of firms offering an intermediary fee service in recent years.
  - We estimate that a simple route to market service could cost [X] - [Y]%, whilst a broader suite of risk management services (e.g. shaping for demand and managing balancing risk) would cost considerably more. Even the lower bound of these figures

is higher than that used in the CMA's analysis which suggests that the fee used is too low and not reflective of a properly priced intermediary fee.

153. **b) The five year period chosen does not reflect a complete set of commodity market circumstances:** In focussing on a five year period, this analysis has failed to consider a full commodity cycle. In volatile periods, profitability is likely to be more constrained as our ability to pass through these additional costs to customers is limited. Conditions such as this were witnessed as recently as in 2007-2008 which was not a uniquely volatile period in energy markets: stressed conditions of this type are normal in a typical commodity cycle so any model of competition needs to take them into account. It is not clear that the intermediary fee model used in this analysis would do so. Indeed the mid-tier companies' business models, upon which the analysis appears to be heavily dependent, have not experienced the impact of rising or volatile market prices. Therefore excluding such periods means the CMA's findings are not fully tested, overstate profitability and need revisiting.
154. **c) The working capital estimates do not recognise that gas and SME supply need a higher level of working capital than residential/electricity supply:** This is primarily due to slower payment terms and (typically) longer contracts for SME customers, and seasonality in demand for domestic gas customers which creates a greater mismatch between debtors and creditors compared to electricity supply. These factors require a greater working capital allocation when compared to other segments. The SME business is also riskier due to the substantial bad debt risk observed (which is correlated with general economic conditions and therefore not diversifiable by investors), increasing the cost of capital. For these reasons we believe the analysis has underestimated our relative working capital needs and thus overstated our ROCE as we have a relatively higher proportion of gas and SME customers.
155. **d) The level of cash needed to meet working capital shortfalls for a standalone supplier is underestimated:** The analysis has overestimated the credit terms that that could be obtained by a standalone supplier in relation to payments for commodity costs. The creditor days reported by the SLEF would not be achievable by a standalone energy supplier as they reflect the internal group arrangements of a VI business not the payment terms of arm's length deals. Furthermore, this analysis assumes that the "credit facility" offered by the intermediaries would help meet a supplier needs. However we find this assumption questionable as we cannot find evidence in the financial statements of the mid tier suppliers that they use any such facility as a means to manage their working capital requirements. As a result, this analysis significantly underestimates the level of cash a standalone supplier would need.
156. **e) The use of British Gas's Information Systems (IS) asset values as an industry benchmark is inappropriate:** By using British Gas's IS asset values and depreciation charges as an industry benchmark for the other SLEF, whilst not also considering how the associated investments will have influenced our product offer (and thus revenues) in comparison to those of the other SLEF, the CMA will have underestimated their profitability compared to British Gas.
157. **f) The WACC estimate is too narrow and reflects too low a range:** We do not believe that the WACC used by the CMA reflects the range of risks associated with activity in the energy market and as such both its equity risk premium and beta are too

low. This will exaggerate the CMA's assessment of any excess profitability and will also result in an underestimation of what an appropriate EBIT level is. In our view a more appropriate range for the WACC would be 11.6-15.3%.

158. **g) The ROCE estimate has failed to adjust for the impact of colder than 'normal' weather conditions:** The CMA's analysis is based upon the period 2009-13 which included three particularly cold years. As a result the reported returns are higher than those that could be expected under normal weather conditions.

### ***Analysis of competitive benchmark prices and costs***

159. **h) Commodity cost benchmarks are not achievable:** The CMA's analysis assumes the supplier with the lowest commodity cost in any given year will set the price of the market, whilst other suppliers would need to match this price, and absorb the cost of any more expensive commodity they may have purchased. This is not achievable on two counts:
- Wholesale costs are an outcome of a hedging strategy decided months/years before delivery and it is simply not feasible to change a forward purchasing strategy on a regular basis.
  - A supplier cannot procure at the same price in all market conditions and will not be able to scale up their procurement to the "cheapest in market" by the time they realise their hedging strategy has turned out to be the cheapest.
160. Further in an environment of low margins, and very high customer switching rates, the suppliers would take steps to mitigate the risk of having to price at a loss on occasions where their commodity costs turned out not to be the cheapest – by changing hedging strategies and passing the risk of volatile price movements to customers, and/or through exit fees. A more suitable estimation of benchmark commodity costs would be to consider these in aggregate over at least a 7 year period, rather than considering individual years. Our concerns with the ROCE analysis outlined under Section 1 will also impact this commodity benchmark analysis. Taken together, this means that this analysis has underestimated the realistic commodity cost that could be achieved by the market.
161. **i) Indirect cost benchmarks should be treated with caution:** We do not agree with the premise that any inefficiency in suppliers' indirect costs will always result in customers paying more than appropriate compared to an effectively operating market, as there is evidence that higher opex results in lower profits. Nor do we agree that differences in indirect costs levels across the industry are solely the result of inefficiency as such differences can also, for example, be the result of differences in IS investment or investments in innovations such as smart metering.

### ***Margin benchmarking across markets and within energy retail***

162. **j) The impact of differences in customer mix on profitability is not properly accounted for:** This analysis largely ignores the impact of different product mixes (between SME and domestic and between gas and electricity) on the different levels of ROCE, EBIT and gross margin seen across suppliers. Suppliers with a higher proportion of domestic gas and SME customers will be exposed to a greater level of risk and capital requirements. Specifically:

- SME bad debt risk (particularly in the Microbusiness segment) is higher than for domestic (or I&C) customers and is strongly correlated with the economic cycle, resulting in a non-diversifiable risk that will drive a higher cost of capital. SME customers also pay more slowly than domestic customers (resulting in a higher working capital requirement), and typically sign longer contracts, requiring a longer hedging horizon (and therefore more risk capital to support margining requirements).
  - Gas prices and demand are far more volatile than electricity and demand far more seasonal, resulting in both higher working capital requirements (to manage mismatch between payables and receivables due to seasonality) and higher **risk capital** requirement (to manage more volatile prices driving greater margining requirements, as well as the costs of managing weather variations).
163. By failing to consider the impact of such differences the proposed EBIT range is neither sufficiently broad nor high enough to reflect these differences in risk.
164. **k) GB energy suppliers face significantly more risk, which should be compensated, compared to companies in regulated markets, or those confined to I&C customers:** The EBIT benchmarking analysis fails to recognise that GB energy suppliers are exposed to demand risk whilst suppliers in regulated markets tend to be able to easily pass such risk onto customers through the regulatory mechanism. Similarly it fails to recognise differences in the cost pass through risk faced by domestic suppliers compared to I&C suppliers. Many I&C customers effectively manage this risk themselves, with the supplier simply purchasing specified quantities on their behalf and passing through the full cost of doing so. In comparison, domestic suppliers manage this risk for their customers, but undertaking this risk transformation employs capital that needs to be compensated in order to compete in the capital markets against other potential uses.
165. **l) The EBIT margin for a supplier who outsources commodity risk management to an intermediary for a fee should be lower than a supplier who self manages this risk:** The use of mid tier suppliers in the determination of the proposed EBIT range fails to recognise differences in their operating structure when compared to the SLEF. Firms which manage their own commodity risk (i.e. the SLEF) rather than contracting this out need to reward the capital employed in that risk management exercise. This should be reflected in a higher EBIT margin.
166. **m) The assessment of gross margins fails to recognise the impact of differences in customer mix on operating costs:** The analysis has not fully taken into account the impact that differences in customer pay type and customer service preferences can have on suppliers' indirect costs and therefore relative gross margin levels. Costs associated with prepayment meters and servicing customers via call centres are greater than those for a direct debit, online customer. The mid-tier suppliers have targeted customers who prefer to transact online and pay by direct debit and as such they will naturally have a lower gross margin (reflecting lower opex). By not considering the impact of such differences this analysis the analysis incorrectly assumes that the SLEF generate a greater level of profits than the mid tier suppliers.
167. All in all, we do not believe the analysis in the PFs is sufficiently robust to support a final conclusion that excessive profits are being earned. Indeed the fact that the PF estimate of excessive profits exceeded what was earned by the entire industry in most

years calls into question the basis for those estimates. It remains our view that, given the risks we face as an energy supplier and how such risks vary by customer segment, an appropriate EBIT range for energy suppliers is between 4-6%. On this basis, we do not believe that the CMA's PF of the amount customers have paid in excess of what its analysis suggests should have been paid is valid. Our assessment suggests that based upon a series of assumption changes in line with our comments in a) to m) above, the CMA's provisional findings of excess profits could fall to around zero. This is set out in Table A below (which is explained in more detail in the Profitability section of our Appendix). In our view this reflects the reality that in a competitive market profit is an outcome. Provided the conditions for competition and customer engagement exist, reasonable profit margins and levels will be set by the market.

Table A - Variation in CMA estimation of customer overcharging<sup>45</sup>

(£m)	Avg. Annual Excess		
	B2B	B2C	Total
<b>CMA headline estimation of customer excess cost</b>	<b>530</b>	<b>1,163</b>	<b>1,693</b>
a. Adjusting the analysis to include an additional 1% trading fee	(100)	(125)	(225)
b. Extending the period of analysis to include 2007/08	0	(325)	(325)
d. Increasing the allowed EBIT to reflect a WACC of 13.4% (the mid point of our proposed range)	(150)	0	(150)
f. Increase in capital employed to reflect peak working capital requirements	(50)	(125)	(175)
h. Calculating the lower quartile commodity benchmark over the full five year period and the inclusion of BG in the commodity benchmark	(100)	(175)	(275)
j-l. Increase in EBIT to a range of 4-6% reflecting the risks associated with the GB energy market	(25)-(225)	(200)-(650)	(225)-(875)
<b>Revised estimation of customer excess cost</b>	<b>100-(100)</b>	<b>200-(225)</b>	<b>325-(325)</b>

168. Our concerns over the reliability of the profitability analysis stem not only from the fact that we believe it understates the competitiveness of the energy markets, but also from the implications for the implementation of remedies. Several of the CMA's proposed remedies (most notably Remedy 11 but also Remedy 14) appear to be heavily influenced by the assumptions in the PFs regarding what the relationship between price and costs should look like in this market and the impact this may have on consumers. This has major implications for the efficient operation of the market in the future. It also risks the market failing to withstand the sort of periods of market stress seen in 2005-2006 and 2007-2008, for example.
169. The rolling blackouts experienced in California during 2001 illustrate the need for caution. While the reasons for these blackouts may seem obvious with the benefit of hindsight (where retail prices were capped at the same time as suppliers were

<sup>45</sup> Note the reference to a trading fee in this table is purely illustrative

discouraged from using hedging for risk management, which resulted in suppliers relying to a large extent on spot market for purchases), that was not appreciated when these regulations were designed. They were thought to have built in plenty of headroom to deal with all plausible market outcomes. In reality the regulated market set-up proved incapable of dealing with unanticipated events (increased demand) resulting in a serious market malfunction.<sup>46</sup>

170. There are potential parallels with elements of the analysis and remedies set out in the Provisional Findings: in the CMA's competitive benchmark pricing scenario, hedging would be uneconomic (as there would be a risk of a significant loss when wholesale market prices were falling), and a safeguard tariff could easily form a cap on competitive retail prices, meaning that periods of market stress could result in similar tensions between unregulated wholesale market conditions and regulated retail market conditions to those seen in California.

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<sup>46</sup> For a detailed discussion of the Californian energy crisis and the regulatory system that resulted in the blackouts see "Causes and Lessons of the California Electricity Crisis", Congress of the United States Congressional Budget Office, September 2001. <http://www.cbo.gov/sites/default/files/californiaenergy.pdf>

## Structure and Governance of the regulatory framework

171. We agree with the CMA that a number of specific policies and regulations have had a detrimental impact on both consumers and competition.<sup>47</sup> We also agree with the CMA's provisional conclusions regarding the broader regulatory framework, as well as with many of the findings in respect of code governance. This section sets out our position on each of these findings, with further details provided in our responses to the relevant remedies later in this document.

### *Broader regulatory framework*

#### ***Analysis on the impact of energy policy***

172. The CMA is correct to say that customers often do not fully understand the principal reasons for the increases in retail energy prices since 2008.<sup>48</sup> We believe this is in part caused by confusing and inaccurate analysis published by a range of parties including Ofgem and DECC, as well as a significant amount inaccurate reporting in the media.

173. For example, we believe that the widespread assumption that rising profit margins are the primary factor behind rising bills has not been helped by the publication of the Supply Market Indicators (SMI), which has consistently over-estimated retail supplier profits by as much as 100%. We also believe that DECC's annual "Impacts of Policies on Household Bills"<sup>49</sup> analysis to be based in part on questionable assumptions such as the take up of highly energy efficient white goods, and unhelpfully expressed as a counterfactual to what would have happened in the absence of those policies.

174. We agree with the CMA that there is information available on the various cost elements that make up the retail bill but the quality of that analysis is also sometimes poor. For example:

- DECC tends to assess specific policy interventions using an inappropriate counterfactual – i.e. the impact on estimated future customer bills. This is a confusing approach, as it means DECC's counterfactual often includes changes in bills other than DECC's policy intervention. In contrast, it would be far clearer were DECC to assess the impact on bills of the policy intervention in isolation (e.g. impact on current bills, absent other changes). This is more consistent with the analysis we provide in our "lightbulbs", when explaining changes in the composition of customers' bills. The basis for key underlying assumptions such as projected consumption trends or wholesale energy price paths are sometimes unclear, and at other times inaccurate. For example, in our view the likely long term increase in electricity network costs under National Grid's "Gone Green" scenario<sup>50</sup> is often significantly under-estimated.
- There is limited recourse to genuine independent analysis. For example, DECC assumptions are often taken as an input for third party analysis instead of actual cost

<sup>47</sup> Provisional Findings, para.11.3 and 11.51.

<sup>48</sup> Ibid, para.11.9.

<sup>49</sup> <https://www.gov.uk/policy-impacts-on-prices-and-bills>

<sup>50</sup> As set out in their "Future Energy Scenarios" report (July 2015): <http://fes.nationalgrid.com/>

data, and draft projections are rarely issued for public consultation or stakeholder feedback.

175. We disagree with the Energy and Climate Change Committee's conclusion that "the complex vertically integrated structure of [firms] made it difficult to determine where profits and losses were being made within them and how they might relate to energy price rises".<sup>51</sup> Through the Consolidated Segmental Statements (CSS), large energy suppliers now provide more transparency than most other FTSE companies over how much, and where, profit has been made. Importantly, the CSS is subject to strict regulatory control and rigorous independent financial audit.
176. Similarly, we reject Which?'s suggestion<sup>52</sup> that we are somehow able to move profit between business segments. This question was investigated by independent forensic auditors appointed by Ofgem in 2011 who found that transfer pricing policies were "broadly fit for purpose".<sup>53</sup> Importantly, we have also provided evidence to the CMA that internal energy transactions between Centrica's business units take place on an 'arm's-length' basis, and are based on external prices. Our structure, policies and procedures simply do not provide scope for us to move profits arbitrarily between business units in the manner that 'Which?' suggests.
177. We agree with the CMA that<sup>54</sup> energy policy would benefit from a meaningful and consistent carbon price signal across the economy, as opposed to multiple layers of complex intervention. We recognise however that this issue is complicated by the ineffective design of the EU Emissions Trading Scheme (ETS), and the fact that the UK Carbon Price Floor is limited in its application to power generation fuels. Notwithstanding this, we believe that more could be done to analyse and compare alternative means of delivering defined policy goals.

### **Ofgem's Duties**

178. We agree with the CMA that the decision to make competition a secondary principle within Ofgem's duties has contributed to poor outcomes for both competition and consumers.<sup>55</sup> We agree that the Retail Market Review, and the prohibition of regional price discrimination are good examples of changes that have not been beneficial to competition.
179. We strongly support the movement towards principles based regulation and away from prescriptive regulation. We believe this change has the potential to enhance competition materially, but only if implemented appropriately. In this regard, Ofgem's approach to the definition of fairness will be critical. Specifically, we do not believe that a "fair" outcome is necessarily a "standardised" outcome. Customers who invest more time in trying to find a price or product that best suits their budget or needs should be able to choose products that suit those needs, even if that results in outcomes that differ from the average customer.

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<sup>51</sup> Provisional Findings, para.11.16.

<sup>52</sup> Ibid, para.11.17.

<sup>53</sup> <https://www.ofgem.gov.uk/ofgem-publications/39646/irtcondocfinal.pdf>

<sup>54</sup> Provisional Findings, para.11.41 and 11.42.

<sup>55</sup> Ibid, para.11.52 onwards.

### **DECC and Ofgem interactions**

180. We also agree with the CMA that the relative responsibilities of DECC and Ofgem have at times become blurred.<sup>56</sup> In our view, DECC's role is to set out overarching GB energy policy framework, whilst Ofgem's role is to design and implement the regulatory framework in a way that is consistent with their Primary Duties.
181. Despite this, there have been areas where DECC have become involved in the specific detail of policy.<sup>57</sup> For example we have seen DECC legislate to ensure Ofgem's RMR tariff reforms went ahead (even consulting in parallel on similar issues), seek to standardise the end of Direct Debit plan process, and more recently secure the introduction of 'QR codes' on energy bills.<sup>58</sup>
182. This has resulted in responsibility for regulatory decision making at times becoming unclear, and the process for making such decisions inefficient.

### **The governance of industry codes**

#### **Harmonisation of codes**

183. We agree with the CMA that there is scope and benefit in streamlining aspects of the code governance framework.<sup>59</sup> We also agree that a consolidation of codes in itself would not bring significant competition benefits.<sup>60</sup> We believe that the roll out of smart meters and the implementation of Project Nexus are major opportunities to deliver simpler industry processes and procedures which in time will enable code simplification.
184. The creation of a single 'Design Authority' (DA) may support this, taking on the role played by Code Administrators today, and providing the vehicle for harmonisation of administration practices such as change control. A DA may also be able to better co-ordinate cross-code change, resolve areas of contention, prioritise, and generally help project manage proposals such that they are delivered more promptly than today.

#### **SCR process**

185. We acknowledge that the Significant Code Review (SCR) processes held to date have taken a long time to complete. In part, and as Ofgem note, this reflects the high complex and technical nature of the problems being investigated.
186. It also reflects however the fact that, at times, the quality of Ofgem's initial proposals and supporting analysis has been poor. For example, in the Gas SCR significant changes were required to both the initial proposals and supporting analysis before a final decision could be taken.
187. We also have concerns that Ofgem often do not appear to have appropriate resources to thoroughly analyse the most complex and technical aspects of the energy industry. For example, in the Gas SCR we believe that the proposals consistently underestimated the impact and consequences of imbalance risk exposure. Given this, we

<sup>56</sup> Ibid, para.11.65 to 11.70.

<sup>57</sup> Ibid, para.11.71 and 11.72.

<sup>58</sup> [https://www.gov.uk/government/uploads/system/uploads/attachment\\_data/file/352685/QR\\_codes\\_-\\_Govt\\_Response\\_-\\_Final\\_Template\\_version\\_dotx.pdf](https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/352685/QR_codes_-_Govt_Response_-_Final_Template_version_dotx.pdf)

<sup>59</sup> Provisional Findings, para.11.104.

<sup>60</sup> Ibid, para.11.106.

do not accept that the length of SCRs held to date can be accounted for simply by large energy firms resistance to the measures proposed.

188. Finally, in paragraph 11.146, a spurious “not” has been added to our position in line 10 with the effect that the meaning has been changed. Specifically, we believe that Ofgem may on occasions reject industry proposals for reasons which were apparent before the detailed assessment and proposal development work began. This is not only frustrating for industry participants engaged in the process; it can also lead to unnecessary delay to important industry change.

### **Code Administrators**

189. We agree with a number of CMA comments regarding the process and criteria for selecting Code Administrators.<sup>61</sup> In our experience, we see examples of best practice exhibited amongst Code Administrators, but also examples where their quality of their work is either inconsistent or poor.
190. Notwithstanding this, we have some reservations with the suggestion that Code Administrators could be selected by competitive tender. Whilst cost of service is an important factor in choosing a Code Administrator, we believe that the quality and experience of resource is equally – if not more so – important. For example, the role of BSC Code Administrator requires a specialist and in-depth understanding of complex wholesale electricity market arrangements.

### **Ofgem powers to direct change**

191. As above, we believe that Ofgem should be responsible for designing and developing the regulatory framework necessary to enact DECC’s stated policy. We therefore accept that Ofgem needs to have appropriate powers to direct industry change, for example as they do today with changes to market participant’s licences.

### **Code Panels**

192. We agree with the CMA that the composition of Code Panels is not fundamentally biased in favour of large energy firms.<sup>62</sup> Moreover, we are not aware of any evidence that Code Panels or Working Groups have deliberately sought to delay or to prevent pro-competitive change in the narrow interests of a particular company or group of companies.

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<sup>61</sup> Ibid, para.11.128.

<sup>62</sup> Ibid, para.11.125 and 11.139.

## Nature of wholesale market competition

193. We agree with the CMA's provisional finding that there are no features in the wholesale gas market that lead to an AEC, nor any ability or incentive of generators to exercise unilateral market power in the wholesale electricity market, and hence no AEC. We have no further comments on these issues beyond those we provided in our response to the Updated Issues Statement.

## Wholesale Market Rules and Regulations

194. We generally support the provisional conclusions of the CMA in respect of wholesale electricity market rules and regulations, as set out in Chapter 5 of its Provisional Findings report (and associated appendices), subject to the detailed comments set out below which we cover in the following sections:

- Self-dispatch
- Absence of locational prices for transmission losses and constraints
- Imbalance price reforms
- Capacity Market
- Contracts for Difference

### *Self-dispatch*

195. We agree with the CMA's provisional finding (paragraph 5.30) that the GB self-dispatch system does not reduce price transparency, increase transaction costs or give rise to systematic technical inefficiency.

196. In our experience the current GB system of decentralised self-dispatch provides a high level of wholesale price transparency, with transaction costs that are broadly comparable to those of a centralised dispatch alternative.<sup>63</sup> Furthermore, we consider that a self-dispatch system may even be more efficient, based on the superior knowledge of plant operators regarding the operating and cost characteristics of their individual generation units.

197. The CMA's assessment of generating plant dispatch, including the Intergen evidence making reference to one of our own power stations (paragraphs 11-21 of Appendix 5.1), is consistent with our own interpretation. We agree with the CMA's conclusion that the Intergen evidence does not raise any material concerns around the overall technical efficiency of self-dispatch in the GB electricity market.

### *Absence of locational prices for transmission losses and constraints*

198. We support the principle of cost-reflective network charging in the interests of encouraging economically efficient investment/location decisions and promoting economically efficient plant dispatch.<sup>64</sup> In this respect, the outcome of the Project

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<sup>63</sup> Please see our response dated 30 March 2015 to the CMA's Working Paper of 27 February 2015 on Wholesale electricity market rules.

<sup>64</sup> Please see our response dated 30 March 2015 to the CMA's Working Paper of 23 February 2015 on Locational pricing.

TransmiT Significant Code Review is unfortunate since, in our view, it marked a move away from fully cost reflective transmission charging. We also agree with the CMA's assessment (paragraphs 39-40 of Appendix 5.2) that there is no 'customer confusion' argument sufficiently compelling to overturn the principle of cost-reflective network charging.

199. We therefore support the principle of introducing locational prices for transmission losses (paragraph 5.44), provided that a scheme can be developed which sends appropriate cost-reflective price signals and remains robust in the face of significant changes in both generation mix and transmission network configuration. As far as possible, individual generators should face the costs of transmission losses to which their location and dispatch decisions give rise and the basis for those locational price signals should be sufficiently predictable that they can be factored in with reasonable accuracy when an investment decision is made. If these conditions are not satisfied, then locational pricing of transmission losses would not deliver the expected efficiency benefits.
200. We did not support the P229 proposals mentioned in paragraph 5.43 because we had concerns about the accuracy of the modelling used to calculate locational transmission loss factors, which seemed likely to lead to significant allocation errors in a number of instances. In particular, we considered that the impact of offshore wind generation on the allocation of losses to onshore generation in the same transmission zone would have led a number of onshore generators to face charges for transmission losses well above a genuinely cost-reflective level. Moreover, the proposed methodology did not, in our view, create sufficient transparency/predictability around the longer term allocation of transmission losses to be factored into plant investment decisions. We therefore considered that the distributional impact of P229 was disproportionate relative to the likely efficiency gains.
201. We raise this example to illustrate the fact that 'the devil is in the detail' when it comes to designing a robust and economically efficient pricing scheme. Given the conditions sets out above for delivering meaningful efficiency benefits, we would not support the revival of those P229 proposals (paragraph 5.55).
202. Since transmission losses are already reflected in plant dispatch algorithms and related IT systems, albeit on a uniform non-locational basis, implementation costs may well be modest relative to the expected benefits of locational loss allocation (paragraph 5.51). Nevertheless, careful design will need to be supported by updated cost-benefit analysis and consideration of the transitional impact on investment/development projects already 'in flight'.
203. There may also be a case, in principle, for moving to a more cost-reflective scheme of charging for transmission congestion, but the benefits case is much less clear-cut and we agree with the CMA that it would be premature to consider this in detail before the relevant EU legislation is settled. The complicating factors include the significant investment currently in train to relieve existing transmission constraints, especially those between Scotland and England. We would also be concerned if any 'market splitting' which resulted from locational charging for constraint costs led to a material dilution of wholesale electricity market liquidity which (as Ofgem and the CMA have both recognised) plays an important role in the effective operation of a competitive electricity market. In addition, we concur with the CMA's assessment (paragraph 5.70, also paragraph 24 of Appendix 5.2) that the transition and implementation costs of

locational charging for constraints would be significantly higher than those related to locational charging for transmission losses.

204. The decisive factor as regards the timing of any GB initiative in respect of locational constraint costs is in our view that highlighted by the CMA in paragraphs 5.74-5.76, i.e. impending EU legislation via the binding network code process. We do not therefore believe it would be appropriate to initiate a review of GB practice in this respect until the impact of such EU legislation becomes clearer.

### ***Imbalance price reforms***

205. We supported the principle of moving to a single electricity cash-out price as reflected in Ofgem's EBSCR decision and we also saw the need to provide a 'sharper' (more marginal and cost reflective) imbalance price signal. However, we shared the concerns of many others about the proposed move to a 'PAR 1' methodology for establishing those prices. In particular, PAR 1 cash-out prices may not prove sufficiently robust, consistent and competitively determined.
206. The CMA's assessment highlights the position of smaller suppliers under the proposed new cash-out and balancing rules (CMA Appendix 5.1, paragraphs 59-60). The position of larger energy firms is not discussed, but logically their imbalances are likely to be more strongly correlated with overall system imbalance, i.e. they will be relatively more exposed to 'being short when the system is short.' In our view, therefore, both larger and smaller suppliers may be adversely affected if our concerns about PAR 1 cash-out prices materialise.
207. In Appendix 5.1, paragraph 88, the CMA considers the extent to which EBSCR incentives feed through effectively to retail supply based on standard load profiles. We believe, in the short to medium term, the cost savings available to individual domestic customers to shift load away from peak – currently around £20/annum – will be unlikely to drive behavioural changes, and thus demand for dynamic Time of Use Tariffs. Notwithstanding this, some incentives to shift load away from peaks already exist for domestic customers with traditional meters (eg for those customers with "white meters" on a two-part day/night tariff), and we believe that smart metering will enable more sophisticated static Time of Use tariffs to be developed, for example our 'Free Saturdays' tariff.
208. Given that an EBSCR decision has now been made, it will be important to monitor the impact of the introduction of the transitional 'PAR 50' arrangements, and remain open to the possibility of subsequent adjustment should these concerns appear to be well-founded. We are encouraged by Ofgem's reassurance in this respect, reflected in paragraph 5.129 (a), and we support the CMA's conclusions in paragraph 5.18 as well as in paragraphs 5.130-5.132.
209. We consider that the CMA may have over-stated the likely impact of Reserve Scarcity Pricing (RSP), once 'flagging and tagging' is taken into account (Appendix 5.2, paragraph 54 and specifically footnote 26). Nevertheless, we share some of the CMA's wider concerns (Appendix 5.2, paragraph 110) about the underlying inconsistency of supply security criteria adopted and applied across the GB electricity sector. It is important that various measures introduced to support supply security should be fully 'joined up' in that sense.

## Capacity Market

210. We support the underlying rationale for the Capacity Market and consider it to be broadly well-designed on the basis of a market-wide, technology-neutral competitive auction. Given the large-scale development of intermittent renewables, which looks set to continue, we consider that an energy-only market is unlikely to provide incentives for the development and maintenance of sufficient thermal generating capacity to ensure an adequate level of supply security.
211. It is right to keep the detailed design of the Capacity Market under review and there are likely to be specific aspects which require adjustment over time. Nevertheless, we also consider it important to ensure sufficient stability of CM rules, in the interests of maintaining a predictable investment climate, unless there is compelling evidence to support a change.

## Contracts for Difference

212. Action to drive investment in low carbon generation should be carried out as cost-effectively as possible. This is in the interests of consumers, the wider economy and (over time) the political sustainability of climate change policy itself. We therefore support the CMA's remarks (paragraph 5.179) around the economic case for an appropriate Europe-wide carbon price signal and the current failure of the EU ETS to provide that signal. This sets the context for UK policy around support for low carbon generation and other necessary interventions such as the UK Carbon Price Floor.
213. To be effective, the CfD regime needs to provide a predictable investment climate (i.e. avoid creating an undue level of policy risk) and at the same time promote cost-effective GHG abatement. We remain concerned that making only limited use of competitive bidding may put both these important objectives at risk.
214. We recognise that a competitive mechanism for allocating CfDs is unlikely to be feasible or appropriate for unique 'First of a Kind' (FOAK) projects such as new nuclear or Carbon Capture and Storage (CCS).<sup>65</sup> This is consistent with the CMA's conclusion in paragraph 5.189. This makes it all the more important, in such cases, to be clear that the technology concerned can realistically be expected to contribute towards the goal of cost-effective carbon abatement in the longer term.
215. We support the CMA's assessment of the case for making use of competitive CfD allocation, wherever possible (paragraph 5.188) and agree with the suggestion that DECC should provide a clear and objective justification for any non-competitive CfD allocation, as well as for the apportionment of low carbon technologies between competitive allocation 'pots'.
216. We also see a need for clear signals to given well in advance of the point at which a given low carbon technology will:
- cease to qualify for subsidies (and thus CfDs) because is it considered cost-effective enough so as no longer to need them;
  - be considered sufficiently 'established' to move from Pot 2 to Pot 1 of the competitive CfD allocation process; or

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<sup>65</sup> Please see our response CMA's Working Paper on Wholesale electricity market rules.

- c) be deemed unlikely ever to deliver cost-effective GHG abatement and therefore cease to justify the provision of subsidies.
217. In relation to (a), the recent government decision to phase out subsidies for onshore wind projects earlier than expected may have an adverse impact on some relatively low cost renewable projects which were already under active development but had not yet reached FID. In relation to (b), there will be a need to clarify, in the near future, the basis on which offshore wind projects will transition from the 'non-established' to 'established' category – given the substantial experience which now exists with such projects in the UK – such that they compete directly with other low carbon projects in 'Pot 1'.
218. We therefore agree with the CMA's provisional conclusions (paragraphs 5.244-5.246) in favour of greater transparency, robust arguments and evidence to support the treatment of different low carbon technologies and projects in respect of CfD allocation.

## Vertical integration

219. We welcome and agree with the CMA's findings that there is no potential competitive detriment resulting from vertical integration and provide comments on the following sections:
- Potential competitive detriment resulting from VI
  - Benefits of VI
  - Provisional conclusions on VI

### *Potential competitive detriment resulting from VI*

220. We agree with the conclusion in paragraph 6.26 that VI is unlikely to have a significant impact on which products are available to trade on the open market and we welcome the provisional conclusion that VI firms do not appear to be experiencing a competitive advantage in relation to liquidity.
221. On the issues of customer and input foreclosure, considered by the CMA, we recognise and agree with the conclusion in paragraph 6.47 that the evidence does not indicate there is a problem arising from foreclosure in GB electricity.

### *Benefits of VI*

222. We agree that vertical integration benefits consumers through reducing transaction costs and creating efficiencies across the vertically integrated group, for example cost and system efficiencies and reduced credit and collateral requirements.
223. We do not agree with the conclusions reached in paragraph 6.111. In particular we do not agree that there is no evidence that VI leads to a lower equity beta nor with the conclusion that there should not be a material difference in beta between a stand-alone supplier and a vertically integrated entity. This ignores the netting off benefits that can accrue to vertically integrated entities in terms of margining and credit risk and

smoothing earnings,<sup>66</sup> and also ignores the evidence that in reality vertically integrated suppliers do have lower equity betas than standalone suppliers (e.g. compare the betas of Centrica at around 0.4 and Just Energy at 0.9-1.2).<sup>67</sup> We respond further to these points in the Profitability appendix.

### ***Provisional conclusions on VI***

224. We do not agree that there are financial transparency issues that arise partly due to firms' VI structure that give rise to an AEC (paragraph 6.123). Centrica provides a transparent and audited view of our accounts as part of the annual Consolidated Segmental Statement process which gives stakeholders assurance that the stated profits earned upstream and downstream are accurate. We consider and respond to the point raised on the regulatory requirement for clear and relevant financial reporting in our response to Remedy 14.

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<sup>66</sup> See Centrica response to G21a, and Moody's statement at para.17 of Provisional Findings Appendix 10.3 p.35 which says that "the ability of a VI firm to achieve a strong credit rating arises from several factors. An important factor is the ownership of generation, transmission and distribution, and retail supply, and also in some cases being part of the wider global group. This smoothes [sic] and diversifies earnings."

<sup>67</sup> Provisional Findings Appendix 10.4, p.17, Table 4.

## Response to the Notice of Possible Remedies

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## Remedy 1 – Locational transmission losses

225. **We support the principle of cost-reflective network charging in the interests of encouraging economically efficient investment/location decisions and promoting economically efficient plant dispatch. We therefore support the principle of introducing locational prices for transmission losses, provided that a scheme can be developed which sends appropriately cost-reflective price signals and remains robust in the face of significant changes in both generation mix and transmission network configuration.**
226. This is a complex issue. Careful design will be needed to ensure that losses are allocated appropriately and a robust cost-benefit analysis is required to reflect implementation and transition costs, as well as the efficiency benefits. If not properly cost-reflective, or sufficiently predictable as regards the likely allocation of losses over the life of generation plant investment, a system of locational transmission losses will fail to deliver the expected benefits.
227. A well-designed mechanism may be beneficial, in terms of efficient dispatch and investment location, but flawed proposals have been rightly rejected in the past. The efficiency benefits will need to be set against the implementation and transition costs.

### **Response to CMA's Questions (Remedy 1):**

*(a) What would be an appropriate method for ensuring that variable transmission losses are priced on the basis of location?*

- This is a complex matter which will need careful, detailed design to ensure cost-reflectivity, including as regards the zonal allocation of generators/consumers and the application to consumer sites on which decentralised generation is taking place.
- The key principle should be that transmission losses are (as far as possible) borne by the parties which occasion them and that the allocation remains robust to changes in generation mix and network configuration over time.
- An appropriate method for allocation of locational transmission losses should be technology-neutral.

*(b) How should the variable transmission losses be allocated between generators and suppliers? Is the 45-55 split appropriate or could efficiency be improved further by changing this allocation?*

- The 45-55 split between generation and demand (in effect, 50-50 adjusted for transformer losses at the interface) may be an appropriate starting point, consistent with the existing 50-50 split of BSUoS.
- However, the allocation of transmission losses between generators and 'demand' might need to change over time, e.g. if incremental losses were attributable to additional remote wind farms and/or network enhancements (such as the offshore 'western bootlace') designed to accommodate them.
- The allocation of losses needs to be sufficiently flexible to take account of this in a cost-reflective manner.

*(c) What will be the distributional impacts of this remedy? Should the CMA take these into account in coming to a view on the proportionality of this remedy?*

- The key challenge is to develop a loss allocation mechanism which is, and remains, cost-reflective.
- A flawed mechanism in this sense is likely to have undue and unintended distributional impacts (between generators and/or consumers) which should be avoided.
- If the question refers to the impact of genuinely cost-reflective transmission loss allocation on consumer bills in different regions, then in our view this would be a matter for policy makers rather than industry participants to consider.

*(d) Should the CMA implement this remedy directly, i.e. via an order, or should it make a recommendation to Ofgem to initiate a BSC modification instead? Are there any particular aspects of Ofgem's objectives and duties to which the CMA should have regard if implementing this remedy by a licence change?*

- Given the complex design issues, the associated risk of unintended consequences and the likely distributional impacts, we consider that a BSC modification would be appropriate to ensure that industry stakeholders are fully engaged in the process.
- We consider that priority should be given to cost-reflectivity and effective competition. It should not be the function of transmission loss allocation to provide 'hidden' support for offshore wind farms or any other specific type of generation plant.

## Remedy 2 – CfD Allocation

228. **We support the principle of using competitive CfD allocation as widely as possible once low carbon technologies can be regarded as sufficiently ‘established’.**
229. We support the principle of cost-effective emissions abatement to address the risk of adverse climate change, and thus support the principle of using competitive CfD allocation as widely as possible. However, competitive allocation of CfDs may not be appropriate in the case of unique or emerging low carbon technologies with genuine longer term potential to help meet that goal.
230. The design of CfD auctions is proven and generally effective. The greater challenge is to decide (and signal well in advance) when a particular low carbon technology is sufficiently ‘established’ to move to a more competitive allocation approach, or has made such progress in cost reduction that subsidies are no longer required, or else seems unlikely to become cost-effective and therefore no longer warrants CfD support. For example, we consider that it may now be appropriate to review whether/when offshore wind should now be treated as an “established” low carbon technology. Recent experience with competitive auction-based allocation of CfDs is that it can be effective for a number of low carbon technologies.

### **Response to CMA’s Questions (Remedy 2a):**

*(a) Would the remedy ensure that CfDs that are allocated outside the auction mechanism are awarded only when the benefits of doing so outweigh the costs?*

- This could, in our view, help to ensure that (a) the pros and cons of different allocation approaches are thoroughly aired and evaluated and (b) that there is sufficient transparency around any future changes in allocation approach.

*(b) How much discretion should DECC retain in terms of the weight it places on each factor that it takes into account in coming to a decision on which projects to award CfDs outside the CfD auction mechanism? Should DECC be required to consult on and determine these factors and their relative importance in advance to enhance transparency? Should the weighting of each factor be constant across projects?*

- We are not certain that it would be possible to place ‘scientific’ weights on each factor, in a consistent fashion.
- Nevertheless, we support the principle of maintaining a consistent, transparent approach (as far as possible) and consider that a clear and thorough IA/consultation process would help to achieve this goal.

*(c) In which, exceptional circumstances should DECC be able to allocate CfDs outside the auction process? For example, for reasons of industrial policy, where there are wider market failures, or where there may be insufficient competitors to hold an auction?*

- The clearest justification for CfD allocation outside an auction process is where there is a ‘unique’ low carbon technology with genuine long term potential to become cost-effective, but insufficient candidate projects to support a competitive allocation (e.g. FOAK new nuclear and/or CCS)

## **Response to CMA's Questions (Remedy 2b):**

*(a) Would the remedy ensure that future decisions by DECC on the allocation of technologies and the CfD budget to the different pots are taken in a robust and transparent manner?*

- This could, in our view, help to ensure that (a) the pros and cons of proposed allocation approaches are thoroughly aired and evaluated and (b) that there is sufficient transparency around the allocation approach.

*(b) Is the remedy likely to result in a positive change in how DECC makes decisions regarding the allocation of the CfD budget to the different pots?*

- The practical impact of this remedy is largely a matter for DECC, but we consider that it is likely to be helpful in this regard.
- We consider that the effectiveness of remedies 2a and 2b could potentially be enhanced by extending the remit of the CCC to cover specialist advice on the cost-effectiveness of GHG abatement - and not simply whether or not a given abatement target is likely to be achieved.
- The NAO may also have a potentially useful role to play, e.g. in terms of periodic 'value for money' scrutiny of the CfD allocation policy and process.

*(c) How regularly should DECC review the allocation of technologies between pots? What information should DECC publish when deciding to amend the allocation of technologies between pots? Should it also on a regular basis consult and/or publish reasons for not amending the allocation of technologies between pots?*

- We do not have a hard and fast view, but we consider that default review period of every two years might be appropriate, if an earlier consultation has not been triggered by proposed changes in approach.
- In our view, this approach risks becoming over-mechanistic and thus insufficiently flexible.

*(d) Should DECC be limited in the maximum proportion of the CfD budget that it can allocate to each of the different pots?*

- In our view, this approach risks becoming over-mechanistic and thus insufficiently flexible.

## Remedy 3 – Remove ‘simpler choice’ element of RMR

231. **We support the proposed remedy. However, we believe this Remedy should be extended to also include a repeal of the rules which limit what can and cannot be bundled with energy tariffs. The remedy should also relax the prescriptive information remedies introduced by Ofgem as part of the “clearer” package of RMR remedies.**
232. Remedy 3 as proposed will enable suppliers to develop a range of products that will allow them to better target the customers of other suppliers, and enhance competition materially. Removing the four tariff cap will also remove the barriers suppliers face today in trialling new tariffs. Today, if a supplier is already using their full allotment of tariffs, they can only trial a new tariff by either first seeking derogation from Ofgem or developing a white label partnership. In our experience the derogation process can take several months to complete. As well as limiting suppliers’ ability to compete with each other, this places Ofgem in the position of determining what innovation should and should not take place in the market.
233. We agree with the CMA’s proposals to end the ban on cash discounts. We know that customers find cash offers more engaging than non-cash offers, and believe that removing the ban will further enable suppliers to design offers that engage customers and compete harder with rivals.
234. We are aware that some have argued that the use of cash discounts may lead to customers choosing a tariff with a high up front discount and a high unit cost of energy. However, we believe that both the increasing use of Price Comparison Websites (PCWs) and the shift towards fixed term contracts (FTCs) we propose under Remedy 10 would help mitigate this risk. It will also enable suppliers to bring back popular offers that have previously been prohibited, for example the Prompt Payment Discount.
235. In addition to the remedies already proposed in this area, the CMA should also look to relax the information remedies that were introduced as part of the RMR. Although we support the aim of ensuring that customers have all the information they need in order to make an informed decision, the way that suppliers have been required to implement these remedies has been too restrictive, and contributed to customer confusion which may have discouraged customer engagement. In particular, this can be seen in the rules that prescribe the format and content of the energy bill and the rules which prevent suppliers from providing offers of mitigation with any price increase notification.
236. Other elements of the information remedies will be inappropriate for the future market envisioned by the CMA. For example, we believe the current obligation to provide customers with the Cheapest Tariff Mechanism (CTM) will act as a barrier to the type of exclusive deals between PCWs and suppliers that the CMA believes will become a feature of the market. It is also incompatible with a market shifting towards tariffs that are accompanied by a range of discounts and tailored services and products. The obligation to provide the CTM should therefore also be removed as part of this remedy.

237. Furthermore, the CMA should also remove the obligation to provide a Tariff Comparison Rate (TCR).<sup>68</sup> Suppliers are currently obliged to provide a TCR to their customers so that they may more easily compare tariffs across the market. The metric is only accurate for customers who use exactly the amount of gas or electricity that Ofgem determine as ‘average’ however, with the results turning increasingly inaccurate the further a customer’s consumption is from that ‘average’.
238. Our experience is that the unnecessarily prescriptive and scripted nature of the TCR and Personal Projection (PP) prevent us from having customer friendly sales conversations. We are also concerned that the inaccurate results produced by the TCR will falsely market some tariffs as good value when they are not, potentially undermining customer trust in future switching.
239. These remedies would all be relatively cheap and easy to implement, requiring only a change in the regulations.<sup>69</sup> We therefore consider them to be effective, feasible and proportionate.

### **Response to CMA’s Questions (Remedy 3):**

*(a) Would this remedy be effective in increasing competition between domestic retail energy suppliers and/or between PCWs? What additional tariffs would energy suppliers be likely to offer that they currently do not due to the RMR restrictions?*

- Yes, as above, this remedy would be effective at increasing competition by enabling suppliers to better compete with each other by developing more engaging and innovative products and product structures.
- We also agree that this remedy would enable suppliers to once again agree exclusive offers with individual PCWs. This would enhance competition within both the retail and PCW markets. As above however, in order to facilitate this change, we believe the CMA should remove the obligation to provide the CTM.

*(b) Removing the four-tariff rule is likely to increase the range of tariffs on offer and result in different tariffs being offered on different PCWs. Are there, therefore, any remedies that the CMA should consider alongside this remedy, to encourage domestic customers to use more than one PCW in order to facilitate effective competition between PCWs and domestic energy suppliers?*

- No. We believe that, provided PCWs are required to be transparent about the extent of market coverage they provide, the market should find a solution to this. For example, we believe it possible that some PCWs could seek to gain an advantage by providing a ‘whole market view’. Remedies in this space may crowd out such innovations.

<sup>68</sup> As defined in SLC1, the TCR is derived by calculating the cost of the non-conditional elements of a tariff, including standing charge, unit rate, bundles, discounts and charges, over the next 12 months for a customer consuming an ‘average’ amount of energy, as determined periodically by Ofgem.

<sup>69</sup> Specifically, by repealing SLC22B, and amending SLC31 in respect of the Personal Projection and Tariff Comparison Rate. The CMA should also seek to remove the reserve powers the Secretary of State has to reintroduce these regulations, within the Energy Bill (2013).

*(c) We note that if this remedy were to be imposed, Ofgem's Confidence Code requirement for PCWs to provide coverage of the whole market appears likely to become impractical as the number of tariffs offered increases and PCWs agree different tariff levels and commissions with energy suppliers. Should this element of the Confidence Code be removed, therefore, as part of this remedy? If so, are alternative measures to increase confidence in PCWs required? For example, in order to maintain transparency and trust, should PCWs be required to provide information to customers on the suppliers with which they have agreements and those with which they do not?*

- In order to enable customers to make informed decisions about which PCW they use we believe that the Confidence Code should require PCWs to be transparent about the extent of market coverage they provide.
- However, we do not believe that all PCWs should be required to cover the whole market. Some PCWs may well seek to be selective, with others preferring to provide whole market coverage. The decision over providing differentiated services by PCWs should be part of the competitive market dynamic. We therefore agree that the current obligation to provide coverage of the whole market should be removed from the Confidence Code.

*(d) Rather than removing all limits on tariff numbers and structures, would it be more effective and/or proportionate to increase the number of permitted tariffs/structures? If so, how many should be permitted and which tariff structures should be allowed?*

- No. Limits on the number or structure of tariff structures would limit the effectiveness of competition. We also believe that the rise of PCWs aids tariff comparability across suppliers and will mitigate any search costs associated with an increase in the number of tariffs. We are also aware that the market has previously demonstrated the ability to self correct when customers found tariff proliferation increased the difficulty with finding the right product.

*(i) For example, would requiring domestic energy suppliers to structure all tariffs as a single unit rate in pence per kWh, rather than as a combination of a standing charge and a unit rate, reduce complexity for customers, while avoiding restricting competition between PCWs? Alternatively, would such a restriction on tariff structures have a detrimental impact on innovation in the domestic retail energy markets?*

- No. Limits to the number, structure or type of tariffs and products would limit the effectiveness of competition. High consuming households would become very profitable, and low consuming households would become loss making. This in turn could lead to a two-tier market emerging, where low consumers become increasingly less well served by the market.
- A single unit rate would also prevent suppliers from competing on different tariff structures, for example with products designed to target low consumers with low standing charges and high unit rate.

## Remedy 4 – Barriers to switching by domestic customers

### 4a – Measures to address barriers to switching by domestic customers

240. **Our experience – and the evidence the CMA has at their disposal - does not support the CMA’s provisional findings on levels of customer engagement. Notwithstanding this, we fully support any measures that can be shown to have a positive impact on engagement and which promote effective competition in the retail market.**
241. Central to this will be the introduction of smart metering which enables suppliers and third parties to create products and services that enable the customer to better control their energy use. We therefore recommend that the CMA also look to ensure the roll out of smart meters is completed on time as part of any customer engagement remedy.
242. Comments on the questions asked by the CMA regarding specific barriers identified in this section of the Remedies Notice are set out below.

### **Response to CMA’s Questions (Remedy 4a):**

*(a) Will the roll-out of smart meters address the feature of uncertified electricity meters? If not, what additional remedies should we consider to address this feature?*

- Yes. The smart meter roll out will ensure that the current population of uncertified meters are all replaced.
- We note that there is a risk in the short term that the problem of uncertified meters may get worse before it is finally resolved by the smart meter roll out. For example, one driver of uncertified meters in the market today is the fact that smart meters cannot yet be installed in every domestic premises. In such cases, suppliers incur stranding charges for installing a traditional meter in the short term. There would also be some customer detriment associated with multiple meter exchanges within a short period of time.
- This problem should be seen in context - only [X] of Centrica’s meter points are uncertified today – however the CMA may consider providing suppliers with derogation from the certification rules for certain meter types until the smart meter roll out completes in 2020.

*(b) Will the roll-out of smart meters address the barriers to switching faced by customers with Dynamic Teleswitched (DTS) meters? If not, what additional remedies should we consider to address this feature?*

- Dynamically teleswitched (DTS) meters work in a similar way to traditional ToU meters, except for the fact that the time when the meter switches between peak and off peak is controlled remotely by the network operator. Often the time at which the meter changes which register is used varies depending on a range of factors, for example the weather.
- Whilst we understand that all suppliers supply DTS customers, the fact that the peak or off peak usage is both unpredictable and controlled by a third party means that suppliers can find it difficult to create a tariff to match the customer’s peak / off peak

profile. Consequently, suppliers will need to either need to price in the risk associated with a change in peak / off peak consumption or put the customer on a 'best fit' tariff. Many of the offers these customers find in the market are therefore not attractive compared to what can be offered by the incumbent supplier.

- Unfortunately, although the smart meter roll out will mean that these customers will have their DTS meters exchanged for meters that meet a common specification, the network will still remain in control of the time when the meter changes between peak and off peak usage. Consequentially, we believe that suppliers will continue to face problems in creating a tariff which can match the customer's usage profile.
- We believe that this problem will persist for as long as there is a disconnect between who controls the time periods and who controls the price. Alternatively, customers could be encouraged to have a non-DTS system installed. This may however be difficult given the fact that many DTS systems are integrated with the customer's heating system.

*(c) Should PCWs be given access to the ECOES database (meter point reference numbers) in order to allow them to facilitate the switching process for customers? To what extent would this reduce the rate of failed switches and/or erroneous transfers? Are there any data protection issues we should consider in this respect? Will access to this database still be relevant once smart meters have been introduced?*

- We support industry efforts to reduce the frequency of erroneous transfers, and believe that changes such as the introduction of the ECOES industry database have helped to improve the switching process for customers.
- We do not however agree that giving PCWs access to ECOES would be beneficial. All PCW sales are already passed to suppliers for fulfilment, and at that time will be checked against ECOES to ensure that the right site is being applied for. A further check by the PCW would therefore add no value to the process. It would however mean that personal data held about the customer is shared with a third party (with implications for data privacy).<sup>70</sup>
- This proposal would have implications for data privacy. Whilst we presume that the PCW could easily gain the necessary customer consent in order to access this information it would still create the risk of misuse of the data, without reducing the instance of erroneous transfers or providing any other benefit. This remedy would therefore be ineffective and disproportionate.

*(d) Should there be penalties for firms that fail to switch customers within the mandated period (currently 17 days, next day from 2019)? How should these penalties be administered? At what level should the penalties be set? Should customers who suffer a delayed or erroneous switch receive the penalty as compensation?*

- We support the proposal to properly compensate customers for losses incurred as a result of delayed switching. We also believe this would act as both an additional control on non-compliance with obligations in this area, and an incentive on suppliers to deliver faster switching. Properly designed, this remedy could be both effective and proportionate.
- The agreement made to switch customers within 17 days in electricity and 18 days in gas is a voluntary agreement with DECC however, based on the understanding that

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<sup>70</sup> For example, the meter serial number, the MPAN (or supply reference number), home address and switching history.

achieving this would not be possible in 100% of cases, for example when an objection is raised. Any compensation measures should be therefore against the 21 day mandatory target and not the 17 day voluntary target.

- We support a flat fee compensation rate provided it reflects a reasonable estimate of the customer loss from a delay, with a minimum payment level of, for example, [X] per day to avoid paying immaterial amounts.
- Finally, we assume that the compensation should be paid for by the new supplier, given the obligation to enact the switch rests with them. Procedures would need to be agreed to ensure any costs can be recovered from the old supplier when the delay was attributable to them.

*(e) When next-day switching is introduced, will a ‘cooling-off’ period still be required? Could it be avoided by requiring that no exit fees are charged within two weeks of switching?*

- Replacing cool-off with a ‘no-exit fee’ switch window would achieve the same level of consumer protection, remove a potential barrier to switching and work well with the post-smart metering design. We therefore support this remedy in principle, believing it to be both effective and proportionate.
- The CMA would however need to overcome the legislation which requires suppliers to provide a cool-off period.<sup>71</sup> We note that this is an area which Ofgem and suppliers are already looking at, with the remedy proposed by the CMA one of the possible options.

*(f) Are specific measures required to facilitate switching for customers living in rented accommodation (either social or private)?*

- We understand that this issue typically arises when some landlords include terms within the tenancy agreement that prevent tenants from switching energy supplier.
- The CMA could also consider what information gaps may exist that give rise to the misconception amongst some tenants that they are unable to switch. Whilst suppliers include prompts reminding customers that they can switch on bills and other communications, there may be a role for Ofgem or third party organisations such as the Citizens Advice Bureau or housing associations to play.

*(g) Does the ‘Midata’ programme, as currently envisaged, provide sufficient access to customer data by PCWs to facilitate ongoing engagement in the market? Should PCWs – with customer permission – be able to access consumer data at a later date to provide an updated view on the potential savings available?*

- PCWs have played a growing role in the market in recent years and generally act to improve customer engagement in the market. When combined with other proposed remedies, such as the roll-back of tariff restrictions and the development of further engagement prompts, we believe this remedy could have a positive impact on competition. We believe this remedy would be both effective and proportionate, provided it is accompanied with appropriate consumer protection mechanisms.
- To be most effective consideration will need to be given to how to avoid poor customer experience, which could harm rather than help engagement. For example, we believe that express customer consent to both the data access and any switch must be central to this remedy. We also believe that there should be default limits on the amount of contact, for example no more than quarterly. We also believe that

<sup>71</sup> As per the Consumer Contracts (Information, Cancellation and Additional Charges) Regulations 2013.

access to the data should be time limited without fresh consent, for example to 45 days after the end of the customer's contract.

- Finally, assuming express consent had been given, PCW prompts could also form part of the engagement Default Tariff customers receive.

*(h) Do customers need more or better information or guidance on how their new smart meters will work?*

- Part of the smart meter benefits case is realised by simply having the meter on the wall, for example by ending estimated bills and removing the need for pedestrian meter readings. We recognise however that for smart metering to realise its full engagement potential, customers need to be both enabled and encouraged to engage with the meter.
- Appropriate minimums should be, and are, set out within the regulations.<sup>72</sup> These ensure that customers receive sufficient information and guidance to receive the benefits envisioned by the smart metering business case. Added value advice and service is an opportunity for differentiation, and should be left to the market to provide.

#### ***4b – Removal of exemption for Centrica on two-year inspection of gas meters***

**243. We support the extension of the must-inspect derogation to all suppliers, on the basis this will ultimately be necessary to deliver the benefits case of smart meters (and do not support the removal of our existing exemption).**

244. We agree with Ofgem that this obligation is unnecessary given “other regulations and policies, including safety obligations and recently enhanced theft detection and billing accuracy obligations, protect consumers with traditional and smart meters more effectively than the existing inspection obligation”.<sup>73</sup> We therefore agree with Ofgem’s proposal<sup>74</sup> to remove the obligation for all suppliers within the next year. As an interim measure, we believe that our exemption should be extended to all suppliers until the obligation is formally removed.

245. Given the role played by alternative safety measures, including both our theft detection activities and the measures outlined above by Ofgem, it would be disproportionate to remove our derogation at this time. This would result in short term investment in meter inspection capability, which would then be stranded in the near future.

246. Importantly, we also do not agree that, given that an acquiring supplier does not know the last inspection date until the acquisition is complete, our derogation distorts competition. The derogation therefore does not hinder their ability to gain sites. We do not therefore agree that the proposed remedy would be effective.

247. Instead, we support the Ofgem proposal to remove the obligation for all suppliers and believe that – given the alternative safety measures present in the market today – there are grounds to extend our derogation to all suppliers in the interim.

<sup>72</sup> Smart Metering Installation Code of Practice (SMiCoP).

<sup>73</sup> Ofgem – “Reforming suppliers’ meter inspection obligations”, p.1.

<sup>74</sup>

[www.ofgem.gov.uk/sites/default/files/docs/2015/07/reforming\\_suppliers\\_meter\\_inspection\\_obligations\\_final\\_0.pdf](http://www.ofgem.gov.uk/sites/default/files/docs/2015/07/reforming_suppliers_meter_inspection_obligations_final_0.pdf)

248. Finally, we would like to correct the claim made by First Utility about the number of British Gas sites that are past the two-year inspection date. As of March 2015 [X] of our gas sites not had an inspection during the last 2 years.

**Response to CMA's Questions (Remedy 4b):**

*(a) Would this remedy be effective in removing the distortion to competition that currently exists as a result of Centrica's derogation on the inspection of gas meters?*

- We do not believe that our derogation is creating a distortion to competition, as suppliers are blind to which meters require inspection until they acquire them. Therefore whilst they may incur costs following a switch, it is not creating a disincentive to switching.

*(b) Would it be preferable to remove Centrica's derogation, or extend the derogation to other suppliers?*

- No. As above, we support the Ofgem's proposals to remove the obligation for all suppliers and believe that, given the alternative safety measures in place, our derogation should be extended to everyone until this is completed.

*(c) If Centrica's derogation were removed, should it be phased out over a period of time? If so, how long should Centrica be given in this respect?*

- As above, we do not believe Centrica's derogation should be removed. To do so would be neither effective nor proportionate.

## Remedy 5 – Smart roll-out prioritisation for prepayment customers

249. **Whilst we agree with the principle of bringing smart meters to domestic prepay customers early in the rollout process, we do not believe it is necessary or proportionate to make prioritisation mandatory. We do however advocate an intervention requiring the DCC to enrol SMETS1 meters as soon as possible.**
250. Smart meters will significantly improve the prepay customer experience and will reduce cost to serve for this customer segment, driving prepay tariff prices closer to Direct Debit prices once we have built sufficient scale.
251. However, we do not believe it would be sensible to mandate a prioritisation of smart meter rollout for prepay customers. It would be very challenging to implement and the benefits would not outweigh the costs to the wider customer base. We have five key objections to this, listed below:
- **Smart prepay technology is still in its infancy.** This technology is more complex than credit smart meters as the smart infrastructure needs to be integrated with prepay vending and debt management systems. It is therefore essential to ensure this technology is working fully before we roll out in order to avoid a poor customer experience, particularly with regards to the switching process.
  - **Not all prepay customers are currently eligible for smart.** For example, smart meter solutions for tall buildings e.g. blocks of flats, and wide buildings, are still being developed.
  - **Significant costs would be added to the energy bill** if new requirements are included in the smart meter mandate, such as requiring suppliers to replace prepayment meters before traditional credit meters, mainly due to:
    - Additional stranding costs from removing standard prepay meters that have been installed in recent years rather than prioritising the replacement of older credit meters first; and
    - Additional costs of booking appointments.
  - **Suppliers will become incentivised to do this anyway.** When the technology is ready (and trials have been completed successfully) there will be an incentive for suppliers to rollout smart meters for prepay customers. This is because smart prepay meters generally have a lower rental and cash collection costs and also provide the opportunity for suppliers to increase the levels of engagement with prepayment customers.<sup>75</sup>
  - **Many credit customers say they would choose to switch to prepay** if they had a smart meter, so it is important to upgrade credit at the same time as prepay.
  - The central delivery body, Smart Energy GB (SEGB) conducted a survey<sup>76</sup> that showed c.50% of the population would welcome the convenience of smart prepay as a method of payment if it was available, which is far higher than the existing proportion of prepayment customers (c. 20%).
252. We believe one intervention on the smart roll out that would be beneficial for consumers and would promote competition is a requirement for the DCC to enrol SMETS1 meters as soon as possible, so that customers with a smart meter are able to switch suppliers faster and more easily.

<sup>75</sup> See “The benefits of smart meter” within the PF Appendix for more details

<sup>76</sup> <http://www.smartenergygb.org/node/32>

## **Response to CMA's Questions (Remedy 5):**

*a) Would this remedy be effective in allowing prepayment customers to engage fully in the market and benefit from a wider range of tariffs? Would it be effective in reducing the costs of supply to prepayment customers?*

- The smart section of the PF Appendix sets out the benefits of smart including the specific benefits that smart prepay customer can expect. The mass roll out of smart prepayment meters would increase the ability for us and other suppliers to offer nonstandard tariffs in the future and as such enable customers to more regularly take advantage of new innovations (such as fix and fall tariffs or time of use tariffs).
- Post install of a smart prepayment meter and any stranding of legacy meters, the ongoing costs associated with meter rental and cash collection costs would be lower than current non smart prepay meters thus reducing the overall costs associated with the tariff potentially enabling suppliers to reduce prepay prices accordingly.
- We estimate that after large-scale smart meter roll-out, the cost to serve a customer on a smart prepay tariff will be broadly similar were they on an equivalent Direct Debit tariff, a significant difference to the current position.
- Whilst ongoing costs to supply to prepayment customers would be reduced, this should not be considered in isolation. It is important to also consider the extra costs that could be incurred by prioritising prepay – see details below.

*(b) Which version of this remedy would be more effective and/or proportionate?*

- We do not believe remedies to further prioritise prepay are necessary or proportionate and have concerns that such remedies would add extra cost to the overall roll out of smart meters.
- We believe that there are commercial incentives for suppliers to disproportionately favour prepayment meters being replaced with smart prepayment meters where there are no technological impediments. This is because smart prepay meters generally have a lower rental and cash collection costs.
- However, whilst there are commercial incentives to prioritise prepay, this is not the case for all customers. Installing smart to some prepay customers will increase the cost of the roll out through:
  - Additional stranding costs from removing standard prepay meters that have been installed in recent years rather than prioritising the replacement of older credit meters first; and
  - Additional costs of booking appointments where multiple attempts and/or incentives would be required to encourage some prepay customers to make an appointment
- Given the above, we believe suppliers will prioritise prepay where appropriate, but that the prioritisation of prepay should not be at the expense of further costs to the wider customer base. Remedies to force the prioritisation of prepay would not therefore be appropriate.
- British Gas is already working hard to balance the need to keep the cost of the roll out down whilst bringing the benefits of smart to prepay customers as quickly as practical. Further remedies could make this harder to achieve and add complexity to the roll out, which is already a significant change programme.

*(c) Would any additional or alternative measures be required to ensure that this remedy comprehensively addressed the overarching feature of weak customer response arising in particular from those with prepayment meters?*

- We believe that Smart Prepay will transform how Prepay customers interact with both their energy usage and supplier. [3<]
- Providing customers with these benefits will drive greater engagement and ultimately the ability to reduce costs through consumption reduction. Based on our studies, the average smart customer currently saves around 2% through their interactions with their in home display and we expect this to improve with access to online consumption data.

*(d) What issues may arise as a result of prioritising the installation of smart meters in the homes of customers who currently have prepayment meters?*

- As above, prioritising smart for prepayment customers would drive extra costs, driven by:
  - Additional stranding costs from removing standard prepay meters that have been installed in recent years rather than prioritising the replacement of older credit meters first;
  - Additional costs of booking appointments where multiple attempts and/or incentives would be required to encourage some prepay customers to make an appointment
  - Additional labour costs as we would need to rescale our labour force to reflect the non-equal distribution of prepayment meters throughout the country (e.g. greater numbers in Scotland);
- In addition, this solution would be disproportionate as it would delay the benefits of smart to credit customers.
- Smart Energy GB commissioned a study that suggested that a number of customers do not choose prepayment as a payment type because of the specifics of the prepayment experience. However when presented with smart prepayment, c.50% of credit customers would be interested in smart prepayment, citing the ability to maintain control over their energy use. By prioritising prepayment customers, these credit customers would be denied the choice of smart prepayment.
- We do believe prepay customers could benefit if there was a requirement for the DCC to enrol SMETS1 meters as soon as possible, so that customers with a smart meter are able to switch suppliers faster and more easily.

*(e) Would it be more effective and/or proportionate to require energy suppliers to accelerate the roll-out of smart meters across the retail markets as a whole, in order to facilitate engagement more broadly, rather than focusing on customers on prepayment meters?*

- We recognise the benefits that smart meters will have on the entire market with regard to engagement. However, we do not believe that this will be proportionate as an acceleration of the rollout will have significant costs to the industry, and therefore the end consumer, which may outweigh any engagement benefit. We continue to support the 2020 mandate date but believe bringing this forward would not be possible unless additional costs were to be incurred.

## Remedy 6 – Ofgem PCW

253. We do not believe this remedy is necessary for the following reasons:

- **The market will deliver a solution;**
- **A market solution will be more effective and efficient;**
- **An Ofgem solution could distort the market; and**
- **There is already the means by which the issue of trust in PCWs can be addressed.**

We expand on each of these points in turn below.

### ***The market will deliver a solution***

254. As we explained in our response to Remedy 3 above, we support the removal from the Confidence Code of the requirement for all PCWs to show the whole of the market. We agree with the CMA that the proposed removal of the RMR tariff simplification rules will open the gateway for bespoke supplier and PCW deals (supported by the removal of CTM), something that has the potential to improve competition in both the retail energy and PCW markets.
255. We recommend that the CMA instead ensures that there are provisions within the Confidence Code that require PCWs to be transparent about the extent of market coverage they provide. This should ensure domestic customers can make an educated decision about which PCW they use.
256. This would still mean that, were there a demand for a whole market view, certain PCWs could provide it in order to differentiate themselves by becoming “meta-PCWs” (as is observed in other markets such as travel).
257. We therefore do not believe that a ‘whole of market’ price comparison service provided by a regulator is necessary and moreover, as outlined below, we consider that it risks “crowding out” a market solution.
258. Similarly we support an increase in PCWs in the Microbusiness sector, but the focus should be on providing the framework for competition so that the market develops this service itself – we believe that remedy 7a, 7b and 8 will do this.

### ***A market solution will be more effective and efficient***

259. We do not believe that running a price comparison service is, or should be, a core competency for a regulator. We would therefore have serious concerns about Ofgem’s ability to run an effective and efficient price comparison service as they are not a commercial entity and do not currently appear to have sufficient resources or capabilities to run one (or to even oversee one were it to be run by a third party).
260. It is therefore questionable whether an Ofgem service would create the engagement intended by this remedy. The cost of such a service would also ultimately be borne by all customers through Ofgem’s licence fee. In contrast, a market solution would be paid for by the consumers that use the service and subject to competitive pressure to deliver a service that was effective and efficient.

### **An Ofgem solution could distort the market**

261. Third party price comparison services, such as PCWs, are a crucial driver of competition in the energy market and we welcome the growing role they have played in recent years. We are therefore mindful of the risk that interventions in the PCW market may have unintended consequences which stifle this vibrant and effective channel.
262. A possible unintended consequence of this remedy could be to take away traffic away from commercial PCWs that would otherwise have gone to them and hindering their expansion. This could undermine their business model and reduce their effectiveness at driving switching. This applies even if the site is only a 'reference site', but even more so if it is also 'transactional'.
263. A further possible unintended consequence is that trust in PCWs could be undermined, rather than improved. The existence of an Ofgem service could imply that PCWs cannot be trusted even if they are accredited by Ofgem and adhere to the Confidence Code. This could result in fewer customers being willing to use PCWs.

### ***There is already the means by which the issue of trust in PCWs can be addressed***

264. Even if the requirement to show the whole of market is removed from the Confidence Code (as we and the CMA advocate), a revised Code can still be effective in addressing the CMA's aim of improving trust in PCWs.
265. The Ofgem accreditation process uses the Confidence Code to provide assurance that the service provided by PCWs meets the principles of independence, transparency, accuracy and reliability. For example it requires PCWs to be clear in the choice that they are offering and to make commission arrangement transparent.
266. The revised code only came into force in Q1 2015 so, as the CMA states, "it is too early to assess the impact of the change to the Confidence Code"<sup>77</sup>. We would therefore question the need for this remedy as there is already a mechanism in place to address this issues.

### **Response to CMA's Questions (Remedy 6):**

*(a) Would this remedy be effective in increasing customers' trust in PCWs and thereby encourage engagement in the markets and switching?*

- No it would be neither effective nor proportionate.
- Whilst we believe that trust in PCWs is extremely important, we do not believe that this remedy would significantly increase trust, in fact it could have the opposite effect. The existence of an Ofgem service could imply that PCWs cannot be trusted even if they are accredited by Ofgem and adhere to the Confidence Code. This could result in fewer customers being willing to use PCWs and limit the entry / expansion of commercial PCWs.
- We also note the concerns with regulator-run PCWs in other jurisdictions raised by the "Ex-Regulators" in their submission (published by the CMA on 17 July), including the "potential for "a supplier to game such a regulatory website" (paragraph 99). We support their conclusion that "The presence of a variety of PCWs in the market, each

<sup>77</sup> Summary of provisional findings report, paragraph 154

using its preferred method to evaluate tariff offers and to advise customers, is the more effective way to protect customers and encourage them to engage” (paragraph 100).

*(b) Should this service be online-only, or should it also operate over the telephone for those customers without access to the internet?*

- We do not believe this remedy is necessary, but if the CMA insists on implementing it, the service should be provided by phone, but targeted only to those without internet access (e.g. sending the number by post to only those customers if known, or via 3<sup>rd</sup> parties such as Citizens Advice who may have relationships with such customers).
- Without this targeted approach, the phone service could be used extensively by those *with* internet access as well, which would result in materially higher costs for the service (due to size of the call centre operation required).

*(c) Is there a risk that such an independent service could undermine the development of other PCWs in the energy sector? How could this risk be mitigated?*

- Yes, we believe this is a significant risk as it could undermine the development of other PCWs by ‘crowding out’ more effective and efficient services, diverting traffic (and hence revenue) away from commercial PCWs and undermining trust in such entities. If the service was also transactional then this risk even higher.
- PCWs are incentivised to encourage people to switch as this is how they make money. Ofgem would not have the same powerful incentive to actively target customers for switching, so would be less effective, and may reduce switching.
- We also note that in New South Wales (the case study cited by the CMA) a key driver behind the regulator running a comparison service was that that PCW usage, at 14%<sup>78</sup>, was not very well established in the energy market. This driver is simply not present in the UK where over 70%<sup>79</sup> of UK consumers said they used PCWs to find out information about different suppliers in the CMA’s GfK survey.

*(d) Should the Ofgem website quote the energy suppliers’ list prices only? Or should it seek to provide full details of all quotes available on the market (including on other PCWs), i.e. function as a meta-PCW?*

- If implemented, it should provide full details of all quotes available on the market.
- If the site does not include quotes from other PCWs then this could be confusing to customers who think they are seeing a whole market view (when they are not) and it would divert business away from PCWs (who are key drivers of switching)

*(e) How could we ensure that an Ofgem price comparison service was robust in terms of offering all tariffs available on the market? Should there be an obligation on retail energy suppliers and/or PCWs to provide information to Ofgem on their tariffs?*

- If implemented, principles-based regulation should be used to drive appropriate supplier behaviour and the Ofgem accreditation process (based on the Confidence Code) should be used to ensure PCW behaviour.

<sup>78</sup> "Consumer Research for 2015 Nationwide Review of Competition in Retail Energy Markets", AEMC, July 2015 (page 180) and "Review of the performance and competitiveness of the retail electricity market in NSW", IPART, July 2015 (page 30) . 14% of customers said that they used PCWs as an information source the last time they changed electricity company or plan, and another 26% said they used Google/an internet search).

<sup>79</sup> GfK survey, figure 63, page 68

*(f) Should any price comparison service operated by Ofgem be transactional, ie be able to carry out switches for consumers, or should it provide information only?*

- No, if it were transactional then this would further increase the risk of undermining other PCWs, potentially resulting in them exiting the market. Given that PCWs are a key driver of switching, this could severely reduce switching rates in the market.
- We would also have significant concerns about Ofgem's capability to run an effective and efficient service (even via a third party) as they are not a commercial entity.

*(g) What would be the likely costs to Ofgem of offering this type of price comparison service? Would Ofgem need additional funding and/or statutory powers in order to provide this type of service? If so, where should this funding come from?*

- We do not have an accurate view on costs, but suspect that they would be significant and result in an increase to consumer bills as suppliers seek to cover the incremental costs.
- The CMA would need to be satisfied that Ofgem had sufficient resourcing to oversee / manage the development of such a service (we do not believe such a capability exists at present)
- If implemented it should be not-for-profit and funded by click through / commission from recipient PCWs / suppliers

*(h) How should customers be made aware of the existence of this service? Should information be provided by energy suppliers on bills/during telephone calls? Should PCWs be required to provide links to the Ofgem website during the search process to allow customers to cross-check prices?*

- We do not have a firm view on this question as we do not think the remedy is necessary, but the CMA should consider carrying out research to understand customer preferences. In doing so the CMA would need to consider the potential for customer confusion of providing another step in the search process.

*(i) Is there any additional information that Ofgem should provide on its website relating to energy suppliers and/or tariffs to facilitate the customer search and switching process?*

- Yes, the CMA would need to consider a number of variables that customers actually take into account when making their decision which go beyond purely the headline price. This might include discounts, rewards and bundled products and services, product type (e.g. variable/fixed), pay type (e.g. Direct Debit), account management type (e.g. online only); contract length and exit fees.

## Remedy 7 – Microbusiness Price and TPI Transparency

267. We believe that requiring suppliers to provide online quotations is the best way to facilitate price transparency rather than publishing confusing and complex pricelists. We also fully support the promotion of TPIs (including PCWs), however, we're concerned by the practices of some brokers and the lack of commission transparency. We believe that a robust Code of Practice with stringent disclosure requirements is necessary. We elaborate further below.

### 7a – Price transparency

#### **Price accessibility and comparability**

268. Whilst we agree that price transparency and comparability greatly benefit customers, we believe that it would be confusing and counter-productive for suppliers to publish their full lists of microbusiness prices.
269. Microbusinesses vary considerably in their characteristics and requirements and BGB currently has [X] discrete electricity price points to reflect variations in; location/region, Profile Class, meter type, standing charge, Time Pattern Regime<sup>80</sup> and consumption band. And this is before factoring in contract duration. This flexibility provides more tailored and cost-reflective pricing.
270. We believe that price accessibility and comparability is most effectively achieved using automated online quoting tools. These have the benefit of allowing microbusinesses to engage with energy suppliers quickly and conveniently (e.g. in the evening or at weekends). Concern about whether customers have access to the Internet is not relevant in the microbusiness sector. We currently offer this service and support all suppliers offering such a service, where a customer can get at least one quote on a comparable basis (e.g. one-year fixed term) in only a few minutes.
271. Importantly, this possible remedy would be inappropriate and ineffective if it were to limit suppliers' ability to offer more tailored and cost-reflective pricing, both online and offline, or if it prevented product differentiation and innovation. This could easily happen if online pricing requirements/obligations are over specified or overly prescriptive. In particular, innovation in Smart products and propositions (e.g. load shifting incentives) is expected to grow rapidly in the coming years. Any requirement or restriction must not hamper suppliers' ability and incentive to compete effectively and meet customer demand.

#### **Role of PCWs**

272. We recognise the important role that TPIs and PCWs can play in servicing customer needs and promoting engagement. We already provide prices to TPIs, whether they use them for offering price comparison services or other broker services. Indeed, in the right circumstances and with the appropriate governance framework, we would be willing to allow PCWs to remotely access our online pricing tool in order for them to have real-time access to microbusiness prices. Alternatively, a simpler approach would

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<sup>80</sup> Time Pattern Regime (TPR) relates to Registers on metering systems. Each TPR is associated with a pattern in usage that defines the times/periods in the day at which the register is recording energy data.

be for suppliers to provide prices to PCWs in an agreed format, which are updated on a daily basis and remain valid for an agreed time period.

273. Moreover, it has been said that non-negotiable prices would encourage PCWs to emerge. However, [X] by introducing rules governing TPIs' practices including commission transparency, as discussed further in our response to Remedy 7b, the right competitive environment and commercial dynamics would be created to support the natural market entry of PCWs.

### **Response to CMA's Questions - Remedy 7a:**

*(a) Would this remedy be effective in increasing price transparency for microbusiness gas and electricity tariffs? Would it serve to make comparisons between different suppliers easier, either directly or by encouraging the development of PCW services for microbusinesses? If not, are there other measures that would encourage this development either as an alternative to this remedy or in conjunction with it?*

- Online access to prices would be effective in increasing transparency but it would be confusing and counter-productive for suppliers to publish their full lists of microbusiness prices.
- Availability from every supplier of an automated online quote facility with output of at least one fixed-term contract price would enable customers to more easily compare suppliers' quotes.
- The CMA's proposal would not be effective if it were to create limitations on the ability of Suppliers to offer more tailored pricing required by many microbusiness customers or if it prevented product differentiation and innovation, especially if Smart products and propositions (e.g. load shifting incentives) are developed. It must not hamper suppliers' ability and incentive to compete effectively.

*(b) Do microbusinesses have sufficient access to the information they need (for example on their meter types) in order to engage effectively in the search and switching process?*

- All information required to get a quote from us online can be found on any of the customers bills
- We provide clear and transparent information to our customers and their authorised agents (e.g. TPIs) upon request. We are obliged to provide some of this information and we make the remainder available voluntarily in order to foster positive relationships with our customers.
- We recognise the value of the Midata initiative in the domestic market but we have seen no evidence to indicate that the benefits would outweigh the cost of extending this initiative to microbusinesses.
- Ofgem's 2014 survey showed that more than 60% of respondents who had recently looked at their contract documentation were extremely satisfied with various aspects of it. Ofgem's 2015 survey showed that 84% of fixed-term customers know (at least approximately) the date when their contracts end, enabling them to clearly know when they can and should engage. This proportion has gone up very significantly from 63% in 2013.

*(c) How long should energy suppliers be given to provide the required information?*

- Prices should be immediately available online.

(d) Should energy suppliers be permitted to fulfil this requirement by providing an automated quoting service on their websites (where microbusinesses can put in their details in order to obtain quotes) rather than a list of prices?

- We believe that the requirement to provide clear prices for microbusiness customers is most effectively achieved using automated online quoting tools. These have the benefit of allowing microbusinesses to engage with energy suppliers in the evening and at weekends. Concern about whether customers have access to the Internet is not relevant in the microbusiness sector.
- We currently offer this service and support its extension across all suppliers.
- Microbusinesses have very varied requirements and online quoting tools facilitate access to more tailored pricing which reflects customers specific pricing variables (e.g. meter type, consumption amount and consumption pattern, etc.).

### **7b – TPI transparency**

274. We fully acknowledge the part TPIs play in the non-domestic market and we support their growth and expansion. However, we remain concerned by the practices of some brokers and the general opaqueness of the service they are providing relative to the costs borne, directly or indirectly, by customers. We believe greater transparency will lead to better customer outcomes and that this can be delivered through the introduction of a Code of Practice which includes targeted stringent disclosure requirements and a clear and robust enforcement mechanism.

#### **Information provision and transparency**

275. We support the Ofgem Code of Practice and the proposed licence obligation on suppliers to only work with TPIs accredited to the Code, but it does not go far enough to improve transparency. We believe that TPIs should be required to provide customers with the following information:

- the extent to which they cover the markets, i.e. highlighting which suppliers they have agreements with and which they do not and whether any quotes/prices are sourced by searching all or part of the market; and
- the level of commission and how they are paid.

276. This information should be clear and succinctly provided to customers, and confirmed in writing, using plain and intelligible language, prior to any contractual commitment. Without this level of transparency it is impossible for customers to make the right choice for them and to properly value the service they are receiving.

#### **Governance and enforcement**

277. We recognise that Ofgem has had concurrent powers under the Business Protection from Misleading Marketing Regulations since late 2013. However, Ofgem has not openly used these powers and based upon our own experience very few industry participants are aware of these Regulations and Ofgem's concurrent powers. Consequently, they do not act as an effective deterrent.

278. While we have no doubt these powers would be effective at punishing malpractice, we believe pre-emptively specifying a framework for good practice, rather than solely relying on the BPMMRs ex-post civil/criminal sanctions, would be more effective at engendering trust and confidence in TPIs.

279. We also do not believe it is appropriate or practicable for suppliers to enforce broker conduct under the Code of Practice. It should be robustly enforced by Ofgem or another capable and independent party with the ability to impose proportionate sanctions.

### **Response to CMA's Questions - Remedy 7b:**

*(a) Would this remedy be effective in improving transparency over incentives and trust in TPIs in the energy sector? How could the CMA ensure that this remedy was enforced, i.e. that TPIs were providing the specified information?*

- This remedy would improve both transparency of TPI incentives and trust in TPIs provided that stringent disclosure requirements are included.
- We believe that Ofgem's proposals are insufficient and that disclosure requirements are needed in relation to incentives and to the services which are being provided by the TPI; see part (b) below.
- A Code of Practice is required with an appropriate mechanism for enforcement (either by Ofgem or an appropriately capable and experienced independent party). We know Ofgem has had powers under the Business Protection from Misleading Market Regulations since 2013 and that these can be used as backstop powers to enforce the provisions of the Code. However, we believe that built into the Code should be the ability for the governing party to impose proportionate and timely sanctions (including improvement orders) and that removal of a TPI's accreditation should be the ultimate sanction.

*(b) What information should be provided by TPIs to microbusinesses in order to enable them to make informed choices?*

- TPIs should provide customers with the following information:
  - the extent to which they cover the markets, i.e. highlighting which suppliers they have agreements with and which they do not and whether their quotes are derived by searching all or part of the market; and
  - the level of commission and how they are paid.

*(c) Could the provision of certain types of information have unintended consequences (e.g. customers choosing tariffs based on commission rates rather than total price)? If so, are there any steps that could be taken to mitigate this effect?*

- TPIs should explicitly state the supplier's price and the commission both separately and together in order to mitigate the risk of customers choosing tariffs based on commission rates rather than the total price. Customers need to recognise that they are paying for two distinct services, (i) the supply of energy, and (ii) the TPI's service.

*(d) Should the specified information be provided to customers in writing or orally (or both)? At what stage in the sales process should this information be lent/provided?*

- The information should be provided both orally and in writing prior to agreeing the TPI's service contract.
- The Ofgem Code could prescribe that Letters of Authority (LOAs) provided to Suppliers by customers (confirming the TPI is acting on their behalf and permitting Suppliers to interact with the TPI) must state the agreed TPI commission that the

Supplier is authorised to charge on the customer's bill and recycle to the TPI on the customer's behalf.

*(e) Should this remedy be introduced in addition to Ofgem's proposed code of conduct? Or should only this remedy (or only Ofgem's code of conduct) be introduced?*

- Ofgem's Code of Practice should reflect the requirements of this remedy.

*(f) Are there any additional measures that should be implemented alongside this remedy to enhance its effectiveness?*

- The Code of Practice must have an appropriate enforcement regime which ensures that customers must behave consistently with the Code of Practice. See further details in our response to (a) above.

## Remedy 8 – Microbusiness ban on auto renewal

280. **We believe that the ending of auto-rollover contracts would be beneficial both to customers and to trust and engagement in the market. We observe that this has already largely happened as a natural consequence of competitive market forces.**
281. We believe that the ending of auto-rollover contracts by many suppliers has helped to promote greater consumer engagement as their options and ability to switch are not foreclosed. We also believe it has helped to reduce the barriers and create the right conditions for PCWs to emerge, because the previously short window of opportunity for customers to switch supplier before being automatically rolled onto a new contract has been removed. The emergence of PCWs, combined with greater information provision and transparency by TPIs, will increase price transparency and comparability and this will, in turn, diminish the remaining few suppliers' reliance on, and use of, auto-rollovers as consumers react before being automatically locked in to a subsequent term at high prices.

### **Response to CMA's Questions (Remedy 8):**

*(a) Would this remedy be effective in allowing microbusiness customers greater opportunity to engage (by removing the narrow window in which they can choose not to roll-over automatically)?*

- Yes, it removes the time constraint entirely.

*(b) Are there any means by which energy suppliers could circumvent this remedy to continue to lock customers into energy tariffs that they have not chosen for extended periods of time?*

- Only if the Default Tariff locks them into a long notice period or if there was an exit fee.
- There should be a minimum requirement for the frequency with which suppliers should attempt to contact customers who are no longer on FTCs; we suggest a specific discrete prompt at least every 12 months with additional prompts provided with bills.

*(c) What is the minimum or maximum notice period that customers should be required/allowed to give in order to exit a contract that they have been rolled on to?*

- BGB's VPP customers have to give 30 days' notice and we believe this strikes the right balance between risk and flexibility.
- The benefit of a notice period is that it allows suppliers to mitigate the hedging risk and reflect that in lower prices to the benefit of customers.

*(d) Should energy suppliers be required to inform customers that they are nearing the end of their contract and prompt them to switch?*

- Yes. Suppliers already have an obligation to provide a renewal letter around 60 days before the contract end date. BGB recently introduced a further voluntary prompt by sending a reminder around 30 days before the contract end date. Customers also get a further prompt by way of issuing new contractual terms once the fixed term has

ended. This means our fixed term customers get three prompts to engage within c.60 days.

## Remedy 9 – Reduce informational barriers to switching

282. **We welcome measures to provide domestic and microbusiness customers with different or additional information to reduce actual or perceived barriers to accessing and assessing information. We believe the key to achieving this is to remove the prescriptive elements of regulations and replace them with specific outcome based goals for suppliers.**
283. Our ability to differentiate ourselves from rivals through how we engage with existing and prospective customers is critical to how we compete. We believe that by providing customers with better, more useful information, in a clearer and more engaging way than our competitors, we can distinguish our brand and attract customers from our rivals. This can be seen in innovations such as our personalised My Energy report.<sup>81</sup>
284. Our ability to do this however is seriously constrained today by the regulatory framework and the way in which it is applied. Whilst the principles behind the regulations such as the ‘clearer’ element of RMR may be appropriate, the prescriptive way in which they have been implemented has hampered competition.
285. The format and content of key customer communications such as the bill, annual statement, price change notification or fixed term contract notice, are prescribed by licence condition<sup>82</sup> - in some cases entirely. This prescription extends to specifying the information that should be provided, where on the page it should be provided, and what wording and font size should be used.
286. In the case of price change notifications, we are also prevented from including other information in the same envelope, meaning a separate mailing must be made if we want to offer a customer alternative products and services which might mitigate the impact of a price rise and better meet their needs.
287. The degree of prescription also extends to verbal interactions with customers. Our experience is that customers do not understand the information we are required to give, for example the TCR, and that the process now acts as a barrier to customer switching.
288. In effect, this places the regulator in the position of determining how best to communicate with energy customers on sales calls, and not the energy suppliers who have the experience and insight in to how best to do this, and the incentive to do it better than their rivals. For example, our insight tells us that customers would value a simpler, clearer, bill, however we are now in the position of waiting for Ofgem to advise whether we need derogation from the rules in order to trial a new version of the bill that research tells us will be far more successful.
289. As part of efforts to remove the barriers to customer engagement, the CMA should relax these regulations and replace them with an emphasis on ensuring suppliers achieve specific outcome based goals. This would allow suppliers to use their insight to deliver the information customers want, in an engaging way which allows differentiation of brand and more active competition for their rivals’ customers.

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<sup>81</sup> <http://www.britishgas.co.uk/smarter-living/control-energy/smart-meters/my-energy-use.html>

<sup>82</sup> In particular, SLC31.

290. Were this to happen in conjunction with our Remedy 3 proposals, we would conduct additional research to understand whether bills could be improved further by removing or modifying other elements prescribed by RMR, such as TCR and CTM for example.

### **Response to CMA's Questions (Remedy 9):**

*(a) Does the current format and content of energy bills facilitate engagement by customers? Is there additional information that should be included on bills? Should the quantity of information on bills be reduced to enhance clarity?*

- As above, the level of prescription on bills prevents suppliers engaging customers in the way they are demanding. It also prevents differentiation, limiting suppliers' ability to compete effectively against rivals. The level of prescription should be removed, and replaced with an obligation to achieve customer focused outcomes.

*(b) When customers seek to switch tariffs, are they given enough/too much information on the terms and conditions of their new contract?*

- Yes, too much. As above, sales conversations are now increasingly lengthy, scripted and unengaging. Whilst we believe that customers must be given all the information they need in order to make an informed decision about the right product for them, we believe that suppliers could deliver this in a simpler and clearer way, were they allowed to focus on customer outcomes as opposed to a prescriptive list of regulations.

*(c) Should customers be prompted to read their meters (quarterly or annually), either by information on their bill or by a phone call from their energy supplier? Would this increase engagement by improving the accuracy of billing?*

- Whilst smart metering will resolve the issues associated with estimated bills in the short to medium term, we recognise the importance of encouraging customers to read their meter.
- In order to maintain customer engagement and avoid over contacting them (and thus increasing overall opt out rates), it is important that customers retain the choice over what contact they receive from suppliers, and through what channel.

*(d) Once customers reach the end of a contract period, should subsequent bills highlight that they have now been moved onto the standard variable tariff and/or other Default Tariff and encourage them to check whether they are on the most appropriate tariff for them?*

- Yes, we believe that end of contract notifications are a key customer engagement trigger, and therefore an important time to highlight that the customer will move on to a standard or Default Tariff and other options available to them. Suppliers should therefore have the flexibility to design engaging end of contract communications that achieve given customer outcomes in a way that enables differentiation.
- We also note that under Remedy 10 customers who fall on to a Default Tariff would face a series of ongoing prompts encouraging them to find a new fixed term contract. This is another area where our proposals support effective competition.

## Remedy 10 – Prompting the disengaged

291. **We believe that the engagement triggers identified in Remedy 10 (combined with some of the remedies outlined above, particularly Remedy 3) have the greatest potential to increase engagement and negate any need for the introduction of the CMA’s proposed Remedy 11.**
292. However if the CMA maintains its finding of unilateral market power (which we dispute) and considers intervention beyond the proposed Remedy 10 is required, then we believe there are more effective ways of doing so than introducing the regulated tariff cap proposed in Remedy 11 (which is fundamentally flawed as we explain later).
293. Our experience suggests that one of the most powerful triggers for engagement is the process customers go through when they come to the end of a fixed term contract [X]. The power of this trigger is not being fully harnessed under the CMA’s current proposal for Remedy 10.
294. Therefore, rather than imposing Remedy 11, we believe that the CMA should consider the phased withdrawal of evergreen tariffs from the market supported by additional measures that we outline below which incentivise both customers and suppliers to minimise the number of customers on a default tariff.
295. Such a remedy should include a sunset clause which would allow the CMA to review the need for such regulatory intervention in the future (particularly as the market develops and smart technology is rolled out more widely).<sup>83</sup>
296. We expand on our thinking further in the following sections:
- Ending evergreen tariffs
  - Phased customer notification
  - Future levels of ‘inactive’ customers
  - Design of the new Default Tariff

### **Ending evergreen tariffs**

297. One of the most powerful triggers for customer engagement is the process customers go through when they come to the end of a fixed term contract. [X]
298. This gives us confidence therefore that the mandated **withdrawal of evergreen tariffs from the market** could significantly increase engagement. This would mean:
- The ending of evergreen contracts for customer acquisitions, by a specified date;
  - All new acquisitions (and customers that switch internally) can only be offered fixed term products, with either a variable price (VP) or fixed price (FP);
  - The phased notification of contract end dates to all customers on evergreen tariffs informing them that their current contracts were coming to an end;
  - These notifications (and other communication such as bills) would prompt customers to switch on to fixed term products.
299. By moving the energy market to fixed term contracts this remedy would also have the potential to change customers’ attitudes towards energy such that they see it as a

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<sup>83</sup> See the ‘smart’ section of our Appendix for evidence of the impact smart meters have on engagement

product in which they should engage on a regular basis as is the case, for example, with insurance products. This would be further reinforced by the competitive activity, advertising and media coverage that would accompany the mass roll-off from evergreen contracts, as well as the rollout of smart meters. As the CMA notes, smart technology has the potential to further increase customers' awareness and interest in switching and will make it easier and faster to do so.

### **Phased termination of evergreen contracts**

300. It is essential that the notification of contract end dates to customers already on evergreen tariffs is phased for the following reasons:

- To give time for remedies to take effect, so that suppliers and PCWs can compete more effectively to acquire current evergreen customers with engaging products and prompts;
- To give customers time to respond to pull and push (prompting) activity and to shop around as new propositions come to market;
- To avoid dramatic spikes in customer contact and switching that would severely harm the levels of customer service and trust and add substantial industry costs:
  - A rapid phasing (e.g. notifying all evergreen customers within 6 months) would increase contact levels far beyond that which could be handled today;
  - To maintain even a basic level of customer service in this scenario we would need to open several new contact centres (which could take up to 18 months before they were fully operational with trained staff);
  - In addition it is likely that some supplier and industry systems would need upgrading to cope with such spikes.
- To avoid the poor customer service levels that would inevitably ensue on an *enduring* basis (not just in the initial period referenced above) in a FTC-only market if suppliers were not given sufficient time to increase their contact centre capacity and systems capability to cope.

301. We therefore propose the following phased approach which would reduce the issues of a shorter phasing noted above.<sup>84</sup>

- All customers currently on SVT would be notified that their contract is coming to an end and that they need to choose an alternative fixed term contract;
- This notification process would be phased over 24 months, starting with those who have been on evergreen tariffs the longest;
- Once any given customer has received this notification, they would have one year to choose another tariff (during which time they would receive additional prompts<sup>85</sup>);
- At the end of this period, if they have still not switched supplier or tariff, they would be switched to a Default Tariff (described below) to ensure continuity of supply.

### **Future levels of 'inactive' customers**

302. Once the phased removal of evergreen is complete, we are confident that most customers would have actively selected a new tariff and most importantly would

<sup>84</sup> We believe this approach would still require additional contact centre capacity [§<].

<sup>85</sup> We would carry out customer research to determine how to maximise the effectiveness of these prompts in terms of content, channels, timing and frequency.

continue to select the best products and tariffs for themselves on an ongoing basis, benefitting fully from the highly competitive market.

303. Our confidence is based on the following:

- Our belief that many customers on SVT should actually be considered as engaged already and so are likely to choose a variably priced FTC under the new model;
- Our own experience of high levels of customer engagement at contract end (as noted above), and our belief in the effectiveness of new prompt mechanisms;
- Our anticipation that the mass, phased roll-off from evergreen contracts would see suppliers (and PCWs), fiercely compete to acquire these customers, supported by increased awareness through media and advertising (such as was seen with the Ofgem “Power to Switch campaign<sup>86</sup>);
- Our belief in the likely effectiveness of the range of remedies proposed by the CMA (e.g. Remedies 3 and 9); and
- The dynamic and structural changes that the market is already going through – with the emergence of new entrants, growth of PCWs and roll out of smart meters [§<].

304. We have developed a basic model to estimate the potential impact of some of the CMA’s proposed remedies, combined with the phasing out of SVT and the increasing influence of smart technology.

305. There will inevitably be some customers who are temporarily on the Default Tariff before they switch to another tariff or supplier (e.g. during a home move or if they need more time to shop around after their previous contract). These customers, who will have actively switched at least once since being on SVT, are identified as “Active Default”.

306. We recognise there will still be some customers who may be classified as ‘inactive’ if, after intensified prompting in the market including the cessation of evergreen, they have failed to actively switch to a new tariff or supplier after their SVT tariff comes to an end under our proposed phased roll-off (the “Inactive Default” [§<]).

307. At this point they would go onto a supplier set Default Tariff (described below). Their supplier would notify them that they have been put onto a Default Tariff, remind them that they have a choice and recommend other products. They would then receive additional prompting during the period they are on the default.

308. We consider that the increased competition from other remedies such as Remedy 3, innovations such as smart and our proposed alternative to Remedy 10 will ensure the size of this segment is no larger than would be expected in a normal functioning competitive market. We would also note that social policy measures provided by Government (e.g. WHD) will complement this model by providing specific assistance for the financially vulnerable.

### ***Design of the new Default Tariff<sup>87</sup>***

309. Unlike most other markets (such as insurance) where customers can be out of contract (and therefore not receive the product or service), energy is an ‘essential good’. Whilst

<sup>86</sup> According to DECC the campaign increased switching rates by 130,000 over four weeks: <https://www.gov.uk/government/news/millions-saved-in-one-month-as-switching-energy-supplier-rockets/>

<sup>87</sup> We use the term “Default Tariff”, but CMA should test terminology with customers to identify which name is the most effective at prompting customers to take action.

it is possible to withhold supply (through disconnection) it is an extreme course of action that, rightly, is rarely taken and only as a last resort. So there will always be the need for a mechanism by which suppliers can charge out of contract customers for the energy that they use.

310. Whilst a default mechanism is required, we do not believe it would be necessary for the CMA to put in place a remedy that regulates the design of this mechanism (particularly given that smart technology could present alternative approaches), but if the CMA does so, we believe it should only be in place for a transitional period.

311. We also believe that any regulation of the default mechanism should be principles-based to limit the unintended consequences that prescriptive regulation could bring in a dynamic and evolving market. However, for illustrative purposes, we have proposed a design which the CMA could consider when defining such principles (though we note there are additional and alternative features that could also be considered).<sup>88</sup>

312. The core elements of our proposed Default Tariff design for domestic customers<sup>89</sup> are as follows, these are then described in more detail below.

- Supplier set
- Variable price
- One year fixed term
- No exit fees

313. In addition the CMA could consider the adding some of the following complementary elements to the remedy (also described below):

- Supplier prompting
- Monitoring of default tenure
- Regulator prompting of the least engaged
- Monitoring of default pricing

314. **The Default Tariff level would be set by suppliers and not capped by the regulator.**

- Fundamentally, we believe that a regulator set or capped price would be a deeply regressive step and significantly harm competition in the market (our views on this are set out in more detail in our response to Remedy 11).
- Instead each supplier should set the Default Tariff for each fuel type<sup>90</sup> in order to reflect the actual costs and market forces that they face. Unlike a regulator set or capped tariff, this would enable the price to reflect material, structural differences in supplier cost bases, driven by a range of factors, such as customer mix (region, pay type, consumption levels), hedging approach, Government exemptions, Smart meter rollout strategy and more.

315. **The Default Tariff would have a variable price.**

<sup>88</sup> For example, each supplier could have a single, variable default tariff (with an annual contract layer on top for each customer) or a more complex regime whereby a series of annual, variable Default Tariffs are launched (e.g. quarterly), so that customers are on an annual product as well as an annual contract). Each have pros and cons and there are other considerations as well. We would be happy to discuss these further at a working level.

<sup>89</sup> If the CMA also believes that Remedy 10 is necessary for microbusinesses then there are additional considerations. For example, that fixed prices are the norm for business customers, so an alternative approach may be required to avoid dissatisfaction or confusion (which may otherwise make it harder to engage them).

<sup>90</sup> A Default Tariff would be required for each fuel type with the usual cost-reflective adjustments for region and payment type (and meter type, consumption and deemed if applied to microbusinesses)

- We believe the risks of purchasing commodity for the default tariff would be best managed through variable pricing. The nature of the Default tariff means that both the number and tenure of customers on the tariff is uncertain and likely to vary significantly. This unpredictability creates material uncertainty as to the volume of commodity suppliers should purchase for customers on the default tariff. It is therefore highly unlikely that suppliers would be able to purchase all of its commodity requirement (as it will be unknown) at the time of setting the Default Tariff price and would therefore need the flexibility to re-price as incremental commodity was bought or sold.
- To manage these risks through fixed price tariffs would not only result in higher prices to cover the risks, but also multiple Default Tariffs, possibly as frequently as monthly. This could result in some customers on the Default Tariff paying a materially higher or lower price than others simply because they happened to drop on to it at a time when underlying costs were higher. Given they have not chosen this product such a disparity may result in confusion and lower trust – which could harm levels of engagement.
- Fixing the price would also eliminate price changes within each annual contract, which would lose an opportunity for a further, powerful prompt.

**316. All customers on the Default Tariff would be on one year fixed term contracts.**

- Whilst the price will not be fixed, the term will be fixed. Customers would receive an annual fixed term contract to provide a powerful prompt at the end of the contract (in addition to other prompts in throughout the term). This will also help shift consumer attitudes so that they view the energy market as one with which they should engage on a regular basis (in the same way that they do in other markets, such as insurance).

**317. There would be no exit fees for the Default Tariff.**

- The lack of exit fees will avoid a potential barrier to switching. In the longer term, other market developments (smart meters, next day switching) should add further to the ease of switching.

**318. Supplier prompting customers to switch away from the Default Tariff.**

- Whilst the measures outlined in this section mean that it will be in suppliers' interests to prompt Default Tariff customers, the CMA may deem it necessary to introduce regulations that mandate supplier prompting. If this is the case then we would urge it to avoid prescriptive regulation due to the potential for unintended consequences such as those which the CMA itself has identified regarding the 'clearer' element of the RMR regulations (see Remedy 9). Instead the CMA should provide a framework with boundaries (such as a minimum number of prompts) within which suppliers have freedom to determine the most effective approach to prompting in terms of content, format, channels and timing.

**319. Monitoring of Default Tariff tenure.**

- Suppliers should separately submit data showing a profile of how long customers have been on a Default Tariff. This would help the regulator to monitor supplier performance and could be published (much like complaints data) to enable the pressure of public scrutiny to further incentivise suppliers to engage customers so

that they move off the Default Tariff. Publication could also act as a nudge to consumers to move off the Default Tariff.

**320. Regulator prompting of the least engaged customers.**

- We note that the CMA is also considering whether other parties should be allowed to prompt a supplier's least engaged customers. If the CMA deems this significant intervention to be necessary then we would advocate that an additional, annual prompt is sent to customers who have remained on the Default Tariff for over a year without changing tariff or supplier.
- This would allow a reasonable period of time after the end of a customer's current contract for them to engage in the market and also for their supplier's prompts – including the powerful end of contract prompt – to take effect.
- This additional prompt could be sent by the regulator (or by suppliers on its behalf), expressing regulatory concern or encouraging the customer to switch to another tariff or supplier. We expand on this in response to questions 10d and 10f below.

**321. Monitoring of Default Tariff pricing.**

- To give regulators and stakeholders the assurance that suppliers do not make excessive profits. This could be implemented through the existing CSS process, with suppliers required to submit additional data on costs and margins specific to the Default Tariff. The CMA would need to consider whether this information should be made public or not. We discuss this in more detail in response to Remedy 14.

## **Conclusion**

322. We believe that the mandatory removal of evergreen tariffs would result in a price that **incentivises customers** to become active in the market due to the available gains from switching to other tariffs. This is because the underlying costs for the Default Tariff are likely to be somewhat higher than for many other products in the market due to the volume risk, annual contract cadence, the cost of prompting (including any price change notifications) and the freedom to move without exit fees.

323. Moreover, **suppliers will be incentivised** to encourage customers to switch away from the Default Tariff due to increased competitive activity to win those customers (as the other remedies take effect) and due to the public and regulatory scrutiny of the tenure of customers on the default tariffs and the level of pricing. Should these incentives need to be strengthened further, any customers who still remain on the default after a year – despite ongoing supplier prompting – could receive a further annual prompt from the regulator.

324. In any competitive market there will be a proportion of customers who remain disengaged. Provided the proportion is relatively low, the CMA should be satisfied that the market is sufficiently competitive. Provided the Default Tariff is transparent, and the customers on it are being prompted and reminded of their choice, the regulators should be satisfied that these customers do not require further safeguarding.

## Response to CMA's questions (Remedy 10):

(a) What information should be included in the prompts to customers on Default Tariffs in order to maximise the chances that they are acted upon?

- In the proposal above, suppliers are incentivised to encourage customers to switch away from the Default Tariff, so any regulations regarding prompting give suppliers the freedom to determine the most effective approach in terms of the content, format, channels, timing and frequency of prompts.
- This would provide a source of competitive differentiation as suppliers use their own insight to compete to find the most effective way to prompt their customers learn from customer response, adapt to evolving consumer preferences, and improve communication to enhance engagement and satisfaction.
- Our recent small scale survey<sup>91</sup> found that the prompts which are most effective at persuading customers to consider switching are those which [§<]. However, the best product to offer them as an alternative will vary depending on their needs. Our research shows that when customers are offered a portfolio of four tariffs in a realistic choice task, each tariff appeals to someone even if some are more expensive due to customers' different needs and preferences.<sup>92</sup>
- In keeping with our response to Remedy 3, this suggests that the CMA should remove the requirement to provide rigidly defined cheapest tariff messaging on correspondence. Whilst we would still expect prompts to suggest alternative products, the best ones to offer will vary depending on the type of customer.
- Whilst the product with the cheapest unit rate will appeal to many customers, others will respond better to products which include upfront cash discounts or vouchers, energy efficiency products or cost saving features such as Time of Use tariffs. As well as being more appealing, these products may well result in the best value for the customer over the term of their contract, but may not appear to be the cheapest tariff as defined by CTM rules.

(a-i) Should customers who have failed to engage be informed that they are 'no longer under contract for energy', that they have been 'rolled onto a safeguard tariff', or an alternative message, for example, emphasising how many customers in their area have switched in the last year?

- Under our proposal it would be appropriate to make clear to customers that they were going on to a contract for a Default Tariff which they have not actively chosen and that there are better alternatives (which will vary depending on customer).
- The exact wording however, should be rigorously tested (including the name of the Default Tariff) using a randomised, controlled trial to understand the most effective approach. Many approaches that might be assumed to increase engagement, for example, could in fact have the opposite effect (as the FCA has found).<sup>93</sup>
- Our recent survey suggests that the CMA's suggestions would not be effective [§<]

<sup>91</sup> Online survey of 2044 customers from multiple suppliers conducted by Decision Technology, July 2015

<sup>92</sup> 'Tariff Lab III', Decision Technology - Feb 2014 (4,502 customers) - Submitted to CMA in response to the SQ.

<sup>93</sup> The FCA is advanced in using Behavioural Economics to guide them. It is noteworthy that in the first field trial of framing, one proposed nudge that they thought would improve effectiveness of customer comms actually made them worse <http://www.fca.org.uk/static/documents/occasional-papers/occasional-paper-2.pdf>

*(b) How should prompts be communicated to customers? For example, there is some evidence from the financial sector that text prompts are particularly effective at raising awareness in terms of overdrafts etc.*

- As a principle customers should be given a choice of channels through which they would prefer to engage. The channel should not be dictated by regulation.
- We would note that for the quoted example in banking, the evidence shows that SMS prompts are most effective in combination with mobile banking, so that a consumer can respond to the alert as soon as they receive it. So this may well be effective for the increasing number of customers who use our apps, but not necessarily for those that do not.
- We also note that some customers have opted out of some or all marketing communications, so it may not be possible to prompt them in certain ways without a change to regulations.

*(c) What should be the timing and frequency of prompts in order to balance effectiveness in terms of encouraging engagement with the cost and potential irritation that might arise from repeated prompts?*

- The contract-end date (which all customers would have under our proposed FTC-only model) provides a firm date around which suppliers can design a powerful prompting approach. For example this might include:
  - Prompting when a customer first goes on to the Default Tariff;
  - Price change notifications (these would be more effective prompts if the CMA were to reverse the Ofgem RMR ‘clearer’ rule preventing suppliers from offering alternative tariffs on such notifications);
  - Bill messaging; and
  - Contract termination prompt(s) towards the end of their annual term.
- However our experience suggests that excessive contact can be disengaging and we have seen a correlation between increased frequency and increased opt-out, whilst the preferred timing and frequency can vary between customers.
- So different approaches may be better for different types of customers.
- Our recent research<sup>94</sup> suggests that the ideal frequency preferred by most customers was [X].

*(d) Who should provide the prompts: customers’ energy suppliers, Ofgem or another party?*

- We believe suppliers should provide the prompts to avoid a material risk of customer confusion and/ or irritation as well as data protection issues.
- Our research<sup>94</sup> suggested that customers agree with “Own Supplier” being the most popular preference when asked who should prompt them [X].

*(e) Are there particular groups of customers who should receive prompts at specific points? For example, should house-buyers be prompted to engage with the market on completion of their purchase?*

- Further research would be required to identify appropriate timing for different groups of customers and again we would advocate giving suppliers the flexibility to determine this for themselves [X]

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<sup>94</sup> Online survey of 2,044 customers from multiple suppliers conducted by Decision Technology, July 2015

*(f) Is there benefit in others in the markets, such as rival energy providers or TPIs, being made aware of which customers remain on Default Tariffs (or have been rolled on to the safeguard tariff)? In this respect, data protection issues would need to be carefully considered. The ability of other market participants to identify inactive customers, however, has the benefit of potentially encouraging the customer to switch tariffs once out of contract.*

- As a principle we do not believe customers should be contacted without consent.
- Our recent survey suggests that [X].
- As such, the vast majority of customers would prefer not to receive prompts from other suppliers and TPIs, so to force them all to do so would be highly contentious and could lead to distrust and disengagement.
- We would be particularly concerned if customer data was provided to multiple parties (even with consent) due to the potential for simultaneous contacts from over 40 entities (e.g. 12 accredited PCWs + 29 suppliers = 41) as this is also highly likely to damage trust and engagement (and result in more customers opt-outing of all communications, even from their own supplier).
- However, as mentioned in our alternative approach to Remedy 10 above, there may be a case for Ofgem to send an annual prompt (directly or via suppliers) to customers who have been on the Default Tariff for over a year to express concern and encourage switching. It would not be appropriate within the first year as it is reasonable to expect there to be a number of customers who are temporarily on the Default Tariff (e.g. whilst they find time to shop around or during a home move) and therefore they (and their suppliers) should be given more time to engage.
- The CMA would need to consider how this might be funded and how it could be delivered cost effectively and without breaching privacy laws.

## Remedy 11 – A transitional ‘safeguard regulated tariff’ for disengaged customers

325. **We consider the CMA’s proposal for a “safeguard” tariff to be both fundamentally incompatible with the CMA’s principles of improving the framework for competition and facilitating widespread customer engagement and also in direct conflict with the CMA’s other proposed remedies.**
326. Were the CMA to proceed with this remedy, we have serious concerns that the market distortions it would introduce would be counter-productive – damaging rather than promoting engagement, and significantly harming competition.
327. Once a safeguard tariff is introduced, it will be extremely difficult for a regulator to remove. The negative impact of such a tariff on engagement, together with the significant risk of political pressure (and potentially direct political interference), could lead to the safeguard tariff becoming a permanent feature of the market.
328. Setting the level of any tariff cap would prove extremely difficult, as recognised by the CMA. If set too low, such a tariff is likely to have a particularly negative effect on engagement and switching, with customers viewing the regulated tariff as a “safe haven” (as has been observed in New South Wales<sup>95</sup>). In volatile wholesale market conditions, a low tariff level also increases the risk of significant market failure, as was seen in the California blackouts in 2001.
329. In contrast, a high tariff cap may have limited impact on supplier pricing or even distort supplier pricing, potentially leading to tariff “bunching” at or very near to the cap. It is therefore highly unclear that this remedy would be effective in remedying any potential AEC. Moreover, even identifying the relevant cost base over which to set this “headroom” level is not a straightforward exercise, as the profitability analysis set out in the Provisional Findings has clearly shown.
330. In summary, we believe it is highly unlikely that this remedy would achieve the CMA’s desired outcomes. In addition, the risk of unintended consequences is so severe with this proposal that we believe it could only be a proportionate remedy if the CMA were to conclude that there is no reasonable prospect of competition. We do not believe this to be the case given the evidence set out in our response to the PFs: while we accept that there is always room for improvement, in our view the evidence suggests that competition in energy is working well and providing good outcomes for the great majority of customers.
331. We also believe that our response to Remedy 10 (and our proposed new Default Tariff) presents the CMA with a solution that would effectively and proportionately address the identified AECs (if they are upheld) while avoiding the introduction of Remedy 11, and thus all of the significant unintended consequences associated with it.
332. We suggest that in any case, any consideration of a safeguard tariff set by the regulator is held in abeyance until the consequences and functioning of other

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<sup>95</sup> In 2014, the Australian state of New South Wales took the decision to end the tariff cap in the electricity market, as the market was seen as being sufficiently competitive that the continued existence of a regulated price would likely worsen rather than improve customer outcomes. One of the main reasons for its removal was that customers tended to stay on this non-competitive tariff because of “a belief that the regulated price is reasonable”. See our ‘Case Study’ later in this document for further details.

remedies, including supplier default tariffs, and the size of any 'residue' of inactive customers, are known.

333. We believe in a well functioning competitive market, it is likely that the other remedies will function well and the residue will be small. In such a scenario, a regulated safeguard would not be necessary so avoiding price regulation, something the CMA has indicated it is not minded to pursue.

334. We set out our specific views on Remedy 11, as proposed by the CMA, in the following sections:

- Risk of permanent regulation;
- Challenges with setting the level of the safeguard tariff; and
- Challenges with implementation.

### ***Risk of permanent regulation***

335. Once a regulated tariff is introduced, it will be extremely challenging for a regulator to remove it, notwithstanding any intention that such a measure is transitional.<sup>96</sup>

336. As noted in the case study below, the "safe haven" effect is likely to ensure a large number of customers remain on the safeguard tariff (either actively or passively), despite the presence of more competitive offers.

337. This limiting factor on engagement, together with the significant risk of political pressure (and potentially direct political interference), could lead to the safeguard tariff becoming a permanent feature of the market, marking an unnecessary shift towards regulated rather than competitive market outcomes. Removing the cap would be even more challenging if energy bills began to increase once more.

338. The time required to introduce the remedy (given it will affect up to estimated 19m current evergreen customers across the market) and then to phase it out (notwithstanding concerns about its effective permanence) would be significant, further emphasising how this would inevitably become a long-term market intervention.

339. Given the potential safe haven effect, we believe that the introduction of Remedy 11 could create a long-term regulated outcome for a large proportion of domestic market participants. This would represent a significant and highly regressive step for the competitive market.

### ***Challenges with setting the level of the safeguard tariff***

340. There are major challenges with setting the level of the safeguard tariff, as recognised by the CMA. Not only is it potentially complex to identify the relevant cost base, but there is also a difficult judgement call to make about the level of "headroom" to allow above costs.

341. If set too low (or even at a 'correct' level), the safeguard is likely to be seen as a "safe haven" tariff - sanctioned by the regulator and therefore set – from a customer's perspective - at a reasonable level. This would directly counter and reduce the impact of the other remedy measures designed to stimulate engagement.

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<sup>96</sup> See "Submission on Summary of Provisional Findings report and Notice of Possible SV Remedies", Littlechild et al, p.10, para.44 and "Penalty tariffs, open-ended regulation and embedding overcharging", Helm, p.19, para.71.

342. A low tariff cap may also drive other unintended consequences, as seen in the California blackouts in 2001. In that instance, a relatively low retail cap combined with short hedges meant suppliers could not cope with unanticipated spikes in demand, leading to a major market malfunction. This was in spite of the regulations having been explicitly designed with what was believed to be sufficient headroom to allow for all plausible market conditions.
343. Low tariff caps generally make hedging uneconomic, and so employing this level of cap in the UK risks creating similar tensions between unregulated wholesale market conditions and regulated retail market conditions to those seen in California.
344. If the tariff is set too high, there is a risk of it either having no effect or it distorting supplier pricing, leading to tariff “bunching” at or very near to the cap, due to reduced incentives to compete on price. This would not be in the best interests of customers (and particularly not in the best interests of those customers who remain disengaged in spite of the extensive planned engagement activities set out under Remedy 10 and elsewhere).
345. Evidence from NSW suggests that the safe haven effect is observed even when the safeguard tariff is priced significantly above the cheapest tariff in the market. There, the regulator identified a “safe haven” effect despite the regulated price being an average of 12-16% higher than the cheapest market tariff.<sup>97</sup> This compares to CMA analysis indicating that SVT in the UK has been on average 14% higher than the cheapest market tariff.<sup>98</sup> This logically suggests that a Regulated Safeguard Tariff set at SVT price levels would create a similar “safe haven” effect.
346. Furthermore, the current UK price differential (between SVT and the cheapest market tariff) is likely to reduce over the next 12 months, as the typically longer hedge profile of SVT ceases to be such a disadvantage in cost terms and potentially becomes an advantage if wholesale prices rise. This would serve to amplify this “safe haven” risk, were the Regulated Safeguard Tariff to be set at SVT price levels.
347. This suggests that a “safe haven” effect, with its destructive effects on competition, would be unavoidable unless the tariff cap is set materially higher than the current SVT level.

### **Challenges with implementation**

348. From a feasibility perspective, we identify a series of challenges with how the tariff would be set, adjusted and introduced.
349. In terms of the setting of the initial price, a “one size fits all” tariff will fail to account fairly for material, structural differences in supplier cost bases, driven by a range of factors, such as customer mix (region, pay type, consumption levels), hedging approach, Government exemptions, Smart meter rollout strategy etc. It will therefore inevitably create a non-level playing field for suppliers, unless a separate safeguard tariff is set for each supplier. The impact of this non-level playing field would be exacerbated by the fact that the tariff could affect up to c.70% of the customers of the SLEF, and thus the majority of each of their cost bases.

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<sup>97</sup> St. Vincent de Paul Society, New South Wales Tariff-Tracking Project, May Mauseth Johnston, August 2013; as referenced in Review of Competition in the Retail Electricity and Natural Gas Markets in New South Wales, AEMC, 3 October 2013, p.ii (highlighting a \$300-\$400 saving on a bill of c.\$2,500)

<sup>98</sup> As stated in CMA’s Provisional Findings, para.22

350. Setting the price through a ‘cost plus’ or a ‘market-based’ pricing approach both have material disadvantages:

- “Cost plus” is a fully regulated solution that could effectively create regulator-set price controls for 70% of consumers (if all evergreen customers moved onto this tariff). This removes all elements of market-driven pricing and is severely detrimental to competition. It is also extremely complex to set a single price given the structural differences in supplier procurement, capital and operating costs (as set out above);
- Pricing “based on other retail prices” creates a significant risk of unintended consequences, including “gaming” by market participants in order to affect competitor price levels, and challenges for supplier risk management (e.g. due to impact of different hedging approaches and lack of price change predictability).

351. Determining the frequency of price adjustments will also be challenging:

- Frequent changes will enable close tracking of market prices, but could drive significant bill volatility, with potentially damaging financial consequences for customers, particularly the fuel poor, and for customer trust.
- Infrequent price changes could lead to supplier losses and the regulator being “held to blame” for both price rises and any perception of “feather pricing” if falls in wholesale costs are not passed on immediately. In periods of wholesale price rises, infrequent change could mean the Default Tariff becomes highly attractive, reducing the incentive for customers to choose a different product and move off the default.

352. The introduction of a Default Tariff, together with the ending of evergreen tariffs, will mean switching an estimated c.19m residential customers and up to 700k microbusiness meter points to new tariffs and potentially new suppliers. As outlined in our response to Remedy 10, we believe any such transition must be done over a phased period (we suggest three years for our proposal in Remedy 10) to ensure (a) the opportunity for customers to become engaged (rather than go onto the Default Tariff) and (b) to manage the risk of major customer disruption through the failure of supplier systems and operations to cope with the significant increases in customer interaction.

353. As noted above, there would also need to be a clear, credible and feasible plan for how the safeguard tariff would be phased out, to avoid long-term regulation of a material part of a competitive market.

### **Case study: New South Wales**

354. The CMA highlights the Australian state of New South Wales (NSW) as a potential exemplar when considering a Regulated Safeguard Tariff. We agree that NSW is an instructive case study to consider, as the market has a number of similarities to the UK, and has been subject to a Regulated Safeguard Tariff.

355. However, we think the NSW example provides strong evidence as to why it would *not* be appropriate to introduce a Regulated Safeguard Tariff in the UK.

356. Firstly, the tariff cap was only introduced in NSW as a transitional step as the market moved from full regulation to full liberalisation. It was not, as is proposed under Remedy 11, the introduction of new price regulation into an already-liberalised market.

357. Secondly, in 2014, New South Wales took the decision to end the tariff cap in the electricity market, as the market was seen as being sufficiently competitive that the

continued existence of a regulated price would likely worsen rather than improve customer outcomes. One of the main reasons for its removal was that customers tended to stay on this non-competitive tariff because of “a belief that the regulated price is reasonable”.

358. Thirdly, at the point that the NSW regulator deemed the market sufficiently competitive to remove regulated pricing, competitive pressures in the market appeared comparable with the UK against a range of competition metrics, for example<sup>99</sup>:

- Similar awareness of ability to switch supplier (88-89% in NSW versus 89% in the UK);
- A similar gap between the cheapest market tariff and the regulated tariff or SVT (see above);
- Similar levels of customer satisfaction with electricity suppliers (74% in NSW vs 73% in UK);
- Customers in the UK are substantially more likely to have been contacted by an energy company suggesting they switch supplier in the last year (63%) compared with NSW (39%)
- Customers in the UK are much more likely to use PCWs to obtain information about their options (71% in the UK versus 18% in NSW);
- Among customers who have not switched/considered switching, a significantly lower proportion of customers in NSW gave positive reasons (e.g. only 26% said they were happy with their current retailer, 4% that they were happy with their current arrangements, and 3% that their company had a cheaper price) – compared with in the UK (where 48% gave cost/tariff as the reason and 18% quality/reliability).
- Greater market consolidation (in 2012, 95% of the NSW market was with one of three suppliers, compared to <90% of the UK market being with one of six suppliers today).

359. Fourthly, the regulator has recently published its draft conclusions from a review of the NSW market, one year after price deregulation. They conclude that competition is working effectively and therefore a “detailed review of retail prices and profit margins is not necessary”.<sup>100</sup>

360. We reiterate therefore, that the NSW electricity market provides an example of why price regulation in the UK market would be detrimental to competition, and supports our position that a Regulated Safeguard Tariff should not be introduced as a market remedy.

### ***Response to CMA’s Questions (Remedy 11):***

**We reiterate our strong belief that the introduction of Remedy 11 would be in direct conflict with the CMA’s Principles 1 and 2 for considering remedies, and that it would undermine, rather than promote, the CMA’s aims (as we explain above in full).**

<sup>99</sup> See "Review of the performance and competitiveness of the retail electricity market in NSW", IPART, July 2015 and "Consumer Research for 2015 Nationwide Review of Competition in Retail Energy Markets", AEMC, July 2015.

<sup>100</sup> Review of the performance and competitiveness of the retail electricity market in NSW, IPART, July 2015, p.1

**We therefore believe that the questions below around design considerations are moot, in that they do not address our fundamental concerns. Nonetheless, we set out our initial views on the questions to the extent possible, in the hypothetical event that the CMA decides to proceed and recommend the implementation of the Remedy.**

*(a) Should the safeguard tariffs be set on a cost-plus basis, or should they be related to other retail prices?*

- Both ‘cost plus’ and ‘market-based’ pricing approaches present highly material challenges when considering how to feasibly set an effective and fair tariff level
- “Cost plus” is a fully regulated solution that could effectively create regulator-set price controls for over 60% of consumers (if you consider all those currently on evergreen tariffs). This removes all elements of market-driven pricing and is severely detrimental to competition.
- It is also extremely complex to set a single price based on ‘cost plus’ given structural differences in supplier costs, due to differences in customer mix, hedging profile, mandated cost exemptions etc. For example, costs associated with prepayment meters and servicing customers via call centres are greater than those for a Direct Debit, online customer. The mid-tier suppliers have targeted customers who prefer to transact online and pay by Direct Debit and as such naturally have a lower cost to serve than the SLEF.
- Pricing “based on other retail prices” creates a significant risk of unintended consequences, including “gaming” by market participants in order to affect competitor price levels, and challenges for supplier risk management (e.g. due to impact of different hedging approaches and lack of price change predictability). It would also fail to account for the structural differences in supplier cost bases as noted above.
- Overall, however, we would recommend a cost plus approach that allows for a different regulated tariff level for each supplier, to allow for differences in cost base.

*(b) If the safeguard tariffs were set on a cost-plus basis, which approach(es) we should consider to determining the wholesale energy cost element of the tariffs? What are the relative merits of the proposed approach(es) in the context of the purpose of the safeguard price cap?*

- The wholesale costs could need to be determined based on a hypothetical hedging strategy, including incurred and forecast costs. The index needs to be truly reflective of the actual costs incurred by suppliers on wholesale purchasing, e.g. including the costs of fully meeting varying customer demand.
- In order to minimise bill volatility and avoid potential customer gaming given seasonal cost variances, the CMA might consider a forward hedge of at least 12 months.
- There would also need to be a mechanism through which suppliers could pass through sudden increases in wholesale costs, in order to avoid significant financial risks.
- The CMA will also need to consider how to determine other key cost elements – in particular a return on capital employed (and either a return on risk capital or an appropriate fee to cover the costs of risk management). This will be complex and will depend on wholesale market conditions and the hedging profile of the regulated product, for example.

*(c) Could the imposition of a transitional safeguard price cap result in energy suppliers reducing the quality of service offered to customers on this tariff? Is this risk reduced by customers' ability to choose alternative, unregulated tariffs?*

- Yes, this is a clear risk, particularly if price points are set relatively low, creating an unavoidable need for suppliers to cut costs in order to achieve profitability.
- It could however be argued that some suppliers would look to avoid this as reduced quality of service reduces supplier benefit (higher churn, poor service begets higher costs to handle complaints/ resolve problems, NPS damage).
- The risk of reduced service levels would be limited to some extent by customer ability to switch, though as the proportion of customers on a Default Tariff dwindles, any remaining customers on it will likely be the most disengaged – these customers are more likely to remain on that tariff even if service levels are poor.

*(d) Should all domestic and microbusiness customers on Default Tariffs be rolled onto the safeguard tariff, or should this remedy only apply to a subset of these customers? If this remedy should not apply to all customers, why? And how should energy suppliers identify those customers who should be covered?*

- We believe that for simplicity there should be a single residential Default Tariff for each supplier that applies to all current evergreen customers who do not actively choose a tariff (though note that in practice there may need to be up to 84 different tariff levels to account for different regions, fuels and payment types).
- It should also apply to all microbusiness customers though there may need to be multiple tariffs, as a single tariff may need to be relatively highly priced to account for high debt default levels (on deemed), and to ensure suppliers can cover their costs.
- It should be noted, however, that there are currently an estimated c.19m domestic customers on an evergreen tariff. Moving all current evergreen customers onto new fixed term contracts will be a highly significant market intervention, with major operational implications.
- In light of this, and as noted below, moving customers off evergreen tariffs and onto fixed term tariffs (whether competitive tariffs or default) will need to be a phased process, to maximise engagement and minimise the risk of poor customer experience through the transition. As part of this process, we suggest prioritising those customers who are most likely to be disengaged and moving them off evergreen first (potentially using current length of tenure on evergreen as a proxy for disengagement).

*(e) How should the headroom be calculated to provide the right level of customer protection while not unnecessarily reducing healthy competition?*

- As noted, we believe a regulated tariff will inevitably serve to significantly reduce market competition.
- As also noted, we see significant complexity in setting the 'right' tariff and the potential unintended consequences of a regulated price point (set too high could inflate prices, set too low will further reduce competition). It will be difficult both to identify the relevant cost base and to assess the optimal amount of "headroom" above that cost base at which to set the regulated price.
- As a basic principle, however, headroom on the safeguard tariff should allow for a profit margin over the agreed costs that is materially larger than the typical profit margin achieved on competitive tariffs, in order to ensure a price point for the

safeguard that incentivises customers to engage with the market and actively choose a better value tariff. We note that this was the approach taken in New South Wales, prior to deregulation.

*(f) What regulatory information would be required to set the safeguard tariffs?*

- Deep cost knowledge would be required to set safeguard tariffs effectively (a greater level than required for the current CSS, e.g. cost bases by region and pay type), with implications for regulator capacity/ expertise and overall industry costs.
- In particular, there would need to be deep understanding of full hedging, balancing costs including liquidity constraints and access to these costs.

*(g) How long should the safeguard price caps be kept in place? Is it appropriate to include a specific sunset provision, or should there be a commitment to review the need for and level of the safeguard price caps after a certain period of time?*

- As noted in our main response to this remedy, we believe the safeguard tariff would take several years to introduce and would be extremely difficult to remove at all, for reasons of low engagement and political risk. Although the CMA posits the safeguard tariff as a transitional measure, we believe the safeguard tariff would inevitably be in place for an extended period of time.
- However, if the remedy is introduced as proposed, we would recommend:
  - a regular review process (e.g. annually) to understand changes in the way the market is responding to competition, given uncertainties about impact and effectiveness of this remedy in practice.
  - relevant, effective and measurable metric(s) against which to measure progress
  - a sunset provision (potentially tied to smart implementation) – this is essential to ensure that the intervention is time limited and creates regulation of the market (to the detriment of competition) for the shortest time possible.

*(h) How frequently – if at all – would the level of the cap need to be reassessed? If the cap is set on the basis of directly passing through wholesale and network costs, then it may not be necessary to revisit the safeguard price level.*

- Assuming a cost+ pricing approach, we would recommend reviewing on a regular basis so that all costs (and changes in cost) are tracked appropriately.
- Even if changes in wholesale prices and network cost changes were simply passed through, there would still be a need to reassess the level of the cap on a regular basis (e.g. every 12 months) to account for changes in other costs (e.g. operating costs, risk management costs, actual vs forecast fuel costs, smart metering costs)
- As above, there would also need to be a mechanism through which suppliers could pass through sudden increases in wholesale costs, in order to avoid major financial consequences.

*(i) Which energy suppliers should be subject to the safeguard cap, and why? Should it be restricted to the Six Large Energy Firms, or should all retail energy suppliers be covered?*

- The cap should apply to all suppliers as part of the principle of a level competitive playing field, and to avoid customer confusion.
- Most small suppliers also currently have material differentials between their lowest tariff and SVT, indicating that this structure is not limited to the Six Large Energy Firms.

*(j) How should the transition from the current arrangements be managed? We note that an immediate requirement to change the prices for all customers on standard variable tariffs, rollover, evergreen, deemed and out-of-contract tariffs might put pressures on certain suppliers more than others. Should there be, therefore, a period over which the safeguard price cap is phased in? If so, how long should this period be and how should the transition work?*

- A phasing in of the tariff would be essential to give the market the best chance of engaging customers prior to them being moved to the default. Phasing would also manage the risk of significant customer disruption from supplier system and capacity failures (e.g. billing systems, call centre capacity). It would also allow current hedging positions to unwind, in the event there was a mandated wholesale price.
- As set out in our response to Remedy 10, we believe a one year notification period followed by a two year migration period would be optimal.

*(k) Would energy suppliers have the ability to circumvent the remedy, for example, by encouraging disengaged customers to switch on to less favourable, unregulated tariffs, and how such risks could be mitigated?*

- In theory this might be possible, but we believe it would be challenging, unfair and brand damaging to convince a customer to move to a less suitable tariff, and so the normal workings of the market would limit the risk of this happening.
- Some selected tariffs may be higher priced but still favourable given customer preferences (e.g. less volatile or fixed to manage risk, with an appropriate premium)
- To mitigate the risk for Microbusinesses, this remedy could be introduced alongside Remedy 8 - ban on autorenewals.

*(l) Should the CMA set the level of the safeguard price caps itself, or should make a recommendation to Ofgem to do so?*

- Ofgem regulation may be preferable in that it would limit the number of regulatory participants in the market.

*(m) Are there any potential unintended consequences of setting safeguard price caps, for example, in terms of their potential impact on the level of other, unregulated tariffs?*

- As noted in our main response to Remedy 11, there are significant unintended consequences of introducing regulator-set tariff caps.
- A regulator-set Default Tariff is likely to create a “safe haven” effect, reducing customer engagement.
- Price caps are likely to influence the level of other tariffs in the market. For example, if set too low, there is a risk that they will drive up prices at the lower end of the market, reducing price differentials and reducing the incentive to switch/ engage (due to lower available benefit from switching). If set too high, they could lead to clustering of prices at the top end of the market and reduce price competition.

## Remedy 12 – Gas Settlement

### 12a – Project Nexus

361. **We support the CMA’s proposal to ensure the project is delivered as soon as possible.**
362. The timely implementation of Project Nexus (which will increase the frequency of individual meter point reconciliation) and completion of the smart meter roll out (which will increase the volume of actual readings collected) are central to resolving the problems associated with gas settlement. In particular, Project Nexus will deliver material improvements to the gas settlement system.
363. We note that a new implementation date of October 2016 has been confirmed.<sup>101</sup> Given this, we believe that the CMA should therefore define timely delivery as meaning this date, or before.
364. This remedy needs to be complimented however with proposals to address the impact on settlement of unidentified gas. In particular, we agree with Scottish Power’s assessment of the risk of cross subsidy between small supply points (SSPs) and large supply points (LSPs).<sup>102</sup> Currently unidentified gas, regardless of whether it originates in the Daily Metered (DM) or Non-Daily Metered (NDM) sectors is allocated to the NDM sector. In effect, gas lost to factors such as theft or measurement error anywhere in the system is paid for exclusively by domestic and SME customers.
365. This misallocation of costs means that DM customers and suppliers do not receive the right incentives to adjust their behaviour, for example by investing in theft detection activities. Similarly, domestic customers are allocated costs over which they have no control. We estimate that this misallocation equates to approximately £90m p/annum. Importantly, these problems will persist even following the introduction of UNC 473.
366. This could be resolved by ensuring the costs of unidentified gas are shared equally between all suppliers, based on their market share of volume supplied.

### **Response to CMA’s Questions (Remedy 12a):**

*(a) How long should the parties be given to implement Project Nexus?*

- As above, we believe that CMA should mandate implementation by October 2016.

*(b) Should the CMA implement this remedy directly (eg via an order and/or a licence modification) or should it make a recommendation to Ofgem to implement the remedy?*

- We believe Ofgem have sufficient power to implement this kind of requirement. We would therefore be happy for the CMA to make a recommendation to Ofgem to implement the remedy.

<sup>101</sup> <http://www.xoserve.com/index.php/project-nexus-steering-group-votes-for-1st-october-2016-uk-link-programme-delivery-date/>

<sup>102</sup> Provisional Findings Appendix 8.6, para.20.

## **12b – Monthly AQs**

**367. The proposed remedy is disproportionate and we oppose its introduction.**

368. AQs are updated using actual meter readings. Mandatory monthly updates to the Annual Quantity (AQ) values would therefore entail suppliers collecting actual monthly meter readings. This would come at a significant cost; we estimate an additional £85m for Centrica alone.

369. There is no evidence that gas AQs are being gamed – the risk is theoretical. The costs associated with this remedy are therefore disproportionate to the potential benefit it could create. This is particularly the case given Project Nexus will ensure that sites are individual reconciled against each reading received (i.e. removing the element of choice and therefore tackling gaming), and smart metering will increase the volume of readings captured. The CMA should therefore focus instead on remedies which ensure the timely delivery of Project Nexus and smart metering.

370. Smart metering will also mean that meter readings are collected on a more frequent basis, improving the accuracy of settlement, and Project Nexus will then ensure that all meter readings collected are used to update the AQ, removing the element of choice and therefore most of the gaming risk.

371. We agree that there may be a small residual risk of gaming after both Project Nexus is implemented and after the smart metering roll out is complete. We believe a more proportional response to this issue would be the introduction of a Performance Assurance Framework (PAF).

### **Response to CMA's Questions (Remedy 12b):**

*(a) Is it proportionate to require the mandatory monthly updating of AQs? Would it be more proportionate to require less frequent updating of AQs? Would less frequent updating still be effective in terms of removing the scope for gaming of the system?*

- No. As above, we believe that mandating monthly updating of AQs would be disproportionate, particularly as the issue will largely be resolved with the implementation of Project Nexus and the smart metering roll out.

## Remedy 13 – Half-hourly electricity settlement

372. **We have a number of concerns with the proposal to mandate the creation of a binding plan for the introduction of half-hourly (HH) settlement at this time.**

373. Centrica believe HH settlement could lead to improvements in the speed and accuracy of settlement. Whilst many benefits can be realised today with static ToU tariffs, we also recognise that HH settlement could enable the development of future dynamic ToU tariffs which can be used to support demand side response.

374. However, whilst HH settlement is ultimately desirable, it is premature to commit the industry to developing a binding implementation plan in the short to medium term. In particular, we believe that:

- A full cost benefit analysis of HH settlement is needed before any implementation plan can be agreed;
- The incremental benefits HH settlement brings are likely to be limited in the foreseeable future, meaning it is likely to be too early to consider implementing HH settlement for Profile Class (PC) 1-4 sites; and
- Implementation of HH settlement would take significant resources and therefore risk undermining other important projects occurring now and in the future.

375. We also acknowledge the privacy concerns raised by the CMA, however believe that with proper controls these may be overcome.

### ***A full cost benefit analysis of HH settlement is needed***

376. We agree with those who have highlighted to the CMA that the costs of implementing HH settlement remain unknown.<sup>103</sup> We are aware that implementation will involve both suppliers of PC 1-4 sites and their metering agents however, and that it will also involve significant change to central industry systems.

377. These costs will remain uncertain until the specific design of HH settlement arrangements is known. This in turn can only be firmed up once the overall post-smart metering market design is understood.

378. It also remains unclear when the expected benefits will arise and how much they will be. This is crucial to understanding when the industry should target the implementation of HH settlement for PC 1-4 meters. For example, settlement benefits may only be realised once a critical mass of smart meters have been installed and related product innovation is brought forward. The primary barrier to the latter is the fact that the value of load shifting on an individual customer basis [X] is currently insufficient to incentivise customers to change their behaviour, and thus demand dynamic ToU tariffs. Such tariffs will not be developed when they become technically feasible – only when customers demand them,

### ***The incremental benefits HH settlement brings are likely to be limited***

379. We also believe that much of the smart metering benefits can be realised today in the absence of HH settlement.<sup>104</sup> For example, suppliers are already able to deliver innovative static ToU tariffs that encourage basic load shifting, for example our 'Free Saturdays' product, but potential demand for even these remains relatively low at the

<sup>103</sup> Provisional Findings Appendix 8.6, para.84b.

<sup>104</sup> Provisional Findings Appendix 8.6, para.90.

moment. Costs and revenues can still be matched for innovative products like this today by creating a new Standard Settlement Configuration (SSC) with a Time Pattern Regime (TPR) that matches the peak and off-peak configuration at the meter.<sup>105</sup>

380. We acknowledge that dynamic or automated ToU tariffs may enable further demand side response, such as that envisioned as part of a future smart grid. As above, the amount of savings available to customers from shifting their consumption is currently small however. At these levels, the incentive to change when they consume things such as entertainment and heating is insufficient to stimulate demand for dynamic or automated ToU tariffs. We consider this is likely to remain the case as long as peak / off peak cost differentials remain low, or until affordable home energy storage is generally available.
381. The risk of agreeing an implementation plan today for the introduction of HH settlement is that it may then be delivered before sufficient benefits can be realised to offset the cost.

### **Implementation of HH settlement would take significant resources**

382. The scale of the project that would be required to implement HH settlement for PC 1-4 meters would be significant, similar in size to Project Nexus. As well as upgrading supplier, metering agent and central industry systems to handle the amount of data HH settlement entails, we also agree with Ofgem that settlement process would need to be reformed, system changes to facilitate an orderly transition, and privacy controls all need to be introduced.<sup>106</sup>
383. There is therefore an opportunity cost element to any decision about when to implement HH settlement for PC 1-4 meters. For example, a decision to implement now would be likely to lead to delays to other industry initiatives such as faster switching or the smart meter roll out.

### **Privacy concerns**

384. We note the CMA cites potential privacy concerns around the use of HH settlement data.<sup>107</sup> Whilst we agree with these, we consider that these can be overcome by ensuring that customer consent is at the heart of future market design in this area. For example, we support a customer's right to allow third parties to utilise their data provided that use is subject to explicit time bound customer consent, and subject to appropriate controls to avoid misuse.
385. Customers could also seek to mitigate privacy risks by controlling the level of data granularity that is provided to third parties. For example, it is not clear to us that all third party applications of HH settlement data will require access to HH, as opposed to daily, data.
386. We therefore believe the proposal to mandate the development of a binding delivery plan for HH settlement is premature, and oppose it.

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<sup>105</sup> <https://www.elexonportal.co.uk/faq/view/429?cachebust=d8dpy5yyre>

<sup>106</sup> Provisional Findings Appendix 8.6, para.92.

<sup>107</sup> Provisional Findings Appendix 8.6, para.81 to 83.

## **Response to CMA's Questions (Remedy 13):**

*(a) Would this remedy be effective in stimulating tariff innovation, in particular time-of-use tariffs?*

- No. As above, we believe these tariffs will only be developed once there is customer demand for them. This will only follow when the sufficient financial incentives exist for individual customers to change their behaviour and shift consumption away from peak times.
- Much tariff innovation is possible today around static time of use tariffs. Suppliers are able to match revenue to costs through the creation of new settlement profiles to make them commercially viable, as we have done with our 'Free Saturdays' product.

*(b) How long should the parties be given to agree this plan?*

- As above, we believe that the plan can only be agreed once a full cost benefit analysis has been completed. Key to this cost benefit analysis will be identifying the point at which the business case for HH settlement for PC 1-4 turns positive. Until this happens, we cannot be sure that HH settlement for PC 1-4 is a good use of customer's money.

*(c) What are the principal barriers to the introduction of a cost-effective option to use half-hourly consumption data in electricity settlement for profile classes 1 to 4? How could these be reduced?*

- The cost of HH settlement for PC 1-4 is predominantly driven by the increase in data inherent with such a shift – from one read per quarter to one read per half hour. This will require significant investment in supplier, metering agent and industry systems. As the increase in data is inherent with a HH settlement process, we do not believe these costs can be avoided.

*(d) Should the use of half-hourly consumption data in settlement for these profile classes (or certain of them) be optional for energy suppliers, or should it be mandatory? What are the advantages/ disadvantages of each approach?*

- We have set out the possible advantages and disadvantages for each option below:
- Optional - Advantage: it can be targeted at the customers with the greatest benefit from half-hourly (HH) settlement, i.e. those customers whose usage do not fit standard profiles or cannot be settled accurately through potential new profiles.
- Optional - Disadvantage: it creates the risk of gaming whereby suppliers can HH settle those customers whose difference from a profiled usage benefits the supplier's imbalance and trading position. It could also create dislocation of customer experience, itself becoming a barrier to switching.
- Mandatory - Advantage: there is no risk of gaming as all customers must be HH settled. The accuracy of settlement, and therefore cost allocation, will be maximised.
- Mandatory - Disadvantage: The majority of customers would not see an economic benefit for HH settlement, i.e. the cost of implementing HH settlement outweighs any allocation benefit they receive, so they would lose out financially.

*(e) Are there distributional considerations that we should take into account in relation to time-of-use tariffs? For example, might vulnerable customers end up paying more if they fail to change their consumption patterns? Or will the decline in the required generation capacity outweigh any increase in peak prices?*

- We believe that distributional impacts from this may be negligible overall. Where they do occur, they will be dependent on different customers' ability or willingness to shift their consumption in response to the price signals received.
- We consider it plausible that those customers able to afford smart appliances (e.g. fridges, washing machines, electric vehicles) will probably be the principle beneficiaries of dynamic ToU tariffs. We would expect this hypothesis to be tested by a full cost benefit analysis before any implementation plan is drawn up.
- Finally, we anticipate that even in a post-HH settlement world, suppliers will continue to offer flat rate tariffs for those who want them. This could mitigate any distributional impacts.

*(f) When should (optional/mandatory) use of half-hourly consumption data replace settlement based on assumed customer profiles? Is it necessary to wait until 2020 when all domestic customers have smart meters installed? Alternatively, could use of half-hourly consumption data be phased in for customers with smart meters prior to 2020?*

- As above, we do not believe an implementation plan can be drawn up until the costs and benefits are better understood. Any move to allow elective HH settlement for smart meter sites before the end of the roll out should also provide controls against gaming, for example preventing suppliers from choosing which sites to nominate for HH settlement and which to keep in the current process.
- We believe the CMA should therefore review the situation post smart meter roll out. A later implementation of HH settlement for PC 1-4 is likely to be cheaper and have more demand.

## Remedy 14 – Regulatory framework for financial reporting

387. Our views on possible Remedy 14 are as follows:

- We do not believe that transparency will be increased by the possible remedy as expressed; and
- We instead suggest that increased reporting requirements are only introduced for the default tariff (as outlined in our response to Remedy 10).

388. We expand on each of these points in turn below.

### **Transparency**

389. In possible Remedy 14, the CMA proposes to encourage transparency and consistency by adjusting reported wholesale energy costs on the basis of standard products. We have interpreted this to mean that the CMA would propose that suppliers recalculate their energy costs on the basis of spot prices.

390. However, we do not believe that adjusting reported wholesale costs on the basis of spot prices will result in increased transparency and comparability<sup>108</sup>. Instead we are concerned that such a practice could result in a greater level of confusion amongst our customers, media and other stakeholders. This is because it will require us to restate actual incurred costs, and report these in the context of an artificial construct which will be complex to interpret and explain.

391. To illustrate our concerns, we present a highly stylised example in Table B below. Consider two suppliers (A and B) who, over the course of a year, supply identical volumes, purchase energy for the same price and sell it at the same margin. The only difference is their consumption profile with Supplier B supplying more winter demand. From a *financial reporting* perspective both suppliers would earn identical profits and their customers would have paid the same price.

392. In this example, spot prices in Q4 are below the forward market price (which would result, for example, if Q4 winter was warmer than expected). Were these suppliers to report profits using *spot price reporting* their profitability would look very different with Supplier B looking like it earned a far greater profit than Supplier A.

393. On this basis it could be (erroneously) interpreted that Supplier B made high profits and/or overcharged its customers, despite the fact that both suppliers sold their energy at an identical price (based upon the market prices at that date the contract was sold) and delivered an identical financial profit. The only factor that has influenced their relative levels of profitability as measured by the Remedy 14 *spot price reporting* approach is differences in the suppliers' relative consumption profiles.

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<sup>108</sup> Please refer to our submission "13/3/15 Electricity spot price scenario - response to the CMA analysis of wholesale electricity costs" for analysis that supports this view.

**Table B – Remedy 14 illustration**

	Supplier A						Supplier B					
	Q1	Q2	Q3	Q4	Profits @ Cost	Profits @ Spot	Q1	Q2	Q3	Q4	Profits @ Cost	Profits @ Spot
Forward Price	10	12	14	16			10	12	14	16		
Spot price	10	12	14	14			10	12	14	14		
Profit per unit	1	1	1	1			1	1	1	1		
Volume	25	25	25	25	100	100	37.5	12.5	12.5	37.5	100	100
Revenue	275	325	375	425	1400	1400	412.5	162.5	187.5	637.5	1400	1400
Purchased cost	250	300	350	400	1300		375	150	175	600	1300	
Spot cost	250	300	350	350		1250	375	150	175	525		1225
profit	25	25	25	25	100	150	0	0	0	75	100	175
<b>Profit earned per unit</b>					<b>1.0</b>	<b>1.5</b>					<b>1.0</b>	<b>1.8</b>

394. Given that adjusting profits for spot prices, even in a simple example such as this, can result in significantly different profitability outcomes we strongly suspect that the CMA’s proposals would cause confusion when considering supplier profitability.

395. We have experienced similar difficulties in attempting to explain the difference between theoretical constructs and financial reality in the context of Ofgem’s (suspended) Supply Market Indicators (SMIs). Given we have found it extremely difficult to explain the difference between our financial performance and SMI outputs, we believe media and other stakeholders would find Remedy 14 similarly confusing.

**Proposed alternative**

396. While we have concerns about possible Remedy 14 as proposed, we believe that there would be material transparency benefits from introducing enhanced reporting requirements for the default tariff (as set out in our response to Remedy 10). This is because we would expect the majority of the least engaged customers to be supplied on the default tariff. Increased regulatory scrutiny of the costs of supplying this customer base would therefore be an important way in which stakeholders can gain confidence the level of the level of the default tariff is being set appropriately.

397. We therefore propose that all suppliers should be required to consistently report the costs and prices of their default tariff. This should also include a requirement to provide more detail on cost drivers (e.g. a requirement to split out costs of government social and environmental schemes such as ECO would make it easier for customers to understand why the prices for larger and smaller energy suppliers might differ).

398. The increased transparency and regulatory oversight created by such a requirement should encourage customer engagement, as this should serve to reinforce the availability of more attractive tariffs and propositions in the market. We also believe this reporting would serve as a complement to the existing CSS reporting requirements.

**Response to CMA’s Questions (Remedy 14):**

*(a) Should scope of the individual areas reported on align with scope of the markets as set out for generation and retail supply in our provisional findings? For example, should a requirement to report wholesale energy costs on the basis of standard products traded on the open wholesale markets be imposed?*

- We do not believe that reporting should be conducted on the basis of standard products. This would shift financial reporting away from actual costs incurred (and

therefore actual profit made) to one based on theoretical costs (and therefore theoretical profits).

- For example, it implies that instead of looking at the actual costs incurred for energy, e.g. through bi-laterally negotiated contracts, we would instead calculate costs using a reference price such as the day ahead price quoted on the day in question.
- We do not believe that such an approach would improve comparability. Instead it would result in the production of a set of financial results that lack accuracy or relevance. We do not therefore believe that any such reporting would add value.

*(b) What regulatory reporting principles would be particularly relevant to the preparation of regulatory financial information in this sector?*

- Formal regulatory reporting is usually used in markets with price regulation and a mechanism to handle over/under recovery. It is not clear why this would be necessary in an industry with market driven prices.
- Creating an extra set of books and principles based on theoretical costs is not relevant for a sector where the market sets the costs. It is more relevant to sectors with full price controls.
- Relevant regulatory reporting principles include a requirement to publish simultaneous with year end, and apply these on a consistent basis across all suppliers.

*(c) Would summary profit and loss account and balance sheet information for each area be sufficient to enable the effective regulation of the sector and the development of appropriate policies? Or should the large domestic and SME energy suppliers be required to collect and submit additional, more granular financial information?*

- Such information must reconcile to group Annual Report and Accounts (ARA) to ensure transparency
- Summary profit and loss account and balance sheet information should be sufficient, provided they are subject to a full financial audit.
- Further granularity may help provide further confidence, but this would entail extra cost. Publication of more granular information would also give rise to co-ordination risks.

*(d) Should Ofgem require that the summary profit and loss and balance sheet information be audited in accordance with the regulatory reporting framework?*

- Yes. This occurs today.

*(e) Should this remedy apply to the firms that are currently under an obligation to provide Ofgem with Consolidated Segmental Statements? Or should it apply to a larger or narrower set of firms?*

- This should apply to all energy companies that hold both supply and generation licences (and therefore have vertically integrated structure).

*(f) What would be the costs of imposing such a remedy? We note that some firms' reporting systems are not currently capable of providing information on such a 'market-orientated' basis and that our remedy could require significant additional system requirements.*

- The existing segmental statements already impose a significant cost burden on licensees. We believe possible Remedy 14 would increase these costs materially, given it would involve recalculating every trade based on market data generated at

least 12 months ago. This would be complex and time consuming, and involve significant changes to our financial reporting procedures.

- While there additional costs would also be incurred in increased relating to the default tariff, we believe these are justified given the anticipated transparency benefits.

*(g) Should the CMA implement this remedy by way of licence modifications or by way of a recommendation to Ofgem?*

- We do not favour introducing Remedy 14 as proposed. However, we would suggest that enhanced reporting requirements relating to the default tariff would best be introduced as a licence modification.

*(h) To what extent should this financial information on performance be published?*

- We believe that publication helps serve a wider transparency purpose, and helps improve confidence in the sector.
- We believe this could equally be achieved however by submitting the CSS to Ofgem for them to assess and issue a statement confirming whether they had confidence or not in the results claimed.

## Remedy 15 – Assessment of impact of policies on prices and bills

399. **We strongly support remedies that will increase the transparency of policy decisions relating to prices and energy bills.**
400. The impact of energy policies on consumer bills is generally poorly understood. We therefore support any sensible measures to improve the accuracy of analysis provided on this.
401. Importantly, such scrutiny should be completed independently. There have been occasions in the past where we have questioned the quality of DECC and Ofgem analysis, for example.
402. As part of any changes, we recommend that Ofgem appoint a Chief Economist with the responsibility to ensure proposals are subject to robust quantitative impact assessments (IAs) on a regular and consistent basis. We set out our views on this proposal in more detail in the context of Remedy 17.
403. In our view, the focus of bill impact assessment also needs to move away from the counter-factual, for example justifying the benefit of policy interventions compared against taking no action, to a more transparent, straightforward presentation of policy impacts on consumers and bills. Such an approach would remove any inaccuracies arising from the uncertain nature of counter factual, for example in future energy prices, and help consumers better understand the impact on them of energy policy.
404. We believe that the proposed remedy would improve the effectiveness of assessments of tradeoffs between policy objectives and the impact on bills. This is particularly true if the assessment is independent. The remedy may in effect result in a pooling of the existing, separate, independent analysis which is completed by various organisations today.

### **Response to CMA's Questions (Remedy 15):**

*(a) Are such assessments of the impacts of policies on prices, bills and on the trilemma trade-offs carried out to a sufficient extent currently? Are there specific areas where such assessments are not currently carried out, or might be undertaken more comprehensively?*

- No. As above, we have some concerns with the way in which bill impact assessments have been regularly carried out. Consumers still do not have a good understanding of what has driven higher bills and in our view the issues set out above with these assessments have contributed to this.

*(b) Are the assessments sufficiently scrutinised?*

- Whilst there are some examples of effective scrutiny, for example by the Public Accounts Select Committee, it is not clear to us that all assessments are either subject to consultation or formal independent scrutiny.

*(c) Are the assessments sufficiently disseminated to interested parties? Which parties need to be informed about these assessments?*

- We believe that the success (or otherwise) of current dissemination procedures should be judged by the extent to which interested participants, including consumers,

understand and engage with them. On that basis, we do not consider the assessments to be disseminated effectively.

*(d) Is there an additional role for either Ofgem and/or DECC in carrying out assessments of the impacts of policies and trilemma trade-offs, or communicating the results of them?*

- As above, we favour a role for more independent analysis on the impact of policies on bills.

*(e) Should further, authoritative analysis be published to assist the public discussion? What form might this take? Which existing bodies are best positioned to undertake this role?*

- We believe this proposal could have merit. We believe the Office of Budget Responsibility (OBR) or National Audit Office (NAO) may be able to play a role in this.

*(f) Is there a sufficient case to justify creating a new, independent body tasked with scrutinising the impact assessments of policymaking?*

- There may be, if the OBR and / or the NAO are not considered well-placed to take on the suggested role. In our view this is may prove more difficult than extending existing organisations remits to cover this task.

## Remedy 16 – Revision of Ofgem’s statutory objectives and duties

405. **We share many of the CMA’s concerns that undue regulatory intervention may have stifled innovation and harmed effective competition. We therefore welcome this proposed remedy, and consider it an important step towards returning the promotion of competition to being the priority in the hierarchy of Duties applied in regulatory decision making.**
406. We have observed a shift in Ofgem’s regulatory approach, away from the promotion of effective competitive markets as the primary way of furthering the interests of consumers. This shift coincided with the changes to Ofgem’s statutory duties introduced in the Energy Act 2010.
407. This has also been reflected in Ofgem’s approach to implementing “fairness” since the RMR. Importantly, we do not believe that a “fair” outcome is necessarily a “standardised” outcome. Changes to Ofgem’s duties which place competition as a priority should also help here, allowing suppliers to differentiate in how they achieve customer outcomes such as this.
408. We therefore support the proposed remedy to restore the primacy of competition as the best way of protecting consumers’ interests, and consider that Ofgem’s Duties prior to the Energy Act 2010 are an appropriate template to follow. Specifically, we would favour:
- Removing Ofgem’s current Duty to consider means other than competition of furthering the Principal Objective before proceeding with a course of action; and
  - Amending Ofgem’s Statutory Duties to state that it must “seek to further the Principal Objective wherever possible by promoting competition” (replacing the current wording of “wherever appropriate”).
409. Such a change would ensure that the Duty to promote competition would be the first consideration in any analysis or policy formulation process.

### **Response to CMA’s Questions (Remedy 16):**

*(a) What specific changes should be made to Ofgem’s statutory objectives and duties in order to ensure that it is able to promote effective competition in the energy sector? For example, would it be possible to revert to the role of competition that existed before the introduction of the Energy Act 2010?*

- As above, we believe that Ofgem’s Principal Objective needs to once again place competition as the primary means through which it will achieve its aims. This could be achieved by amending Ofgem’s Statutory Duties to state that it must “seek to further the Principal Objective wherever possible by promoting competition”. We also support the removal of Ofgem’s current Duty to consider means other than competition of furthering the Principal Objective before proceeding with a course of action.

## Remedy 17 – Addressing disagreements between DECC and Ofgem

410. **We fully support remedies which clarify roles and responsibilities, and improve the transparency of regulatory decision making.**

411. We support any measures that clarify that:

- DECC is responsible for setting overall GB energy policy; and
- Ofgem, as independent regulator, is responsible for overseeing and maintaining well-functioning competitive markets and the regulatory framework, primarily through the promotion of effective competition.

412. These roles and responsibilities have been blurred at times with DECC increasingly prescribing the way in which the regulatory framework, and energy market rules should evolve. An example of this was DECC's decision to take reserve powers to introduce tariff regulations which mirrored those being introduced by Ofgem through RMR.<sup>109</sup>

413. Note that, while this Remedy is expressed in terms of interactions between DECC and Ofgem, it would be more appropriate to consider interactions between government more broadly and Ofgem in this context. We have observed instances where other elements of government (including but not limited to the Deputy Prime Minister's Office<sup>110</sup>) have been engaged in the detail of the operation of energy markets.

### **Response to CMA's Questions (Remedy 17):**

*(a) In which circumstance should Ofgem have the right or duty to express views on DECC's policies and DECC/Ofgem strategy for their implementation? What format should such views take? Should DECC have a duty to formally respond?*

- As with any other interested market participant, Ofgem should have the ability to express views on any DECC policy. However, to the extent Ofgem considers any given DECC policy conflicts with its objective of maintaining a competitive and well-functioning market, it should be required to make this clear.
- As above, where Ofgem believes that a DECC policy conflicts with the objective of promoting competition (irrespective of whether DECC is asking Ofgem to implement the policy) we believe Ofgem should issue an open letter to DECC setting out its view in full, with an obligation being placed on DECC to respond.

*(b) In what circumstances should Ofgem have right to seek a formal direction from DECC to implement a policy?*

- Given Ofgem's independence we consider there should only be a limited set of circumstances in which:
  - DECC should be able to issue a formal direction; or
  - Ofgem should feel it necessary to seek such a direction.
- However, we do think it appropriate that Ofgem should have the right to ask for a formal policy direction from DECC in the event that it considers, in assessing any given policy, it finds its Duties to be materially conflicting. We would note that a

<sup>109</sup> <https://www.gov.uk/government/consultations/ensuring-a-better-deal-for-energy-consumers-decc-discussion-document>

<sup>110</sup> <https://www.gov.uk/government/news/government-and-energy-suppliers-reach-agreement-to-help-consumers-get-best-deal>

simplification of Ofgem's Duties (with a refocus on promoting competition as Ofgem's priority) should help to limit the instances where this arises.

*(c) Would DECC's formal direction undermine (or appear to undermine) Ofgem's independence?*

- There is a risk, yes. However, the independence of the regulator is protected by European legislation; a direction may be challenged if it undermines that independence. A key importance of this remedy is to ensure that discussions and disagreements are carried out in the open, thus enhancing regulatory certainty.
- To limit the potential for Ofgem's independence to be compromised, any specific DECC direction should be in direct response to a request for direction from Ofgem (and remain within the bounds of such a request).
- As above, we also recommend the CMA remove DECC's reserve powers to implement detailed regulatory solutions, for example tariff simplification reform.

*(d) Would other measures be effective in promoting the independence of regulation?*

- As noted in Remedy 15, we suggest that Ofgem is obliged to appoint a Chief Economist with specific responsibilities for ensuring the robustness of regulatory decision making and policy formulation (e.g. as is the case at the CMA, or DG COMP). To emphasise the importance of this role, the Chief Economist should be a member of the GEMA Board.
- We believe robust impact assessments should be at the core of regulatory decision making, are an essential part of a transparent consultation process, and should be quantified wherever possible. Such principles are already a feature of other regulatory processes.<sup>111</sup> We would suggest the Chief Economist is required to develop and maintain similar principles for Ofgem, and ensure these are applied consistently.
- Finally, it would help to deliver consistency in the rigour and quality of regulatory decision making across Ofgem if Ofgem formally appointed a General Counsel (also with a seat on the GEMA board) with a standalone legal team, as opposed to having legal resource allocated by Directorate. This would increase the ability of Ofgem's legal resource to provide an objective analysis of the extent to which policy being formulated or considered for decision is consistent with or attains Ofgem's Duties.

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<sup>111</sup> For Ofcom's approach, see [http://stakeholders.ofcom.org.uk/binaries/consultations/better-policy-making/Better\\_Policy\\_Making.pdf](http://stakeholders.ofcom.org.uk/binaries/consultations/better-policy-making/Better_Policy_Making.pdf)

## Remedy 18 – Codes

### 18a – Code Administration

414. **We support the possible remedy of making code administration a licensable activity. We believe it is likely to be helpful in harmonising arrangements and raising standards.**
415. Over time, the smart metering programme should provide the scope to simplify industry processes and potentially reduce the number of retail electricity codes. In parallel, it would make sense to explore the scope to streamline and harmonise Code Administration.<sup>112</sup> Ensuring Code Administrators are subject to a licensing regime would be an effective and proportionate way of achieving this. It could also enable the sharing of best practice, raising standards across the board.
416. The CMA should also consider whether the creation of a Design Authority could help co-ordinate retail market code changes and project manage the change process. This could also facilitate a reduction in the number of Code Administrators over time.
417. More generally, we believe that Project Nexus and the smart metering roll out offer a significant opportunity to simplify code arrangements, and must be seized. We support any remedies the CMA may bring forward which help achieve this.

### **Response to CMA's Questions (Remedy 18a):**

*(a) Is this recommendation likely to result in a positive change in the initiation, development and/or implementation of code changes that pursue consumers' interests*

- Yes. As above, we believe that making code administration a licensable activity would be helpful in harmonising arrangements and raising standards.

*(b) Would this remedy be more effective if certain functions currently carried out by code panels and/or network owners (e.g. setting up working groups) were transferred to code administrators?*

- We are open to this possibility, but note that effective participation in working groups requires a 'coalition of the willing'. Passing responsibility for setting up work groups to Code Administrators would not of itself change this situation. Instead, this could be addressed by developing and encouraging various forms of collective representation, especially for smaller independent suppliers with limited resources.

*(c) Would this remedy be more effective if Ofgem or DECC were to impose stricter requirements relating to the selection (e.g. competitive tender), financing and/or independence of code administrators (and/or delivery bodies)?*

- Yes. Any tender process would however need to strike a balance between selection on terms of both cost and ability. Simply selecting the cheapest potential administrator could make the situation worse if they then lacked the expertise to effectively manage what can be technical and complex codes.

<sup>112</sup> We note for example that there may be logical and appropriate differences in the different forms of credit accepted between codes. Parent Company Guarantees may be appropriate for network access codes, however the real time nature of electricity settlement means that letters of credit or cash may only be suitable for the Balancing and Settlement Code.

## 18b – Ofgem Powers Regarding Code Changes

418. **We consider that Ofgem would benefit from an enhanced capability to initiate and lead material industry change that has a direct connection to how they achieve their primary duties. However we believe focus should be on requiring Ofgem to make better use its existing substantial powers, rather than extending its power materially.**
419. Ofgem already has significant powers to direct code change, for example in the ability to commence an SCR.<sup>113</sup> There are also precedents for Ofgem to take further powers, for example in the case of gas security of supply the power for Ofgem to directly raise their own UNC modification.<sup>114</sup>
420. Whilst better use of these existing powers could be made, we agree that there may also be limited scope to enable Ofgem to raise their own code modification proposals where the nature of the change is clearly related to the design and development of the regulatory framework as opposed to the detail of industry arrangements. Importantly, Ofgem must continue have meaningful stakeholder involvement before imposing change.
421. If Ofgem is given any new power to raise modifications, we believe it is important to limit the scope of the new power to matters which directly impact on Ofgem's primary duties, as opposed to being simply a general power. Similarly, where Ofgem do raise their own modification, we believe it important that industry has the ability to appeal 'on the merits' of the case.
422. Finally, there may be a role for Ofgem, or a new Design Authority, to help manage change where it is either contentious or has interdependencies across multiple codes. For example, there may be scope for 'guillotining' powers so that a decision can be made once proposals have been made and developed.

### Response to CMA's Questions (Remedy: 18b)

*(a) Is this recommendation likely to result in a positive change in the development and/or implementation of code changes that pursue consumers' interests?*

- As above, we believe that Ofgem already has powers in this area. Any benefit could therefore be limited to where the code proposal has material impacts on Ofgem's primary duties.
- We consider that Ofgem would benefit from an enhanced capability to initiate and lead complex industry change – especially in areas such as prioritisation, programme management and impact assessment analysis.

*(b) Would this undermine the principle (and effectiveness) of industry-led code changes?*

- Yes. We believe that Ofgem lack both the bandwidth and resource to manage significant volumes of industry change. Were Ofgem to become involved in anything other than changes which had a material impact on their primary duties, we believe

<sup>113</sup> See, for example, the various SCR triggers listed by Ofgem: <https://www.ofgem.gov.uk/ofgem-publications/61740/guidanceinitiating-and-conducting-scrcfinal-draft110810.pdf>

<sup>114</sup> The Gas Act S.36c.

that it could slow down the change process and reduce the quality of the final decision.

*(c) Should this power be limited to the completion of certain elements of the development or implementation phase (e.g. consultation, setting up working groups)?*

- As set out above, we do not consider that further general legal powers would be helpful, save for where there is a material impact on Ofgem's primary duties.

*(d) Should Ofgem's ability to use this power be limited to defined circumstances (e.g. modification proposals which are relevant to Ofgem's principal objectives) or should it be left to Ofgem's discretion?*

- Yes. As set out above, we believe any change should be limited to where there is a material impact on Ofgem's primary duties.

### **18c – Independent Code Adjudicator**

423. **We are not convinced that this proposed remedy would be effective. Ofgem already acts in the role as an independent code adjudicator, and provided the CMA ensure that their primary duties are correct, we so no benefit in establishing a further independent adjudication body.**

#### **Response to CMA's Questions (Remedy 18c):**

*(a) Are there benefits in terms of independence, impartiality and/or industry know-how of an independent code adjudicator that are not available with Ofgem, given its other responsibilities, when undertaking the adjudicator role?*

- As above, we are not convinced that a new body would be more capable than Ofgem of fulfilling this role more effectively. The focus should instead be on equipping the existing independent energy regulator to lead and evaluate industry change more effectively.
- We believe there may be benefit in establishing a Design Authority to help with the co-ordination and project management of industry codes, however ultimately see that disputes will need to be determined by Ofgem.

*(b) Would there be unintended consequences, arising for instance from an increased lack of coordination between code modification governance, licence modifications and legislation?*

- As set out above, we are concerned that the proposed remedy would complicate and exacerbate any existing co-ordination issues rather than helping to resolve them.

## Energy Market Investigation

### Centrica Non-confidential response to provisional findings and possible remedies

#### Appendix

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## The benefits of smart meters

### *Summary*

1. British Gas is using smart meters to transform customers' relationships with their energy usage and their supplier. We have led the market in rolling out smart meters (having installed over 1.5 million to date), and we have seen from our own experience the substantial impact smart meters have on customer engagement and wider customer benefits.
2. We believe smart meters drive benefits in five key areas:
  - Increased customer engagement and satisfaction;
  - Availability of innovative new propositions;
  - Lower energy usage (and bills);
  - Reduced customer inconvenience and cost; and
  - Settlement.
3. By 2020, these benefits will be available to everyone as every home in Great Britain will be able to use smart metering technology.
4. This appendix sets out what smart meters do and provides evidence of the range of benefits they confer, both on customers and on the wider industry

### *What smart meters do*

5. Smart meters enable customers, for the first time, to see how much gas and electricity they are using as they use it and the cost in pounds and pence, through their smart energy monitor.
6. As part of our overall smart meter proposition, British Gas also offers personalised advice to customers through the recently launched "Myenergy" report. Based on smart meter data, this service provides an interactive view of:
  - The customer's energy consumption, day by day, compared to similar local households;
  - An estimated breakdown of a customer's energy use, broken down by type of use (lighting, heating, hot water, cooking & appliances);
  - Tailored tips to reduce energy, showing how much money could be saved (e.g. by improving insulation or turning off specific appliances at the wall); and
  - An historic view of a customer's energy spend by day, week, month or year.

### *Benefits of smart meters*

#### ***Increased customer engagement and satisfaction***

7. Together, smart meters and energy reports (such as Myenergy) drive material increases in customer engagement, putting control of energy use into the customer's hands.

8. Over the next few years, smart meters will be rolled out to all UK domestic customers, and the average length of tenure on smart will increase.
9. Other customer research we have undertaken has demonstrated the substantial impact a smart meter can have on customer engagement.
10. Smart metering also improves the customer experience, with our smart meter customers demonstrating higher levels of customer satisfaction than standard customers. For example:
  - 2014 Brand NPS was 14pts higher for smart vs. standard customers (14 vs. 0); and
  - Smart meter customers also make 20% fewer complaints than non-smart customers.

### **Availability of innovative new propositions**

11. Smart meters will enable a wide range of new propositions, some of which have already been introduced to the market and which have been shown to significantly increase customer engagement. For example:
12. **Smart Prepay:** Smart meters enable the removal of current tariff slot restrictions for prepayment customers driven by industry infrastructure. This restriction, together with the “simpler choices” element of RMR, means most prepayment customers (though not British Gas customers)<sup>1</sup> are currently forced to remain on SVT, even if they would prefer to choose a different tariff. In a post-smart world, and assuming the removal of the “simpler choices” element of RMR (as per proposed Remedy 3), prepayment customers will have a wider choice of tariffs and are thus more likely to engage in the market.
13. We have built on this by developing a British Gas Smart Prepay offer that we believe will transform how prepay customers interact with both their energy and supplier.
14. **Pay-as-you-go:** Research by Smart Energy GB has also demonstrated that 48%<sup>2</sup> of all domestic customers would be interested in using a smart meter in pay-as-you-go mode rather than using the current payment methods available with dumb meters. This could lead to the development of new payment propositions that attract and help engage a material proportion of the domestic customer base.
15. **Smart Tariffs:** Smart meters are a gateway technology that enables the introduction of Time of Use tariffs, allowing customers to move their energy usage outside of expensive, peak demand times and save money.
16. British Gas has launched a ‘Free Saturdays’ product to provide customers with an option of a more flexible, innovative tariff. This incorporates a unit rate of zero on electricity between 9am and 5pm on Saturdays, incentivising customers to move their energy usage away from times of peak demand, when wholesale energy is more expensive.
17. Customers have responded positively to this new tariff.

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<sup>1</sup> British Gas, unlike most suppliers, offers fixed price pay-as-you-go tariffs for prepayment customers

<sup>2</sup> Attitudes around buying gas and electricity with smart pay-as-you-go, Smart Energy GB, Nov 2014, p.20

18. Similarly, the Customer-Led Network Revolution (CLNR) project<sup>3</sup> has provided insight in to the ability of time of use tariffs to drive greater engagement.
19. **New technologies:** British Gas is already developing technologies that will interact with smart meter data, such as Hive Active Heating. This technology enables customers to control heating and hot water from a connected device (such as a phone or laptop) and receive temperature alerts when their home reaches a set temperature.

#### **Lower energy usage (and bills)**

20. Our customer research identified that 90% of British Gas smart meter customers now take simple daily steps to reduce energy use in the home. This is further supported by data which suggests the average smart meter customer uses c.2% less electricity than similar non-smart customers. We also believe this 2% figure will rise further as customers' engagement with our Myenergy reporting tool increases.

#### **Reduced customer inconvenience and cost**

21. Smart meters will allow for a smoother, more convenient customer experience, for two principal reasons:
  - Bills will be accurate, based on the energy customers have actually used, rather than on estimated usage. This will virtually eliminate the currently material volume of billing enquiries and complaints relating to estimated readings; and
  - Meter readings will be automated, avoiding the need for customers to submit manual meter readings and to accommodate pedestrian meter reading operatives at home.
22. The two factors above will also drive a significant reduction in the cost of supplier metering operations. This in turn enables savings to be passed onto customers in the form of lower bills.

#### **Settlement**

23. We also agree with Ofgem<sup>4</sup> that smart metering will provide an opportunity to significantly improve the quality of gas and electricity settlement, principally by increasing the number and frequency of readings entered in to settlement. This in turn should lead to more accurate reconciliation and enable the length of settlement to be significantly reduced.

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<sup>3</sup> A project to assess the potential of novel smart grid network technologies, new commercial arrangements and customer flexibility solutions to find cost-effective ways to prepare UK electricity networks for the future. The project is funded by Ofgem's Low Carbon Network Fund and DNO Northern Powergrid. See [www.networkrevolution.co.uk](http://www.networkrevolution.co.uk) for more details.

<sup>4</sup> Provisional Findings Appendix 8.6, para.64-65.

## **Nature of retail competition**

### **Summary**

24. We continue to believe that the level of cost pass-through seen in the industry is consistent with the operation of a well-functioning market and therefore does not provide any indication of a lack of competition.
25. We broadly recognise the summary of analysis of cost pass-through as outlined in Paragraph 83, Appendix 7.2 of the Provisional Findings and welcome the CMA's observation that differences in the cost pass-through of SVTs and NSTs is driven by differences in hedging and that the degree of cost pass-through seen in 2014 and 2015 on SVTs was reflective of suppliers' forward purchasing strategies.<sup>5</sup>
26. However there are a number of areas in the CMA's latest analysis on this topic that we would like to comment on further as we continue to believe there are flaws in the way in which this analysis has been constructed which undermine the analysis. Our comments follow the same order as the CMA's appendix on this area.

### **Economic theory**

27. Paragraph 11 – When considering the drivers of a firm's ability to pass-through short run industry-level cost movements or the speed at which a firm is able to pass through long-term cost movements the CMA should also consider the time required to make such changes and the costs involved. It is our experience that it can take 6-12 weeks to agree and implement a price change – longer for price increases, due to the requirement to notify our customers of these changes in advance.

### **Analytical framework**

28. Paragraph 13 – The PFs continue to use Ofgem's stylised SMI as a benchmark commodity cost. We do not believe that this index is representative of the costs incurred by energy suppliers and note that Ofgem themselves have decided to cease publishing this calculation. Our concerns with this approach are further outlined in pages 4-5 of our cost pass-through working paper response and we do not consider that they have been properly taken into account in the Provisional Findings.

### **Approach**

29. Paragraph 19 – We submit again that the PF's view that only the cost of forward purchases should be considered by a firm when setting prices is flawed. The hedging activity we and many other suppliers in the market conduct is a fundamental aspect of the products we offer and the risks we manage: in a market where prices reflected only forward costs then current hedging practices (and the resulting smoothing of prices) would not be sustainable. The costs we have incurred as a result of this activity are therefore key in any price-setting decision as discussed further on page 3 of our cost pass-through working paper response.
30. We would also note the CMA's approach is not consistent with the observations made by the CMA in regards to commodity cost benchmarks (Appendix 10.5). Its conclusions on customer overcharging are a result of an assumption that competitive

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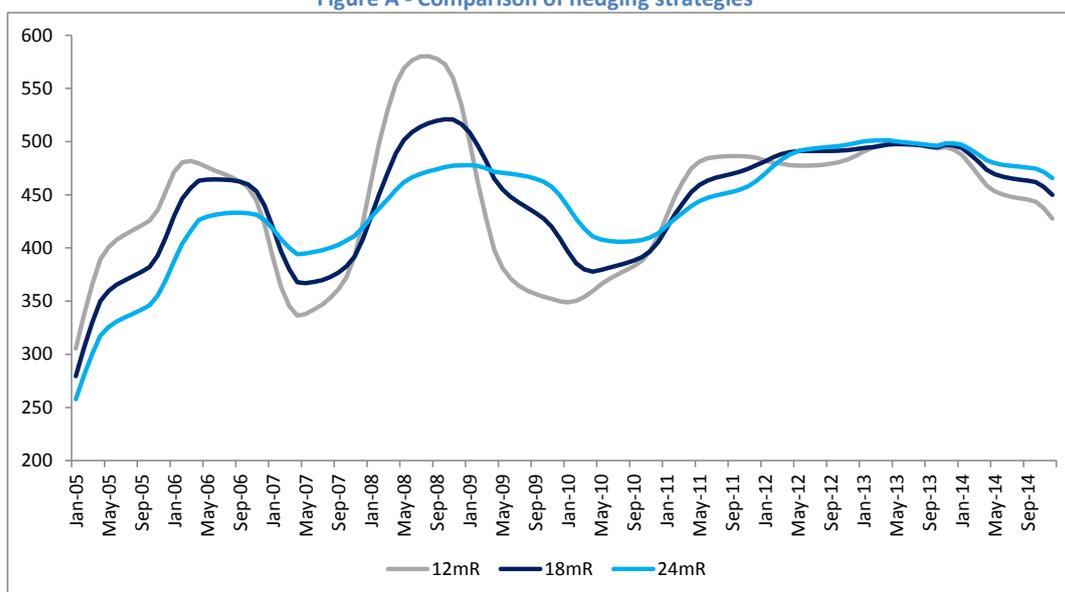
<sup>5</sup> Provisional Findings Appendix 7.2-26 para.74

prices should be driven by lower quartile forward rateable/rolling purchasing costs – not short term swings in the forward market.

**Measures of expectations of energy costs**

- 31. Paragraph 28 – As noted above, we strongly disagree with the CMA’s view that a one-year expected cost benchmark is an appropriate comparator for SVT prices.
- 32. The SVT proposition provides customers with a smoothed price over an extended period of time. Looking only at a one year cost horizon is not appropriate. Comparing SVT prices with one year forward costs is comparing ‘apples and pears’: SVT smoothed pricing is simply incompatible with procuring in this way. In choosing this approach the CMA appears to have taken some comfort from the fact that their assessment of a one-year cost benchmark is similar to an 18 month or two year indices. However we do not believe that the basis upon which these indices have been constructed is an appropriate representation of the costs that would be incurred from forward purchasing strategies.
- 33. As we set out in our response to the CMA’s cost pass-through working paper, this misses the fundamental difference between forward purchasing at a single point in time (where expectations may be rather similar regardless of whether we look 12, 18 or 24 months ahead), and a *rateable* purchasing strategy of the type we pursue to support our SVT offer, whereby we procure *over time* and therefore achieve a “smoothed” exposure to changes in forward prices – reflecting the fact that, over time, the market’s views on future market conditions will change.<sup>6</sup> Our own assessment of costs purchased over these different time frames on a rateable basis (as illustrated in Figure A below) shows that in volatile periods, such as those seen throughout 2011, a different timeframe for purchasing can result in significantly different costs. They are therefore not as similar as the CMA’s Figure 1 suggests.

Figure A - Comparison of hedging strategies<sup>7</sup>



<sup>6</sup> Centrica’s response to cost pass-through working paper, Figure A, illustrates the difference in costs between a 12 month forward purchase strategy (such as might be used to support a 1 year fixed price product) and 24 month rateable strategy (such as might be used to support an SVT).

<sup>7</sup> mR = months rateable.

**Measures of expectations of other direct costs**

34. Paragraph 33 – We submit that the CMA’s continued approach towards excluding indirect variable costs such as metering from its analysis on the grounds that these are not material and do not vary materially is flawed.
35. As described on pages 5-6 of our response to the cost pass-through working paper, we believe that indirect costs should form part of the CMA’s assessment because such costs vary with customer numbers and/or consumption levels and will therefore feed into pricing decisions in a competitive market. We also observe that metering costs in particular have grown by £21 per customer since 2007. This is a significant rise in costs given that British Gas earns a profit of c. £50 per year per customer.

**Analysis of price setting and cost expectations**

36. Paragraph 47 – we agree with the CMA observations on the frequency of price changes in regards to 47a and 47b, and note that a driver of the frequency and time lag seen in price changes affects the time taken to implement such changes (for example, this can take c. 12 weeks for a price rise).
37. However we strongly disagree with the CMA’s conclusion that “SVT prices have been mostly rising since 2011 despite expected costs remaining broadly flat”.<sup>8</sup> Such an observation is solely the result of the CMA’s chosen cost benchmark and is not reflective of our experience of the actual costs incurred. Indeed, the CMA itself recognises this later in its paper, where it states: “Unlike decreasing spot and forward energy prices observed in the market in 2014, costs incurred by the suppliers during that year continued to increase albeit at a lower rate. This is consistent with the suppliers having purchased energy ahead of time at higher prices”.<sup>9</sup> The CMA’s approach fails to properly take into account the evidence set out in our cost pass-through working paper response. This demonstrates that costs and prices have gone up by an essentially equal amount over this period.
38. Paragraph 48 – The fact that non-standard tariff prices more closely followed the CMA’s one year cost benchmark is not unexpected as some of these products may be one year fixed term contracts (for which the one year forward cost would be directly relevant) – or other products whose hedging strategy more closely approximates this cost than is the case for SVTs, which are hedged further ahead and on a rolling basis. This explains the CMA’s observation at Paragraph 45 that “the majority of NSTs were launched at a discount to SVT”.
39. We would note that a large number of NSTs (around a third) were also launched at a premium to SVT. We also understand from the Data Room exercise that the proportion of NSTs launched/sold above or below SVT prices varies substantially from year to year, and that there is a clear association between relative prices of NSTs and SVTs and the relative cost of the CMA’s benchmark cost (which may be more relevant to procuring for a 1 year fixed price NST) and Centrica’s actual procurement costs.
40. Paragraph 51 – We welcome the observation that the magnitude of suppliers’ price increases/decreases in relation to changes in cost sees prices moving less than costs

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<sup>8</sup> Provisional Findings Appendix 7.2-15, para.47.

<sup>9</sup> Provisional Findings Appendix 7.2-26, para.74.

when costs *increase* as well as when costs *decrease*, and is reflective of "suppliers hedging their costs and smoothing the SVT price".

### **Empirical analysis**

41. Paragraph 64 - There are flaws in the CMA's analysis as set out in Table 2. Most critically these calculations rest on an "apples and pears" comparison which compares changes in the CMA's one year forward cost benchmark (more appropriate to pricing a 1 year FTC) with SVT price changes (which follow a longer term rateable hedging strategy). If the analysis were reconstructed using actual expected costs then – as can be seen from the CMA's own Figure 6 – the relationship between cost changes and price changes would be much closer.<sup>10</sup>
42. We note that Table 2 mainly serves to illustrate the smoothing role that SVTs take, with average price changes significantly smaller than average cost changes (both up and down). The CMA does however suggest that the ratio calculated at the bottom of the table gives an insight into asymmetry in pricing reactions to costs: we do not agree with this conclusion. Rather than showing asymmetry, the ratio primarily reflects smoothing. For example, consider a situation where the smoothing offered by the SVT was even stronger (so that both price rises and price falls were smaller, but with the same overall price increase over time). In this scenario the CMA's ratio would increase (which the CMA appears to interpret as a problematic measure of asymmetry) – but all that has changed is that price changes (both up and down) are more smoothed.<sup>11</sup>
43. We also strongly disagree with the suggestion that cost reductions have not been passed through to prices. Any such observation by the CMA is the result of using inappropriate commodity cost benchmarking and/or excluding indirect costs. As highlighted in Figure E of our response to the CMA's cost pass-through working paper we have seen costs increases steadily since 2007 with profit levels remaining flat over this period (once unusual weather conditions in 2010 and 2014 are controlled for).

### **Analysis**

44. Paragraph 73 – The CMA notes that direct costs have increased by a lesser extent than prices since 2010. This observation of the CMA fails to take account of the impact of falling consumption levels over this time and the impact that this has had on the recovery of opex. Even to the extent that some of this opex relates to fixed costs, these are still costs that competitive firms must cover over the longer term (or they will fail to compensate their shareholders for the cost of capital and ultimately will exit the market).

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<sup>10</sup> See CRA's Second Data Room Report for a replication of the CMA's findings in Table 2 using actual expected costs.

<sup>11</sup> For example, consider a scenario where instead of increases averaging £6.90 and falls averaging £1.60, increases averaged £5.90 and falls averaged £0.60: in this case the CMA's ratio of increases to decreases would increase from 4.3 to 9.8: but clearly this does not represent greater asymmetry or any detriment to customers.

## Gains from switching

45. There are three key areas where we have material concerns with the gains from switching analysis presented in Appendix 7.4. These relate to:
- Constructing a like for like comparison;
  - Interpreting “snapshot” results; and
  - Taking account of discounts.

### ***Constructing a like for like comparison***

46. As noted in our previous submissions, there are a number of product characteristics that drive customer tariff selection besides simply price. For example, some customers have a strong preference not to be tied into a contract, and therefore will not sign up to a fixed term deal.<sup>12</sup> Others like the smoother prices offered by an SVT or a longer-term fixed price. Some customers are not comfortable transacting online, and will wish to receive a paper bill and/or have access to a telephone call centre to deal with any queries and problems.<sup>13</sup> Some customers will be willing to pay in advance in return for a lower price – whereas others will only want to pay by cash or cheque in arrears. None of these choices is inherently wrong or irrational – and many are driven by customer characteristics that are outside the control of the energy suppliers. No matter how good a supplier’s website, some consumers will not wish to transact online, or even be able to through lack of internet access.
47. It is not appropriate to treat all price differences between products with very different characteristics as “gains” that reflect a lack of consumer engagement if not taken advantage of. We therefore disagree that the CMA can interpret its results as a measure of “domestic customers’ engagement with the market” unless care is taken to ensure a like-for-like comparison of products.<sup>14</sup>
48. The closest scenario that the CMA has to providing a “like-for-like” comparison across suppliers is Scenario 3b, which includes some basic controls for payment type and tariff type. However, we are concerned to note that the main body of the Provisional Findings does not discuss these results in detail, focusing instead on Scenarios 4b and 5, which treat gains from switching between *very different* products as evidence of lack of engagement.
49. Moreover, even Scenario 3b does not control for several product characteristics which are important to many customers. In particular:

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<sup>12</sup> We note that the CMA suggests that it does not need to control for exit fees in its analysis on the basis that “customers on the SVT do not face exit fees and it is these customers who are estimated to have the most to gain from switching” (Provisional Findings Appendix 7.4-13, paragraph 38). This misses the point that the CMA’s Scenarios 4a, 4b and 5 will assume that many of these customers switch to products with exit fees: this may well not be acceptable to customers, and is a perfectly logical reason why customers may not switch despite an apparent “gain”. By failing to take account of the “losses” (in this case of flexibility to leave the new tariff) that go along with the “gains” the CMA’s analysis is clearly flawed as an attempt to measure customer engagement.

<sup>13</sup> Indeed, some online tariffs will remove online discounts if customers call their supplier.

<sup>14</sup> Provisional Findings Appendix 7.4, p.1, para.3.

- Although the CMA has now include a sensitivity for **online** products (defined as “a tariff available through on-line channels only or sold predominantly through on-line channels or a tariff that require online management of the account and/or paperless billing”),<sup>15</sup> it only controls for this in a scenario that then fails to control for tariff or payment type except pre-payment customers (Scenario 4a).<sup>16</sup> That is, it assumes that customers cannot care about paper bills/telephone help centres *and* their payment terms and tariff type, but only one or the other. There is no basis for this assumption.
  - Although one of the reasons the CMA gives for not including smaller independent suppliers is that their tariffs “appeared to often be products with specific characteristics (for example, requiring advance payment of the bill)”,<sup>17</sup> and despite having a flag in its data for products that require **payment in advance**, the CMA does not include any controls for these products. Clearly paying in advance has a real cost for customers and as such cannot be ignored in a “like-for-like” comparison.
50. It is our understanding that the data being used contains the necessary controls to undertake a more fully “like-for-like” comparison. Our advisers have used the Data Room exercise to add these controls. Taking account of these characteristics further reduces the gains available from switching, to an average of around £60 – well below the levels that most customers report they would require to switch.<sup>18</sup> Indeed, under a scenario that controls for online tariffs as well as tariff type/payment type, only around 15% of customers can make a gain from switching that is greater than the level they report they would consider necessary to make switching worthwhile (even before controlling for whether tariffs require payment in advance).<sup>19</sup> That is, the claim of hundreds of pounds of gains from switching that the CMA’s Provisional Findings comes at the cost of switching customers onto products with very different characteristics to their own, which will in many cases not be appropriate for, or desirable to, these customers.

### **Interpreting “snapshot” results**

51. In our response to the Updated Issues Statement we pointed out that the “snapshot” nature of the analysis would need to be taken into account in interpreting the results. While such a snapshot (if subject to appropriate controls for product characteristics) can capture the short term benefits that customers may achieve by switching to an alternative product, it cannot tell us whether those gains would be sustained over time. As we pointed out in our previous submissions,<sup>20</sup> given that some of the products consumers were assumed to switch to in order to achieve a gain offered time limited savings, or were later withdrawn from the market, it is not possible to draw any conclusions on the longer term benefits available to consumers without investigating what prices those consumers would pay over the longer term.

<sup>15</sup> Provisional Findings Appendix 7.4 p.24, Table 2.

<sup>16</sup> Provisional Findings Appendix 7.4 p.7, Table 3.

<sup>17</sup> Provisional Findings Appendix 7.4 p.6, para.17.

<sup>18</sup> According to the GfK NOP Customer Survey Report, Figure 70, p.75.

<sup>19</sup> See CRA’s Second Data Room Report.

<sup>20</sup> Centrica’s response to CMA’s Gains from Switching working paper; CRA’s First Data Room Report, slide 10.

52. The CMA appears to reject this argument on the basis that “this was a period where the relationship between SVTs and fixed-term tariffs was fairly stable and the prices of fixed-term tariffs were not generally declining.”<sup>21</sup> However, in our view comparisons between SVTs and fixed-term fixed-price tariffs is in any case not a valid “like-for-like” comparison: such comparisons will assume, for example, that a customer who has expressly chosen to lock in their price on a long term fixed-price tariff would switch to SVT whenever SVT prices are lower (even though it will not provide price protection when prices start to increase) or that a customer on an SVT should always switch to a short-term FTC if it is cheaper, even if that is likely to result in an upwards shock in prices at a later stage when commodity costs start to increase. Indeed, even considering these scenarios, the evidence clearly shows that the relationship between FTC and 1 year fixed term prices is driven by the shape of the forward curve at the time.<sup>22</sup> This only serves to highlight that the conclusions of a snapshot comparison of prices between different product types cannot be assumed to result in consistently better prices (let alone better value) over time, assuming that in a well-functioning market customers should not have to switch every single year in order to obtain a good deal.
53. Moreover, the CMA’s response says nothing about even its own Scenarios 3a and 3b, which do at least control for tariff type. In these scenarios customers are assumed to have a preference for their current tariff type (so savings from switching to a different type cannot be characterised as an unambiguous “gain”). For these customers the problems with a snapshot view have nothing to do with the relationship between SVT and short-term FTC prices. Rather, the question is what happens to customers who switch to products that are only temporarily offered in the market once those products are withdrawn/expire, or when the price is changed.
54. Even for customers who are assumed to switch from one firm’s SVT to another, it cannot be assumed that the price difference observed at the point of switching would be constant over time (as the CMA’s conclusion that their analysis reflects whether customers have subscribed to products that “consistently offered poor value compared to other tariffs”).<sup>23</sup> This can be seen from Figure 7.16 in the Provisional Findings which shows that it is not the case that the relative prices of different suppliers’ SVT offers are constant over time. The CMA has simply not addressed this question.

### ***Taking account of discounts***

55. The CMA rejected our earlier criticism that discounts and rewards were excluded from the analysis by stating that “we have seen no evidence that the exclusion of such discounts and rewards would introduce a systematic and material bias in our estimates” and that “on average the omitted discounts and rewards have not been material in size”.<sup>24</sup>
56. As the CMA has not shared the contents of Annex D with us, we are unable to see what size of discount they consider to be material. We understand however from our

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<sup>21</sup> Provisional Findings Appendix 7.4 p.17, para.52.

<sup>22</sup> See CRA’s Second Data Room Report – discussion of cost pass through.

<sup>23</sup> Provisional Findings Appendix 7.4 p.17, para.52.

<sup>24</sup> Provisional Findings Appendix 7.4 p.9, para.27.

advisors' data room exercise that the CMA's methodology has excluded Warm Home Discounts from Centrica's average discount, which will clearly understate even average discounts in our case.<sup>25</sup> However, even more critically, the average discount does not capture the fact that in our view, these discounts can indeed be material for the individual customers who benefit from them.

57. For example, customers with suppliers over a certain size (including all the SLEFs) who benefit from the Warm Home Discount will obtain £140 per annum. If they switched to a smaller supplier who did not offer this discount, they would lose £140 which would need to be set against any gain from switching.<sup>26</sup> The CMA has not controlled for this effect: but clearly £140 is highly material in comparison to the savings identified in the Gains from Switching analysis. As noted above, we understand from our economic advisors' review of the methodology applied in the Data Room that the Warm Home Discount has in any case not been taken into account for British Gas.
58. Similarly, British Gas customers earning a prompt payment discount would save £15 per annum per fuel (so £30 per annum for a dual fuel customer) – again, clearly taking account of this type of saving will be material if the CMA's analysis assumes that customers switch to a tariff that does not offer similar discounts.
59. For particular customers in receipt of multiple discounts, the exclusion of all discounts would be particularly material.
60. Therefore we continue to view the exclusion of discounts from calculated prices as a clear flaw in the analysis.

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<sup>25</sup> See CRA's Second Data Room Report.

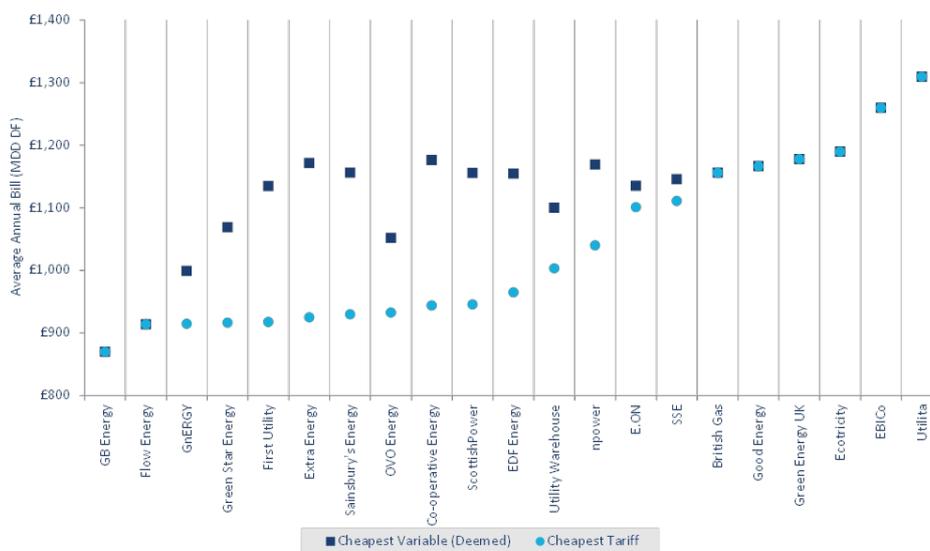
<sup>26</sup> First Utility and Utility Warehouse only joined the scheme in 2014, as noted by the CMA in PF Appendix 7.1 p.8. According to PF Appendix 10.2 p.32, Ovo Energy did not participate in the scheme during the period (2007-2013) covered by the profitability analysis. Therefore none of these rivals will have offered the Warm Home Discount during the majority of the period covered by the CMA's gains from switching analysis (March 2012 to June 2014).

## Price discrimination

### Introduction

61. Paragraph 3 – We question the CMA’s rationale for excluding the smaller/mid tier suppliers from its analysis on this topic as we have observed that currently the price difference between their SVT and NST are similar or higher than those for the SLEF (see Figure B).

Figure B - Comparison of SVT and NST prices



62. Paragraph 3 – We are concerned that the CMA’s decision to only focus on tariffs launched between July 2013 and March 2015 will result in conclusions that are inconsistent with pricing outcomes throughout a full commodity cycle. To fully assess whether differences in prices for SVT and NST are appropriate, it is necessary to also consider their relative pricing during periods of higher volatility and rising prices – neither of which occur during the period of the CMA’s assessment. This indicates that the forward cost of purchasing for a 12 month fixed price product has been consistently declining during the review period, and that in earlier time periods increasing commodity costs will have seen different relative costs (and therefore prices) underlying the procurement of SVT and NST products respectively.

### Background remarks

63. Paragraph 8 – We disagree with the CMA’s view that fixed-rate fixed-term products should always be more expensive than SVTs and believe that such an assumption would only hold in periods of rising prices. While longer term FTCs may provide some “insurance value” which would be reflected in a premium price, shorter term FTCs do not in practice provide materially more price certainty than an SVT. As the period of the CMA’s analysis has focussed on a period of falling prices it is unsurprising that such products, hedged differently than SVT would be priced at a discount, taking

advantage of the lower price for commodity available for a short term back-to-back strategy compared to the longer term rateable strategy employed for SVT customers.

### ***Evolution of suppliers pricing strategies in response to regulation***

64. Paragraph 11 – Whilst we note the comment about our pricing strategy, as previously discussed with the CMA, this was a result of our strategy to offer a compelling Dual Fuel proposition which encouraged our gas only customers to also purchase their electricity from us, and rivals' Dual Fuel customers to switch to us with a good value Dual Fuel proposition.
65. Paragraph 14 – We welcome the CMA's decision to consider the impact that pay type differences can have on the overall gross margins of SVT compared to NST products.

### ***Evidence on price differentials***

66. Paragraph 46/48 – We believe the CMA's statements around the average level of discount offered on NST products are entirely misleading given that the CMA's chosen dataset only selected products that were launched at a discount to SVT (see Paragraph 41) thus excluding any products offered at premium, or launched at the SVT price. We understand that overall around a third of NSTs were launched and/or sold at prices above the average SVT price over the longer period considered in the CMA's cost pass through analysis,<sup>27</sup> and in some years around half of all NSTs were launched at a premium to the average SVT price, so this is a material omission. We also note that the CMA analysis does not include any products with non-price discounts such as our Fix & Control product which, although priced at a premium to SVT, included a free installation of Hive (our remote heating product) valued at £199.

### ***Energy costs***

67. Paragraph 53 – We disagree with the CMA's interpretation of British Gas's hedging strategy.
68. The CMA's assessment of the differences in wholesale costs resulting from different strategies is inaccurate. In reality there are significant differences in the resulting costs of such strategies and that these will directly result in differences in the price of SVT products compared to NST products.
69. Figure C below illustrates how commodity costs might vary for a 24 month rateable product (used for hedging SVT products for example) compared to a 12 month forward purchased product (used for hedging a one year fixed price offer, which is a common product in the NST category).

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<sup>27</sup> See CRA's Second Data Room Report.

Figure C - Comparison of hedging strategies



70. Paragraph 54 – We therefore fundamentally disagree with the CMA’s view that differences in energy costs arising from how a supplier has chosen to purchase energy does not provide an objective basis for assessing their relative cost.

### Indirect costs

71. Paragraph 64 – We do not agree with the CMA’s view that the cost to serve for Direct Debit dual fuel customers on standard and non-standard tariffs is similar and do not believe we have suggested as such to the CMA.
72. Indeed in Paragraph 55 of our “Working paper response – Assessment of profit margin comparators for the competitive benchmark in retail energy supply” we explained to the CMA that we would expect costs for NST products to be lower than SVT products even for the same payment type.
73. The CMA appears to agree that such cost differences do exist and observes in Paragraph 66a that the level of online discounts offered could be assumed to be reflective of the size of cost savings achieved by suppliers where customers transact online. We note that Ovo offer a discount of £60 p.a. for a Dual Fuel customer, which suggests the cost saving for Ovo online customers to be £60 per annum.

### Summary

74. Paragraph 69/70 – We disagree with the conclusion reached by the CMA in regards to the justification for price differences between SVT and NST products. It is our view that flaws in the CMA’s analysis have led the CMA to inaccurate conclusions. In particular we do not believe that the CMA has appropriately considered how differences in commodity cost and indirect costs can impact the relative pricing of SVT and NST products or considered how the pricing of such products can evolve throughout the commodity cycle.

## Profitability

### *Centrica's detailed views on profitability*

75. In this section of the Appendix, we set out our detailed comments on the three approaches adopted by the CMA to assess profitability in the energy market. We also highlight why we do not believe it is right to regard the three pieces of analysis as providing the independent assurance the CMA believes they do. The findings of all three pieces of work are strongly influenced by the same key assumptions which do not stand up to scrutiny – in particular:

- a. **Failure to recognise differentiated costs and prices across products:** The analysis fails to recognise the value consumers place on different products with different underlying commodity (and other) costs – and therefore that in a competitive market the prices of these different products will reflect those different costs. This can be seen in the CMA's own cost pass through analysis, which shows that NSTs tend to be sold at lower prices than SVT in years when the 1 year forward cost benchmark is lower than Centrica's procurement costs, but at similar prices in years when that cost-advantage disappears.<sup>28</sup> Yet the analysis of profitability assumes away these differences: in building assumptions on capital requirements, in creating competitive pricing benchmarks, and in making EBIT comparisons across different products and suppliers.
- b. **Failure to recognise differences in the risks and capital required to support different customer segments:** The assessment of working capital and identification of EBIT benchmarks fail to consider the greater risk of supplying SME and gas customers as a result of, for example, a greater risk associated with bad debt and exposure to consumption volatility respectively. This fundamental flaw will affect the assessment of ROCE, the capital charge which feeds into the price benchmarking and the underlying EBIT benchmarking all which fail to appropriately distinguish between the differing levels of risk/return seen in the residential or business gas and electricity markets.
- c. **Unrealistic assumptions on the benefits of the intermediary fee model:** The analysis assumes that the model of intermediated risk management used by a couple of our smaller rivals could be implemented across the entire UK supply sector at the same or lower cost. Given that this business model has not survived a full commodity cycle in the UK and is not in fact employed at scale (and, in Centrica's experience in the United States, that these services are not available at scale), this is not a robust basis for analysis. The analysis also appears to assume that this model could be used to effectively give a "free lunch" – with a single (apparently very low) fee covering the costs of converting a volatile underlying commodity product into a smoothed price product for consumers, to be provided at a pre-agreed price regardless of the weather (and therefore quantity) demanded *and* providing a credit facility that can be used to manage other business risks. For the reasons set out below, we believe this

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<sup>28</sup> See also CRA's Data Room paper, to be submitted.

conclusion is based on a number of fundamental misunderstandings of how trading in commodity markets works.

**d. Undue reliance on a period of benign and falling wholesale market costs:**

The CMA's analysis also focuses unduly heavily on the period since 2009 (and in particular since 2013) – a period which has been characterised by relatively benign (stable) and more recently falling wholesale market costs. Analyses based on these shorter periods will fail to recognise the lower profits that have in fact been earned over a full commodity cycle, or the higher costs and risks associated with managing volatile commodity market conditions. As such they risk relying on hypothetical price outcomes which would not in fact be achievable by an efficient firm, and an intermediary business model which has not been tested through a full commodity cycle.

76. We are limited in our ability to comment in detail on the intermediary fee model/assumptions because neither the assumption on fee, nor a clear description of the terms of the hypothetical contract, have been shared with us. Given that these are bespoke contracts and that the fee will depend almost entirely on the risks managed and credit terms offered, for example, this makes it very difficult for us to comment on the specifics of the CMA's approach. From what we can tell,<sup>29</sup> the assumed fee appears to be based on the bespoke contractual arrangements of just two small suppliers in the UK energy market. However, precisely what risks are managed under these contracts, have not been shared and no further information on these contracts has been made available to our advisers in the data room for them to be in a position to disclose the gist of the CMA's analysis to us (the only additional information provided in relation to the intermediary fee model was the CMA's own assumption of the fee). Neither have we been provided with a clear definition even of the assumed terms of the service that would accompany the assumed fee level. Furthermore, our own estimates of a fee using standard risk pricing models have been rejected based on the assertion that "such arrangements appear to cover additional services and fees than those we observed for independents operating in the GB markets".<sup>30</sup> But the CMA's assumption on fee appears to be lower than even the costings calculated for a standard route to market service, despite including an important credit facility that (according to the CMA) can be used to manage working capital peaks. We simply do not understand how this could be the case at scale, based on standard risk pricing approaches.
77. These themes emerge throughout the analysis of ROCE, competitive price benchmarking and EBIT comparisons relied upon by the CMA in reaching its Provisional Findings. We have a number of other serious concerns about the approach taken which are set out below and, since several of our concerns apply to more than one approach (e.g. assumptions on working capital and cost of capital, affect both the ROCE and competitive benchmarking analyses), the three approaches cannot be seen as independent cross-checks on one another – but rather as three manifestations of a broadly common set of underlying assumptions which we believe to be flawed.

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<sup>29</sup> Provisional Findings Appendix 10.3, para.89-91.

<sup>30</sup> Provisional Findings Appendix 10.3-61, para.118.

## Section 1: Analysis of out-turn profits (using Return on Capital Employed - ROCE)

78. In its attempt to assess the ROCE of energy suppliers, the analysis has sought to recreate what their capital employed and EBIT levels would be had they operated as a standalone supplier which had entered into a trading agreement with a third party intermediary. We are extremely concerned that the assumptions used have resulted in overestimates of the levels of ROCE achieved in the GB energy supply market. Each of our separate concerns on this topic are covered in this section as follows:
- a. **The intermediary fee is not a credible**
  - b. **The five year period chosen does not reflect a complete set of commodity market circumstances**
  - c. **The working capital estimates do not recognise that gas and SME supply need a higher level of working capital than residential/electricity supply**
  - d. **The level of cash needed to meet working capital shortfalls for a standalone supplier is underestimated**
  - e. **The use of British Gas's Information Systems (IS) asset values as an industry benchmark is inappropriate**
  - f. **The WACC estimate is too narrow and reflects too low a range**
  - g. **The ROCE estimate has failed to adjust for the impact of colder than 'normal' weather conditions**
79. In our view, if adjustments were made for these factors, then the assessment of Centrica's ROCE would reduce from 28% to 13%.

### ***a) The intermediary fee is not credible***

80. The reasoning is based on the following, flawed assumptions:
- That lack of demand is the only reason that this fee-based approach is not widely available, and that increased demand would generate increased supply without any increase in price;<sup>31</sup>
  - That trading intermediaries can trade on a collateral free basis with other market participants, and therefore they will not be exposed to adverse working capital movements (e.g. margin calls);<sup>32</sup>
  - That trading intermediaries will incur no additional costs to offset a significantly larger market risk position when supporting the hedging of the entire market, than they do today;<sup>33</sup> and
  - That the bespoke agreements for the two small suppliers are reflective of arm's length pricing for commodity risk management, are priced to effectively reflect the risks which are, today, self-managed by the SLEF, and contain sufficient provision

<sup>31</sup> Provisional Findings Appendix 10.3-56, para.101.

<sup>32</sup> See for example Provisional Findings 10.3-57, para.103b.

<sup>33</sup> Provisional Findings Appendix 10.3-56, para.102.

for the trade intermediary to protect them against excessive credit exposure for the SLEF business models and scale.<sup>34</sup>

81. The precise level of the intermediary fee is a critical assumption for the profitability analysis because it is used as a proxy for the cost which a standalone supplier would incur to outsource the risk (and associated capital requirements) to support commodity procurement (rather than holding capital on its own balance sheet to support procurement).
82. The fee, although currently underestimated, also underpins the other two pieces of analysis carried out by the CMA – not only is the EBIT for suppliers adjusted by the fee in order to calculate the ROCE, but the fee is also incorporated as an additional cost in the competitor benchmark analysis and (as we will set out below) should also be used to adjust the EBITs used in the CMA’s EBIT comparison to ensure consistency. The CMA apparently intends that these adjustments should capture the cost of managing procurement risk (and of providing a large line of credit to allow the supplier to manage its other business risks): but this means that the same assumption will influence the findings of all three approaches to profitability assessment.
83. As we note above, we do not have sufficient information about the contracts underpinning the intermediary fee service to understand the services provided and hence the costs thereof. For example, we are told that, in addition to the intermediary fee service (in return for the intermediary assuming “counterparty credit risk and price risk”), suppliers can access products including lines of credit, weather derivatives and insurance products – but no price appears to be included in the CMA’s calculations for these other services.<sup>35</sup> It is therefore unclear to us whether these costs are incorporated into the assumed fee, or instead whether the associated risks are assumed to be passed on to customers, or absorbed by shareholders in the form of a higher bankruptcy risk, for example. Neither have any details of the terms of credit offered been shared (although we note that if the credit available were as flexible as the CMA’s analysis suggests, we would expect to see it regularly drawn on – which we do not see in independent suppliers’ published accounts, as set out below).

***It is wrong to assume that demand is the only constraining factor to the fee being widely applied at these levels in the market***

84. The current fee arrangement is priced to support a fraction of the risk which is currently absorbed within the SLEF business models:
  - The fee arrangement supports c.10TWh of customer supply, and would need to support an additional c.600TWh.
  - The credit facility that the CMA describes as a part of the arrangement would equate to £35bn-£40bn<sup>36</sup> if it were provided across the retail market.
85. Increases in scale of this magnitude cannot be assumed without taking account of the additional risk which would be taken on by the intermediaries. At this scale it would be more costly to offset the market risk and would expose the intermediaries to

<sup>34</sup> Provisional Findings Appendix 10.3-27, para.96-97, and 10.3-61, para.115(c)

<sup>35</sup> Provisional Findings Appendix 10.3-25, para.89b, 89e

<sup>36</sup> The CMA describe a significant credit facility provided to manage working capital in para.79, Appendix 10.3 as 1.5 annual wholesale energy costs

substantial credit risk exposure and working capital volatility. Further, trading intermediaries are able to absorb relatively small supplier requirements in the context of a larger portfolio and price that activity on a marginal cost basis. Once the requirement becomes a significant proportion of the trade intermediary's activity (and absolute volumes increase), the basis for pricing will, by necessity, increase to reflect the need to compete with other uses for the capital required to support the product.

86. We believe it is wrong to conclude that the limiting factor to the scalability of the fee is demand. Given the increases in scale required, it is our view that supply will also be a significant driver of the price at which such a service is made available. The model would require a number of intermediaries with suitable portfolios capable of managing the risk. Beyond a small number of oil majors (e.g. BP and Shell) and a very limited (and declining) number of banks, it is not clear who this would be. Particularly since 2008, as regulations on financial institutions have tightened capital availability, we have seen banks, including some which have previously provided intermediary services, exiting this market:<sup>37</sup> in our view to induce them to re-enter and on the sort of scale contemplated by the CMA's approach would require a significant increase in price to compensate them for the capital that would be required to support the risks. Against this background, the simple assumption that fees will stay the same or even reduce with increased demand for this service is therefore inconsistent with commercial reality.
87. The CMA's analysis uses Just Energy Inc as an example of a company that has grown out of their intermediary arrangement with Shell and now trades on their own account, and suggests that Just Energy's cash balance at year end is therefore a good indicator of the levels of cash needed for an independent stand-alone firm undertaking its own procurement to manage its trading requirements.<sup>38</sup> From our review of Just Energy's financial statements, we believe that this may be a misinterpretation of how Just Energy procures its energy. Just Energy uses a consortium of commodity partners to procure their energy through bespoke long term contracts. Whilst the terms of these contracts are not disclosed, our experience would indicate that such arrangements command a fee. Therefore the characterisation of Just Energy Inc as a standalone supplier which accesses the wholesale accounts on their own account is incorrect: their business model is more akin to a fee arrangement. As a result, the analysis of Just Energy's cost of trading is incorrect and the cash they hold has no relevance to determining the cash requirements of a stand-alone entity. It is simply incorrect to conclude that Just Energy was able to "grow out of the fee arrangement and to trade on its own account without large sums of notional capital"<sup>39</sup> – or to infer more generally that trading in the wholesale markets does not require capital.
88. We note that the CMA's analysis appears to rely heavily on discussions with one potential intermediary (Shell): but there is no evidence in the PFs that the CMA has taken soundings from a wider range of intermediaries including those who have exited the market. This is essential given that a substantial number of intermediaries would need to participate in the market for the CMA's hypothetical risk-management structure to exist. It is also not apparent that Shell were asked what the impact would be

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<sup>37</sup> We have seen JP Morgan, Barclays, Morgan Stanley, Deutsche Bank exit this market

<sup>38</sup> Provisional Findings Appendix 10.3-45-46, para.69-74.

<sup>39</sup> Provisional Findings Appendix 10.3-57, para.104b.

should the model be applied to the market as a whole. We do, however, note that Shell appears to have said that “so long as it could find offsetting positions to remain hedged, scale was not a barrier to expansion”<sup>40</sup> – this is a crucial qualification. It is not clear whether Shell have said that they expect they (or other intermediaries) would be able to find sufficient offsetting positions to provide this service to the entire energy retail sector at the same or lower cost than they do for small supplier(s) today.

***It is wrong to assume that the trading intermediaries can trade on a collateral free basis***

89. The CMA’s analysis suggests that the trading intermediaries it expects to undertake risk management on behalf of a standalone supplier would require very little, if any, capital to support this service. The PFs go so far as to say that the CMA “disagree[s] with the concept of renting out risk capital” and that trading intermediaries are “employing limited amounts of working capital for short periods, and not significant amounts of notional or risk capital at all”.<sup>41</sup> We disagree fundamentally with these statements, which fail to recognise the credit risk that the trade intermediary would face and overstates the extent to which the intermediary could manage risk by netting off positions.
90. The CMA’s analysis fails to recognise that credit facilities are a finite resource. Credit facilities are negotiated on a bilateral basis, and in direct our experience, the majority of counterparties will have a limit to the amount of credit exposure they are able to tolerate to any individual counterparty, irrespective of credit rating.<sup>42</sup> The more trading an intermediary is required to do with the market to offset the market risk of a large supply position, the more this service will use the limited amount of collateral free trading available to the trade intermediary. Offered at scale, this service will be priced to reflect the fact that it uses capital and therefore displaces other profitable trading opportunities. A rational trade intermediary will take this opportunity cost into account; calculate the capital requirement to support the derivative trading and charge for this capital at a hurdle rate above WACC.<sup>43</sup> This will increase the fee charged to the supplier.
91. In our case we post cash collateral for a third of our trading: this includes trading where thresholds are exceeded, and trading on exchanges (10% of our UK gas is traded on exchanges). We have provided the CMA with an estimate of the cash collateral which would have been required by British Gas as a standalone entity, assuming a standalone British Gas had the same credit rating as today’s VI entity. This is a reasonable assumption to apply to the risk taken on by a trade intermediary with a strong credit rating. We used this information and standard risk modelling techniques (VaR analysis) to calculate an amount of equity capital required of the order of £1bn.
92. Neither do we believe it is right to conclude that the intermediary could readily find netting positions in the market as “by implication, the generation businesses of the Six Large Energy Firms would be standalone” and therefore “the intermediary manages

<sup>40</sup> Provisional Findings Appendix 10.3-58, para.106.

<sup>41</sup> Provisional Findings Appendix 10.3-59-60, para.112

<sup>42</sup> See example described in detail as an Annex to our response to the CMA’s Working Paper “Analysis of retail supply profitability – ROCE” – which shows that even with Centrica as a parent there are limits to the extent of collateral free trading that counterparties are prepared to offer at any fee.

<sup>43</sup> The CMA confirms that “notional capital” will be charged at WACC in Appendix 10.3-42, para.56

risk not so much with capital but by remaining hedged so that it is not significantly exposed to one side of the market”.<sup>44</sup> We have previously explained to the CMA how different physical and financial factors drive generation technologies and supply businesses to have very different hedging requirements. For example, a supplier will purchase power, while a generator with a CCGT fleet will sell power, buy gas and buy carbon. This combination of trades will be an ineffective offset of market risk for the trade intermediary. Moreover, renewable energy is seldom hedged in advance of day ahead due to the risk of intermittency. This is why we do not offset our generation and supply portfolio positions as a matter of course before hedging the market risk externally. The CMA’s belief that trade intermediaries will sit between power suppliers and generators, and can offset positions before externalising the (net) positions in the market is, based on our experience, misguided and will underestimate the costs of providing the service.

93. The CMA model of independent suppliers and generators seeking out trade intermediaries to manage their risk does not apply to gas (where the hypothetical separation of generation and supply would not change the current market setting).<sup>45</sup> Suppliers purchase gas from large producers, who are unlikely to require the services of a trade intermediary. The CMA’s hypothetical trade intermediary in relation to gas will therefore be entirely reliant on the wholesale market to offset the market risk, on a collateral free basis: we do not believe this is a realistic model.

***It is wrong to assume that the trading intermediaries will incur no additional costs to offset the market risk***

94. Commodity market pricing dynamics (consistent with standard economic principles) dictate that prices increase with demand – i.e. the more a trade intermediary needs to source from the market, the more they will have to pay to offset that market risk.<sup>46</sup> We have demonstrated this stacking bid/offer system embedded in broker screen trading to the CMA<sup>47</sup>. As an offer is lifted, more commodity is made available but at a higher price. Thus, the more commodity a trade intermediary would need to purchase from the market to hedge the position of the supplier, the more they will have to spend.
95. The CMA model assumes a very different form of the UK market with the overall number of market participants significantly reducing as the Six Large Energy Firms (SLEF) would no longer be trading in the market directly, instead doing so via a trading intermediary. It is our belief that the trade intermediaries would need to already have an existing presence in this market. The removal of the SLEF would result in trading risk being concentrated amongst the few remaining trading intermediaries and residual producers. This will increase the amount of credit exposure the counterparties were previously able to spread amongst a number of strongly rated market participants. The consequences of this action would be:

- Risk for market participants will increase, not decrease; and

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<sup>44</sup> Provisional Findings Appendix 10.3-52 para.92 and Appendix 10.3-56, para.102.

<sup>45</sup> Provisional Findings Appendix 10.3-52, para.92.

<sup>46</sup> Consistent with the financial literature cited in Professor Cooper’s submission to the CMA, unless the supply of risk management services is infinitely elastic (which the CMA appears to believe to be the case, as outlined in PF Appendix 10.3-56 para.101, but does not provide evidence to support), then increased demand for the service will result in a higher price.

<sup>47</sup> CMA site visit, 19 September 2014.

- The cost for the trade intermediaries will increase not decrease.
96. The trading intermediary would be exposed to the material credit risk of the standalone suppliers (and generators) as well as the credit risk exposure of other OTC market participants. While this is true today of the existing arrangements, the size of the credit risk would be materially larger (including larger exposure of trade intermediaries to a particular industry sector). We consider these exposures would be too big for even large trading intermediaries to tolerate. For example, the credit facilities (as an indicator of potential credit risk exposure) if scaled up to cover all suppliers would be £35bn-£40bn. Even a proportion of that exposure would be material to a company like BP with a market capitalisation of £73bn. We believe the Provisional Findings puts undue weight on the security of assets as an effective form of credit risk mitigation given these standalone suppliers would be asset light business without a credit rating according to the assumptions set out in the Provisional Findings.
97. The model assumes the trading intermediary will not use the ICE exchange as a source of liquidity to hedge the gas positions, because exchanges require collateral. The ICE exchange is an additional and significant source of market liquidity which the trade intermediary is likely to require access to. The exchange requires committed capital for initial margin posting, and settlement of variation margin within 24 hours. Given that a significant proportion of gas trading is conducted via the exchange today, this would seriously reduce the routes to market available to the intermediary.
98. The points above demonstrate that the hypothetical model suggested by the CMA could have material consequences for the wholesale market structure and market liquidity which are not reflected in the analysis. We believe the evidence instead supports an alternative hypothesis where the costs of risk management increase for larger positions, and the very material capital required to support the service would be factored into a higher fee. We therefore believe that the conclusion that this structure can be scaled to cover the whole UK supply market at the same or lower cost is incorrect.

***It is wrong to assume that bespoke agreements for the mid-tier suppliers are reflective of arm's length pricing for commodity risk management***

99. There appears to be a significant dependence on the assumption that the fee arrangements of two mid-tier suppliers are representative of an arm's length risk pricing mechanism for energy procurement. The bespoke nature of the agreements make their application on a proxy basis to the entire market inappropriate, as it is very unlikely that the bespoke terms offered to two small suppliers would be the same as those required to allow the entire market to use this type of service.
100. The analysis also assumes suppliers can use the "credit facility" provided by the trade intermediaries, which is disclosed by the CMA as a very significant sum, as a means to manage working capital peak requirements – for example stating that the arrangement provides "access to a significant credit facility, which provides extra headroom in the short to near medium term to meet day-to-day cash flow requirements from adverse

shocks”.<sup>48</sup> We do not believe this description can be correct given our experience in the market and from the evidence in the mid-tier suppliers’ financial statements (Ovo and First Utility).

- If the credit facility can be used by suppliers in the manner suggested by the CMA, it would be akin to an overdraft facility (and indeed the term “credit facility” is usually understood as the ability to borrow money for any purpose). Given the suppliers have paid for the facility through the fee embedded in their wholesale costs (and we understand from the CMA that the fee accounts for the totality of the costs associated with the arrangement) – we would expect to see them make use of it and this would be evident in the cash flow analysis and disclosures in their financial statements. That is not the case. The use of the facility must, therefore, be heavily restricted.
  - Based on our experience, we suggest that the “Credit Facility” is more likely to be a calculation of the amount of credit exposure that the trade intermediary is willing to accept to the mid-tier supplier. It is likely to be a combination of any mark-to-market profit or loss on the derivatives traded through the intermediary, as well as payment due for commodity purchases which have been delivered, but not yet paid for.
  - It is not clear from the disclosure as to whether the facility would allow the creditor position to be extended beyond the standard market settlement terms or not. It is not evident from the financial statements that this is the case.
  - It is therefore far from clear that the “credit facility” described could in fact be used to manage other “business risks” in the way the analysis suggests.
101. There are other factors incorporated in the agreements which would alter pricing including security provided, and covenants – these can have a material impact on the ability of management to operate a business, the risk to the equity holders (which in turn would increase the required return on equity capital), and the ability of management to self-determine the strategic direction of the business. For example, these types of arrangement may impose covenants relating to gross margin percentages which may impact the ability of a supplier to price products at the rate of their choosing or respond to competitive pressure. There are therefore rational reasons, beyond cost, which would encourage a supplier to self manage their commodity procurement.
- 102. In view of all our concerns about the trading fee, we propose alternative models (described below) to approximate the capital required to support commodity trading, either to test the robustness of its fee assumption or as an alternative.**
103. Using standard risk pricing tools to estimate the amount of risk capital which would be required to support the derivative trading inherent in the SLEF business models, would mean these could be consistently applied across suppliers and would remove the need to rely on confidential bespoke arrangements and their application in a hypothetical

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<sup>48</sup> Provisional Findings Appendix 10.3-47, para.78d. See also Provisional Findings Appendix 10.3-58, para.108, which suggests that a “well managed supplier” could “use the fee arrangement to lay off wholesale market trading related risks and use the associated significant credit facility to act as a buffer against other business risks” and Provisional Findings Appendix 10.3-62, para.119, “our benchmark trading fee covers the lay-off of wholesale market risk and getting access to a significant credit facility that would allow a well-managed supplier to manage its business risks.”

construct. The risk capital can be converted into a proxy fee arrangement by multiplying the capital by the WACC.

104. In fact, Centrica has provided the CMA with a verifiable estimate<sup>49</sup> of the proportion of trading which requires cash collateral to be posted (being a combination of exchange trading, and trading via broker screens on a bilateral basis). That proportion can be applied to the mark to market profit or loss of the British Gas trades (which can be calculated from the commodity trades allocated to British Gas, with a sensitivity applied for different credit ratings). For example, our risk management assumes we increase our collateral posting should our credit rating fall.<sup>50</sup> A further cash requirement can be calculated using standard risk management techniques e.g. Value At Risk (VAR) whereby a probable loss is calculated on outstanding trades, and the cash for a number of days is set aside. This cash must be available to meet any immediate cash calls on the collateralised positions. This would be consistent with the methodology employed by commodity exchanges to calculate initial margin requirements.
105. Using information we have provided to the CMA, we estimate a capital commitment for a simple route to market service at [X] during the period 2010 to 2014 which would translate to a fee arrangement of between [X] at a WACC of 10%. Using the midpoint of our proposed WACC range (discussed under section f) of 13.4% would give a fee of between [X].
106. Alternatively, the CMA could employ the models (CDD/CRD framework)<sup>51</sup> used by the FCA to calculate a proxy for equity capital which would need to be held by financial institutions to support the degree of commodity trading required by a stand-alone supply business<sup>52</sup> In our view, the reasons stated in the PFs for rejecting this model are not valid:
- These models are used by financial institutions, whether they are deposit taking or not,<sup>53</sup> to ensure they have sufficient capital for the risks they are entering into. The objective is to limit the disruption to the financial system should the risk crystallise (through default, large price movements or operational losses); and
  - These models have risk based capital requirements and leverage based capital requirements. It is therefore wrong to reject the analysis on the basis that the standalone entity does not carry debt. The risk based capital requirements are based on market standard risk quantification methods which have been used for many years to calculate the risks inherent in derivative trading, and are therefore directly relevant to the commodity trading risk (which is in the form of derivatives) absorbed by the SLEF.
107. Dismissing this alternative misses the point that non-financial institutions face precisely the same risks and capital requirements associated with forward trading and hence have the same need to protect their investors' capital as banks do. The fact that the

<sup>49</sup> During our meeting with the CMA on 22<sup>nd</sup> May 2015.

<sup>50</sup> This is a reasonable sensitivity to apply as such a downgrade would immediately trigger additional capital requirements. This is consistent with the collateral calculations we apply at a Group level.

<sup>51</sup> "Virtual CRD/CRR Capital Framework for a British Gas Standalone Downstream Business", April 2015, submitted to the CMA on 7th May 2015

<sup>52</sup> The CMA has rejected this framework as a means to estimate risk capital. We have commented on the CMAs findings in our response to Appendix 10.3 which is detailed in Section 4 of this Profitability Appendix

<sup>53</sup> See Section 4 of this Profitability Appendix

formal regulations applying to banks do not apply to the likes of BP or Shell does not mean that these institutions would fail to undertake standard risk pricing assessments to understand the extent to which their investors' capital was being put at risk and to take action accordingly.

108. On the basis of these calculations we estimate that the minimum fee required for even a simple route to market service offered at scale would likely be in the range [X] - [X]%. An increase in the fee by 1% would result in a reduction in the market ROCE from 28% to 25%, reducing the CMA's perceived excess profits from £871m to c. £710m.<sup>54</sup> This would still leave the standalone supplier's shareholders exposed to a number of costs and risks (e.g. shaping, weather) which, in practice, Centrica manages on behalf of its shareholders and for which it would therefore expect to make a return.

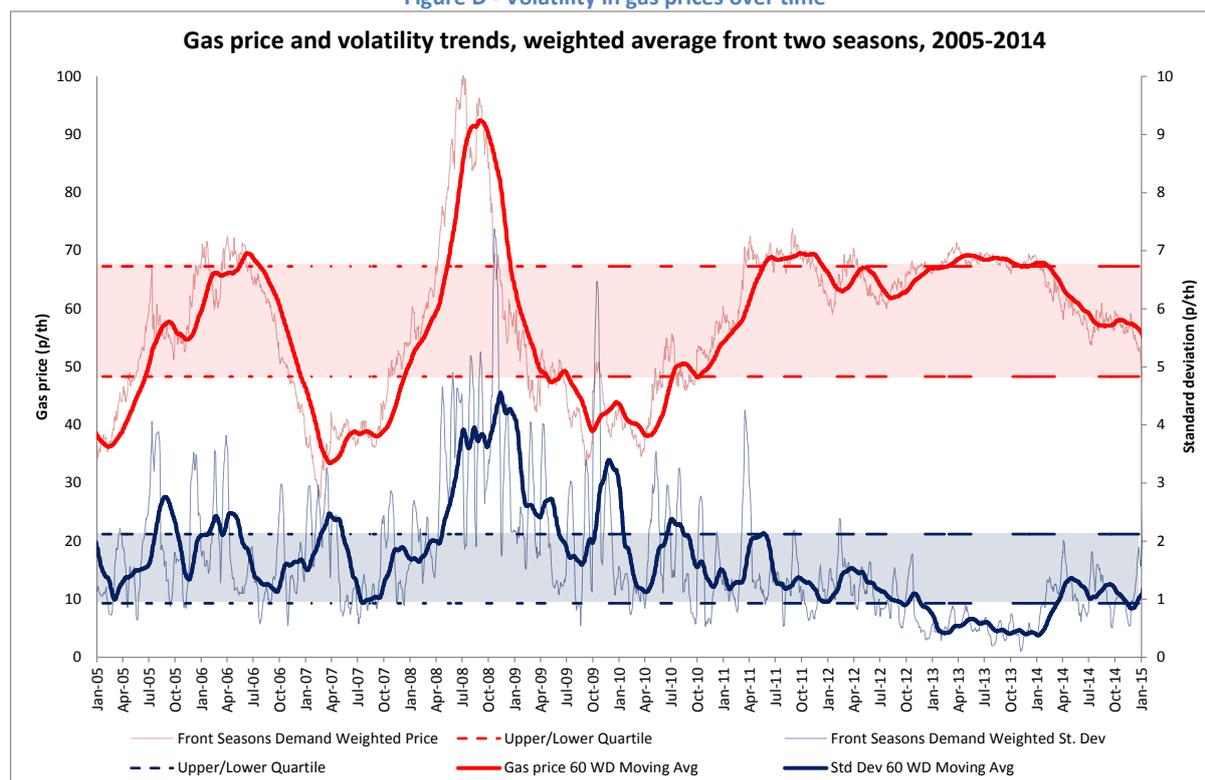
***b) The five year period chosen does not reflect a complete set of commodity market circumstances***

109. The analysis primarily focuses on the period of 2009 to 2013 and therefore excludes earlier periods during which commodity prices were more volatile. Figure D below highlights the average to low volatility environment during the entire period under review. Stressed conditions such as those seen in 2005/06 and 2007/08 would be expected in any typical commodity cycle and therefore excluding these periods means the CMA's conclusions are not robust to a full range of normal market conditions. They also fail to take account of how such conditions affect the relative pricing of different products, the implications for consumer price volatility of different hedging models (e.g. hedging only 1 year ahead), or the sustainability of the business model the CMA hypothesises for a standalone supplier (based on the experience of rivals who have not yet experienced a full cycle).

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<sup>54</sup> An increase in the fee of 1% is assumed to be equivalent to a 0.5% change in EBIT (on the basis that commodity costs account for 50% of the bill). With industry profits estimated at 4% and the CMA's assessment of excess profits of £871m assumed to relate to its derived EBIT of 1.3% we can calculate that  $((0.5\% / (4\% - 1.3\%)) * 871) = 161$ . £871m less £161m = £710m

Figure D - Volatility in gas prices over time



110. Whilst suppliers are able to pass industry-wide changes in costs through to customers in the long term, during periods of volatility, profitability will be more constrained owing to, for example, the length of time it takes to increase prices (the impact of this constraint is evidenced by the profits realised by the SLEF in 2008).<sup>55</sup> By excluding such periods, the analysis will therefore overstate any assessment of excess profitability. A longer period of analysis which includes the impact of price volatility, such as in 2007/08 for example, on profits should, in our view, be used. Indeed, we note the CMA requested, and we have provided, information for that full period, so it is unclear why it has chosen to focus only on the shorter period.

***c) The working capital estimates do not recognise that gas and SME supply need a higher level of working capital than residential/electricity supply***

111. The working capital calculation selects the lowest quartile debtor days and the highest quartile creditor days for the SLEF as reported in their financial statements. The resulting difference (“net days”) is in turn applied to each supplier’s revenues by segment (direct debit/cash cheque, residential/SME, gas/electricity) to calculate the working capital requirements of each business area.<sup>56,57,58</sup> This approach to estimating

<sup>55</sup> In 2008 the cost of purchasing gas for a year ahead (similar to the approach that would be taken for a fixed price fixed term contract) varied in price by 44.3p/them - in comparison 2013 prices varied by just 5.1p them. This resulted in a reduction in industry profits from an EBIT of 1.4% to 1% (the lowest profits seen throughout 2007-13).

<sup>56</sup> Provisional Findings Appendix 10.5, Table 3.

<sup>57</sup> Provisional Findings Appendix 10.3, para.81.

<sup>58</sup> We note the CMA references the credit facility offered by the trade intermediaries as a means to manage working capital peaks, however this does not appear consistent with the representation of this facility in the mid-tier suppliers’ financial statements. This is discussed in para.124.

an efficient firm's working capital requirements fails to fully consider how differences in customer mix and operating structure can change a firm's capital requirements. We believe this will have directly led to the view expressed in the PFs that there is "no clear cost or risk-related justification for the higher margins earned by Centrica on gas"<sup>59</sup> and thus, because we have a far greater proportion of gas and SME customers compared to the other SLEF, this will have led to an overestimation of British Gas's overall financial performance in comparison to other suppliers.

### **Impact of pay type mix**

112. A supplier with a higher proportion of direct debit and prepayment customers will have a lower level of debtors, which will therefore reduce their working capital requirements. As British Gas has a smaller proportion of customers who choose to pay via direct debit or prepayment compared to the other SLEF, our relative working capital requirements will be higher.<sup>60</sup> This is not a function of working capital inefficiency but is instead a reflection of the choice over payment mechanism that we give to our customers in a competitive market.<sup>61</sup>

### **Impact of fuel mix**

113. Our working capital varies significantly across the year due to the sensitivity of consumption to weather.<sup>62</sup> This seasonal variation, which is particularly seen in gas supply, requires a higher level of capital employed on a per customer basis. Under separate cover, we will provide data to the CMA on British Gas's debtor profiles split by customer segment in order to assist with analysis of this.

### **Impact of SME, I&C and Residential mix**

114. We also see significant differences in the debtor profiles of our business and residential customer segments with our business customers having a debtor days period that is more than double that of our residential business customers. Such a significant difference in the debtor days of these businesses will mean that, even on a per unit basis, our business customers will need a substantially higher level of working capital compared to our residential customers - a need that will not be fully reflected by simply allocating out the balance sheet based upon revenues as analysis in the PF appears to have done.

115. Given the differences in the debtor profiles of gas and electricity, or between business and residential customers, it is not appropriate to choose the lowest quartile debtor days and assume that these would apply to any efficient supplier. In so doing, the analysis risks interpreting differences in customer and product mix (weighted more towards electricity supply and/or domestic customers) as differences in efficiency, resulting in an assumed "efficient" debtor profile which an efficient supplier with the

<sup>59</sup> Provisional Findings Appendix 10.2, para.12.

<sup>60</sup> Page 2, [https://www.ofgem.gov.uk/sites/default/files/docs/2014/12/monitoring\\_social\\_obligations\\_-\\_q4\\_2013\\_data\\_report\\_0.pdf](https://www.ofgem.gov.uk/sites/default/files/docs/2014/12/monitoring_social_obligations_-_q4_2013_data_report_0.pdf)

<sup>61</sup> Customers can choose to transact by cash cheque, direct debit or on Pay As You Go. British Gas has promoted the benefit and cost saving opportunities presented by paying by Direct Debit. However, we have found that a large proportion of our customers continue to choose to pay by cash cheque with [3<] of BG customers continuing to choose this pay type.

<sup>62</sup> We also covered this in Figure 1, Centrica's response to the CMA's Working Paper: "Analysis of retail supply profitability – ROCE".

“wrong” customer and product mix could not, in fact, achieve. This is of particular concern to British Gas as we have a far greater proportion of gas and SME customers compared to the industry overall.<sup>63</sup>

116. Given the number of factors that can justifiably result in variations in a supplier's relative level of debtors and thus working capital, we recommend using individual supplier's actual debtors rather than an industry benchmark as there is no evidence that suppliers are inefficiently slow at collecting their debts, and using actual debtor days will ensure that differences in customer mix are accounted for.

***d) The level of working capital needed by a standalone supplier has been underestimated***

117. The analysis relies on an estimate of suppliers' working capital requirements based on the average working capital needed across the year. Any shortfalls in working capital are then apparently expected to be met through the use of cash reserves and/or credit/overdraft facilities. For the purposes of its analysis, the CMA has included a cash balance equivalent to 2% of a supplier's COS in order to meet this gap. A cash balance equivalent to 2% of COS is, however, insufficient to fund the shortfall in business as usual peak requirements and we are concerned that the analysis has therefore:

- a) Overestimated the credit terms a standalone supplier would be able to secure for its payment of commodity costs by assuming that the pattern of internal payments within the SLEF would apply to a standalone supplier;
- b) Inaccurately assumed that the cash balances held by Just Energy and RWE are an appropriate benchmark; and
- c) Assumed that the “credit facility” provided by a hypothetical trading intermediary can be used to help fund a business's peak working capital requirements.

118. Looking first at point (a), by using the reported creditor days of the SLEF, the analysis will have overestimated the credit terms than could be achieved by a standalone supplier when making payment for commodity costs. It is likely that the SLEF have different, and likely longer, credit terms with their internal counterparties than would be achieved by a standalone supplier.

119. A more appropriate means of estimating what the creditor days of a standalone supplier would be is to consider the standard settlement arrangements which are common to participants who use exchanges and broker assisted trading. This would provide a fair and more accurate calculation of the credit terms a standalone supplier would face when settling commodity purchases. These are c.27 days for power,<sup>64</sup> and c.35 days for gas.<sup>65</sup>

120. Table A below highlights the difference between the creditor days as reported in our balance sheet compared to an approximation of those that we would expect to see for a standalone supplier (based upon a bottom up assessment of the standard market payment terms for commodity and transportation and distribution costs).

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<sup>63</sup> Centrica's response to the CMA's Working Paper: “Analysis of retail supply profitability – ROCE”, Table 7.

<sup>64</sup> Standard terms require these to be paid on the 10th working day each month.

<sup>65</sup> Standard terms require these to be paid on the 20th day each month.

Table A - Creditor days sensitivity<sup>66</sup>

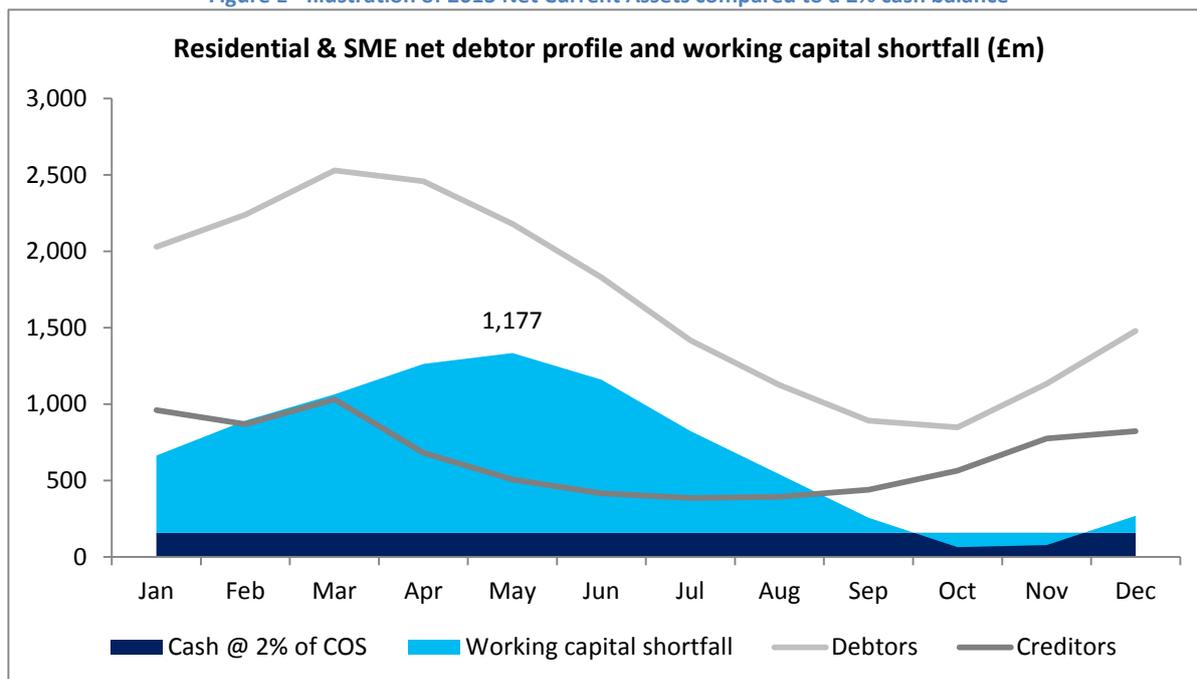
Sensitivity analysis of creditors assumptions (2013)	Days
Reported Balance Sheet	75
Bottom up model based upon standard credit terms	33

121. To adjust for the impact of this issue on the determination of a benchmark creditor days period in the CMA's analysis, we recommend the current calculation of creditor days is replaced with an estimate of what credit terms could be achieved by a standalone supplier trading with third parties at arm's length.
122. Turning to point (b), the cash balances for RWE and Just Energy are irrelevant as an approximation for the working capital requirements of a standalone entity. RWE has access to wider group resources and Just Energy has access to a large (albeit expensive) credit facility. The amount of cash these entities hold at year-end does not give any indication of the amount of cash that would be required by a standalone supplier, unable to rely on the debt markets, to meet business as usual fluctuations in working capital. Figure E below shows that, at their peak, our working capital requirements are as much as £1,200m above the cover provided by a working capital balance equivalent our actual debtors and a bottom up estimation of the creditor days for a standalone supplier plus a cash balance equivalent to 2% of our COS. Such a balance would therefore be insufficient to meet our peak working capital requirements (which arise from the sensitivity of consumption to weather). As a standalone supplier would not have access to overdraft facilities,<sup>67</sup> this shortfall would result in bankruptcy in a normal year.

<sup>66</sup> Reported balance sheet debtor days based upon Balance Sheet and P&L data provide to the CMA. Bottom up estimation based upon standard market settlement terms for gas and electricity commodity costs and the standard settlement terms for the payment of network and distribution charges. These costs make up 80-90% of the bill with the payment terms for our indirect costs assumed to be similar to these. Total debtor has then been weighted between gas and electricity based upon supply to our average Dual Fuel mix.

<sup>67</sup> As a standalone supplier would not have a credit rating it is unlikely they would be able to secure any forms of debt finance. See Centrica "Analysis of cost of capital of energy firms Working Paper response".

Figure E - Illustration of 2013 Net Current Assets compared to a 2% cash balance



123. Finally, in relation to point (c), to meet any shortfalls described under point (b), the CMA states that the credit facility associated with using an intermediary to procure energy can be used by suppliers to “provide extra headroom in the short to near medium term to meet day-to-day cash flow requirements from adverse shocks”.<sup>68</sup> This statement does not provide sufficient information on the credit facility, or the terms on which is made available to enable us to understand the gist of the CMA’s position. However, as noted earlier, we can find no evidence in the financial statements of OVO or First Utility of any such facility being used. Based on our experience we suspect, but without access to the agreements cannot be certain, that the “credit facility” may instead be the calculation of the credit risk to which the trade intermediary will tolerate an exposure to on any unrealised loss on traded positions combined with commodity which has been delivered but not yet paid for. If this is the case, it would not be of any use in the management of the working capital gap we have identified above.

124. Therefore, and as previously outlined,<sup>69</sup> we believe that the CMA’s analysis should use a supplier’s peak, rather than average, working capital in its analysis, rather than assuming an arbitrary (and insufficient) cash balance. Alternatively it should assume suppliers hold a higher cash balance to fund their working capital shortfall. In both cases, it is also necessary for the CMA’s calculations to be adjusted to take account of suppliers’ relative exposure to gas and SME customers.

**e) The use of British Gas’s Information System (IS) asset values as an industry benchmark is inappropriate**

125. The use of British Gas’s reported fixed asset values to model the average fixed costs per customer for the industry overall is likely to overestimate the level of capital employed for many of the SLEF when compared to British Gas as only E.ON has both

<sup>68</sup> Provisional Findings Appendix 10.3-47, Annex A, para.78 (d).

<sup>69</sup> Centrica’s response to the CMA’s Working Paper: “Analysis of retail supply profitability – ROCE”, para.107.

scaled their smart technology roll-out *and* upgraded their Customer Relationship Management systems as British Gas has done.

126. Such investments add direct value to our customers, which contributes to our ability to differentiate our products and pricing. Our revenues therefore reflect our investments (and associated depreciation costs) whilst other suppliers' revenues reflect their, potentially lower, costs. As the CMA's analysis has adjusted the capital employed and associated depreciation charge for these suppliers but not their associated revenues, its approach could result in British Gas's profits appearing disproportionately high compared to the rest of the SLEF.
127. Furthermore, we note that the Net Book Value of our IS assets has not been adjusted to reflect their higher replacement cost despite our suggestion to do so.<sup>70</sup> We do not regard the argument that the replacement cost of these systems should not be used because a "new system could be expected to lower operating costs"<sup>71</sup> as valid in all cases. Our current billing system continues to offer us capabilities which, if we were to purchase it today, would cost more than the system's NBV: as such the value of these assets is undervalued in our reported Balance Sheet.

#### ***f) The WACC estimate is too narrow and reflects too low a range***

128. We continue to view the assessment of the cost of capital as both too narrow a range and too low a level. Moreover, having developed a range of possible levels of WACC (between 9.3% and 11.5%), the analysis then uses a single point estimate towards the lower end of that range (at 10.0%) elsewhere. This use of point estimates is inconsistent with the uncertainty which the CMA acknowledges is inherent in such exercises. It is therefore not clear why or credible that the CMA's analysis does not use a range of results to reflect that uncertainty.
129. There are two key reasons why we believe the range relied upon by the CMA is too low: the first relates to beta, the second to the assumption on the equity risk premium.
130. First, in relation to beta, it remains our view that a range of 1.0-1.2 would be a far more appropriate estimate than the 0.7-0.8 relied upon in the PFs:<sup>72</sup>
- Such a range assumes that energy retail is less risky than the average business. The CMA's own analysis accepts that a standalone retailer would be unable to raise debt. However, our previous argument,<sup>73</sup> that a firm that cannot raise debt would be more risky (and have a higher beta) than the average across the market (thereby implying a beta above 1) is not addressed.
  - Whilst regarding the beta of Just Energy (at between 0.9 and 1.2 unlevered), one of the few large standalone suppliers in existence as "relevant", the CMA's analysis does not then explain how this can be reconciled with its 0.7-0.8 range.<sup>74</sup>
  - In reaching the apparent view that there should be no material difference in beta between a standalone supplier and a vertically integrated entity,<sup>75</sup> there is a

<sup>70</sup> Centrica's response to the CMA's Working Paper: "Analysis of retail supply profitability – ROCE", para.108,

<sup>71</sup> Provisional Findings Appendix 10.3, para.50.

<sup>72</sup> Centrica's response to the CMA's working paper "Analysis of Cost of Capital of Energy Firms", pp.4-5.

<sup>73</sup> Centrica's response to the CMA's working paper "Analysis of Cost of Capital of Energy Firms", p.9.

<sup>74</sup> Provisional Findings Appendix 10.4-24, para.64.

contradiction in the CMA's analysis. For example, in contradiction to the CMA's view, Appendix 10.3, highlights the material benefits the VI structure provides in terms of credit rating and netting off benefits that materially reduce collateral requirements.<sup>76</sup> Furthermore this view is at odds with the existing evidence that vertically integrated suppliers do have lower equity betas than standalone suppliers (one only need to compare the beta of Centrica at around 0.4 with Just Energy at 0.9-1.2).<sup>77</sup>

- The rejection of adjustments to take account of reversion to mean (so-called Blume adjustments) are based on the assumption that GB energy retail is a low risk business, akin to a regulated utility: this is simply not the case for the reasons set out in greater detail in paragraph 172 to 175 below and in previous submissions.<sup>78</sup>
- The CMA has not explained why the use of weekly betas would not be reliable: continuing to cite a source which identifies problems only with daily betas as a reason not to rely on weekly figures.

131. Second, the CMA's range of equity risk premium (ERP) at 4-5.5% continues to be unduly low. We believe a range of 4.5-6.0% would be more appropriate. In reaching its PFs, the CMA does not appear to have addressed our earlier arguments<sup>79</sup> that:

- Estimates of ERP available from different sources range between 4.4% and 8.2%. These are drawn from reputable academic and financial sources which we have previously provided to the CMA<sup>80</sup> but these appear to have been disregarded in Appendix 10.4. And the range, rather than sitting in the middle of the available estimates, only selects the lower estimates available;
- The CMA's analysis also takes account of both geometric and arithmetic means: the arithmetic mean is the right measure for capturing the anticipated returns of an investment – and should therefore be the relevant measure for the assessment.<sup>81</sup> This would also result in a higher ERP.

132. A revised range, following these two adjustments, of 11.6-15.3%, is, in our view, more appropriate for a competitive standalone retailer.

133. Just to demonstrate the sensitivity, were the CMA to use the mid-point value of 13.4% its estimation of excess profitability based on economic profit analysis would reduce by c.£150m. Moreover, having recognised, that a range for WACC is appropriate, it is illogical for the CMA's analysis (and hence its PFs) to then rely on, not only a single figure but one which sits towards the lower end of its chosen range.

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<sup>75</sup> Provisional Findings p.229, para.6.111

<sup>76</sup> See Centrica's response to G21a, and Moody's statement at paragraph 17 of A10.3-35 which says that "the ability of a VI firm to achieve a strong credit rating arises from several factors. An important factor is the ownership of generation, transmission and distribution, and retail supply, and also in some cases being part of the wider global group. This smoothes [sic] and diversifies earnings."

<sup>77</sup> Provisional Findings Appendix 10.4-17, Table 4.

<sup>78</sup> Centrica's response to the CMA's working paper "Analysis of Cost of Capital of Energy Firms".

<sup>79</sup> Centrica's response to the CMA's working paper "Analysis of Cost of Capital of Energy Firms", pp.3-4.

<sup>80</sup> Centrica's response to the CMA's working paper "Analysis of Cost of Capital of Energy Firms", p.4.

<sup>81</sup> Centrica's response to the CMA's working paper "Analysis of Cost of Capital of Energy Firms", p.3.

**g) The ROCE estimate has failed to adjust for the impact of colder than “normal” weather**

134. The CMA’s analysis recognises that the financial performance of energy suppliers will have been impacted by underlying demand in any given year<sup>82</sup> and therefore suggests that profits over a longer period in aggregate should be considered.<sup>83</sup> As previously highlighted to the CMA<sup>84</sup>, we do not believe that simply looking at the 2009-2013 period would appropriately deal with the impact of weather on profits, as three of the five winters in this period were unusually cold. Profits will therefore appear higher over this period than they would be on a weather adjusted basis or over a longer cycle which included warmer than normal years. For example, if 2014 were included in the analysis the estimation of ROCE would reduce. Furthermore, the impact of weather on profits will be larger for suppliers with a greater gas focus, and therefore failing to adjust for weather (or use a sufficiently long period to gain a representative sample of weather outcomes) will not only give unreliable results on the average industry ROCE but also on the relative ROCE of different suppliers.
135. To ensure that industry profits are appropriately assessed, the CMA’s analysis should adjust these for normal weather conditions. Our own analysis suggests that adjusting for this colder than usual weather could result in a reduction to the CMA’s assessment of ROCE from 28% to 24% (see Table B).

Table B - Impact of demand on above average demand on CMA ROCE assessment<sup>85</sup>

Sensitivity of ROCE Analysis to changes in consumption	2009	2010	2011	2012	2013	2009 - 2013 Avg
<b>CMA Industry Total (ROCE %)</b>	<b>23</b>	<b>46</b>	<b>23</b>	<b>29</b>	<b>24</b>	<b>28</b>
CMA Industry total EBIT margin (£m)	1,100	1,800	1,300	1,600	1,600	1,480
Industry weather impact	(82)	(716)	163	(393)	(104)	(226)
Revised Industry EBIT margin (£m)	1,018	1,084	1,463	1,207	1,496	1,254
<b>Revised industry ROCE</b>	<b>21</b>	<b>28</b>	<b>26</b>	<b>22</b>	<b>22</b>	<b>24</b>

**Summary of the overall impact of these considerations**

136. We are concerned with the CMA’s interpretation of their ROCE analysis and believe that its conclusions regarding an appropriate EBIT margin are too low and excess profitability is too high.
137. The CMA has stated that, based upon its ROCE analysis, an appropriate EBIT margin of 1.3% can be derived<sup>86</sup>. We believe that this would not, in fact, give a sufficient

<sup>82</sup> Provisional Findings Appendix 10.3, para.106.

<sup>83</sup> Provisional Findings Appendix 10.3, para.108.

<sup>84</sup> Centrica’s response to the CMA’s Working Paper: “Analysis of retail supply profitability – ROCE”, para.175.

<sup>85</sup> Assessment of industry weather impact uses our own assessment of the impact that weather has had on BG’s profits (see Figure 2, Centrica’s response to the CMA’s Working Paper: “Analysis of retail supply profitability – ROCE”) and our estimation that BG’s volumes are equivalent to 33% of those for the SLEF as a whole (see Table 7, Centrica’s response to the CMA’s Working Paper: “Analysis of retail supply profitability – ROCE”).

<sup>86</sup> Provisional Findings, Chapter 10, para.39.

return on capital to an efficient firm with British Gas's customer and product mix, based on our concerns with the methodology set out above. For example: British Gas faces the risk of lost EBIT margin as consumption is reduced in the event of warm weather<sup>87</sup> in any given year.

138. We do not have access to the data and calculations underpinning the CMA's analysis or to accurate data for our rivals, and therefore are unable to provide a precise calculation of the impact that these issues would have on the calculations in it. However, based on the data that is available to us, we are able to make some simple assumptions to estimate the likely scale of the impact. We set out below these illustrative calculations: the CMA will of course have access to the necessary data to make these adjustments in a more precise way. However even based on our illustrative estimations it can be seen that these issues have a very material impact on the ROCE calculation.
139. If a 7, rather than a 5 year basis were used, industry ROCE reduces from 28% to 24% (see Table C). Additionally, flexing for some of the most important assumptions such as a higher intermediary fee, the additional capital needed to meet peak requirements and stripping out the impact of weather further reduces the assessment of average industry ROCE to 13%.<sup>88</sup> This compares with our view of a reasonable range of WACC which we believe should be the region of 11.6-15.3%.
140. Specifically this sensitivity is calculated by using a "triangulation" of the following figures shared with us by the CMA, which we understand should be equivalent and allow us to translate between costs, EBIT and ROCE respectively:
- a. The CMA's estimation of absolute excessive industry profits, which can be used to benchmark **cost** impacts (at an annual average of £871m over the 2009-2013 period – Table 2, Appendix 10.3);
  - b. The CMA's estimation of excessive industry **EBIT** (at 2.7%, comparing actual industry EBIT of 4.0% against the CMA's "competitive" industry EBIT of 1.3% - Table 1, Appendix 10.2 and Figure 4, Appendix 10.2 and Paragraph 10.39, Chapter 10);
  - c. The CMA's estimation of excessive **ROCE** (at 18%, comparing the CMA's estimated industry ROCE of 28% against its estimated industry WACC of 10% - Paragraph 61, Appendix 10.5 and Table 1, Appendix 10.3).
141. The equivalence of these figures allows us to estimate the impact of sensitivities using available estimates on the likely impact on absolute costs/profits, EBIT % and/or ROCE %.
142. The specific sensitivities we have been able to run using this approach are as follows:
- **Increase in fee by 1%:** Commodity costs are assumed to represent 50% of the average bill, therefore a 1 % increase in the fee would reduce EBIT by 0.5%.
  - **Move to assessment of ROCE on a 7 year basis:** Based on Table 1 Appendix 10.3, this translates to a 4% decrease in ROCE.

<sup>87</sup> Centrica's response to the CMA's Working Paper: "Analysis of retail supply profitability – ROCE", para.162

<sup>88</sup> We would recommend the CMA considers some of the additional adjustments set out in Section E of Centrica's response to the CMA's Working Paper: "Analysis of retail supply profitability – ROCE".

- **Impact of an increase in working capital:** We estimate that the difference between peak and average working capital balances for a standalone British Gas using actual debtor balances and industry standard creditor terms is c.£1bn. If we assume that our share of industry working capital is roughly equivalent to our gas share of 44%,<sup>89</sup> this results in an estimated industry capital requirement of £2.3bn, which assuming a 10% WACC would result in an additional £240m of cost/additional EBIT of 0.5%.<sup>90</sup>
- **Removal of above average weather impact:** Using our estimation of the impact that variations in weather have had on our own profits over the period of 2009-13, combined with the assumption that such variances are caused by gas of which we have a 44% market share, we believe that weather will have increased industry profits by an average of c. £170m/yr.<sup>91</sup>

143. We then convert each of these impacts to an equivalent impact on the ROCE (using the approach set out at paragraph 141 above), resulting in the following illustrative impact on ROCE:

Table C - Adjusted ROCE results

Impact of changes on assumption to CMA industry ROCE assessment	ROCE (%)
<b>CMA ROCE Results</b>	<b>28</b>
a). Increase in fee by 1%	(3)
b). Move to assessment of ROCE on a 7 year basis	(4)
d). Impact of increase in working capital	(5)
g). Removal of above average weather impact	(2)
<b>Revised estimation of ROCE performance</b>	<b>13</b>

144. We also draw attention to a similar sensitivity analysis that we understand our economic advisors have carried out in the Data Room.<sup>92</sup>

145. No adjustments have been made in the table for the issues explored in c, e and f for the following reasons:

- The impact of differences in working capital by customer segment will impact the relative performance of suppliers, not the market overall. However, as the CMA's analysis of ROCE is only presented at the total supply level, we are unable to adjust the CMA's findings by reference to suppliers' different customer mixes.
- The incorrect use of British Gas's IS asset values as a benchmark for other suppliers would impact the CMA's estimation of overall market performance and also the relative performance of British Gas compared to other suppliers. However as we do not know our rivals' reported intangible values, we cannot quantify this impact.

<sup>89</sup> We note that this is an illustrative estimate only: the CMA will have access to the necessary data to calculate industry-wide working capital requirements on this basis.

<sup>90</sup> Centrica's response to the CMA's Working Paper: "Analysis of retail supply profitability – ROCE", Table 7.

<sup>91</sup> Centrica's response to the CMA's Working Paper: "Analysis of retail supply profitability – ROCE", Table 7.

<sup>92</sup> Please see the CRA Data Room Report, to be submitted.

146. We would also note that there are other issues discussed elsewhere in our response which are not reflected in the table, but would also result in a higher capital base. For example, we understand that the CMA's analysis has still only capitalised the SME acquisition costs of our rivals, and not of British Gas. We have also set out above that in our view there are a number of other risks associated with managing an independent supplier's commodity procurement that would not be captured even in a [X] - [X]% fee. Therefore even having run these sensitivities, we would still see the resulting ROCE as being at the top end of a reasonable range (and therefore the implied "competitive EBIT" as too low).

## Section 2: Analysis of competitive benchmark prices and costs

147. The CMA's analysis also estimates the prices that it believes would be charged by an efficient standalone supplier – split between domestic and SME supplies and between electricity and gas. This analysis relies upon the intermediary trading fee, many of the capital assumptions set out in the ROCE discussion above (e.g. relating to working capital), and the WACC. It therefore suffers the same flaws described in the previous section and should not be regarded as a truly separate exercise from that earlier work. The impact on this benchmarking exercise is that:

- The fee paid by mid-tier suppliers is too low to be a reasonable proxy for the cost of commodity risk management by the SLEF;
- The methodology for estimating working capital does not sufficiently recognise the amount of capital required by an energy business or how these requirements will differ depending on the suppliers' exposure to gas and SME supply;
- Furthermore the estimation of WACC does not appropriately reflect the risks we face in energy supply, therefore the implied margin is too low and fails to reflect the impact of differences in the capital required to meet the needs of differing customer segments; and
- Finally, by focussing on a five year period, the analysis has not included a rising commodity market as well as a benign or falling commodity market.

148. However, given that the efficiency benchmarking exercise also looks separately at different customer segments, and at the potential for costs to have been lower than were actually seen, it relies on a number of additional assumptions – which we also disagree with. We believe these assumptions result in an understatement of competitive pricing, and a misstatement of the relative prices that would emerge across business segments.

### ***h. Commodity cost benchmarks are not achievable***

149. The commodity cost benchmarks used do not reflect a commodity cost that an efficient supplier could actually achieve. The lower quartile benchmark is a backward looking construct requiring suppliers to benefit from hindsight once it has become clear which supplier's hedging strategy was most successful it would not be possible for the wider market to recreate this in order to procure more commodity at that lower cost.

150. Furthermore the calculation of the average commodity cost is particularly sensitive to assumptions to which participants' wholesale costs are included in each period. We disagree with the application of the methodology and are concerned at the sensitivity of the result to apparently small changes.

### **Lower quartile benchmark**

151. We note first that the different commodity costs of different suppliers will reflect their product mix: a firm selling more 1 year fixed price products will have different costs and prices to a firm selling more SVT products hedged over a longer horizon. This is not a question of inefficiency, but the CMA's methodology will assume that in years when the 1 year forward cost is cheaper, firms with a higher proportion of SVT customers, are inefficient, and vice versa.

152. Even if we leave aside the question of product mix, the lowest quartile commodity cost achieved across the SLEF in any year is an outcome of a risk management strategy and should not be used as a measurement of efficiency. When a supplier selects a hedging strategy to manage uncertainty in future wholesale prices, it can have no means to predict whether it will be in the lowest quartile. Even when it becomes clear (with the benefit of hindsight) whose procurement strategy is cheapest, it is simply not possible to procure from the market at that price.

153. Given that firms could not consistently achieve the lower cost benchmark applied, it is not reasonable to assume that those in the lowest quartile would price to recover their WACC while others would price at an effective loss. On a long term basis, suppliers would on average not cover their cost of capital (with performance in any given year effectively a random result of how their hedging strategy performed against unpredictable market outcomes).

154. Table D illustrates the level of losses the SLEF would have had to have absorbed if they weren't in the bottom quartile. Based upon this we can see that suppliers would have had to absorb losses equivalent to over 50% of the average annual profits earned over the period – such an operating model would be unsustainable.

Table D - Impact on supplier profits of pricing to lower quartile commodity cost<sup>93</sup>

Industry profits (£m)	2009	2010	2011	2012	2013
Profits sacrificed had all suppliers priced to match lowest quartile commodity prices	634	773	1,029	848	653
Actual realised profits	1,100	1,800	1,300	1,600	1,600

155. It would therefore seem the CMA's analysis envisages a competitive outcome where customers switched immediately to the product in the lowest quartile, forcing all suppliers to match that price. However, not only does this falsely assume that the lower quartile firm could procure sufficient additional commodity at a sufficiently low cost to serve this additional demand without making a loss, but it also sets up a hypothetical world in which the SVT product (on which actual revenues are based)

<sup>93</sup> Analysis of industry losses is based upon supplier CSS data for residential and businesses published in 2009-13 and compares the lowest quartile commodity cost by fuel and customer segment (SME and Residential) against the reported costs for each supplier.

would not exist. In this environment, forecasting customer numbers and switching rates would be very difficult. Firms would potentially choose not to hedge (as doing so would make their profits more volatile) exposing customers to a far greater level of price volatility. This is an entirely different (hypothetical) business model, which would result in very different products and price volatility for customers. Such a construct should not therefore be considered when assessing the costs and prices actually seen in the market over the period of the CMA's analysis.

### ***Benchmark of EDF and npower***

156. In setting its alternative commodity cost benchmark, which it believes reflects the costs that would be incurred by suppliers purchasing energy directly from the market, the CMA's analysis has excluded Centrica apparently because we have entered into bilateral contracts.<sup>94</sup> However, since the pricing of our bilateral contracts is linked to wholesale prices (and thus they can be replicated by others), the prices paid are similar to those achieved by standalone suppliers purchasing on the market. These are all arms' length third party contracts, which a standalone supplier could also enter into (as Just Energy Inc has in the US). Our bilateral contracts are more efficient than executing a large number of individual trades for the same overall volume and are therefore a perfectly legitimate part of the benchmark for how an efficient standalone supplier could procure. This does not therefore appear to be a rational reason for excluding Centrica.
157. Furthermore, failing to include Centrica in the gas benchmark results in a sizeable proportion of the commodity costs incurred in this period to serve the gas market being excluded.<sup>95</sup>

### ***i. Indirect cost benchmarks should be treated with caution***

158. It is indeed true that indirect costs per account vary significantly across the industry (as the CMA has observed). However, it cannot be assumed that all this variation stems from inefficiency. Variations in operating costs are wholly consistent with competitive markets as they:
- a. Can reflect a customer choice to pay through different mechanisms,
  - b. Can result from differentiation in the levels of customer service offered by suppliers, and
  - c. May be a result of short term underinvestment which could adversely impact customer service levels in the longer term.
159. We therefore believe the any assessment of the relative level of operating costs should be treated with caution as differences in efficiency level may not be the only relevant factor.

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<sup>94</sup> Provisional Findings Appendix 10.5, Annex A

<sup>95</sup> RWE and EDF represent just 20% of the gas volumes sold by the SLEFs (British Gas alone accounts for a further 40%, Based upon 2013 CSS data for B2C and B2B.

### **Sensitivity: summary of the overall impact of these considerations**

160. As with the ROCE analysis, we therefore believe that the price benchmarking analysis suffers from a number of problems (many of them the same as those with the ROCE analysis) which will invalidate its results. Again, we are unable to replicate the CMA's analysis in full, but we can use a similar approach to the one described above for ROCE to calculate illustrative examples of how correcting for the issues raised above would change the CMA's findings. Taking the points we made in Section 1 (in relation to ROCE), together with those made in Section 2 (relating to cost benchmarking), it is our view that the CMA's analysis should be adjusted at least as follows:

- a. Adjusting the analysis to include an additional 1% trading fee (point a);
- b. Extending the period of analysis to include 2007/08 (point b);<sup>96</sup>
- c. An increase in the derived EBIT based upon an increase in capital employed to reflect peak capital requirements (point d);<sup>97</sup>
- d. An increase in the 'derived' EBIT based upon an increase in WACC to 13.4% (point f); and
- e. Calculating the lower quartile commodity benchmark over the full five year period rather than for each individual year in that period and the inclusion of British Gas in the commodity benchmark (point h).

161. We also believe that the CMA's segmental analysis will need to be adjusted to take account of the differences in working capital requirements and risk, as set out above. Given that many of the CMA's findings on a segmental level have been redacted, we have not run similar sensitivities on a segmental basis here: but believe that this is a critical element the CMA should consider further.

Points (a), (b) and (d) were already considered as sensitivities to the PFs on ROCE above, and we have applied these sensitivities to the price benchmarking analysis on the same basis. We note that these adjustments directly affect the capital charge, and therefore the implied EBIT that should be earned by suppliers. We will return to the sensitivity of the calculation to different assumptions on what a competitive EBIT would be in relation to the CMA's EBIT benchmarking exercise below. Once the necessary adjustments which we have identified are made, the £1.7bn figure set out in the PFs reduces by over half to c.£550m. The fact that these sensible, and relatively small, changes in assumption result in such a material change to the results highlights that these are highly sensitive to assumption and should not be relied upon. Further details can be found in Table E below.

<sup>96</sup> The CMA's data provided in Table 5, Appendix 10.5 does not provide sufficient information for BG to assess the impact that this change in assumption would have on the B2B estimation. However we see no reason not to assume that this would result in a further reduction in the CMA's estimation of the amount customers have paid in excess of what would be achieved in a competitive market.

<sup>97</sup> In Para 10.39, Chapter 10 the CMA outline that their ROCE analysis suggests that an appropriate EBIT margin would be 1.3%. Based on our proposed revised WACC midpoint of 13.4% and an increase in working capital in line with Point d we believe an alternative assessment based upon this approach would be 2.3%.

Table E - Changes in CMA estimation of total industry customer overcharging<sup>98</sup>

(£m)	Avg. Annual Excess		
	B2B	B2C	Total
<b>CMA headline estimation of customer excess cost</b>	<b>530</b>	<b>1,163</b>	<b>1,693</b>
a. Adjusting the analysis to include an additional 1% trading fee	(100)	(125)	(225)
b. Extending the period of analysis to include 2007/08	0	(325)	(325)
d. Increasing the allowed EBIT to reflect a WACC of 13.4% (the mid point of our proposed range)	(150)	0	(150)
f. Increase in capital employed to reflect peak working capital requirements	(50)	(125)	(175)
h. Calculating the lower quartile commodity benchmark over the full five year period and the inclusion of BG in the commodity benchmark	(100)	(175)	(275)
<b>Revised estimation of customer excess cost</b>	<b>130</b>	<b>413</b>	<b>543</b>

### Section 3: Margin benchmarking

162. The proposed EBIT margin of 1-3%, against which the CMA benchmarks the SLEF, fails to adjust for differences in the risks faced by the chosen benchmark companies compared to the SLEF. Because of this, the range is both too low and too narrow. In our previous responses, we have highlighted the necessity for certain adjustments to be made to ensure that the chosen benchmarks provide a like for like comparison. A more appropriate EBIT range, which reflects our relative risks and operating structure is between 4-6%<sup>99</sup> and we explain the reasons for our view in this section under the following headings:

- **The impact of differences in customer mix is not properly accounted for (Point j)**
- **The analysis incorrectly assumes that GB energy suppliers face lower risk than regulated and I&C companies (Point k)**
- **The EBIT benchmarks do not recognise the impact of the commodity purchasing risks taken on by the SLEF compared to the mid tier suppliers who contract his out a third party (Point l)**

<sup>98</sup> Note the reference to a trading fee in this table is purely illustrative

<sup>99</sup> Centrica working paper response to "Assessment of profit margin comparators for the competitive benchmark in retail energy supply, para.11.

- **The assessment of gross margins fails to recognise the impact of differences in operating costs** (Point m)

***j. The impact of differences in customer mix on profitability is not properly accounted for***

163. We disagree with the suggestion that there is no evidence or rationale which explains the need for suppliers to earn higher margins on the supply of gas or from serving SME customers.
164. Where a supplier must hold a greater level of capital to meet the needs of its customers (in terms of working capital and/or risk capital, held by the supplier itself or by an intermediary who procures on its behalf), then it would be expected by its shareholders to also earn a higher return to compensate its investors for the higher capital requirement (and/or, to the extent that non-diversifiable risks are passed on to investors, cost of capital). The supply of gas to residential customers and of both gas and electricity to SME customers will result in such a requirement.
165. It is therefore rational that suppliers with a higher proportion of domestic gas and/or SME customers (such as British Gas) would earn higher relative profits. In this section we will set out the characteristics and market conditions of the SME and gas markets that result in these relatively higher risks and capital requirements when compared to residential and electricity supply.

***Relative risk and capital requirements of gas supply vs. electricity supply***

166. The supply of gas represents a significantly greater risk than electricity as a result of:
- Price volatility risk:** We have provided evidence to show that wholesale gas prices are more volatile than electricity prices.<sup>100</sup> Such volatility poses a risk to suppliers (or third party intermediaries) of having to make cash payments to their counterparties to satisfy margin calls associated with their forward purchasing. The risk of price volatility is further compounded by the fact that it is not possible for suppliers to immediately pass through changes in cost (in particular increases) to consumers;
  - Demand risk:** We have also provided evidence to show that gas demand is more sensitive to changes in weather conditions than electricity.<sup>101</sup> It is not the case that this demand risk can simply be “effectively managed” through forecasting and the use of financial instruments<sup>102</sup>. Energy demand is driven by changes in weather and it is not possible to predict this with certainty. For British Gas, the reduction in demand resulting from a 1/20 warm winter can pose a risk to our annual profits. Although weather derivatives are available, we do not believe the market has sufficient depth to obtain the volume of cover which we would require as the number of providers of such products has reduced. However based upon the products we have purchased we estimate that it would cost c.£50m to obtain coverage for our risk. Therefore we believe suppliers will always face some

<sup>100</sup> Centrica’s response to CMA working paper on: Assessment of profit margin comparators for the competitive benchmark in retail energy supply, Table 2.

<sup>101</sup> Centrica’s response to CMA working paper on: Profitability of retail energy supply: profit margin analysis, p.2

<sup>102</sup> Provisional Findings Appendix 10.2, para.12.

degree of weather risk. As gas demand is more susceptible to variances in temperature than electricity, gas suppliers will face a greater level of risk that, in the event of warmer than normal weather, they would earn a return below their WACC; and

- c. **Seasonal capital demands:** Similar to our concerns on the assessment of ROCE discussed in Paragraph 114 the seasonality of gas demand relative to electricity means that gas suppliers will need to hold a greater level of working capital.

### ***Relative risk and working capital requirements of SME supply vs. residential supply***

167. SME customers represent a greater risk than domestic customers due to:

- a. **Higher cost of capital:** Demand reduction and bad debt risk associated with economic cycle: An economic downturn represents a comparatively higher risk to our SME business compared to our residential business as a result of the risk of both lower demand and increased bad debt. These risks are not diversifiable by shareholders as they are correlated with broader economic conditions that affect all investments. Therefore they will contribute to a higher cost of equity (via a higher beta). We also believe that our exposure to such risks is likely to be more pronounced than that seen by other SME suppliers as we have a greater proportion microbusiness customers who demonstrate an even greater than average risk of business failure and thus default at times of economic downturn.
- b. **Greater risk capital requirements:** The length of our SME contracts (up to 3 years) is longer than the period over which we usually hedge our domestic products, this will increase our SME business's exposure to margin calls relative to our domestic business during periods of price volatility.<sup>103</sup>
- c. **Greater working capital requirements:** As outlined in Paragraphs 115, our SME customers have a longer debtor profile than our domestic customers which will result in the need to hold a proportionately higher level of working capital.

### ***k. GB energy suppliers face significantly more risk, which should be compensated, compared to companies in regulated markets, or those confined to I&C customers***

168. We disagree with the suggestion that suppliers to the SME and domestic markets should earn a return lower than that achieved by regulated companies or by suppliers to I&C customers. This appears to be based on a view that such suppliers are able to effectively manage weather risk and face a lower cost pass through risk than I&C and/or regulated markets. We believe both these views are simply not credible.

### ***Comparability of I&C providers***

169. Our I&C customers take responsibility for their own commodity risk management, effectively using British Gas merely as a route to market. These customers therefore take on all the risk relating to changes in consumption profile and commodity prices

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<sup>103</sup> Under the fee based model the CMA proposes this would be accounted for by an increase in the fee, although we note no allowance for this has been made in the CMA's analysis.

themselves. In addition we are able to pass through all T&D cost changes to them more readily than we are our residential or SME customers. Finally, the profits we earn from supply to I&C customers are not as exposed to weather risk. It is not therefore the case that, in supply to residential and SME customers, we face similar or lower risk compared to I&C.<sup>104</sup>

### **Comparability of regulated returns**

170. To ensure we remain as competitive as possible for as long as possible we will always seek to delay any price increase. Even when we do choose to raise prices, our supply licence requires us to provide our residential energy customers with 30 days advance notice. Conversely many regulated businesses such as Power NI, can rely on formal mechanisms within their regulatory price control to pass through under- or over-recoveries of costs in previous years as a result of either weather/demand variations or cost fluctuations.
171. Furthermore, in setting Power NI's latest regulated return at 2.2%, UREGNI accepted that the effects of competition (even with only 22% of the residential market supplied by rivals as at November 2013)<sup>105</sup> justified a higher return than had been set in the previous price review. In contrast the CMA's analysis proposes that the substantially more competitive GB market would only be consistent with a 1.3% EBIT.
172. In its last regulatory pricing review for electricity in June 2013, IPART in New South Wales, Australia set the regulated EBITDA at 5.7% of total cost. This was based on evidence on both "bottom up" calculations of necessary returns and profitability benchmarking across countries and sectors. This level of profits reflected a significant level of competition (which has since resulted in retail price caps being lifted) – but even today the largest three electricity suppliers in New South Wales control 93% of the domestic electricity market.<sup>106</sup>
173. We therefore believe that these regulatory benchmarks, as with I&C returns, should constitute a lower bound to the returns that one would expect to emerge from a competitive residential energy market. We would also note that both these regulatory benchmarks relate to electricity: for reasons set out above, we would expect higher EBIT returns in gas.

### ***I. The EBIT margin for a supplier who outsources commodity risk management to an intermediary for a fee should be lower than a supplier who self manages this risk***

174. A key assumption underpinning the profitability analysis is that efficient standalone suppliers would enter into an agreement with a third party intermediary. Whilst the ROCE and cost benchmarking analysis are adjusted for the cost of these arrangements, no consideration of this has been made in the EBIT benchmarking

<sup>104</sup> See Section B of our response to the CMA's Working Paper on "Assessment of profit margin comparators for the competitive benchmark in retail energy supply."

<sup>105</sup> Domestic credit customers (see:

[http://www.uregni.gov.uk/uploads/publications/Transparency\\_Report\\_2013\\_NOV.pdf](http://www.uregni.gov.uk/uploads/publications/Transparency_Report_2013_NOV.pdf)): rivals had a higher share of Domestic Keypad (33%) and SME markets.

<sup>106</sup> IPART Review of the performance and competitiveness of the retail electricity market in NSW From 1 July 2014 to 30 June 2015.

analysis. This approach is inconsistent, and means that the costs of risk management are not recognised at all in the EBIT comparison (even to the extent allowed for in the ROCE and benchmarking tests).

175. As the proposed benchmark of 3%<sup>107</sup> appears to be influenced by the views of one of the mid tier suppliers – Ovo – who has entered into such an agreement - we do not believe that their targeted profits are an appropriate guide to the competitive returns of a supplier who does not contract this activity out to a third party. In order for an appropriate EBIT benchmark to be determined against which the historical returns of the SLEF can be compared it is necessary to consider the impact of the fee model as against in-house risk management.
176. A [x] - [x]% fee on commodity costs would be equivalent to a supplier who has chosen to manage this risk themselves earning an additional EBIT of c.1%. Such a supplier would need additional capital to manage the trading activity and would therefore, in a competitive market, earn a higher margin accordingly (i.e. earning both the competitive margin associated with the retail supply activity, and the competitive margin associated with the procurement activity – rather than splitting this profit between the supplier and the intermediary, as is the case under the intermediary fee model).

#### ***m. The assessment of gross margins fails to recognise the impact of differences in customer mix on operating costs***

177. We do not agree with the suggestion that an appropriate gross margin benchmark should be 12% and believe the analysis makes erroneous comparisons between the mid-tier suppliers and the SLEF gross margins. Differences in customer type and commercial strategies of the mid-tier suppliers compared to the SLEF make such a comparison (without adjustment) inappropriate. We consider these points in turn.

#### ***Customer mix impact on gross margins***

178. The CMA has acknowledged that it is more expensive to serve cash/cheque and prepayment customers<sup>108</sup> and that the mid tier suppliers supply a smaller proportion of these customers. We would therefore have expected the analysis to adjust for this when comparing the gross margins of the mid tier suppliers against those of the SLEF. The fact that this has not been done is inconsistent with the CMA's apparent assumption that more could be done by the SLEF to reduce their indirect costs by, for example, persuading more customers to choose Direct Debit.<sup>109</sup> We do not believe this is justified as a suppliers' pay type mix will be a result of customer choice in a competitive market, not relative efficiency.<sup>110</sup> Adjustments should therefore be made

<sup>107</sup> We note that EDF also referenced a targeted EBIT margin of 3.3% (Paragraph 31, Appendix 10.2. However this was described as an average EBIT, not a maximum EBIT and therefore profits above this should not be seen as excessive if a business benefits from a cost/profit advantage - British Gas had such advantages during the period of this analysis owing to cold weather in 3/5 years assessed an average Opex advantage of c.£10 per account over its competitors during 2009-13.

<sup>108</sup> Provisional Findings Appendix 10.5, para.44d.

<sup>109</sup> Provisional Findings Appendix 10.5, para.46.

<sup>110</sup> For example British Gas has heavily promoted the benefits of switching pay type along with providing customers with innovative solutions such as Direct Debit payment holidays.

in the benchmarking for the higher gross margin required to recover these higher indirect costs and meet the needs of these customers.

179. Had adjustments been made to the benchmark to reflect these differences in customer mix, the CMA's analysis would have arrived at a benchmark gross margin level of c.17-18% - consistent with the actual gross margin earned by the SLEF. This analysis is applicable to the domestic market only.

### **Commercial strategy impact on gross margins**

180. As is the case in many industries, new entrants will often invest in growth in order to build critical mass and a strong customer recognition/brand which will allow them to achieve higher profitability in the longer term. This may involve making low (or even negative) net margins in the short term and is thus not a sustainable business strategy as it will fail to offer its shareholders a reasonable return on capital invested over the long term.
181. It is therefore not appropriate to assume that the recent historic prices/profits of the mid-tier suppliers are set at or above the competitive level and we would instead argue that these are in fact currently set below competitive levels (with the "foregone" profits in recent years representing an investment in future profits). We note that the PFs say that it is not "necessarily clear" that the mid-tier firms have been sacrificing their gross margins: but at the same time reports that Ovo Energy (most recently reporting a -0.1% EBIT margin) told them that it believed an EBIT margin of 3% was appropriate (and they have elsewhere said that they target 3-4%).<sup>111</sup>
182. Given that Ovo Energy sub-contracts risk management to a third party, this would translate into around a 4% "fair" margin or a 4-5% "target" margin for a firm that undertook these activities itself: a figure very much in line with the average EBIT earnings of the SLEF in recent years.

### **Conclusions on EBIT benchmarking**

183. When the margins earned/targeted in regulated markets and by small suppliers are compared with our relatively higher exposure to risk (as described in section k and l above) we remain of the view that a target EBIT range of 4-6% is a more appropriate benchmark than the 1-3% proposed in the PFs.

### **Impact of EBIT benchmarking on cost benchmarking analysis (Section 2)**

184. As outlined in paragraph 147, we do not believe that the derived EBIT resulting from the CMA's ROCE analysis of 1.3% (which is then also effectively equivalent to the capital charge applied in the price benchmarking analysis) is sufficient to remunerate suppliers for competing in a competitive market and managing the risks associated with energy supply.
185. As outlined above, a more suitable margin for a supplier managing its own commodity purchasing risk, would be in the range of 4-6%. Based upon this, and the changes we proposed above in Sections 1 and 2 on ROCE and cost benchmarking, we have assessed the impact of a revised EBIT target on the CMA's assessment of the amount

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<sup>111</sup> Provisional Findings Appendix 10.6, para.74 and 79; and interview with Ovo CEO Stephen Fitzpatrick in BA Business Life magazine, 18th February 2014, in which he states "... we are willing to accept a lower profit margin. We aim for 3 to 4 percent."

customers have paid in excess to its cost benchmark. This is set out in Table 10 below.

186. Our analysis in Table F uses the same adjustments outlined in sections a, b, d, f, and h but additionally includes an allowance for suppliers to earn a higher level of margin. For the purposes of this analysis we have modelled the impact of a margin of between 3-5% (compared to the CMA's original assumption of 1.3%). This has been used on the assumption that a margin of 4-6% for a standalone supplier managing their own commodity purchasing risk is equivalent to a margin of around 3-5% for a standalone supplier sub-contracting this activity (and therefore profit) to a third party – on the conservative assumption that such risks could be covered by a 2% fee.

**Table F - Impact of assumption changes on CMA estimation of customer overcharging<sup>112</sup>**

(£m)	Avg. Annual Excess		
	B2B	B2C	Total
<b>CMA headline estimation of customer excess cost</b>	<b>530</b>	<b>1,163</b>	<b>1,693</b>
a. Adjusting the analysis to include an additional 1% trading fee	(100)	(125)	(225)
b. Extending the period of analysis to include 2007/08	0	(325)	(325)
d. Increasing the allowed EBIT to reflect a WACC of 13.4% (the mid point of our proposed range)	(150)	0	(150)
f. Increase in capital employed to reflect peak working capital requirements	(50)	(125)	(175)
h. Calculating the lower quartile commodity benchmark over the full five year period and the inclusion of BG in the commodity benchmark	(100)	(175)	(275)
j-l. Increase in EBIT to a range of 4-6% reflecting the risks associated with the GB energy market	(25)-(225)	(200)-(650)	(225)-(875)
<b>Revised estimation of customer excess cost</b>	<b>100-(100)</b>	<b>200-(225)</b>	<b>325-(325)</b>

187. On this basis, we do not believe that the CMA's assessment of the amount customers have paid in excess of its cost benchmark is valid. Our assessment suggests that, based upon a series of assumption changes in line with our comments, the CMA's view that costs have been £1.7bn higher than its cost benchmark all but disappears. Instead the CMA's methodology, once subjected to these adjustments, would suggest that actual supplier prices and profits are broadly in line with the expected outcome of a market characterised by competition between standalone suppliers.
188. Therefore we do not believe the CMA's analysis is sufficiently robust to support its conclusion that excessive profits are being earned – profits that equate to as much or more than was earned by the entire industry in most years.

<sup>112</sup> Note the reference to a trading fee in this table is purely illustrative

## Section 4: Appendix 10.3 (ROCE and Economic Profit)

189. This is our detailed response to Appendix 10.3 of the Provisional Findings. We use the same structure and headings as the Provisional Findings Appendix 10.3.
190. The CMA itself recognises that the number of assumptions made and judgements taken in reaching the results require the CMA to treat the results as indicative (Paragraph 1). We also believe the analysis presented in the Provisional Findings is particularly sensitive to a number of assumptions, and warrants a greater degree of sensitivity/scenario analysis to cover a range of outcomes. It is therefore illogical that the Provisional Findings present conclusions in the form of a single point estimate, and one which is, in our view, extreme, rather than a range.

### *Principles of economic profitability analysis*

191. Paragraph 19 (b): We maintain our view that conventional ROCE and economic profit measures lead to rates of return which are implausibly high. The capital requirements for a hypothetical standalone supplier operating at scale are complex to estimate, and we do not believe the intermediary fee is a reasonable proxy. We provided alternative means of approximation in our presentation to the CMA on 22nd May 2015. The CMA claims that it is “not persuaded” by this calculation on the basis that “such arrangements appear to cover additional services and fees than those we observed for independents operating in GB markets” but ignores the route to market fee range we provided and does not appear to have accounted for the costs of managing the other types of risks through any other means.<sup>113</sup>
192. Paragraph 21: It is not the case (as the CMA seems to think) that using “economic profits” rather than ROCE will resolve the sensitivity of the measure to fluctuations in working capital over time and between firms. We understand that the CMA has simply calculated economic profits by subtracting an allowed return on capital (calculated as 10% of the estimated capital base) from the Return on Capital Employed. Therefore, if the capital base is measured in a non-comparable way over time or across firms as the CMA suggests might be the case (for the reasons set out below, e.g. in relation to the capitalisation of SME customers, adjustment of working capital to different product/customer mix etc.), this problem will affect the economic profits in fundamentally the same way that it affects ROCE.
193. Paragraph 23: We disagree with the CMA’s conclusion that: “it is reasonable to infer that Centrica believe that [economic profit] would shed light on commercial performance in absolute and/or relative terms compared to Centrica’s peers.” We use economic profit as a metric to apply to the Group as a whole, reflecting our significant investments in fixed assets in the E&P and Power Generation businesses. For the British Gas business, capital is held constant, and capital for the purposes of hedging is not assigned. The British Gas business is, therefore, effectively performance managed on an EBIT basis. This is consistent with the comparisons we, and market analysts, make to our peer group, which is on an EBIT basis.

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<sup>113</sup> Provisional Findings Appendix 10.3-61 para.118.

### ***Incomplete or unsuitable financial information***

194. Paragraph 35: it is not the case that balancing costs for a standalone supplier are “unlikely to differ from that of a VI business”. That may be the case in benign market conditions, but will not be so throughout a full commodity cycle.

### ***Recognition and valuation of assets***

195. Paragraph 49 & 50. We note that the CMA has not adjusted the Net Book Value (NBV) of our current assets to reflect their higher replacement cost as we suggested in our earlier ROCE response.<sup>114</sup> It is our view that such adjustments are needed to reflect what the true costs would be of implementing costly customer services and billing systems – our current NBV is below this. We do not regard the CMA’s argument that the replacement cost of these systems should not be used because a “new system could be expected to lower operating costs” as valid. Our current billing system continues to offer us capabilities which, if we were to purchase it today, would cost more than the system’s NBV: as such the value of these assets is undervalued in our reported Balance Sheet.
196. Paragraph 61: We agree with the CMA that SME acquisition costs should be amortised to ensure that our ROCE is appropriately measured, but noted in our previous ROCE response that this had not yet been done for British Gas.<sup>115</sup> However, feedback from our economic advisers on analysis in the data room, suggests this has not been done. This will lead to our ROCE being overstated in absolute terms and relative to our rivals.

### ***Working capital***

197. Paragraph 72: When considering the working capital needed to trade on the wholesale market as a standalone supplier, the CMA has relied on the SLEFs’ data. That approach is only appropriate if internal settlement arrangements mirror the standard settlement terms of the market. This is not the case for British Gas, where, for example, creditor days will be overstated relative to the available terms from trading directly with the external market. Given that the SLEFs actual data therefore cannot be used for this purpose, we recommend that the CMA should instead use standard settlement conditions for commodity purchases and standard payment terms for network and other costs to model the working capital requirements of a standalone supplier trading at arms’ length.
198. Paragraph 76: It is critical that peak working capital requirements are taken into account, as firms must be able to manage peak requirements and not just annual averages. Failing to do so will result in a significant understatement of working capital.
199. Paragraph 77: It is not appropriate to take different approaches to this calculation for different firms (with some using year-end values and others annual average values) as this will not provide comparable estimates of working capital across suppliers.

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<sup>114</sup> Centrica’s response to the CMA’s working paper: “Analysis of retail supply profitability – ROCE”, para.108.

<sup>115</sup> Centrica’s response to the CMA’s working paper: “Analysis of retail supply profitability – ROCE”, para.111.

200. Paragraph 81: As set out in our comments on the CMA's price benchmarking exercise, if peak working capital requirements are not recognised then cash will be necessary to meet these peaks. We have demonstrated that the CMA's assumption of a 2% cash balance would not be sufficient to manage the gap between British Gas's peak and average working capital requirements in the normal course of business. Therefore either working capital or cash balances need to be increased to ensure that the stand alone supplier does not run out of cash.

### ***Notional capital (for business risks)***

201. Paragraph 89 (c): The CMA uses Just Energy Inc. as an example of a company that has grown out of their intermediary arrangement with Shell and now trades on their own account, and suggests that Just Energy's cash balance at year end is therefore a good indicator of the levels of cash needed for an independent stand-alone firm undertaking its own procurement to manage its trading requirements.<sup>116</sup> From our review of Just Energy's financial statements, we believe that the CMA may have misinterpreted how Just Energy procures its energy. Just Energy uses a consortium of commodity partners to procure their energy through bespoke long term contracts. Whilst the terms of these contracts are not disclosed, our experience would indicate that such arrangements command a fee. Therefore the CMA's characterisation of Just Energy Inc as a standalone supplier which accesses the wholesale accounts on their own account is incorrect: their business model is more akin to a fee arrangement. As a result, the analysis of Just Energy's cost of trading is incorrect and the cash they hold has no relevance to determining the cash requirements of a stand-alone entity. It is simply incorrect to conclude that Just Energy was able to "grow out of the fee arrangement and to trade on its own account without large sums of notional capital"<sup>117</sup> – or to infer more generally that trading in the wholesale markets does not require capital.

202. Paragraph 89 (d): The CMA also uses the "credit facility" associated with the intermediary fee agreement, which is later disclosed by the CMA as a very significant sum, as a means to manage working capital peak requirements arrangements – for example stating that the arrangement provides "access to a significant credit facility, which provides extra headroom in the short to near medium term to meet day-to-day cash flow requirements from adverse shocks".<sup>118</sup> We do not believe this description can be correct given our experience in the market and from the evidence in the mid-tier suppliers' financial statements (Ovo and First Utility).

- If the "credit facility" can be used by suppliers in the manner suggested by the CMA, it would be akin to an overdraft facility (and indeed the term "credit facility" is usually understood as the ability to borrow money for any purpose). Given the suppliers

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<sup>116</sup> Provisional Findings Appendix 10.3-45-46, para.69-74.

<sup>117</sup> Provisional Findings Appendix 10.3-57, para.104b.

<sup>118</sup> Provisional Findings Appendix 10.3-47 para.78d. See also Provisional Findings Appendix 10.3-58 para.108, which suggests that a "well managed supplier" could "use the fee arrangement to lay off wholesale market trading related risks and use the associated significant credit facility to act as a buffer against other business risks" and Provisional Findings Appendix 10.3-62 para.119, "our benchmark trading fee covers the lay-off of wholesale market risk and getting access to a significant credit facility that would allow a well-managed supplier to manage its business risks."

have paid for the facility through the fee embedded in their wholesale costs we'd expect to see them make use of it and this would be evident in the cash flow analysis and disclosures in their financial statements. That is not the case. The use of the facility must, therefore, be heavily restricted;

- Based on our experience, we suggest that the “Credit Facility” is in fact more likely to be a calculation of the amount of credit exposure that the trade intermediary is willing to accept to the mid-tier supplier. It is likely to be a combination of any mark-to-market profit or loss on the derivatives traded through the intermediary, as well as payment due for commodity purchases which have been delivered, but not yet paid for;
  - It is not clear from the disclosure as to whether the facility would allow the creditor position to be extended beyond the standard market settlement terms or not. It is not evident from the financial statements that this is the case; and
  - It is therefore far from clear that the “credit facility” described could in fact be used to manage other “business risks” in the way the CMA suggests.
203. Paragraph 89 (e): We note that the presumed access to lines of credit would be dependent on the standalone supplier having a good credit rating: this is inconsistent with the CMA's own assumptions in the calculation of an appropriate stand-alone WACC which assumes that the standalone entity would be unable to raise debt (i.e. would not have a good credit rating)<sup>119</sup> and therefore this source of capital would not be open to a standalone supplier. We therefore question the relevance of this point in the CMA's argument. Further, although weather derivatives may be able to offset a limited amount of risk, the costs associated with such measures would need to be incorporated into the calculation of EBIT (and therefore ROCE) if the CMA's hypothesis is that the standalone supplier would manage risks in this way. However, as far as we are aware (given we have insufficient knowledge of the services covered by the intermediary fee agreement) this has not been done. The same is true of “insurance products”: although we are unclear to which products for which risks the CMA are referring in this comment.
204. Paragraph 95: We disagree with the CMA's conclusion that the limiting factor to the scalability of an intermediary service is a lack of demand. In order to be a credible and cost effective intermediary, there must be other reasons to participate in the market other than providing a route to market service. There are a limited number of credible participants who could operate as trading intermediaries, and there are certain limits, specifically in relation to credit and exposure to a concentrated industry risk, which would be applied. In our view, the increase in risk means it is not rationale that substantial additional “intermediary capacity” would enter the market (as the CMA hypothesises) without any increase in price. Indeed, we believe the evidence suggests that a significant increase in fee would be necessary to attract participants who have been exiting this market as increased financial regulations have constrained balance sheets and capital availability. A more appropriate way to estimate the price of such services at scale is to use standard financial approaches to costing risk. These approaches would suggest at least a [X] - [X]% fee would be required, even

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<sup>119</sup> Provisional Findings Appendix 10.4-29, para.74: “our current view is that a stand-alone retail supplier would not be able to support any material level of gearing”.

for a simple route to market service (with no additional management of e.g. weather risk or provision of shaping services).

205. Paragraph 96: We do not agree that the fee arrangement provides a reasonable benchmark to assess the level of fees because it represents an arm's length market price for the reasons described in relation to Paragraph 95 above. The price observed today has not been set in the context of the much larger requirement that the CMA's model hypothesises. The current pricing currently supports c.10TWh of demand. This would need to scale to provide c.600TWh of demand. We do not believe that an intermediary providing a volume discount to a specific supplier at small scale today can provide any assurance that the market can price this degree of commodity risk management at the same (or lower) price if volumes were to increase significantly. Trade intermediaries are able to absorb relatively small positions in their portfolio and price the opportunity at the marginal cost. However, positions of the scale of the SLEFs' requirements could no longer be absorbed without impacting the trade intermediary's means of accessing the market, and this would need to be priced accordingly. Indeed, we note that Shell itself made comments such that "volume risk could be offloaded for a price" (Annex A Paragraph 96d) and that "So long as Shell could find offsetting positions to remain hedged, scale was not a barrier to expansion." (Annex A Paragraph 96i). These are important qualifications which the CMA appears to overlook—neither of these statements suggests that undertaking these activities at larger scale would not require higher costs.
206. Paragraph 102-3: It is not the case that the 2% cash balance modelled by the CMA is sufficient to meet our regulatory collateral obligations regarding transmission and distribution (T&D) costs. As outlined in Paragraph 110 of our ROCE paper, we believe that, even with the credit available to us under these T&D agreements, we would still be required to post capital equivalent to [X] (compared with the value of a 2% cash balance at just £180m). It is therefore not appropriate to assume that the cash balance modelled by CMA could be used to meet these T&D requirements: indeed, that cash would in any case not even be sufficient to meet seasonal variations in our working capital requirements, still less to cover the need for regulatory collateral also.

## **Annex A**

### ***Business risks faced by energy suppliers***

207. Paragraph 9: We are pleased to see that the CMA recognises GB energy suppliers are constrained in their ability to immediately change prices in line with movements in wholesale commodity costs. We note that the ability to pass through is not only constrained by regulatory considerations and menu costs associated with changing prices (e.g. the cost of informing customers of a price change), but also by our rivals' pricing decisions.
208. Paragraph 11: We agree with the CMA's characterisation of the benefits of hedging (in reducing uncertainty from price volatility and potentially smoothing prices) and the associated capital implications (recognising that this requires more collateral than a shorter-term hedging strategy). However, the CMA does not seem to recognise that this requirement for increased collateral is faced by whichever entity is transacting

directly in the wholesale markets, regardless of whether this is a supplier or an intermediary.

### ***How the Six Large Energy Firms manage business risks***

209. Paragraph 13: We question the relevance of using the amount of cash on the balance sheet as a means to assess collateralisation. Collateral received or posted will form part of our Midstream working capital and thus will not be visible in the British Gas balance sheet. Because of this, we have provided a reasonable approximation of the British Gas collateral requirements to the CMA. The actual working capital usage in Midstream will be a product of the trading of the portfolio as a whole, and therefore is not a good proxy for the position of a hypothetical standalone British Gas. The contingent capital requirement to support our external trading commitments is managed at group level through a variety of financial products, of which cash is one. In addition to cash in hand, we have disclosed in our 2014 accounts lines of credit of £4bn which can be readily accessed.

### ***How independent suppliers manage business risks***

210. Paragraph 30: As noted earlier (Paragraph 77 of this document), we have not been provided with the details of the risks covered by the agreements on which the CMA bases its calculations. However, we do not believe that the suggestion at Paragraph 30 that the agreements essentially cover all business risks for a very modest fee (including access to lines of credit that are effectively free at the point of use – i.e. included in the fee) can be accurate. If this were the case then we would see the use of this facility as a working capital tool reflected in the balance sheet movements, cash flows statements and disclosures of independent suppliers' accounts, which we do not. We discussed our concerns as to this characterisation of the credit facility in paragraph 205 of this appendix.
211. Paragraph 31: we agree that there will always be some residual business risks which are passed on to shareholders (and compensated by the equity risk premium and, to the extent they are correlated with market risks, by a higher WACC reflecting a higher beta). Furthermore, we believe that the residual risks associated with a standalone energy supplier would be material, and materially non-diversifiable, and therefore would result in a beta greater than 1 and a WACC significantly greater than the CMA's estimates suggest. However, we would also note that the UK independent business model has never been tested through a full commodity cycle. As such, the impact of volatile market conditions, and how intermediaries would manage such volatility for the entire market, rather than just a small share, is untested.

### ***Our assessment on notional capital***

212. Paragraph 50: Centrica has not suggested that we required ring-fenced capital. We did highlight the requirement to be able to readily access (significant) cash in order to meet collateral requirements should markets move out of favour. We have had direct experience of this in the UK in 2007/08 and in 2014 in the US markets. We do not hold cash separately for this purpose, but do carefully monitor and ensure that our

cash, debt and lines of credit facilities at group level are sufficient to ensure a stressed market scenario can be managed.

213. Paragraph 53: We suggested a notional capital approximation in response to the CMA's Working Paper on ROCE: however, we disagree with the CMA's apparent view that the standard approaches to risk assessment used in financial markets are not applicable to an entity that is not a bank or financial institution (or even more specifically, is not a deposit taking one).<sup>120</sup> We recognise the difficulty in approximating the capital requirements on a consistent basis given that the business model the CMA wishes to analyse (a standalone supplier of scale which trades on their own account) does not exist.<sup>121</sup> We therefore looked to the financial markets as a sophisticated market which has a replicable means to calculating the equity capital which would need to be put aside to support derivative trading. The tools we suggested using are based on standard methodologies for risk pricing, many of which we use in our business today. This is directly relevant to the capital requirements which are required (albeit they may not be ring-fenced) to support hedging commodity purchases with derivative products (futures and forwards).
214. Still in relation to paragraph 53 we note that in the CMA's trade intermediary model, many of the possible trade intermediaries who currently and in the past have operated this service are financial institutions<sup>122</sup> which are subject to these regulations. The financial regulator has, through extensive experience, come up with a model which calibrates the capital requirements which arise through concentration risk, leveraged risks associated with derivatives and credit risk. In the submission cited by the CMA we focused on the risk based capital requirements in that they can be directly transposed to the nature of the risks inherent in commodity trading.<sup>123</sup> We therefore continue to believe that these risk pricing tools can be used as an objective measure of risk capital which would give a more accurate representation of the costs of risk management than the simple replication of a mid-tier fee for a service which is not clearly defined and has not been priced for risk of this scale.
215. Paragraph 57: The comparison of the costs of holding "notional" (i.e. contingent/risk) capital and a trading fee appears to be calculated as a simple percentage of the commodity cost at an assumed trading fee. It therefore appears that the CMA has not included any other costs associated with subcontracting that trading to a third party (e.g. the lost opportunity to trade profitably around the retail business's position). The CMA has also not revealed whether there are any other profit opportunities (e.g. a bid-ask spread or other fees or profit opportunities) embedded in the intermediary agreements that they are modelling: obviously if there are any such additional costs then those would also need to be taken into account in this comparison.

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<sup>120</sup> We note in relation to the CMA's comments at paragraph 53(c) that the regulatory requirements discussed apply to financial institutions, whether they accept customer deposits or not.

<sup>121</sup> We do not concur that Just Energy Inc. is an example of such an entity in that they use a syndicated intermediary function to access the markets and do not trade directly with the wholesale markets for forward hedging. For further detail see paragraphs 226-231 below.

<sup>122</sup> For example Morgan Stanley and JP Morgan have previously offered this service for the UK market, but have since withdrawn from energy trading.

<sup>123</sup> "Virtual CRD/CRR Capital Framework for a British Gas Standalone Downstream Business", April 2015, submitted to the CMA on 7<sup>th</sup> May 2015.

216. Paragraph 58: The CMA rejects the notional capital model in favour of the fee based model on the basis that the fee based model appears to be more efficient. However, we do not consider the fee based model reflects the arm's length pricing of risk for the commodity procurement of all the SLEFs for the reasons set out above. We have provided the CMA with alternative, standard risk pricing models (used to measure capital requirements for derivative hedging) for the calculation of capital requirements for hedging, as an alternative view which can be simplified and standardised across participants.
217. Paragraph 61: This paragraph appears to imply that the independent suppliers can manage risks including bad debt risks, shape and imbalance risks, and demand volatility at a lower cost than the SLEFs because they "focus on efficiently running their business and controlling costs" (apparently with the inference that the SLEFs do not do so). Given the inherent unknowns in relation to all these risks, we do not believe it is credible that independents are effectively able to manage these risks at much lower cost than we are. No supplier can perfectly forecast demand (which is largely a question of forecasting the weather – discussed further in relation to Paragraph 65 below). Nor can any supplier perfectly forecast which customers will fail to pay (see discussion of Paragraph 63 below). Clearly suppliers with a purely residential customer base will face lower risks in relation to bad debt (and indeed lower capital requirements) than those who also have business customers: but this does not reflect greater skills or efficiency, simply the market segment upon which they have focused.
218. Paragraph 62: We do not have sight of the commercial agreements which describe the terms of the credit facility although, it is described in this paragraph as suitable for "managing working capital peaks and business risks" (i.e. akin to an overdraft facility). We are concerned the restricted use of this facility has not been properly represented as discussed in Paragraph 205.
219. Paragraph 63: We also disagree that bad debt risks can simply be managed away through "effective credit control procedures such as credit checks, prompt billing and direct debit payments from customers". Bad debt cannot be entirely avoided – particularly for SMEs, where bad debt is a significant cost and strongly correlated with the performance of the economy more generally. For example, bad debt levels in the SME market and particularly in the Microbusiness market are higher than those seen in both residential and I&C supply as a result of a greater frequency of business failure and a higher regularity of changes in tenancy at business addresses (where we do not know where our previous customer has gone or who our new customer is – these customers switch onto our deemed tariff bad debt rates).
220. Paragraph 64: We agree with Shell that a suitable hedging strategy can assist suppliers to see through a period of high volatility. However, for a hedging strategy to be effective at managing market volatility, it would need to be in place before the markets were rising and/or volatile. It is important to understand that a hedging strategy seeks to remove price volatility, but does not attempt to solve for the "cheapest" outcome. A hedging strategy which appears with the benefit of hindsight to be "suitable" when commodity costs rise sharply may appear to be wholly "unsuitable" (i.e. expensive) if commodity costs instead fall. We take little comfort in the ability of a supplier to renegotiate its trading terms in times of market stress. In times of high volatility, the amount of capital at risk is likely to increase, not decrease and therefore

the costs of providing a collateral free trading arrangement to a supplier will increase. In our view therefore the use of such an unusually benign period in the wholesale markets as the basis to model the cost of managing risk over a full commodity cycle is inappropriate and gives false assurance to the CMA of the extent to which this model could be used across the whole market.

221. Paragraph 65: We believe the CMA has overstated the ability of any supplier to use accurate demand forecasting as a means to mitigate weather risk exposure. Weather reports are not reliable until a few days beforehand, which can result in a significant amount of energy which will need to be bought or sold to balance to customer demand (especially for gas). Further, we do not agree that weather derivatives are an effective means to manage this risk. We have made clear to the CMA that the weather derivatives which we have used cover a small proportion of our weather risk exposure.<sup>124</sup> They are not available in significant volume, and carry a cost which is not reflected in the CMA's analysis.
222. Paragraph 68: We do not agree with the CMA's conclusion, which is dependent on a belief that the approximate charge for commodity risk management incorporated in the fee (based on 2 mid-tier suppliers' bespoke arrangements) is an appropriate proxy for the risk capital that would be required if this business model were scaled up across the entire energy supply market.

***How a stand-alone supplier of scale has managed business risks in a more cost effective way other than the fee arrangement and notional capital (the Just Energy case study)***

223. Paragraph 72: The amount of cash that Just Energy Inc has on its balance sheet is not an indication of their cost of trading on their own account. A review of their financial accounts and other public information indicates that they have bespoke long term contracts with commodity partners from whom they secure their energy requirements. These commodity partners allow them to procure on a collateral free basis, which is therefore not the same as trading on their own account directly through the wholesale markets. This is more akin to a fee arrangement, and not consistent with trading directly through the wholesale markets. Their financial accounts do not provide any details of the fees attached to these bespoke contracts, however our experience in the US markets would indicate that a fee for this service would be required. The fees for such collateral free trading are likely to be embedded in Just Energy's commodity costs.
224. Paragraph 74: The majority of Just Energy's energy is not procured directly from the wholesale markets. They use a number of commodity partners which form part of a syndicate who have first call on Just Energy assets. As noted above, this is more akin to a fee arrangement, with the costs of this service likely incorporated into their commodity costs.
225. Just Energy has derivatives traded with their commodity partners which are \$630m out of the money. This is a quantification of the credit risk (before accounting for

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<sup>124</sup> Centrica's response to the CMA's working paper: "Analysis of retail supply profitability – ROCE", para.104-105.

commodity delivered but not yet paid for) to which the commodity partners are exposed. Given Just Energy has a probability of default rating of 5%<sup>125</sup> (or a 1 in 20 risk of default) it is not credible that the partners would provide a collateral free trading service without charge. The fees for this service are not disclosed.

226. The amount of cash in the bank at year end, therefore, has no relevance to the costs which Just Energy incurs to procure its commodity requirements. These will be a function of the fees paid to the syndicate, the impact of the syndicate arrangement on their borrowing costs as a result of the first call on assets given to the syndicate, and the costs for working capital which is needed given they no longer have access to Shell's credit facility.
227. We therefore do not accept the CMA's conclusion that they have demonstrated that Just Energy have rationally chosen to move from an arrangement with Shell to their current arrangement (to managing on their own account directly through the wholesale markets) because it was more cost effective.
228. Paragraph 77 (a): Just Energy's accounts state that "Just Energy purchases the majority of the gas and electricity delivered to its customers through long-term contracts entered into with various suppliers".<sup>126</sup> These are bespoke arrangements and it is not possible from that disclosure to ascertain the embedded fees included. Given the US market is dominated by collateralised exchange trading, it would not be rational for strong credit rated counterparties to offer a collateral free route to market service without charge. Further, our own experience in the US markets provides strong indication that a fee would be required for this service.
229. Paragraph 77 (c): We have not had access to details of the CMA's discussion with Shell. However, we do not believe that Shell's comments can be interpreted as concluding that the pricing of the risk management of commodity purchases for the SLEFs as a whole would be on the same basis. We would expect a trade intermediary would be able to price a small amount of such risk as being marginal to their portfolio, but that would change once the exposure is significant, and impacts the trade intermediary's ability to generate income through other means, e.g. proprietary trading. This is because credit free trading is a limited resource (due to the limited willingness of counterparties to take on large exposures to any one entity).
230. Paragraph 77 (c) (ii): We are not clear on the terms of the "credit facility", which seems to have characteristics very similar to a very large overdraft facility based on the CMA's description. If that is the case, the pricing arrangements described by the CMA seem inconsistent with our experience in the financial markets. However, as noted in Paragraph 205 above, this interpretation of the "credit facility" as akin to an overdraft does not seem consistent with what we see in their published accounts.

### ***Strengths and resilience of the fee arrangement***

231. Paragraph 78: We do not agree with the characterisation of the strengths of the intermediary fee arrangement for all the reasons set out above. Further, we note the

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<sup>125</sup> S&P IQ Report, 1 July 2015.

<sup>126</sup> Just Energy Annual Report 2015, p.82 Note 11 c (iv).

CMA has failed to recognise the limitations of the hypothesised fee arrangement which we summarise further below. Specifically:

- The agreements on which the fee assumption is based are bespoke and their terms (or the precise terms of a “hypothetical” agreement that a standalone supplier is assumed to have) have not been shared with us. However, the CMA appears to assume a very low fee which is inconsistent with the estimate we have calculated based on standard risk pricing models;
  - The CMA’s model assumes behaviour by trade intermediaries and other market participants which are inconsistent with commercial reality – for example, the model assumes that:
    - The intermediaries could net trades between generators (and implicitly gas producers) and suppliers to an unrealistically high extent and therefore trade on a largely collateral free basis (despite the fact that the SLEFs today do not trade on a collateral free basis), and
    - The fee would include access to a large credit facility which could be used to manage peaks in working capital requirements (despite the fact that according to their financial statements independent suppliers do not appear to use these “credit facilities” in this way today);
232. The CMA’s model assumes that the fee arrangement used by two small suppliers could be scaled up at the same or lower cost to that provided today (i.e. that new intermediaries or intermediaries who have recently exited this market due to capital constraints would re-enter the market at large scale at the same or lower prices than those under which they exited, and that no increase in price would be required to redeploy capital from supporting other trading opportunities into supporting the operation of the energy supply market or to compensate for the additional risk);
233. We also disagree with the CMA’s characterisation of the benefits of the business model in several respects:
234. Paragraph 78 (b): The route to market arrangement enables the mid-tier supplier to enter into hedging arrangements in standard market products. This will allow a degree of hedging, but due to shape and demand variation (a function of customer numbers, weather and consumption), the route to market will not “offload price risk completely”.
235. Paragraph 78 (d): As per Paragraph 205 above, we are sceptical that the credit facility of the scale and cost described can be used by mid-tier suppliers as an effective overdraft. We further note that there is no evidence of the use of the arrangement disclosed in the mid-tier financial statements.
236. Paragraph 78 (e): The extent to which the costs of having an internal trading function would be avoided would be dependent on the level of service provided. As we have not had access to the agreements, this is not clear. However, the description provided by the CMA implies a route to market execution service only. The service, provided by Midstream to British Gas, extends beyond route to market provision, for example, including the use of the 24 hour logistics desk for managing physical delivery and balancing. Further, under a simple route to market service the supplier would not avoid the requirement to monitor their positions and determine the trades which are required. Therefore, many activities would still be required, assuming the service is route to market only. It is important that the CMA ensures that the service that the

hypothetical fee is covering is very clearly defined, so that (a) all costs of the arrangement (which may go beyond the fee) can be captured and (b) all costs that would still need to be carried by the standalone supplier will be appropriately captured. Without further clarity of the nature of the contract the CMA has in mind, we cannot be confident that this is the case.

237. Paragraph 79: The nature of the “credit facility”, the terms of its use, and any additional costs or fees are not disclosed. We have concerns that the restrictions on use of the facility have not been fully represented or disclosed. We expand on these concerns in Paragraph 205.
238. Paragraph 80: The CMA characterises the volatile market conditions in 2008/09 as unusual due to “extreme weather, global financial crisis and highly volatile wholesale energy prices.” We disagree with the characterisation that these events are highly unusual. Energy prices are volatile – more so than oil, and significantly more so than foreign exchange markets. Wholesale energy prices have been volatile in 2004/05, 2008/09 and more recently in 2010. There are a number of factors which can result in price volatility, of which weather is only one. Shell’s ability at times of stress to provide extensive non-contractual support to small suppliers is likely to be less available in conditions where that exposure to external events is amplified by having a large number of small suppliers and generators, all exposed to the same external stress factors. Nor is there any evidence that this can be relied upon for other unidentified trade intermediaries. We therefore do not believe it reasonable for the CMA to treat this undertaking from Shell as evidence of the resilience of these fee arrangements.

### ***Scalability of the fee arrangement***

239. Paragraph 85: The CMA does not appear to recognise that the arguments put forward by Centrica, (and, it would appear, from SSE), relate to the scalability of the fee arrangement to the SLEFs commodity procurement as a whole rather than whether this would be possible for a single market participant. The problem with scalability is not to scale the arrangement to meet the needs of a single supplier of the scale of one of the SLEFs, but rather to assume (as the CMA’s model does) that the model can be scaled to cover the entire supply market.
240. Paragraph 91: The CMA has not put forward any evidence that the intermediary is scalable to the entire market. We therefore cannot agree that the fee is a reasonable proxy for the capital put at risk by the SLEFs for the risk management of commodity purchases. We do not agree that supply will largely match demand – neither power generators nor gas producers follow the same hedging strategies as suppliers and their tolerance for volatile market pricing will vary. We also believe that the CMA is incorrect to state that “with a greater dispersion of risk among market participants, we would expect trading fees to decline with scale.” The CMA has not demonstrated that there is a dispersion of risk, and in our view the converse would be the case. The CMA model would reduce the number of credit worthy counterparties in the wholesale markets and therefore concentrate the risk of credit, market risk and cash liquidity among a smaller number of wholesale market participants. This change in risk profile for interacting on the wholesale markets will increase the costs of trading not decrease them. The CMA has also not explained why the normal, economic laws of supply and

demand would not apply in this situation (as the finance literature indicates would be the case) – i.e. that, as demand for a service increases, the price must increase in order to attract more supply into the market. The CMA appears to believe that the supply of such risk management services is infinitely elastic (i.e. will match demand without any increase in price) – but provides no evidence to support that assertion.

241. Paragraph 92: The CMA put forward a hypothetical construct on how independent suppliers may or may not interact with a trade intermediary model on the assumption that it would result in a cost effective model at scale with a fee likely to be lower than the current market structure. It does not appear that the CMA has considered an alternative outcome in the hypothetical fee model: where the trade intermediaries are not able to negotiate a portfolio of substantially offsetting positions, and therefore would carry a substantial amount of market risk on their account which they in turn are required to offset in the wholesale markets, with fewer participants and limited credit lines. The trade intermediaries would therefore be required to use working capital to support the service, which will require a capital allocation charged at their hurdle rate. We believe this is an entirely plausible, and far more likely alternative outcome to the CMA's hypothesised scenario and would result in a material increase in the cost of the intermediary fee.
242. Paragraph 96: There is no evidence provided that the intermediary market can be made available at sufficient depth, and at the same cost to the trade intermediaries to support the requirements of the SLEF as a whole. As noted above, we do not know precisely what Shell said and in what context, and it is in fact not clear to us that the Shell comments do suggest that additional capacity could be provided at no additional cost – as their statements are caveated with the conditions that additional volume can be had “for a price” or “as long as Shell could find offsetting positions to remain hedged” – but do not comment on what that price would be, or to what scale (and at what cost) such offsetting positions could be found. These are critical caveats, which the PFs do not appear to give any regard to.

### ***Pricing of the trading fee in the intermediary model***

243. Paragraph 97: We have not had access to the contractual arrangements for the mid-tier suppliers. It is therefore not possible to conclude on whether the fee arrangements have appropriately priced the risk of commodity procurement for the independents and the “credit facility” included in the contract. From the indication of the fee provided, which appears very low, we do not believe this can be the case.
244. Paragraph 98: As noted above in relation to Paragraph 92, we do not believe the CMA is correct to assume that a deep and low cost intermediary market would emerge. Under this hypothetical construct the credit and market risk for the wholesale market would be concentrated amongst fewer counterparties rather than dispersed, and the magnitude of the volumes would increase the exposure of the trade intermediaries. The CMA's conclusions are therefore flawed. As we set out above, we see an alternative outcome from this hypothetical market as more likely, under which the intermediary fee would need to be materially higher.
245. Paragraph 99: Based on the information provided in the redacted annex, Scottish Power does not appear to have priced their exposure. Therefore their statement does

- not appear to confirm the CMA's assumptions on the level of the fee based on the redacted text.
246. Paragraph 101: The CMA has not recognised the limited number of plausible counterparties which could provide this service and the impact of scaling a service of c.10TWh to c.600TWh would have on the (unidentified) trade intermediaries' balance sheets. As discussed in the hearing, we believe the number of plausible participants is very small (a small number of oil majors who actively trade, and a limited number of banks who have remained in commodity trading).<sup>127</sup> Banking participants would also be subject to regulatory capital requirements which would increase the cost of providing the service, contrary to the CMA's belief that supply would increase to meet demand but that "prices would not rise".
247. Paragraph 102: As discussed above, the CMA's assumption that a trade intermediary can hedge a large supply position (whether that is to a single supplier or a number of suppliers) without any capital allocation is not borne out by the reality of trading in derivative markets (where for example Centrica, despite a strong credit rating and balance sheet, still needs to post collateral). Further, the CMA fails to acknowledge the additional credit risk the trade intermediaries would be exposed to by serving a portfolio of independent suppliers and generators, who would be capital light and likely have a poor credit rating.
248. Paragraph 103: As described in detail above, we do not believe the trade intermediary model is in any way based on the same foundations as the current market structure as the CMA appears to believe.
249. Paragraph 103 (a): While the SLEFs may not have separate or ring-fenced risk capital which is observable, they all have credit ratings of BBB or above. They have access to significant amounts of cash resources at short notice through lines of credit, debt or cash. For example, in order to manage these requirements (along with those of its other Group businesses) Centrica Group has access to [redacted] of committed undrawn facilities, in addition to [redacted] of drawn net funding.<sup>128</sup> The working capital requirements to support the British Gas supply business are managed within the Midstream business.
250. Paragraph 103 (b): While the trade intermediaries may have similar credit ratings to the SLEFs, they will be exposed to the credit risk of a number of small suppliers and generators. Therefore their credit risk in this hypothetical scenario is increased. Further, the other market participants are likely to limit the amount of collateral free trading the trade intermediaries can enter into, regardless of credit rating. We do not trade on a collateral free basis. We collateralise a proportion of our trading in the market, which is a combination of exchange and collateralised bilateral agreements for screen based broker trading. In our experience, even with the backing of a parent with a strong credit rating, a supplier can only obtain limited amounts of collateral free trading with any one counterparty, and that the number of counterparties willing to enter into such agreements is limited.<sup>129</sup>

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<sup>127</sup> Morgan Stanley, JP Morgan, Deutsche Bank, Barclays have recently exited energy trading.

<sup>128</sup> Centrica SQ response, question S58, p.121.

<sup>129</sup> Centrica's response to the CMA's working paper: "Analysis of retail supply profitability – ROCE", para.33 and Appendix 1.

251. Paragraph 104 (a): Contrary to the CMA's assertion, the credit rating of the independent suppliers and generators is wholly relevant to the trade intermediary and will be an important factor when considering the amount of exposure the trade intermediary will accept, and the fee which will be charged.
252. Paragraph 104 (b): We note again that Just Energy Inc. is a counterparty with a relatively poor credit rating – with an estimated probability of default of 5%.<sup>130</sup> This is reflected in the significant cost of debt which Just Energy incurs, and a substantial shareholder deficit at the end of the 2015 financial year.
253. Paragraph 104 (c): As described above, we do not believe it is plausible that a trade intermediary will be able to trade on a wholly collateral free basis, and therefore carry no cash flow risk in support of this service.
254. Paragraph 106: We note Shell's condition that they would to offer their supply trading services to large suppliers in the UK "so long as it could find offsetting positions to remain hedged". We believe the cost of remaining hedged would increase in this hypothetical model from a market risk perspective.
255. Paragraph 109: As discussed above, we disagree with the evidence provided by the CMA that the current fee is an accurate market price of the cost of commodity risk management and can be applied as scale. We have provided an alternative view in our comments on Paragraph 92 (as well as in our earlier response to the CMA's ROCE working paper) whereby the fee would increase, not reduce.<sup>131</sup> We have also provided alternative means to estimate the capital at risk which could be applied to the SLEFs to test the CMA's assumption.<sup>132</sup>
256. Paragraph 111 (b): Using standard risk pricing techniques it is possible to demonstrate that the risk, and therefore cost, of hedging in the longer term (e.g. 18 months in advance) is more than in the shorter term. The CMA seems to imply that a trade intermediary would not factor this additional risk into their pricing calculations: we simply don't believe this is a plausible assumption.
257. Paragraph 111 (c): We do not agree that the CMA's approach of using actual procurement costs and actual revenues gives any "benefit" to SLEFs to account for the difference in capital requirements that would apply to a longer dated hedging strategy than a shorter dated hedging strategy. To account for the difference in risk, the fee would need to increase.
258. Paragraph 112: We strongly disagree with the CMA's view that trade intermediaries will employ limited amounts of working capital for short periods, and no significant amounts of notional or risk capital at all. The model the CMA describes is more akin to a broker model, which would be priced on a completely different basis than a trade intermediary model, where the latter certainly would carry significant risk. This is particularly true when the size of the positions managed on behalf of the supplier form a material part of the trade intermediary's business, as would be the case under the CMA's hypothesis.

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<sup>130</sup> S&P Capital IQ report dated 1 July 2015.

<sup>131</sup> Centrica's response to the CMA's working paper: "Analysis of retail supply profitability – ROCE", para.21, 29-34, 63, 76-83.

<sup>132</sup> Slides presented to the CMA on 22<sup>nd</sup> May 2015.

259. Paragraph 118: We provided the CMA with a range of fee estimates to account for differing service levels as it was not possible from the initial working paper<sup>133</sup> to identify what service was provided to the mid-tier suppliers under the CMA's hypothesis. We estimated a fee of [x] - [x]% for a simple "route to market" service fee only, and used standard financial risk pricing techniques to price such a service. This estimate therefore did not include any additional services to those which appear to be assumed in the CMA's hypothesis. We then provided further estimates which layered additional costs for other risk management services pertaining to shape and balancing costs: the CMA does not appear to have allowed for any costs or capital to manage such risks.
260. Paragraph 132-136: We continue to disagree with the view that there is no requirement to hold additional regulatory capital (as previously outlined in Paragraph 110 of our ROCE response). Although we agree that some credit will be provided by the transmission and distribution firms, our interpretation of the contracts underpinning these agreements states that the level of credit that is available is capped. As such we would still be required to provide [x] of capital to support these contracts.

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<sup>133</sup> CMA "Analysis of retail supply profitability – ROCE", version for Centrica, 17<sup>th</sup> April 2015.