NON-CONFIDENTIAL VERSION

CMA ENERGY MARKET INVESTIGATION

SCOTTISHPOWER'S RESPONSE TO THE UPDATED ISSUES STATEMENT

1. INTRODUCTION AND EXECUTIVE SUMMARY

1.1 ScottishPower welcomes the opportunity to respond to the Competition and Markets Authority (**CMA**)'s Updated Issues Statement (**UIS**) dated 18 February 2015 in the CMA's investigation into the supply and acquisition of energy in Great Britain (**GB**) (**Market Investigation**).

1.2 We are also taking this opportunity to comment as appropriate on the working papers which lie behind the UIS. As requested by the CMA, we will provide comments on matters relating to two of the final working papers, 'Gas and electricity settlement and metering' and 'Profitability of retail energy supply: profit margin analysis' in a separate follow-up response.

Generation and wholesale markets

1.3 With regard to upstream markets, we agree with the CMA's initial view that there is unlikely to be a problem with insufficient liquidity, exercise of generation market power or foreclosure by vertically integrated companies. It is helpful that the CMA has investigated these issues so thoroughly, and we broadly agree with the reasoning behind its findings.

1.4 Updated Theory of Harm (**ToH**) 1 raises a number of important issues relating to wholesale market rules. We agree with the CMA that differences between self-dispatch and centralised dispatch are relatively minor and are not as substantive as certain third parties may have submitted to the CMA; indeed, in our view self-dispatch may lead to more efficient dispatch decisions. We share the CMA's concerns regarding Ofgem's cash out proposals, and for the reasons set out below in more detail believe that a combination of single cash out price and a move to PAR100, without reserve scarcity pricing (**RSP**), would be better. The CMA is right to highlight the importance of competition in the contracts for difference (**CfD**) allocation mechanism – as evidenced by the outcome of the February 2015 auction – but we do not believe the first two issues raised by the CMA (CfD 'pots' and the transition from renewables obligation (**RO**) certificates (**ROC**s)) will lead to material inefficiencies in practice and we think the third (reserve power to award contracts non-competitively) may be necessary for support to nuclear or innovative technologies.

1.5 The absence of locational charging for congestion and losses is not a problem in practice. The main impact of such price signals would be on renewable generators which have limited scope to respond to them; and without further adjustments to renewables support schemes, locational charging could lead to less efficient investment. We do, however, believe the CMA should investigate whether the current rules for allocation of network charges (transmission network use of system (**TNUoS**) and balancing system use of system (**BSUoS**)) to GB generators could distort trade between the UK and other European Union (**EU**) Member States.

Retail markets

1.6 We agree with the CMA's initial view that supplier behaviour observed in respect of price announcements is likely to be consistent with unilateral incentives.

1.7 Whilst we agree that certain aspects of the framework in which competition operates could be improved, we believe that the market features highlighted by the CMA – notably a degree of customer inactivity and unrealised gains from switching – need to be seen in perspective. There is evidence to suggest that the energy market is similar to many other competitive consumer product and service markets in regard to switching and price dispersion.

1.8 We do not agree with the hypothesis that suppliers have unilateral market power (**UMP**) with regard to customers on standard variable tariffs (**SVT**). In our view the SVT and product tariffs are part of a single market, with customers moving dynamically between them. For example, in ScottishPower's SVT customer base, around half of those paying by credit or direct debit have been on a product within the last two years. We would therefore characterise much of the SVT population as intermittently engaged. The switching decisions of these intermittently engaged customers provide an effective constraint on SVT prices for all customers.

1.9 Competitive conditions in the prepayment segment are different from other payment methods because of technical limitations which largely prevent suppliers from offering product tariffs of the kind offered to credit and direct debit customers. We think that competition could be improved by removing the RMR prohibition on cash-back payments (which were particularly effective in incentivising PPM customers to switch) and, to the extent practicable, by making necessary changes to industry systems so that they can support multiple tariffs, pending the rollout of smart prepayment meters.

1.10 It would be useful for the CMA to consider whether the use of face-to-face sales techniques could play a role in enhancing competition for consumers who are currently hard to reach via online or telephone sales channels, while ensuring appropriate consumer protection. In this context it could be useful to estimate how the consumer detriment from not being reached through these sales techniques weighs against that arising from the inevitable imperfections of these techniques.

1.11 We agree with the CMA that past regulatory interventions have strongly influenced the nature of competition and that they have contributed to some of the perceived problems today. We would encourage the CMA to give serious consideration to relaxing or withdrawing existing rules which have the effect of constraining competition.

1.12 We also agree that competition in the microbusiness market needs reform. It would be desirable to make the market look more like the domestic market (pre SLC25A and RMR), with more competition around prices listed on price comparison websites (**PCWs**) and fewer opportunities for suppliers to block transfer requests (which currently acts as a significant drag on switching and competition).

Industry codes

1.13 Finally, we agree that there is probably scope to improve the operation and efficiency of the industry code governance process, but we would also caution against making any fundamental change without very careful consideration. The industry codes are multilateral, complex, commercial agreements which provide a vital underpinning to transactions in the sector. Changes to the codes can give rise to very large distributional effects and it is important that parties have adequate protections, including from misguided regulatory decisions. The CMA therefore needs to be realistic about what is achievable in terms of changes to the governance process.

2. UPDATED THEORY OF HARM 1

"The market rules and regulatory framework distort competition and lead to inefficiencies in wholesale electricity markets"

2.1 We welcome the CMA's decision to reposition its assessment of ToH1 to focus on the market rules and regulatory framework governing wholesale electricity markets. We have provided our comments on the updated ToH1 under the following headings:

(a) Self-dispatch;

(b) Cash out prices;

(c) Locational pricing; and

(d) CfD allocation.

2.2 In our section on locational pricing we have highlighted a potential market distortion which does not appear to have been considered by the CMA to date, relating to the greater burden of network charges imposed on GB generators than those in neighbouring markets. This has the potential to distort trade between the UK and other EU Member States over electricity interconnectors connecting with the GB market.

(a) *<u>Self-dispatch</u>*

2.3 We agree with the CMA (paragraph 41 of the UIS) that the differences between the GB system of self-dispatch and systems of centralised dispatch used elsewhere in the world are relatively minor. We also agree with the CMA's observations on the key issues relating to self-dispatch:

(i) **Vertical integration:** We agree the CMA (paragraph 37 of the UIS) that in current market conditions a self-dispatch system does not provide significant incentives to vertical integration.

(ii) **Technical efficiency:** We agree with the CMA (paragraph 40 of the UIS) that bilateral trading is leading to close to technically efficient operation of the system.[1] We also agree with National Grid's observation that generators are better able to factor in maintenance costs than the system operator (**SO**) could under a system of centralised dispatch and that self-dispatch may in this sense be more technically efficient.[2] In our experience, self-dispatch may lead to more efficient operation and pricing than centralised dispatch for a number of reasons:

(A) The short and long-term costs of rescheduling plants are better known by the plant operator than the SO (which relies on data provided by the operator). The plant operator understands the capabilities of its plant, the risks to the health and safety of its employees and the risks of incurring costs in the longer term as a result of following particular dispatch schedules; and the format in which plant data is communicated to the SO in the context of the bidding process may not be able to capture the richness of the information.

(B) Different generation technologies need to make dispatch decisions on different lead times. Thermal plant may need a significant warm-up time, while other

1 As discussed by the CMA in more detail in the Wholesale Electricity Market Rules Working Paper, at paragraph 12.
2 As noted by the CMA in the Wholesale Electricity Market Rules Working Paper, at paragraph 17.

technologies may wish to optimise dispatch as close as possible to real time. This flexibility may be more difficult to accommodate in a centralised dispatch system.

(C) Since the introduction of New Electricity Trading Arrangements (**NETA**) / British Electricity Trading and Transmission Arrangements (**BETTA**) we have developed a better understanding of the costs and risks associated with running our plant and this has led us to invest significantly in improving our plant flexibility. This may not have happened without the move to self-dispatch.

We note that an independent generator told the CMA its CCGT plant runs less frequently than less efficient plant owned by some of the large vertically integrated (**VI**) companies, and offered this as evidence of technically inefficient operation.[3] We agree with the CMA that there are a number of legitimate and rational explanations for competitors operating less efficient plant more frequently. These include better cost forecasting, and obligations arising from ancillary service contracts awarded competitively by National Grid.

(iii) **Price transparency:** We agree with the CMA (paragraph 39 of the UIS) that there will be little difference in the transparency of prices available to market participants between centralised dispatch and the GB system of self-dispatch.[4]

(iv) **Transaction costs:** We agree with the CMA that there would not be a significant transaction cost difference between the self-dispatch system in GB and a centralised dispatch alternative.[5] We note that a centralised clearing house exists and that energy is additionally traded (either bilaterally in an OTC market or centrally via exchanges) on a forward basis in both models, so we do not view self-dispatch as inherently leading to greater transaction costs. Indeed, in the self-dispatch model, in contrast to a centrally cleared pool, initial unsupported credit lines have often been provided by ScottishPower to independent suppliers and generators when justified by their creditworthiness, reducing their transaction costs. This arrangement is further supported by obligations imposed on the Six Large Energy Firms under Ofgem's Secure & Promote licence condition to provide both credit and offers to trade on an objective basis.

(v) **Locational pricing:** Notwithstanding the merits or otherwise of further locational pricing such as locational BSUoS or zonal losses (discussed in more detail below), we believe that self-dispatch does not prevent their introduction.

2.4 Some parties have advocated replacing the present self-dispatch system with centralised dispatch on the basis that this would solve perceived problems of market access for non-vertically integrated suppliers and generators, and improve price transparency. As discussed in the CMA's Foreclosure and Liquidity working papers,[6] there is little evidence that independent suppliers and generators suffer significant market access problems and there is therefore no reason to favour centralised dispatch on those grounds.

2.5 Having operated our businesses under both systems prior to and post implementation of the NETA/BETTA trading arrangements, we believe that self-dispatch offers a number of advantages in terms of competition including:

(i) market prices are set efficiently by both generation and demand-side participation rather than solely by generators as was the case under the previous GB pool system;

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3 As discussed by the CMA in more detail in the Wholesale Electricity Market Rules Working Paper, at paragraph 13.

4 Wholesale Electricity Market Rules Working Paper, at paragraph 23.

5 Wholesale Electricity Market Rules Working Paper, at paragraphs 24 to 29.

6 Foreclosure Working Paper (at paragraphs 67 to 100) and Liquidity Working Paper (at paragraphs 44 *et seq*).

(ii) the current system of self-dispatch is less susceptible to abuse of generation market power than the algorithm-based pricing used in the previous GB centralised dispatch system;

(iii) costs arising from poor generator performance or poor demand forecasting are incurred solely by the parties responsible rather than being socialised across all market participants; and

(iv) as noted above (paragraph 2.3(ii)(A)), better information is available to the plant operator.

2.6 We further note that the day-ahead auctions which arise from existing self-dispatch arrangements retain many of the better attributes of the previous centralised dispatch system including transparent day-ahead and half-hourly reference pricing and fair access for all market participants via a centrally cleared counterparty which objectively assesses and manages credit risk. We therefore consider that the existing system of self-dispatch better facilitates efficient competition in GB energy markets, to the benefit of consumers and investors alike, than centralised dispatch systems either previously employed in GB or presently used in some international wholesale electricity markets.

(b) <u>Cash out prices</u>

2.7 We supported Ofgem's decision to a move to a single price for imbalances since, as the CMA has noted (paragraph 42 of the UIS), it will eliminate the inefficient penalty that was previously imposed on companies that find themselves in a 'helpful' imbalance at any given time.

2.8 We also supported the principle of moving to a sharper cash out price but had concerns about the detail of Ofgem's proposals. We felt that a move to PAR1 would be too extreme and could lead to unpredictable prices which were not necessarily reflective of the cost of imbalance. Instead we favoured a phased approach in which the first step is to move to PAR100 or PAR50. This would minimise the transitional cost and risk to participants of adjusting to more volatile market conditions and give them more time to improve their forecasting and balancing performance. It would also provide more evidence on which to base any decision to sharpen the price further.

2.9 Similarly, we felt that Ofgem's proposals to introduce RSP into the cash out price would potentially be too complex and unpredictable. If market participants are uncertain how it will work in practice and how frequently it will kick in, it may take some time for the impact of RSP to be reflected accurately in market prices. This will limit companies' ability to factor it into a business case for investing in new plant. The investment case may also be affected by the risk of incurring large costs should an unplanned outage coincide with a price spike.

2.10 Moves to sharper cash out prices need to be seen in the context of the Capacity Market. We believe that the two are broadly complementary: both provide incentives for efficient investment in generation capacity, and sharper cash out prices would be expected in the long run to reduce the costs of the capacity mechanism (**CM**). However, the Capacity Market is a more effective mechanism for incentivising investment because it removes the risk that investors would otherwise face in relying on a small number of unpredictable spikes in cash out prices. Given that the Capacity Market is now in place, we see less need to push for ever sharper cash out prices. We therefore support the BSC modification proposal P316 Alternative, which will introduce a single cash out price and a move to PAR100.[7]

2.11 The CMA states that it has heard as part of its investigation that a move to PAR1 could lead to concerns about market power if a generator comes to learn that it may be a price-setter in the Balancing Mechanism (**BM**) (paragraph 44 of the UIS). We do not share these particular concerns.

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[7] P316 'Introduction of a single marginal cash-out price' was raised by RWE Supply and Trading on 4 November 2014. It proposes to progress only the reductions in the PAR and RPAR values and the move to a single imbalance price aspects of P305. See https://www.elexon.co.uk/mod-proposal/p316/.

We agree with National Grid's view[8] that the current balancing and dispatch system is efficient and is likely to be more efficient overall than a system where National Grid (or some other entity acting as a SO) conducted all the balancing and dispatch itself. Moreover, generators may be reluctant to offer energy at a high price during extreme spiky periods out of concern about negative media and political reaction or for fear of investigation for market abuse.

2.12 Finally, the CMA raises the concern that introduction of RSP at the same time as the Capacity Market may lead to an over-compensation of generators (paragraph 45 of the UIS). We agree that this could be an issue, at least in the short to medium term. As noted above, until generators have gained experience of changes to the cash out regime and market prices have adjusted accordingly, it is unlikely that Ofgem's proposed changes would be reflected in CM bids. The risk of overcompensation would be removed if the P316 Alternative proposal is adopted (which we would support), since it does not involve RSP.

(c) *Locational pricing*

2.13 The UIS questions whether the absence of locational price signals for constraints and losses may affect competition in wholesale electricity markets (paragraph 46). The locational pricing working paper also considers the merits of nodal pricing. We comment on these issues below, together with a fourth issue, the distortion of trade between UK and other EU Member States caused by differences in the way that network charges are allocated to generators.

Locational constraint charges

2.14 Although transmission congestion costs are not recovered on a locational basis, transmission investment costs (i.e. TNUoS) do vary locationally, and the relationship between them is such that introducing a locational element for both could result in double-charging. TNUoS charges are designed to recover the costs of network investment, and the TNUoS charge levied on generation in each geographic zone is intended to reflect the incremental impact on the network of accommodating an extra kW of generation capacity within that zone. TNUoS charges reflect the efficient investment cost, not the cost actually incurred. So if additional generation capacity connects in a zone and there is a delay in reinforcing the network, TNUoS charges will not be reduced on account of the delay. Instead, there will be an increase in transmission congestion costs until the network investment takes place.[9] Given that generators in the zone are already paying TNUoS charges that reflect the cost of reinforcement, it would be unfair to target them with the congestion costs that result from a delay in that reinforcement.

2.15 It would also be unfair on investors to change the rules for existing generation capacity, given the clear policy background to this issue in the form of DECC's Connect and Manage initiative. Connect and Manage was introduced in 2009 using powers under the Energy Act 2008 because access to the transmission network was considered a major barrier to new renewable and other generation. Connect and Manage made it possible for generators to get network connections in advance of upstream reinforcements to the transmission network, at the cost of increased constraint costs (recovered via BSUoS charges). It was considered necessary to socialise the constraint costs caused by Connect and Manage since otherwise there would have been insufficient incentive to invest. At the time of its introduction DECC considered carefully whether fixing the socialisation of all constraint costs, rather than simply those due to Connect and Manage, was justifiable, and considered it was. DECC believed it would not be possible to come up with an objective way of isolating constraint costs which were due only to Connect and Manage from costs arising from other factors, and that attempting to create such a division would have been confusing.[10]

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8 See https://assets.digital.cabinet-office.gov.uk/media/5477006240f0b60244000001/Summary_of_hearing_with_National_Grid.pdf.
9 The business case for new network investment is based in large part on the NPV of transmission congestion charges that will be avoided.
10 See https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42979/251-govt-response-grid-access.pdf, at page 11.

2.16 A large volume of renewable generation investment has now been made on the back of the Connect and Manage regime. It would clearly be inequitable to change the rules on which investors made their decisions to deploy this generation – and there would be no efficiency gain from exposing this generation to a locational price signal. If any change is to be made to the charging of constraint costs, it would need to be restricted to new generation, which may then require a higher level of subsidy than would otherwise have been the case. Although it may be desirable in principle to remove 'hidden subsidies', we believe that without further changes to the renewable support regime, introduction of locational BSUoS charges could lead to poor policy outcomes.

2.17 For example, one important effect of locational constraint charges would be to improve the business case for solar photovoltaic conversion (**PV**) generation (which is predominantly located in England) at the expense of onshore wind (which is predominantly located in Scotland). The current CfD support scheme takes no account of the fact that onshore wind is considered to make a contribution to generation at times of peak winter demand[11] whereas solar PV contributes virtually nothing at these times. This means that additional onshore wind capacity would be expected to reduce the amount of capacity that needs to be procured through CM auctions, thereby reducing the cost of the CM – whereas no such benefit would arise from solar PV. It is also possible that increasing volumes of solar PV will cause summer midday wholesale prices to fall, as has happened in other European markets. Under the current CfD mechanism, solar PV would continue to receive the same strike price, resulting in higher levels of subsidy, and insulating investors from that wholesale price signal. It would be inefficient to correct any perceived distortion due to constraint prices without also correcting these distortions in the support regime.

2.18 It should also be noted that the 'overselling' of access rights resulting from Connect and Manage has allowed a significant strengthening of competition in the GB power market by allowing generators behind constraints to compete in the market on an equal footing. Locational BSUoS could lead to more volatile and unpredictable costs, leading to less keen competition and therefore higher wholesale prices for consumers. Indeed, it could cause plant to close prematurely rather than undertake capital investment, including nuclear plant life extensions.

2.19 ScottishPower has always believed that efficient reinforcement of the transmission network is the best response to the high constraint costs anywhere in the GB market since it eliminates the problem at source. Ofgem's methodology for assessing whether to proceed with network enhancements is not affected by the allocation of constraint costs between the parties.

Locational losses

2.20 As explained in the Locational Pricing working paper (paragraph 16), the introduction of zonal charges for transmission losses was the subject of a BSC proposal (P229) which was ultimately rejected by Ofgem on the grounds of the "*relatively modest scale and uncertainty of expected efficiency benefits*" and the much larger and more certain distributional impacts.[12]

2.21 We believe that similar practical considerations apply today. As with locational constraint charges, zonal charging for transmission losses would penalise generators in Scotland and the north of England and favour those in the south while efficiency savings would be realised only where generators change their investment or dispatch decisions in response to the zonal price signal. In practice, the investment decisions that are most likely to be affected by a move to zonal charging relate to renewables generation (e.g. whether to invest in onshore wind or solar PV generation

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11 In its 2014 Electricity Capacity Assessment report, Ofgem introduced the concept of the Equivalent Firm Capacity (**EFC**) of wind, which is the average contribution of wind power to the de-rated capacity margin, i.e. the quantity of firm capacity (capacity that is always available) required to replace the wind generation in the system to give the same level of security of supply, as measured by Loss of Load Equivalent (**LOLE**). Recent modelling by Aurora assumed that the EFC for total wind (onshore and offshore) declines with increasing wind penetration **[CONFIDENTIAL]**.

12 Previous work demonstrated that transmission losses could be expected to reduce by an average of 211GWh, which represented a £9.1 million (2011) saving per year.

capacity). However, given that onshore wind is zero marginal cost, the introduction of zonal charges is unlikely to affect dispatch decisions and therefore is unlikely to result in efficiency savings. Moreover, as noted above, it would be inefficient to introduce zonal charges for losses without first removing distortions from the CfD support regime.

2.22 In summary, if there is any adverse impact on efficiency or competition from not having zonal charges for losses, it is likely to be very modest and insufficient to justify the large distributional impacts that would arise were zonal charging for losses to be introduced.

Nodal pricing

2.23 The Locational Pricing working paper refers to other markets which have adopted nodal pricing (also known as locational marginal pricing). Although nodal pricing is reported to have worked well in a number of US markets, we do not believe that there is a case for introducing it in the GB market. The current GB market arrangements provide efficient signals for network investment, network connection and dispatch decisions – and, as noted above, there is no evidence that absence of locational pricing of constraints and losses has an adverse effect on competition or efficiency. Conversely, there is a risk that nodal pricing could reduce liquidity at each node, reducing the efficiency with which suppliers are able to hedge their positions. Substantial reinforcement is being undertaken within GB with a view to mitigating the current transmission constraints.

2.24 Looking to the future, the EC's Capacity Allocation and Congestion Management (**CACM**) Network Code will provide Ofgem with the ability to launch a review to consider whether GB has the appropriate configuration of zones in the electricity market. Such reviews will need to consider whether any constraints identified are enduring in nature and in this context the considerable transmission reinforcement under construction between Scotland and England may be relevant. Should the case for more zonal pricing change, we believe that this would be the most appropriate mechanism for developing and introducing such reforms.

International differences in charges

2.25 The UIS makes no mention of the distortion of competition that may result from differences in network charges applied to generators in GB and other European countries. With the expected growth in interconnector capacity it will be important to ensure that in so far as possible there is a level playing field between GB and foreign generators.

2.26 GB generators currently face charges for the use of the transmission system (TNUoS and BSUoS) which amount to around £3.75/MWh on average.[13] This amounts to 8.5% of the average annual power price of around £44/MWh, as shown in **Table 1** below:

Table 1: Network charges imposed on generators in GB

Charge	£/MWh	% of power price
TNUoS (generation share)	£1.92	4.4%
BSUoS (generation share)	£1.83	4.2%
Total	**£3.75**	**8.5%**
Average wholesale power price	£44.00	100%

Source: ScottishPower estimates

2.27 In contrast, interconnectors terminating in GB do not incur any TNUoS or BSUoS charges with respect to the GB transmission network, and the equivalent charges faced by generators in other

[13] The TNUoS element varies widely with location.

European countries are typically lower than in GB because a greater share of the cost is allocated to load (i.e. the supply-side of the market) rather than to generation, as shown in **Table 2** below:

Table 2: Sharing of network operator charges in different EU countries

	Sharing of network operator charges	
	Generation	**Load**
Great Britain		
TNUoS	≤ 27%*	≥ 73%
BSUoS	50%	50%
Aggregate (2015/16)	31%	69%
Northern Ireland	25%	75%
Ireland	25%	75%
Belgium	7%	93%
France	2%	98%
Netherlands	0%	100%
Germany	0%	100%
Norway	38%	62%

*The TNUoS charge on generators is subject to a cap of €2.50/MWh under EU Regulation 838/2010 Part B. The generator share was 27% in 2014/15 and earlier years but the cap will result in a 23.2% share in 2015/16. The aggregate figure is based on the 2015/16 share.

Source: ENTSO-E,[14] GB aggregate value estimated by ScottishPower

2.28 If generators seeking to export into the GB market face lower transmission charges, this puts GB generators at a significant disadvantage both against imports and when seeking to export. Other GB levies on generators such as the Carbon Price Floor put thermal generators at an additional disadvantage.

2.29 In an attempt to mitigate these distortions, National Grid raised a Connection and Use of System Code (**CUSC**) modification proposal (CMP201) to move away from splitting the BSUoS charge 50:50 between generators and suppliers to a position where suppliers would pay all charges. This would have more closely aligned GB charging with the prevalent approach in the rest of the EU. However, Ofgem rejected CMP201 following a consultation on its 'minded-to' position in November 2013, justifying its decision on the basis that if GB generators were better able to export to Europe, this could result in GB consumers paying more:

> "*Under the proposal, suppliers would pay the full BSUoS charge and generators would then be able to offer a lower, more competitive wholesale price to the market. Since BSUoS charges are ultimately passed through to the consumer (whether suppliers or generators pay them), this change of itself should have no impact on consumers. However, the consumers are affected. Due to effects on the supply of electricity in GB, the decrease in GB wholesale price is not equivalent to the reduction in generators' costs associated with the removal of BSUoS charges. Specifically, the reduction in a generators wholesale price increases demand from Europe and this in turn increases net export from GB to Europe across the interconnectors. In response to the increased demand for GB generation, more expensive marginal (carbon) generators will switch on to meet total demand – ultimately increasing the GB wholesale price*".[15]

[14] See https://www.entsoe.eu/publications/market-reports/Documents/SYNTHESIS_2014_Final_140703.pdf.
[15] See https://www.ofgem.gov.uk/ofgem-publications/84353/impactassessmentbsuos081113.pdf, at page 4.

2.30 In our response to Ofgem's consultation we said we thought it was wrong, as a matter of principle, to consider that maintaining a distortion to competition (charging BSUoS to GB but not overseas generators) could lead in the long term to an improvement in welfare or efficiency. Subsidising imports (or charging extra on exports) would lead at the margin to inefficient levels of investment that are unlikely to benefit consumers. Accordingly, any benefit to consumers from creating artificial over-supply by taxing exports or subsidising imports is likely to be short-lived and counterbalanced by disadvantages elsewhere in the economy.[16]

2.31 Finally, in the context of increasing interconnection we would highlight the potential conflicts of interest arising from:

(i) National Grid's role as an investor in interconnection, in which it promotes, develops and takes a stake in new interconnector projects; as against

(ii) National Grid's various market administration and coordination roles, including:

- System Operator, where as a monopsonist buyer of balancing services it awards contracts to service providers including generators, interconnector operators and demand-side participants; and

- Capacity Market Administrator, where it operates the auction to award CM contracts to generators, interconnector operators and demand-side participants.

2.32 We would encourage the CMA to include the above 'level playing field' and National Grid conflict of interest considerations within the scope of its ToH1 investigation.

(d) *CfD allocation*

2.33 The UIS raises a concern that a lack of competition in the CfD allocation mechanism may mean that CfDs are not allocated to the most efficient projects or at least cost to energy consumers (paragraph 64 of the UIS). Specifically, the CMA's concerns are that: (i) dividing the CfD budget into three separate pots runs the risk that projects from one pot may be displaced by more expensive projects from another (paragraph 59 of the UIS); (ii) the ability of CfD bidders to seek support under ROCs until March 2017 risks placing a floor on bids for CfDs (paragraph 59 of the UIS); and (iii) that if the CfDs are awarded on a non-competitive basis in future (as was done under the Final Investment Decision enabling for Renewables), this could unduly raise prices for consumers (paragraph 60 of the UIS).

2.34 While we note the CMA's concerns, we believe that on balance the policy decisions taken by DECC in this regard are broadly sensible. The enduring CfD process is intended to award contracts on a competitive basis, and the outcome of the first auction has already shown how this can help drive down the cost of renewable generation – particularly for offshore wind where CfD contracts were awarded at 18% below the administratively set strike price.

2.35 Dividing the CfD budget into pots recognises that technologies differ in their levels of maturity and cost and a mix of technologies is required to meet the renewable energy targets. In this respect, the CMA noted in its Capacity Working Paper that:

> "*DECC's rationale for dividing the budget into separate pots is to protect less established technologies from competition with more established technologies, in order to help them to develop to the point where they can compete with the more established technologies. DECC considers there are dynamic efficiency benefits*

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[16] ENTSO-E Overview of transmission tariffs in Europe: Synthesis 2014, July 2014, available at https://www.ofgem.gov.uk/ofgem-publications/87143/140116cmp201spresponse.pdf.

from protecting less established technologies, as it could enable them to become more efficient over time, to the point where they can compete with established technologies".[17]

2.36 We agree with this rationale and in particular believe that a technology neutral auction at this stage could prevent technologies such as offshore wind being able to effectively compete (both now and in the longer term) and therefore risk delivery of the longer term decarbonisation and broader economic contributions that these technologies can make. Also, without separate pots it could be difficult to get competitive tension among the more established technologies.

2.37 We think the CfD/RO transitional arrangements have served a useful purpose in maintaining the flow of investment into onshore wind, some of which might otherwise have stalled. Looking forward, we think there is limited risk that the option to apply for RO support will place a floor on CfD bids. In the February 2015 CfD auction both onshore and offshore wind projects cleared at a price below the administered strike price, which DECC had set with a view to delivering broad RO equivalence. Furthermore, projects bidding in the next CfD auction (scheduled for October 2015) will have even less time to get up and running by March 2017, limiting the number of projects for which the RO option would be available.

2.38 The reserve power for the Secretary of State to award future contracts on a non-competitive basis may be needed for the purpose of supporting future nuclear projects, or indeed any new technology that needs support to allow it to develop to a point where it can compete. However, we agree that it would undesirable for it to be used in segments where competition has already been used.

3. UPDATED THEORY OF HARM 2

"Market power in generation leads to higher prices"

(a) *Unilateral Market Power*

3.1 The UIS concludes (at paragraph 74) that it does not appear likely, overall, that firms have the ability and incentive to increase profits by withdrawing capacity in generation, through the exercise of either UMP or coordinated market power. We agree with this conclusion and the reasoning behind it.

(b) *Wholesale gas*

3.2 We agree with the CMA's assessment in its Statement of Issues dated 24 July 2014 (**IS**, at paragraph 62) and subsequently in the UIS (paragraph 75) of the GB wholesale gas market. In our view, key characteristics of the wholesale gas market include:

(i) **Low concentration in production:** We note that there is limited concentration in North Sea gas production though we agree with the CMA's initial analysis (paragraph 76 of the UIS) that Statoil may find itself in a position of having UMP. However, we also agree that there is likely to be limited incentive for Statoil to withhold volumes during periods of peak demand (and therefore price) and agree that it would be self-defeating as higher prices would attract competing supplies across interconnectors, from storage operators, from LNG supplies and from demand-side response.

(ii) **Strong interconnection to European and global markets:** The GB wholesale gas market is connected to other European hubs by interconnecting pipelines and to the global gas

17 Capacity Working Paper, at paragraph 69.

market via LNG re-gasification terminals. The extent of these connections is such that in our opinion no individual producer would have the ability or incentive to foreclose suppliers.

(iii) **Competition in storage:** Whilst in our opinion there is market power in the gas storage market resulting from high concentration of ownership, particularly of the Rough and Hornsea facilities, we recognise that there is little scope for abuse of this market power due to regulatory conditions imposed on these operators, which ensure that they are commercially operated at arm's length from their affiliated downstream supply activities.

(iv) **Strong regulatory powers:** We note the strong disincentive for market abuse in the GB wholesale gas market, particularly resulting from the EU-wide REMIT regulation, its penalty regime operated in GB by Ofgem which facilitates imposition of deterrent penalties and restitution orders on organisations and individuals, and the recently introduced criminal sanctions.

(c) *ROCE analysis*

3.3 The CMA found that the pattern of returns from the generation businesses of the Six Large Energy Firms for the period 2009 to 2013 was mixed, with the main technologies all making a ROCE that was in line with or below the firms' cost of capital (paragraph 70 of the UIS). This finding accords with our experience.

3.4 We agree with the CMA's conclusion (paragraph 106 of the Generation Profitability Working Paper) that ScottishPower's CCGT ROCE is similar on the replacement cost and 'MEA I' (like-for-like) bases, and that in both cases average returns are "*relatively low*" over the period.

3.5 We also agree with the CMA's view that ROCE estimates for ScottishPower's hydroelectric and pumped storage facilities based on carrying values are unlikely to provide a reliable view of economic returns, given that these facilities were constructed between the 1920s and the 1960s and have very long asset lives.[18]

3.6 The historic ROCE for ScottishPower's Renewables business for the period 2007 to 2013 is just over **[CONFIDENTIAL]**%. We would note that it is difficult to draw conclusions for future returns based on these historic rates of return for the following reasons.

(i) Over the period 2007 to 2013, wind generation developed considerably in terms of scale of deployment, technology advancement and operational management. ScottishPower has been one of the leading investors in onshore wind and more recently commissioned its first offshore wind farm, West of Duddon Sands. The technology trajectory, as well as operational experience, has resulted in ROCE evolving over time.

(ii) During this period, support in the form of the RO has stimulated investment. However the support mechanism is transitioning from 2014 to CfDs, with the RO closing from 31 March 2017. In the first round of competitive CfD auctions, clearing prices were significantly lower than they would have been without competition (by up to 17% for onshore wind and up to 18% for offshore wind)[19] and the design of the mechanism is meant to lower revenue risk, leading to a lower cost of capital and lower returns. Future returns will be influenced by the ability of renewable generation, particularly offshore wind, to reduce costs and maintain competitiveness with other low carbon forms of generation.

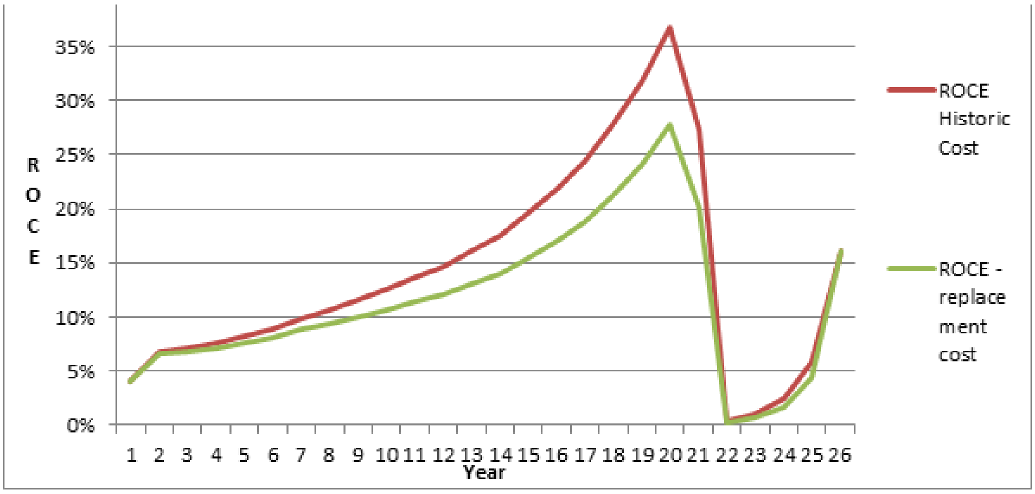
(iii) We do not consider that ROCE is an effective metric for considering returns for future projects. Analysing investment in renewable assets which are characterised by considerable

18 Generation Profitability working paper, at paragraph 89.
19 See https://www.gov.uk/government/news/world-leading-auctions-to-provide-major-green-electricity-boost.

upfront capital and long asset lives, with no regular reinvestment, gives a distorted picture of ROCE over time. Initially, when the investment is first made, a low ROCE (below the target return rate) of around 4-6% is expected. Over time the ROCE increases as the assets are depreciated. Consequently the ROCE at a selected point in the life of a project or asset will be reflective of the returns given the underlying asset value, rather than the return of the project (or portfolio).

3.7 By way of illustration, **Figure 1** shows a typical ROCE profile for a ROC project earning an IRR of c.10% over a 25 year asset life.

Figure 1: Illustrative ROCE trend for ROC project



Source: ScottishPower analysis

3.8 In analysing the return from a project, or a portfolio of projects, we believe the IRR is the best metric to use. ScottishPower Renewables' business plan estimates for the IRR of future projects are based on a range of inputs (e.g. electricity price forecast, average capital cost, operating costs, availability), and are in the range **[CONFIDENTIAL]**% post tax nominal. As mentioned above, these anticipated future returns are heavily influenced by ScottishPower's ability to drive down costs and maintain competitiveness against other low carbon forms of generation.

4. UPDATED THEORY OF HARM 3

4.1 We broadly agree with the CMA's assessment of the benefits of vertical integration, and the fact that the benefits are likely to apply to a different extent to different firms. As set out below, we also agree with the CMA's assessment of the two theories of harm relating to vertical integration.

(a) *ToH 3a – Liquidity*

"Opaque prices and low liquidity in wholesale electricity markets distort competition in retail and generation"

4.2 We agree with the UIS (paragraph 100) that current levels of liquidity appear to be sufficient to allow independent suppliers and generators to trade and hedge in the same way as the Six Large Energy Firms and that a lack of liquidity does not therefore seem to be distorting competition or acting as a barrier to entry or expansion.

4.3 ScottishPower further notes that since the introduction of the Secure & Promote licence obligation, market prices are available at regulated bid-offer spreads in baseload and peakload products for periods up to two and a half years ahead of delivery, every business day. Day-ahead auctions operated by exchanges provide the same ability to all market participants to refine any shaping requirements into half-hourly granularity. We consider that a liquid and transparent forward market exists, where non-VI firms can agree credit terms and transact trades in the sizes, durations and shapes required, on reasonable terms, either bilaterally or via exchanges.

4.4 The CMA cites an independent generator's view that the lack of shape trading until close to delivery is because it is inconvenient for generators to trade non-standard products, and because suppliers' demand becomes more predictable closer to delivery.[20] We agree with this and would also note that suppliers are likely to be unwilling to do any hedging beyond a certain timeframe because customers on variable priced tariffs (and stakeholders on their behalf) expect reductions in wholesale costs to be passed on without delay, incentivising shorter-dated hedging strategies. Generators are also unwilling to trade beyond the point at which they can hedge their input costs.

(b) *ToH 3b – Foreclosure*

"Vertically integrated electricity companies act to harm the competitive position of non-integrated energy suppliers or reducing the sales of non-integrated generating companies"

4.5 We agree with the CMA's initial view (paragraph 103 of the UIS) – and the reasoning behind it – that vertically integrated firms do not have the ability to engage in customer foreclosure (either acting unilaterally or through coordination) or that they would have an incentive to do so. We also agree with the CMA's view (paragraph 107 of the UIS) that it is unlikely that vertically integrated firms have the ability and incentive to engage in input foreclosure.

4.6 We note the concerns expressed by Drax in its response to IS regarding the buyer power of VI suppliers in the market for ROCs. We agree with the CMA that the RO headroom mechanism, if working correctly, should be expected to limit the ability of a VI firm to foreclose an independent generator in such circumstances.[21]

4.7 The CMA argues that suppliers have an incentive to delay purchasing ROCs until the end of the obligation period because they can then take advantage of any falls in the price of ROCs in the knowledge that they will have to pay no more than the (fixed) buy-out price.[22] Deferred purchases may occur if DECC forecast electricity demand or renewable generation incorrectly in setting the headroom mechanism, such that not all ROCs that are produced are needed to achieve compliance. Where such a risk is evident to suppliers, they may defer purchases, but it seems likely that any downward pressure on prices would be a reflection of supply and demand. Furthermore, it is unclear that this would have a detrimental impact on efficiency or on competition. The ROCE for RO-supported wind appears to have been sufficient to deliver investment, and all suppliers should be able to benefit from the lower price.

4.8 We do not believe the scenario outlined by the CMA in which suppliers reduce the scarcity of ROCs is plausible.[23] If a supplier chose to pay the buy-out price instead of buying ROCs and succeeded in driving down the price of ROCs, this would deliver a cost saving to its competitors who did buy ROCs, but would not reduce the supplier's buy-out costs. We cannot see how a supplier would have an incentive to act in this way unilaterally. At an empirical level, when the headroom mechanism is set correctly, we observe that available ROCs are redeemed; if headroom is set too low, generators and suppliers tend to hold the excess ROCs over to the following year. We have not observed suppliers paying the buy-out in order to depress demand for ROCs.

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20 Liquidity Working Paper, at paragraph 40.
21 Foreclosure Working Paper, at paragraph 43.
22 Capacity Working Paper, Appendix A, at paragraph 6.
23 Capacity Working Paper, Appendix A, at paragraphs 13 to 17.

5. UPDATED THEORY OF HARM 4

"Energy suppliers face weak incentives to compete on price and non-price factors in retail markets, due in particular to inactive customers, supplier behaviour and/or regulatory interventions."

Observations on the nature of competition in domestic retail energy markets

5.1 We agree with the CMA's provisional findings that there are aspects of the retail energy market which could be improved – in particular where regulatory interventions have had the effect of dampening competition – and as one of the smallest of the six large suppliers, we would welcome changes that make it easier for us to compete for our rivals' customers. However, it is important to keep the extent of any problems in perspective.

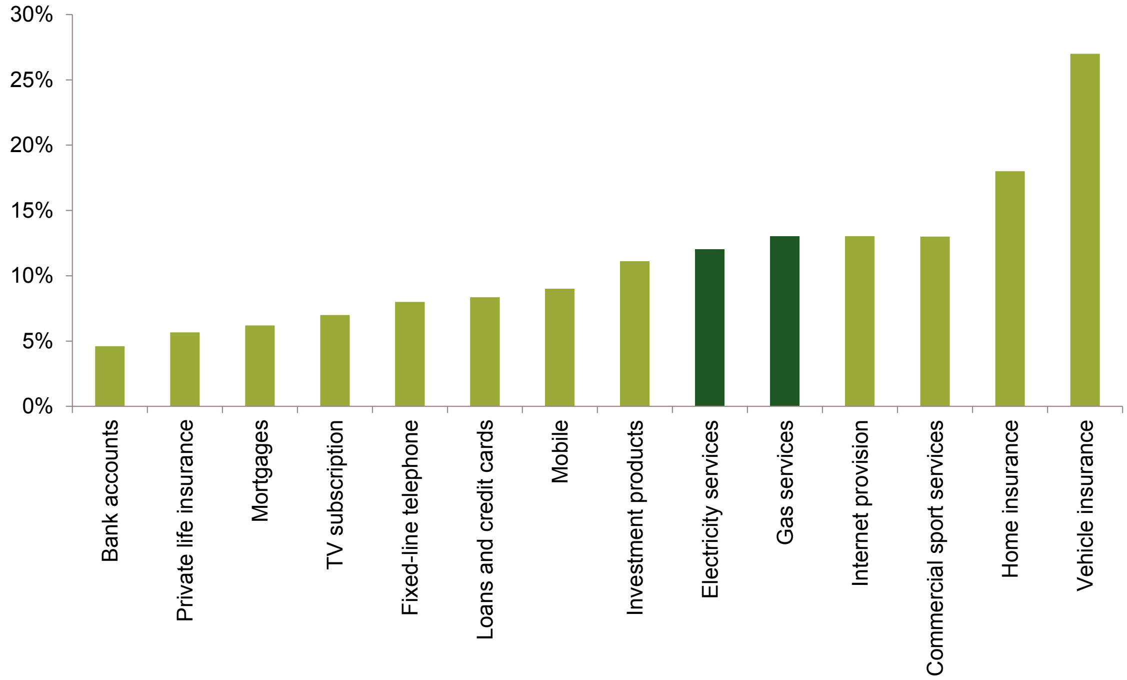
5.2 One of the main findings (paragraph 133 of the UIS) is that there are a significant number of domestic energy customers who are 'relatively inactive' - based on the 'gains from switching' analysis and on the GfK survey results. We discuss below why we consider the CMA may have overstated this given that a significant number of customers are intermittently engaged (paragraph 5.12). In any event, many of the characteristics highlighted by the CMA – customer inactivity, unrealised gains from switching, price dispersion etc – are observed to a greater or lesser extent in other competitive markets. In assessing the evidence for any adverse effects on competition it will be important for the CMA to consider how the GB domestic energy market compares with other domestic retail markets in the UK and with domestic energy markets in other countries.

(a) *Comparison with other UK sectors and countries*

5.3 As noted in our response to the IS (paragraph 3.48), energy market switching rates in GB compare favourably to those in other sectors of the economy. Results of a cross-sectional comparison are shown in **Figure 2** below. This shows that external switching rates in energy are similar to those in investment products and internet provision and are higher than those in fixed-line telecoms, mobile and a number of financial products.[24] When internal switching is included, total annual switching rates in gas and electricity are 19% and 16% respectively.

[24] ScottishPower notes that vehicle insurance represents a high outlier and this is likely to be a result of features particular to this market such as the fact that vehicle insurance is usually purchased for a one-year term (see CMA, private motor insurance market investigation, 24 September 2014, at paragraph 2.5), and high price dispersion relating to the target risk profiles of individual insurance providers.

Figure 2: GB energy retail external switching rates compared with other sectors of UK economy (one year switching rate 2013)

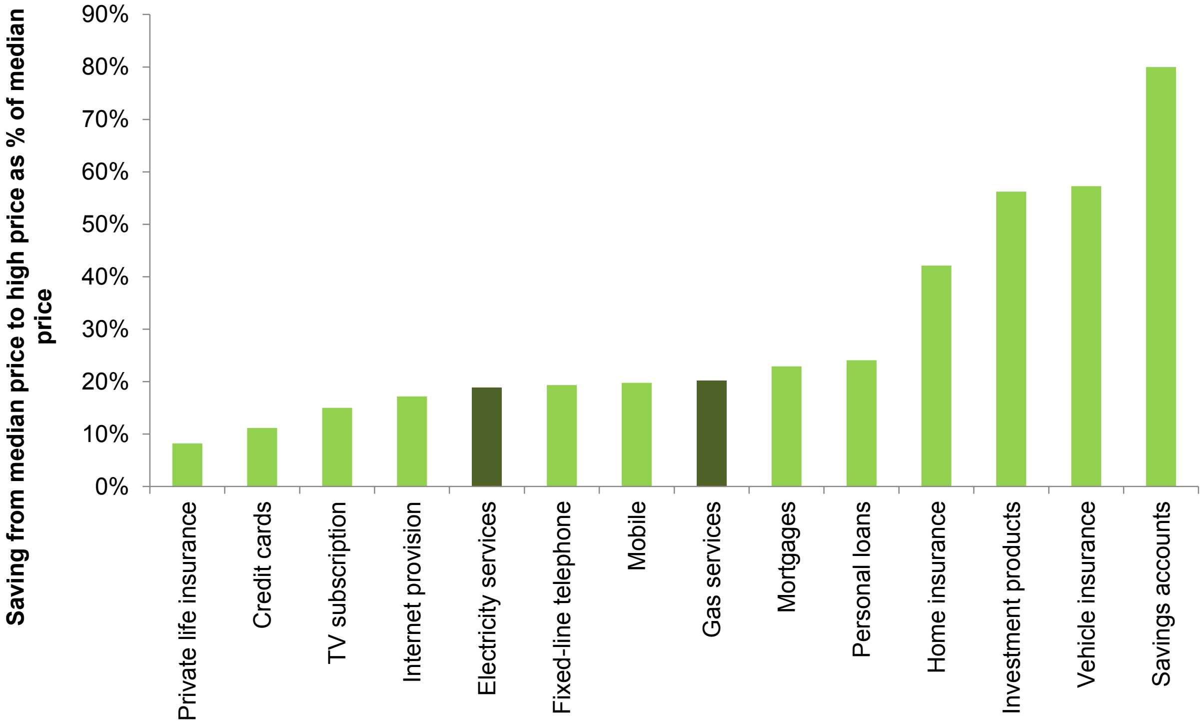


Source: Based on EU data[25]

5.4 Similarly, levels of price dispersion (i.e. the range of different prices charged to consumers for a similar product) appear to be lower in energy than in many other domestic markets. **Figure 3** shows the results of analysis carried out by Oxera for ScottishPower in January 2015 looking at the range of prices quoted for representative products in different markets. The chart shows levels of dispersion defined as the percentage saving that can be realised by moving from the median price to the best price. Further details of the results and methodology are provided in **Annex 1**.

[25] Source is the EU Consumer Market Monitoring Survey (2010) and relates to 2013 UK data. While the project commenced in 2010, data is updated on an annual basis and 2013 represents the latest year available at the time of writing. Percentage is the proportion of respondents answering 'Yes – supplier' to the question 'Have you switched tariff plan or supplier in the past period?' (available at http://ec.europa.eu/consumers/archive/consumer_research/dashboard_part3_en.htm). 'Investment products' includes personal pensions and 'Commercial Sport Services' are defined as membership products such as gyms or sports clubs.

Figure 3: GB energy price dispersion compared with other products markets in the UK



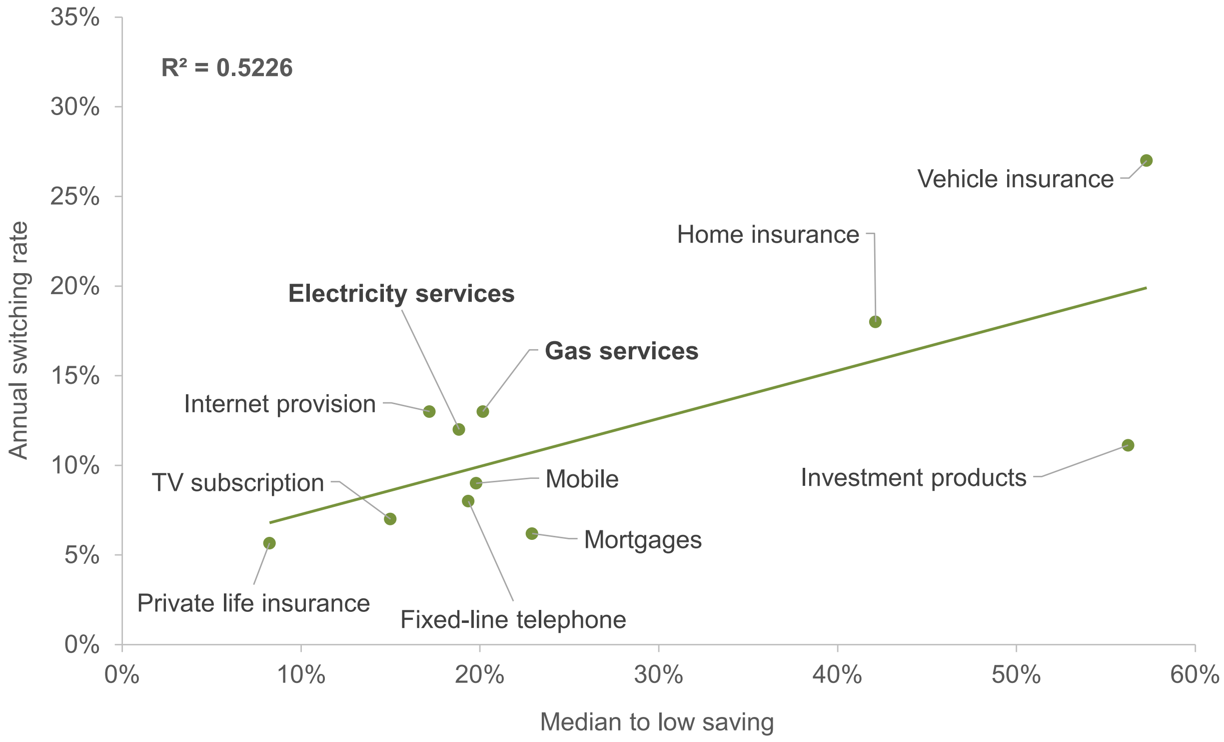
Source: Oxera analysis (see Annex 1)

5.5 The level of dispersion in electricity and gas (19% and 20% respectively) is around the median of the set of markets surveyed and very close to that observed in fixed line telecoms, mobile and mortgages.[26] Indeed, the prices for other products only include actively-marketed (not legacy) products and renewals, so the dispersion in prices actually paid by customers for these products may well be higher.

5.6 The level of switching in a market is likely to be driven (amongst other things) by the level of available savings – and the equilibrium level of price dispersion may in turn be influenced by the amount of saving that consumers require in order to incentivise them to switch. The correlation between switching and price dispersion is illustrated in **Figure 4**, based on the external switching and price dispersion data presented in **Figure 2** and **Figure 3**. Other factors such as the perceived cost of switching would also be expected to affect switching rates and this may explain some of the variability.

[26] The group of former energy regulators make a similar observation in their response to the UIS: "*A cursory review of internet sources today suggests that average savings from switching home insurance and motor insurance lie in similar ranges* [to energy]. *In broadband and pay TV the lowest prices (sometimes including introductory offers) represent an even greater discount on the higher prices. In the mortgage market, average standard variable rates are presently about 4.5% whereas five-year fixed rates are about 2.5% and two-year fixed rates below 2%*", Stephen Littlechild and others response to updated issues statement, 24 February 2015, at paragraph 20.

Figure 4: Comparison of price dispersion and annual external switching rates for different sectors of UK economy (excluding bank accounts)[27]



Source: Based on EU data for switching and Oxera analysis (see Annex 1)

5.7 Finally, as noted in our response to the IS (paragraph 3.47), domestic energy switching rates in GB also compare favourably to other countries. In particular, GB has a higher switching rate in electricity than any other EU market (among those for which data are available), and the third highest in gas.

5.8 In summary, whilst there are areas in which competition in the energy market could be improved, we consider that there is strong evidence that two key characteristics of the GB energy market - customer switching and price dispersion - are very similar to those observed in other competitive markets. It is less easy to obtain comparative data on customer inactivity and unrealised gains from switching, but we would expect those quantities to be correlated with switching and price dispersion and therefore similar to other markets too. It will be difficult for the CMA to conclude that energy customers are 'relatively inactive' (paragraph 133 of the UIS) without reference to comparators such as these.

(b) *Cost pass-through and 'rockets and feathers'*

5.9 The CMA has stated that it intends to develop its analysis of cost pass-through in the next phase of the investigation and assess whether the 'rockets and feathers' hypothesis applies in practice (paragraph 127 of the UIS). We have set out our detailed comments on the CMA's cost pass-through working paper in **Annex 2**, supplemented by an updated report by Oxera in **Annex 3** on the Ofgem evidence for rockets and feathers.

5.10 The UIS acknowledges the influence of regulatory change in the competitive dynamics of the GB energy market (paragraphs 117 to 121), and as we explain in **Annex 2**, it is important to take

[27] Bank accounts are excluded from this analysis because the switching rate relates to current as well as savings accounts, whereas price dispersion relates solely to savings accounts.

regulatory changes into account (e.g. structural breaks) when analysing cost pass-through. We also welcome the CMA's intention to carry out a quantitative analysis, and suggest that the conclusions drawn from it should take precedence over the ones extracted from the qualitative analysis conducted so far.

5.11 As set out in **Annex 2**, we believe it is important, contrary to the CMA's current intention, that cost pass-through is not analysed separately for SVT and for non-standard tariffs. Rather, we consider that the relationship between both tariff prices should be taken into account, as they represent a single market (and not two different markets). We explain why, in our experience, there is a single tariff market in our comments on UMP over SVT customers below (paragraph 5.23 *et seq.*).

ToH 4 - Inactive customers

5.12 The CMA's initial view (paragraph 133 of the UIS) is that there are a significant number of domestic energy customers who are 'relatively inactive'. As noted above, this is based on the 'gains from switching' analysis and on the GfK survey results. We believe that the CMA has overstated the position, and that the percentage of customers who are unengaged is considerably lower than suggested by the CMA, once intermittently engaged customers are taken into account.

(c) *Activity of energy market customers compared to other competitive markets*

5.13 It is a feature of most competitive markets that customers vary widely in their degree of engagement. Such markets usually include some actively engaged customers who switch frequently, both internally and externally, some disengaged customers who very rarely switch and a variety in between. Active switchers provide a competitive constraint on the prices paid by inactive customers, but inactive customers still pay more than switchers, otherwise there would be no incentive to switch.

5.14 In assessing the extent of any problems with competition in the GB energy retail market, it will, as we explain above, be relevant for the CMA to determine whether energy customers are 'relatively inactive' compared to other product or service markets in the UK and compared to comparable energy markets in other countries. The evidence presented above (paragraphs 5.3 to 5.8) suggests that switching rates in the GB energy market compare favourably with switching rates in other domestic markets and with energy switching in other countries. The level of price dispersion in energy is also similar to that observed in other domestic retail markets. We recognise that these are high level measures which may not reflect the fine detail of customer activity (for example the extent to which there is polarisation between different groups of customers) and we welcome the CMA's intention to investigate this further.

(d) *Gains from switching data*

5.15 The CMA cites the results of its gains from switching analysis as evidence that a large proportion of customers are failing to take advantage of relatively significant savings opportunities from switching. These results will provide an important contribution towards developing a better understanding of why different categories of customer may or may not switch, and we would offer two suggestions as to how the results could be made more useful:

(i) Neither scenario 3b nor scenario 4[28] exactly captures the gains from switching between SVT and products. S3b includes switching between SVT and discounted variable products (which were the main focus of competition prior to RMR) but does not include switching from SVT to fixed price products (which have been the major focus of competition post RMR). S4 includes all SVT to product switches, but also includes payment method

[28] Analysis of the Potential Gains from Switching Working Paper, at page 7.

switching. While the option of switching from SVT to a product would be available to most (non-prepayment) customers, there are good reasons why many customers paying by credit might not have been able or willing to switch to paying by direct debit, e.g. if they do not have a bank account or a sufficiently regular source of income. We would therefore suggest redefining scenario 3b to include all SVT to product switches with the same payment method.

(ii) The results of the gains from switching analysis are presented as the range (over suppliers) of the weighted average saving for each supplier (weighting each of the supplier's tariffs[29] by the number of customers on it, considering only tariffs where there is a saving opportunity and taking a simple average over quarters). Given the wide ranges of savings quoted, we welcome the CMA's intention (paragraph 33 of the Potential Gains from Switching Working Paper) to provide more granular information on the distribution of savings.

5.16 We note that the range of savings for scenario S3b (£111 to £153) is broadly similar to the required incentives to switch elicited in the GfK survey (£114 median, £158 mean). Pending more detailed analysis, this suggests that one important reason for the magnitude of these unrealised gains from switching ('money left on the table') is simply that for many customers the available saving is less than the amount that they need in order to be willing to switch. This suggests that it may be relevant to consider what can be done to reduce the hassle (or perceived hassle) of switching such that consumers are willing to switch for a lower saving (see paragraph 5.28) and/or regulatory change so as to facilitate a wider variety of sales channels or products. Information campaigns such as DECC's recent 'Power to Switch' campaign may also have a positive impact on engagement.

5.17 As noted above, the level of price dispersion in GB energy markets is similar to that in other markets in percentage terms. It is possible that the unrealised gains from switching are greater in energy than in other markets, but the CMA has not presented any evidence to this effect.

(e) <u>*GfK survey results*</u>

5.18 The GfK survey results (paragraph 63 and figure 13 of the GfK report) show that around 44% of customers had switched at some point, a further 21% had considered switching or had shopped around in the preceding three years and 34% were disengaged (hadn't considered switching or didn't think it was possible to switch). As with the other metrics discussed above, we have seen no evidence that these levels of engagement are significantly worse than would be observed in other UK product/service markets.

5.19 Should the CMA confirm its view that some energy consumers are relatively inactive (having assessed other competitive markets), it will be important to drill down and understand which particular segments of consumers are contributing to this finding so that specific barriers to engagement can be identified. We agree that refining the understanding of consumer behaviour should be the major focus in the next stage of the CMA's work.

(f) <u>*PCWs and smart meters*</u>

5.20 We agree that third party intermediaries (**TPIs**) and PCWs are both important means by which consumer engagement in the energy market can be increased (paragraph 139 of the UIS). The CMA invites views on whether Ofgem's recent changes to the Confidence Code for PCWs strike the right balance between fostering confidence in PCWs and ensuring their commercial viability. We strongly support Ofgem's interventions to improve transparency, so that customers fully understand what filters may be being applied, but we find it difficult to say whether the correct balance has been

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29 Tariff in this context refers to a tariff and payment method combination.

struck. Although the requirement for a default 'whole of market' view may reduce PCWs' negotiating position for commission, we would note that there is still a strong incentive for suppliers to pay commission so that switches can proceed via the PCW. The drop-out rate if customers have to leave the PCW website and switch via the supplier's website is likely to be significant.

5.21 We also agree that smart meters will improve broader customer engagement by facilitating quicker switching, ensuring accurate billing and making energy consumption more visible (paragraph 143 of the UIS) and in due course allow for innovative propositions such as time of use tariffs. Smart meters will also make the switching process smoother and reduce hassle (no need to submit meter readings, less risk of billing errors). Smart meters will also remove the current significant constraints which prevent suppliers offering products to pre-payment customers in the same way as to credit or direct debit customers.

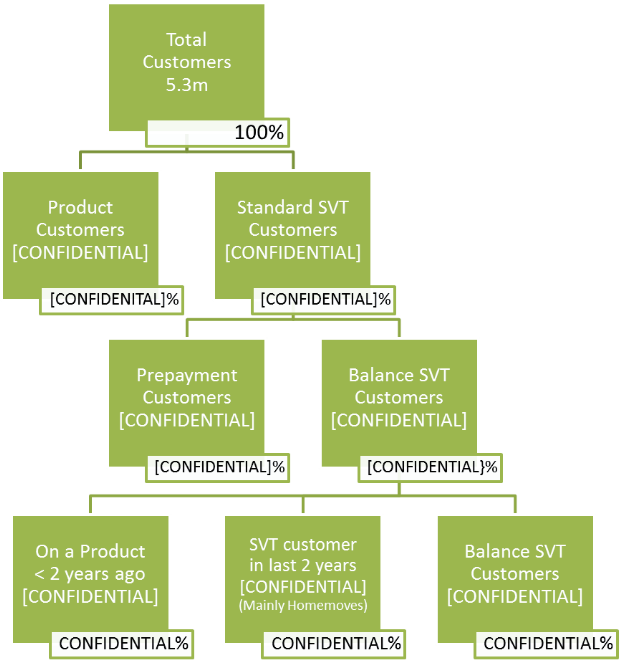
ToH 4 -Supplier behaviour

(g) *UMP over standard variable customers*

5.22 The CMA hypothesises that the Six Large Energy Firms have UMP over their SVT customers because a substantial proportion of SVT customers are disengaged and this tends to insulate suppliers from competitive pressures (paragraph 145 of the UIS). Our evidence, as we explain below, suggests that a substantial proportion of our SVT customers *are* engaged and that our SVT prices are not therefore insulated from competitive pressures.

5.23 We see the retail domestic market as being one market with a competitive dynamic between all the products in the market – including SVT and fixed price products – mediated by customer movement between them. Although **[CONFIDENTIAL]**% of our customers are currently on the SVT, the figure is declining. Moreover, it is not a static set of customers: a significant proportion move back and forth between products and SVT each year, and these customers in particular provide a competitive constraint on our SVT prices. **Figure 5** illustrates the breakdown of our domestic customer base as at September 2014.

Figure 5: Breakdown of ScottishPower's domestic customer base as at September 2014[30]



Source: ScottishPower

5.24 Of our 5.3m total customers, **[CONFIDENTIAL]** (**[CONFIDENTIAL]**%) were on SVT. Of these, **[CONFIDENTIAL]** (**[CONFIDENTIAL]**%) were on prepayment meters and are considered separately below (paragraph 5.31 *et seq.*). The remaining **[CONFIDENTIAL]** (**[CONFIDENTIAL]**%) SVT customers pay by credit or direct debit and fall into three categories: those who have been on a product within the last 2 years (**[CONFIDENTIAL]**, **[CONFIDENTIAL]**%); those who have been acquired as new customers within the last 2 years, mostly home-movers (**[CONFIDENTIAL]**, **[CONFIDENTIAL]**%); and a balance of customers who have been on SVT for more than 2 years (**[CONFIDENTIAL]**, **[CONFIDENTIAL]**%). Around half of our SVT customers (excluding PPM) have therefore been on SVT for less than 2 years, and it is they who provide the main competitive constraint.

5.25 The **[CONFIDENTIAL]** ex-product customers are intermittently engaged in the market, such that they default onto the SVT when their product matures[31] and may then move back to a product when they receive an appropriate stimulus, for example a 'cheapest tariff message' on their bill or annual statement[32] or competitor sales activity. At this point they are likely to compare the offers available on the market and choose either a new ScottishPower product or a product from one of our competitors. Our SVT price is constrained both by our own product prices and those of our competitors. The larger the gap relative to our own products, the more likely it is that the customer will be prompted to engage by a cheapest tariff message. Furthermore, the greater the gap relative to our competitors' products, the more likely we are to lose the customer when they do engage.

5.26 Similarly, when people move house they typically start on the SVT and in many cases engage with the market at some later date, perhaps when they receive a bill or cheapest tariff message or are approached by a competitor. This helps to constrain SVT prices in a similar way as ex-product

30 The diagram shows 100% of PPM customers as being on SVT. In practice, **[CONFIDENTIAL]**% of the PPM customers were on the newly-launched 'Help Beat Cancer' product (**[CONFIDENTIAL]** services).

31 RMR introduced a requirement for suppliers to default customers onto the standard tariff if they do not actively select another product on maturity.

32 RMR obliged suppliers to include details on bills and annual statements of the savings available by switching to one of the supplier's other products.

customers discussed above.[33] Finally, the balance of **[CONFIDENTIAL]** SVT customers who have been with us for longer than 2 years may switch less frequently than the rest, but we still lose a proportion of these customers every year and this contributes to the constraint on SVT prices.

5.27 The net result of this intermittent engagement is a constraint on the gap that can be sustained between SVT and product prices. We would expect the size of this gap to be the result of customers' willingness to switch for a given saving, and the evidence is consistent with this. The CMA's gains from switching analysis found that dual fuel savings were broadly in line with GfK's results on the amount of saving which consumers required to encourage them to switch (£114 median to £158 mean).

5.28 In summary, the market dynamics described above, where SVT prices are constrained by product prices, leads us to the view that SVT and products are part of a single economic market, rather than being separate markets. As such, we do not believe it is correct to conclude that suppliers have UMP in setting SVT prices. Rather, the gap between SVT prices and products is constrained by customer switching behaviour to be around the level of saving that consumers typically require to encourage them to switch. The circa 50% of customers who are engaged from time to time provide protection for those that are less engaged. If the CMA is concerned that the magnitude of the price gap is too large, it would be relevant to consider what can be done to reduce the hassle (or perceived hassle) of switching such that consumers are willing to switch for a lower saving. We would also welcome changes that make it easier for us to compete for other suppliers' customers, such as removing RMR restrictions (see paragraph 5.46) or facilitating a wider variety of sales channels.

5.29 Our preliminary analysis of ScottishPower's customer base suggests that the **[CONFIDENTIAL]**% of customers who have been on SVT for at least 2 years are reasonably representative of our customer base as a whole. Similar percentages are likely to earn more than £50k per annum and similar percentages would be listed on our Priority Services Register. This is broadly consistent with the GfK survey which found that the 'financially struggling' were only slightly more likely to be disengaged than average (53% had not switched in the last three years or considered switching, compared to 50% for the population as a whole, Figure 14 of the GfK report). Other demographic characteristics considered by GfK were more associated with disengagement, such as being older than 65 or having no qualifications. However, the most significant difference identified in the GfK report was internet access, where 75% of those without internet access had not switched in the last three years or considered switching (Figure 18 of the GfK report); this suggests that the ending of face to face sales is likely to have had a significant effect on engagement.

5.30 Finally, the CMA says it has not yet taken a view on the strength of arguments that the Six Large Energy Firms attempt to keep their SVT customers disengaged, so as to retain them on high tariffs (paragraph 145 of the UIS). It is not clear to us what mechanisms are thought to be used for this, other than giving good customer service. We would note that the proportion of our customers on SVT has fallen from **[CONFIDENTIAL]**% in 2007 to **[CONFIDENTIAL]**% in 2015 (and would have been lower still but for the requirement to default customers onto SVT when their product matures); we regularly encourage all our customers, including those on SVT, to contact us to check that they are on the right tariff (supplemented since RMR with cheapest tariff messaging); and we have been successful over the years in persuading our SVT customers to switch from paying by credit to direct debit.[34]

(h) *<u>Prepayment customers</u>*

5.31 As shown in **Figure 5**, around **[CONFIDENTIAL]** of our customers are on prepayment meters (**[CONFIDENTIAL]**% of total customers, **[CONFIDENTIAL]**% of our SVT base). The nature of

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33 This does not apply to all home movers. Customers who move in to rented accommodation on a short-term basis are less likely to engage or be motivated to select a fixed-term product.

34 The proportion paying by direct debit has increased from **[CONFIDENTIAL]**% in 2007 to **[CONFIDENTIAL]**% in 2014.

competition for PPM customers is materially different from credit and direct debit as a result of technical limitations in the prepayment infrastructure. The effect of these limitations is that it is difficult for suppliers to offer or operate multiple tariffs in each PES region, and many customers are generally limited to their supplier's SVT (or a rival's) without the option of moving to a fixed price product. ScottishPower and a few other suppliers have recently succeeded in launching a single product for PPM customers, but are constrained in how frequently they can refresh these products.

5.32 The technical limitation relates to the number of 'tariff codes' which can be accommodated in the industry systems used to process prepayments. These systems, which were developed in the early 1990s, determine the number of kWh or therms that the prepayment meter should be incremented by when the customer tops up with a given sum of money. The system for gas meters is operated by Siemens on behalf of the industry and the system for electricity by Itron. A different tariff code is needed for each supplier, region and (in the case of electricity) meter type. So 20 suppliers and 14 regions would require 280 codes for gas and more than double this for electricity (in ScottishPower's case we need **[CONFIDENTIAL]** codes to accommodate different meter type / region combinations).

5.33 When suppliers offer fixed price products they need to be able to withdraw them from sale and replace them with a new price point on a fairly regular basis to remain competitive. ScottishPower can refresh its fixed price offers as often as once a month. If a supplier wishes to offer a fixed price product to PPM customers it will need a separate tariff code for each version of the product which is 'live' at any given time, not just the version that happens to be on sale. So if ScottishPower was to offer a one-year fixed price product and expected to refresh it every month, it would need 13 (12 months and 1 month to allow for maturity process and the 20 day window obligation) *14 = 182 codes in gas and 13***[CONFIDENTIAL]** = **[CONFIDENTIAL]** codes in electricity, in addition to the 14 gas codes and **[CONFIDENTIAL]** electricity codes required for its SVT. As can be seen from the table below, there are insufficient codes available in the system to support multiple suppliers offering multiple product tariffs.

Table 3: Prepayment industry meter code restrictions

	Gas (Siemens)	Electricity (Itron)
Total number of Industry code available		
Number needed to launch a product across GB	14	[CONFIDENTIAL]
Total ScottishPower have available (unused)	[CONFIDENTIAL]	[CONFIDENTIAL]*
Total Industry wide available to purchase today	0	0**

Source: ScottishPower analysis

* **[CONFIDENTIAL]**

** Itron can only make available codes attached to a new supplier ID, and the supplier ID must first be approved by Gemserv. Each supplier ID is granted 249 codes, and it is not possible to increase the number of codes under a supplier ID.

5.34 During 2014 we took the initiative to buy **[CONFIDENTIAL]** unused codes for gas allowing us to launch a Cancer Research UK fixed price offer for pre-payment customers (which has been refreshed on one occasion). This has proved very popular, with **[CONFIDENTIAL]** customers having taken up this product - demonstrating that the same dynamic between SVT and products that exists for customers paying by credit and direct debit can also apply for customers on prepayment meters. The limit on tariff codes will disappear once dumb prepayment meters are replaced with smart meters, but until then we expect other suppliers to have limited ability to offer competing products without a change in the Siemens and Itron systems.

5.35 The fact that prepayment competition is predominantly between SVTs (i.e. no products) has made it particularly susceptible to regulatory interventions, which may unintentionally have weakened competition as follows:

(i) Prior to 2009, ScottishPower would typically target acquisition activity at prepayment customers in particular regions by offering an aggressive SVT price for that region, accompanied by regional advertising and a face-to-face sales force.

(ii) Following the introduction of SLC25A in 2009, we were no longer able to offer discounted regional SVT prices and therefore struggled to provide sufficient savings to incentivise prepayment customers to switch. We were able to overcome this by offering cashback payments – typically £**[CONFIDENTIAL]** to £**[CONFIDENTIAL]** – which proved very popular with these customers until they were prohibited under RMR (see (iv) below).

(iii) Following our and other suppliers' withdrawal from doorstep selling in 2011, prompted in part by the difficulty of complying fully with SLC25, the level of switching for prepayment customers fell significantly, as this was one of the main channels to that market segment.

(iv) Finally, the RMR prohibition on cashback payments introduced in 2013 means that it is now harder to offer a sufficient saving to overcome customer inertia.[35]

5.36 As noted above, we would expect this situation to change with the introduction of smart prepayment meters. This will not only remove the limit on the number of tariffs, but could also reduce the cost differential - such that prepayment (or 'pay as you go') could potentially become a more popular method of payment.

(i) *<u>Cost pass-through evidence</u>*

5.37 The UIS suggests (paragraph 146) that reductions in costs do not appear to have translated rapidly into reductions in the SVT in recent years (i.e. since 2009) which may be indicative of weak competition. As noted above, regulatory interventions in 2009, notably SLC25A, appear to have changed the nature of competition, with a greater divergence between SVT and product prices, and the CMA will need to consider whether this may be an alternative explanation of the cost pass-through characteristics. The CMA will also need to consider whether cost pass-through in recent months may have been influenced by the Labour Party manifesto commitment to introduce a retail price freeze in 2015.

5.38 We have provided in **Annex 3** a report by Oxera which describes further econometric analysis of the data set used in the Ofgem/OFT 'rockets and feathers' analysis of 2014. Oxera's analysis found that the relationship between SVT prices and overall costs (energy plus social/environmental) could be explained if it was assumed that there was a step change in SVT prices relative to costs starting in 2009, with prices responding to changes in cost in much the same way thereafter. This result would be consistent with the hypothesis that SLC25A led to an overall increase in SVT prices.

5.39 The Oxera results also show that there is no evidence of 'rockets and feathers' behaviour in the data provided, in contrast to Ofgem's findings. We welcome the CMA's intention to investigate cost pass-through effects further and hope that the work done by Oxera will be of help in this area.

(j) *<u>Tacit coordination</u>*

5.40 The CMA's initial view (paragraph 153 of the UIS) is that the public price announcement behaviour by the Six Large Energy Firms is likely to be consistent with unilateral incentives, rather than a mechanism for tacit coordination as suggested in Ofgem's reference document. We agree with the CMA's analysis. The fact that the CMA found no evidence of suppliers adjusting their plans in response to competitors' price announcements (which in practice are a necessary corollary of the requirement for advance notification of customers) is difficult to reconcile with a hypothesis that

[35] Responses to the GfK survey suggest that PPM customers require a saving in the range £165 (mean) to £175 (median) to switch. (GfK_customer_survey_tables.xlsx, at tab T1681).

announcements are facilitating coordination, and as we have previously pointed out[36] there are strong unilateral incentives for suppliers that would explain the observed bunching in announcements of both price increases and decreases.

Regulatory interventions

(k) *SLC 25A*

5.41 We agree that it is important for the CMA to investigate the impact on competition of the SLC25A prohibition on undue discrimination (paragraph 159 of the UIS). We share the concerns of Stephen Littlechild and George Yarrow that SLC25A is likely to have been counterproductive and to have led to a lessening of competition. Although the licence condition has now lapsed, it will be instructive for the CMA to reach a definitive view on the impact of this licence condition on competition.

5.42 As noted above, Oxera have carried out further econometric analysis of the data set used in Ofgem's 'Rockets and Feathers' analysis. Oxera's analysis (see **Annex 3**) found that the relationship between SVT prices and overall costs (energy plus social/environmental) could be explained if it was assumed that there was a step change in SVT prices relative to costs starting in 2009. This result would be consistent with the hypothesis that SLC25A changed the focus of competition in the market and led to an overall increase in SVT prices.

5.43 The CMA raises an interesting question (paragraph 160 of the UIS) as to whether suppliers will continue to act as if SLC25A is in place, even after Ofgem's recent (December 2014) clarification. As Waddams,[37] Littlechild[38] and others have described, the introduction of SLC25A precipitated a significant change in the nature of competition, whereby the focus of competition shifted away from SVT to products, which were largely exempt from SLC25A. Although suppliers may take advantage of Ofgem's clarification to offer regional discounts in SVT prices (e.g. to drive PPM sales), we think it is unlikely that the market will revert to the pre SLC25A conditions in which competition was focused on SVT pricing rather than products. We suspect that the current mode of competition may be one from which it would not be in any supplier's individual interest to depart, since any shift towards lower variable tariff offers may need to be balanced with a change in positioning on product prices. This could lead to a substantial loss of customers if other suppliers continued to offer lower priced products.

(l) *RMR*

5.44 We also welcome the CMA's intention to consider further the likely impact of the RMR tariff reforms on competition and consumer engagement (paragraph 163 of the UIS). As noted in our response to the Supply Questionnaire[39] we were supportive of the principle of the information remedies, though we had reservations about aspects of implementation. Our main concern has always been around the tariff restrictions, which we consider have created an unnecessary constraint on companies' ability to innovate and compete. We raised these concerns in response to Ofgem's consultations, and in response to the original December 2011 consultation, we commissioned a report from Oxera which concluded:

> "*as the OFT has warned, interventions that restrict products and pricing practices can lead to less effective competition and higher prices overall. Ofgem's proposed tariff restrictions represent a highly intrusive intervention that appears to warrant a*

[36] SP's response to question S10 of the Questionnaires.

[37] CMA, Summary of hearing with Centre for Competition Policy (CCP) of the University of East Anglia on 2 December 2014, at paragraphs 19 and 29.

[38] CMA, Summary of hearing with Professor Stephen Littlechild, the former Director General of Electricity Supply and Head of the Office of Electricity Regulation on 11 December 2014, at paragraph 8.

[39] SP's response to question S63 of the Questionnaires.

considerably more thorough analysis of the potential effects than has been conducted to date."[40]

5.45 The RMR rules resulted in a number of tariff features that were valued by customers being withdrawn from the market. These were not niche features: in many cases they were favoured by a substantial proportion of customers.

5.46 **Table 4** lists some of the key regulatory interventions (Probe and RMR) which we consider may have had an adverse impact on market outcomes. We would encourage the CMA to consider whether relaxing them might improve competition and consumer choice.

Table 4: Benefits of relaxing regulatory interventions

#	Regulatory intervention	Benefit of relaxing
1	RMR four tariff cap	Constrains suppliers' ability to compete and innovate. Relaxing or removing the cap could facilitate stronger competition.
2	RMR ban on cashback	This was an important way to incentivise some customers to switch, and in particular for customers with prepayment meters, where it was not possible to offer products in the same way as with other payment methods. (Around **[CONFIDENTIAL]**% of our sales in 2013 included cashback incentives.)
3	RMR ban on discounted products	These were popular before they were banned under RMR (around **[CONFIDENTIAL]**% of our customers were on discounted products) and may appeal more to some customers than fixed price products.
4	RMR ban on prompt payment discounts	These were a popular option before they were banned under RMR, and incentivised customers to pay on time, reducing costs for all.
5	RMR ban on two tier ('no standing charge') tariffs	These were popular before they were banned under RMR (taken by around **[CONFIDENTIAL]**% of our customers), and protected very low usage consumers from the full standing charge.
6	RMR requirement for 20 working day protection from tariff increases (in addition to existing 30 day advance notification requirement)	This reduces the speed with which suppliers can implement price changes and is unnecessary on consumer protection grounds. (The existing 30 day advance notification requirement is sufficient protection for consumers and is compatible with EU rules.)
7	RMR requirement for a uniform payment method differential and the difference to be levied wholly on either the standing charge or the unit charge	Suppliers will still be constrained by SLC27.2A but this would give them greater flexibility in how they comply and would permit more cost reflective outcomes.
8	SLC25 – sales and marketing	If rules were relaxed such that face-to-face selling becomes viable and cost-effective (while maintaining appropriate consumer protection) this would allow suppliers to engage hard-to-reach customers and would place downward pressure on price dispersion. However, political and media hostility may still deter suppliers from returning to doorstep selling

[40] See https://www.ofgem.gov.uk/ofgem-publications/39560/scottish-power-oxera-report.pdf and our covering letter https://www.ofgem.gov.uk/ofgem-publications/39555/scottish-power-covering-letter.pdf.

#	Regulatory intervention	Benefit of relaxing
		unless the CMA makes a strong case for the benefits to disengaged consumers.

5.47 In respect of the RMR four tariff cap it is important to understand that Ofgem's derogation process does not significantly mitigate the restriction on companies' ability to compete by offering new forms of tariffs that customers want. Ofgem's guidance specifies that derogations "*would only be granted in exceptional circumstances*"[41] and clearly implies that derogations are not intended to subvert the principles of RMR, nor are they intended to give a company a competitive advantage;[42] rather they are to protect consumers from substantial unintended or unanticipated negative consequences of the RMR provisions and are more likely to be granted on a temporary rather than on an enduring basis. Two areas in which Ofgem has indicated a willingness to consider derogations are social tariffs targeted at vulnerable consumer groups and pilot schemes for innovative products linked to smart metering. With the exception of these two areas, there is little incentive to invest in new product development given the uncertain outcome of any derogation request and the risk that ideas will be shared with competitors through Ofgem's consultation process. Indeed, Ofgem's guidance document expressly states that "*we do not expect many requests for derogations*".[43]

5.48 The CMA also raises the possibility that RMR tariff rules may restrict competition over PCW commission rates by preventing PCWs from offering a cheaper deal through their website in exchange for a commission sacrifice (paragraph 163 of the UIS). This form of competition existed prior to the introduction of RMR, in the sense that some PCWs competed with each other to offer a cashback incentive (paid for out of their commission) to customers switching via their website. Although RMR prohibited such cashback payments,[44] Ofgem issued an open letter in 2013 which stated that:

> "*Our desired policy outcome is not to stop TPIs from offering cashback or bundled products where these act as a genuine inducement for consumers to engage and do not materially distort consumer choices between different tariffs. Our initial view, subject to consultation, is that we would be comfortable, for example, where an intermediary offers the same inducement irrespective of the tariff chosen, and offers a broad range of tariffs. As such, we are minded to allow cashback and bundled products to be offered in this way. To achieve this outcome, we will need to resolve some detailed issues and go through a formal process to change suppliers' licence conditions. We will work swiftly to consider how to achieve our desired outcome in this area and will consider potential linkages with the Confidence Code review*."[45]

5.49 **[CONFIDENTIAL]**. Ofgem has yet to make any amendments to the licence conditions to reflect this revised position but we understand that a number of PCWs are continuing to offer cashbacks.[46] We would encourage the CMA to explore with PCWs whether they consider the RMR conditions to be a constraint in practice.

(m) *Social & environmental*

5.50 We are unclear from the UIS where the CMA's thinking lies on the question of whether the ECO size threshold acts as a barrier to expansion for small and mid-tier suppliers. The UIS notes that

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41 Ofgem Guidance at paragraph 1.3. (See https://www.ofgem.gov.uk/ofgem-publications/83390/derogationsprocess24sepnew.pdf).

42 Paragraph 2.15 of Ofgem's Guidance says that in assessing applications Ofgem will consider the impact on market distortion, for example any competitive advantage that may arise from granting the derogation.

43 Ofgem Guidance, at paragraph 1.3.

44 SLC 22B prevents suppliers from offering cash discounts (other than Dual Fuel or online discounts). Suppliers are required to ensure that any Representatives abide by these rules. A PCW is a Representative in this context.

45 See https://www.ofgem.gov.uk/ofgem-publications/85343/cashbackandbundledproducts-openletter.pdf.

46 For example Money Saving Expert's Energy Club offers customers an automatic £30 cashback on any tariff if they sign up through the Energy Club, which comes from any commission they make.

some independent suppliers said they had decided to delay growth in order to avoid incurring ECO costs, and others had expressed the view that ECO was a significant barrier, but the UIS does not say what further investigation (if any) the CMA intends to do in this area. The CMA's working paper on 'Case studies on barriers to entry'[47] provides a more mixed picture of independent suppliers' views on this issue: one supplier, First Utility, stated that it took a conscious decision to go beyond the threshold;[48] whereas Utilita explained that it views ECO thresholds as "a massive barrier to growth".[49] The CMA says it will investigate whether the higher social and environmental costs imposed on electricity distort competition between electrical heating systems and alternatives such as gas – but this is a somewhat different question.

5.51 In our view, it would be unsurprising that the ECO threshold acts as a barrier to growth, and the question should be whether the small supplier exemption is efficient, and whether it could be improved so as to alleviate the barrier to growth. As we explained in our response to the IS (paragraph 3.70), the exemption results in:

(i) a substantial cross-subsidy in favour of small non-obligated suppliers, which may encourage inefficient market entry;

(ii) significant barriers to growth for mid-sized suppliers who are on the taper and face a higher marginal cost of ECO; and

(iii) a barrier to consolidation of smaller entities to more efficient medium scale ones.

5.52 We believe these problems could be alleviated by changes in the design to achieve a result which fairly allocates both the fixed and variable costs of ECO. We have previously provided our detailed thoughts on this to DECC[50] and are providing a copy of our letter with this response as **Annex 4** (this letter was previously submitted by ScottishPower to the CMA in response to question SQ36 of the retail supply market questionnaire of 1 August 2014).

(n) *Settlement and reconciliation*

5.53 We will comment on issues raised in this section of the UIS in our follow-up response on the CMA's Working Paper.

(o) *Impact of sales and marketing regulations on face-to-face sales*

5.54 The UIS makes no mention of the impact of regulatory interventions on face-to-face sales. As we noted in our response to the IS (paragraph 3.72), face-to-face selling (whether on the doorstep or in public places) has previously been a feature of the energy sector and was an effective way for suppliers to engage with some of the more 'hard to reach' customers, e.g. those without internet access or who are not comfortable with using the internet and do not wish to engage in telesales calls. While appropriate consumer protection must be ensured in any revision of the rules around face-to-face sales, it could be useful in this context for the CMA to estimate how the consumer detriment from not being reached through these sales techniques weighs against that arising from the inevitable imperfections of these techniques.

5.55 Suppliers withdrew from doorstep selling and in practice almost all face-to-face sales in response to two drivers: intense political and media pressure and the difficulty of complying fully with the requirements of amended SLC 25 (Marketing to Domestic Customers) and Ofgem's interpretation of

47 CMA, Case studies on barriers to entry and expansion in the retail supply of energy in Great Britain, 18 February 2015.
48 Case studies on barriers to entry and expansion in the retail supply of energy in Great Britain Working Paper, at paragraph 156.
49 Case studies on barriers to entry and expansion in the retail supply of energy in Great Britain Working Paper, at paragraph 153.
50 'Energy Companies Obligation (ECO) – Threshold and Taper Policy', letter from Rupert Steele, ScottishPower, to Siobhan Stanger, DECC, 6 September 2013.

those rules. Although it was clearly necessary for Ofgem to introduce stricter rules given the poor sales practices that were being employed by some suppliers at that time, and to take enforcement action when those rules were not followed, it is not clear to us that the correct balance was struck in determining how stringently those rules should be enforced. However well a supplier trains and manages its sales agents, it is impossible to achieve 100% compliance in every sale. If suppliers believe the risks of non-compliance are too great, this may result in a sub-optimal level of face-to-face sales activity from the perspective of consumers as a whole.

5.56 Stephen Littlechild's submission to the CMA of 11 January 2015[51] reviews Ofgem's regulation of marketing including doorstep selling, and its impact on competition. He concludes that "*The present marketing licence condition (SLC 25) and its interpretation have thus restricted and distorted competition in several respects, to the disadvantage of customers, particularly vulnerable customers. Any suggested countervailing benefits – such as the cessation of doorstep selling or the desirable aims of the policy – do not warrant the CMA not taking steps to address these adverse effects on competition. Nor should Ofgem be left to resolve the problems with respect to TPI participation.*"

5.57 We agree with Stephen Littlechild that face-to-face selling is an important area for the CMA to consider, given its potential to address the problem of inactive customers highlighted in the UIS. In our experience the problems of complying with SLC25 marketing rules to a reasonable standard would not be insurmountable. Given appropriate use of technology and sales validation processes, face to face marketing can now be conducted to a much better standard than before - albeit at relatively high cost.

5.58 If the CMA wishes to encourage a return to face-to-face selling, two areas need to be addressed. The first is to review SLC25 (and its interpretation) and consider whether it can be improved to enable suppliers and TPIs to conduct high quality sales as efficiently as possible whilst providing an appropriate degree of protection for consumers. The second is to inform the public debate as to the pros and cons of face-to-face and doorstep selling. Even if compliance problems can be overcome, a widespread return to face-to-face selling is unlikely without a shift in political and media opinion. If the CMA considers that the benefits, in terms of improved energy market engagement for more vulnerable consumers, outweigh the costs, this assessment needs to be communicated.

Microbusinesses: barriers to engagement

5.59 The UIS (paragraph 178) identifies three main concerns about microbusinesses which it considers may warrant further investigation:

(i) microbusinesses may face barriers to engaging in retail energy markets similar to those faced by domestic customers;

(ii) as most energy contracts are negotiated and energy prices are generally not published, this may limit transparency in the non-domestic market; and

(iii) brokers may not be operating effectively or fairly.

5.60 The CMA is correct to investigate these areas further. The lack of transparency over available offers is likely to increase microbusiness search costs and deter microbusinesses with relatively low energy consumption from finding the best deal.

5.61 We believe that competition would function more effectively in the microbusiness end of the SME market if it was subject to similar competitive forces as the domestic market. We set out below

[51] See https://assets.digital.cabinet-office.gov.uk/media/54b8e0d8ed915d1597000007/Stephen_Littlechild_-_regulation_of_energy_marketing.pdf.

some of the key changes which we consider would be necessary to achieve this goal and then consider the difficult question of how a microbusiness would be defined for this purpose.

5.62 To move the microbusiness market closer towards the model of competition that exists in the domestic market (pre SLC25A and RMR), we suggest the following changes would be desirable:

(i) **Published prices**: Suppliers would compete on the basis of published prices, such that PCWs were able to generate comparison tables of different offers and facilitate sales where appropriate. As in the domestic market, suppliers would need to make such offers subject to satisfactory credit checks (and may require a deposit in the absence of credit history). Unlike the domestic market, this should not preclude suppliers negotiating custom tariffs where appropriate, e.g. in the case of larger or more sophisticated business customers, but the goal would be to change the default basis on which tariffs are offered to microbusiness customers. It would mitigate the concern that some suppliers have around debt risk, as different offers could be made available by credit score if the suppliers consider this to be appropriate. We do not have a firm view at this stage of how this transition could best be achieved, but once the nature of competition had changed and a critical mass of supplier offerings were listed on PCWs, it is possible that this form of competition could be self-sustaining, i.e. suppliers would find it in their interest to continue promoting tariffs via PCWs.

(ii) **Same transfer blocking rules as domestic**: Transfer blocking currently acts as a significant drag on switching and competition in the microbusiness market and we see no reason why the rules should not be the same as in the domestic market.[52] The key differences between domestic and non-domestic transfer blocking rules are summarised in **Table 5**. Non-domestic transfers can currently be blocked on the grounds that the customer is still subject to the terms of the contract or has not given its contractual notice period, provided that the contract allows for blocking in these circumstances. We suggest that this should not be allowed for microbusinesses, as in domestic. We would also suggest that blocking of microbusiness transfers for debt should be permitted where the customer is on a deemed contract, as is the case in the domestic market.

Table 5: Domestic and non-domestic transfer blocking rules

	Domestic	Non-domestic
Losing supplier allowed to object to transfer because customer is still in contract term or contractual notice period?	**No**[53]- but losing supplier can charge reasonable early termination fee	**Yes** (SLC14.2(a)) – provided that contract expressly permits transfer blocking in the circumstances
Losing supplier allowed to object to transfer because customer is in debt (contract in place)?	**Yes** (SLC14.4(a))	**Yes** (SLC14.2(a)) - ditto
Losing supplier allowed to object to transfer because customer is in debt (deemed contract)?	**Yes** (SLC14.4(a))	**No** – the reference to 'contract' in SLC14.2(a) does not include a deemed contract

52 There are good reasons to permit such blocking in the case of larger businesses, where suppliers may have forward purchased significant amounts of energy on the back of the contract and where the customer entered willingly into the contract. In contrast, at the micro end of the market, where businesses' consumption may be similar to large domestic customers, we can see no reason for such blocking.

53 SLC14.4(d) provides an exemption that transfers may be blocked if "*the customer is bound by the provisions of a Contract with the licensee for the supply of electricity to the premises which will not end on or before the date of the Proposed Supplier Transfer and that Contract is of a kind specified in a direction issued by the Authority*". As far as we are aware no such directions are currently in force.

(iii) **Rollover at the end of fixed-term contracts**: When microbusiness customers come to the end of a fixed-term contract, we suggest that the supplier should be allowed to roll them over onto another fixed-term contract only if the customer is then allowed to exit the contract at any time without penalty. A number of suppliers, including ScottishPower, have adopted policies on a voluntary basis which have a broadly similar effect, but we believe it should be made a formal requirement.

(iv) **Transparency and brokers**: Ofgem has developed a draft code of practice for non-domestic TPIs, which covers provision of clearer information, fair marketing tactics and effective monitoring and complaints redress, which it proposes should be underpinned by a licence condition on suppliers to work only with code-accredited TPIs. We agree with this proposal and would suggest that it should include similar provisions as the domestic Confidence Code as regards PCWs. There are practices in the non-domestic market which we believe microbusiness consumers should (as a minimum) have greater visibility of, including the ranking criteria used by brokers to decide which contracts to present, and the practice of some suppliers in promoting 'uplift commissions' to brokers (in which the higher the price accepted by the customer, the higher the commission earned by the broker). Greater transparency in the market could reduce the levels of commissions paid to brokers.

(v) **No RMR tariff restrictions**: As noted above, we think the microbusiness market should look more like the domestic market pre-RMR. This would mean no restrictions, for example on offering cashback incentives, two-tier 'no standing charge' tariffs, discounted variable products and prompt payment discounts.

5.63 If the microbusiness market is to operate differently from the rest of the SME market, it will be essential to define a clear boundary between the two markets. We would suggest that this could be done most simply in terms of meter classes and annual consumption limits. Suppliers would be free to define the boundary more widely for internal compliance purposes, if they wish, provided that all customers satisfying the condition benefit from the microbusiness market rules. Our initial suggestions are in **Table 6**.

Table 6: Proposed definition of microbusiness

	Electricity	**Gas**
Definition of microbusiness customer	All the customer's meters supplied by the licensee are in Profile Class 3-4, and the licensee supplies the customer with less than 50,000 kWh of electricity per year in aggregate.	The licensee supplies the customer with less than 150,000 kWh of gas per year in aggregate.

5.64 As noted above, we would envisage that customers would be able to opt out from certain aspects of the rules (e.g. to negotiate custom tariffs where appropriate) but the default position would be as defined above.

5.65 We would encourage the CMA to consider what may be preventing the market from moving to such a model and what could be done to facilitate a transition.

6. UPDATED THEORY OF HARM 5

"The broader regulatory framework, including the current system of code governance, acts as a barrier to pro-competitive innovation and change."

6.1 The UIS identifies two separate issues relating to industry codes (paragraph 194):

(i) whether the number of codes in electricity adds barriers to entry and/or expansion; and

(ii) whether the current system of industry code governance acts as a barrier to pro-competitive innovation and change.

6.2 We do not have a firm view on whether there is scope to rationalise the number of electricity codes. Over the coming years, a number of the codes will be undergoing significant modification as a result of the smart metering implementation programme and the rollout of EU network codes. We therefore agree it would be timely to conduct a more focused review to explore the scope for rationalisation.

6.3 It may also be worth considering whether more can be done by code administrators (as mentioned in Principle 1 of the Code Administrator Code of Practice[54]) to assist new entrants and reduce any barrier to entry or expansion.

6.4 We also believe the CMA is right to consider whether anything can be done to improve code governance, but we would highlight the critical importance of maintaining adequate checks and balances, and the need to have sufficient expert input if changes are to be well founded.

6.5 The industry codes are multilateral, complex, commercial agreements which provide the underpinning to transactions in the sector. The regulator plays a critical role in overseeing agreed and non-agreed changes, which is essential to ensure that the codes can evolve, but it is also important that the regulator's decisions themselves are overseen, either by the CMA or by the courts.[55] Changes to the codes can give rise to very large costs or distributional effects and it is important that both consumers and the parties have adequate protections, including from misguided regulatory decisions.

6.6 The majority of non-contentious code decisions can progress through the code governance process fairly rapidly (say in three to six months) and in a very straightforward way. Cases where decisions have taken much longer than this to progress are generally those where there are large distributional impacts and/or the regulator has sought to impose modifications which the industry considers misguided.

6.7 A good example of the first category is Project TransmiT, which was launched by Ofgem to look at electricity transmission charging and associated connection arrangements.[56] The initial study was launched in September 2010 and led to a significant code review (**SCR**) which ran from June 2011 to May 2012. Following the SCR Ofgem directed National Grid to take the matter through the CUSC modification process which concluded with CUSC Modification Proposal 213 being approved by the CUSC Panel in June 2013. Ofgem then went through two formal consultations on its proposed decision, in September 2013 and April 2014, and made a final decision in July 2014 for implementation in April 2016 – five and a half years after Project TransmiT was launched.

6.8 The TransmiT decision is now being judicially reviewed, which could delay the process further. The length of time taken to complete the process was a consequence of the large distributional impacts of the decision - running to tens of million pounds for some industry parties. Ofgem was aware that its decision was likely to be judicially reviewed (or appealed to the CMA had it decided the other way) so delayed making a decision until it was sure that it had a sufficiently robust legal case. Given that the decision was judicially reviewed anyway, it is arguable that it would have been better for Ofgem to have made the same decision quicker. This would have reduced the regulatory uncertainty for

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54 "*Code Administrators shall be critical friends. A 'critical friend' ... provides support to all with an interest in the code Modification process, but paying particular attention to underrepresented parties, small market participants and consumer representatives*". See https://www.ofgem.gov.uk/ofgem-publications/85687/cacopv30.pdf.

55 Generally, where Ofgem overrules a code panel decision, this can be appealed to the CMA, and where Ofgem confirms a panel decision, the only form of appeal is via judicial review.

56 https://www.ofgem.gov.uk/electricity/transmission-networks/charging/project-transmit#block-views-publications-and-updates-block.

industry participants and allowed consumers to benefit earlier from the modification. It is not easy to see how such an outcome could be achieved, unless through some form of statutory obligation on Ofgem to use all reasonable endeavours to decide such cases in, say, six months.

6.9 A potential example of the second category, where the regulator has sought to push through modifications which the industry considers to be misguided, is the cash out reforms referred to above (paragraph 2.7 *et seq.*). Following its Electricity Balancing SCR (**EBSCR**), Ofgem directed National Grid to raise BSC modifications to implement its conclusions. The relevant modification to implement Ofgem's findings P305 was rejected by the BSC Panel in favour of a different modification (P316 Alternate) which would involve a move to PAR100 instead of PAR1 and would shelve Ofgem's proposal for RSP. Should Ofgem decide to overrule the Panel recommendation, this could lead to the matter being appealed to the CMA. Although this would again result in a prolonged process, we think it is a strength of the current governance arrangements that potentially poor decisions by the regulator can be appealed in this way.

6.10 Although we would be cautious about changing the checks and balances in the system, we believe there may well be scope for improvements to the more detailed aspects of code governance such as membership of code panels, processes for making alternative modifications (how many alternatives are allowed to be considered?), the role of the code administrator (can they do more to help new entrants and smaller players?) etc. Given the complex, multilateral nature of the industry codes regime, and in light of the fact that changes to codes can give rise to very large costs or distributional effects, while we recognise that there is scope for improvement we believe that the CMA needs to be realistic about what is achievable in this respect. We look forward to engaging further with the CMA on this area in due course.

ANNEX 1

PRICE DISPERSION IN OTHER CONSUMER MARKETS

Introduction

1. This annex summarises a survey carried out by Oxera for ScottishPower to compare the level of price dispersion observed in gas and electricity with that in other GB retail markets.

2. The approach was to identify the highest, lowest and median prices for a representative product in each market. The highest to lowest price ratio was not found to be a particularly robust measure as in certain markets (e.g. insurance) as firms may use a high price to signal that they do not wish to provide the particular product in question and this may distort the range and the mean. The difference between the median price and lowest price was therefore considered to be a more robust measure.

Results

3. The results of the survey are summarised in the table below.

Market	**Price unit**	**Price (high)**	**Price (low)**	**High to low saving**[57]	**Price (median)**	**Median to low saving**[58]
Savings accounts	% (AER)	0.05	1.35	96%	0.75	80%
Vehicle insurance	£ (annual)	1,573.3	265.4	83%	621.2	57%
Investment products	% (OCF/TER)	0.47	0.07	85%	0.16	56%
Home insurance	£ (annual)	350.0	93.8	73%	162.1	42%
Personal loans	% (APR representative)	9.8	4.1	58%	5.4	24%
Mortgages	% (APR)	5.3	3.7	30%	4.8	23%
Gas services	£ (annual personal projection)	1,021.0	689.4	32%	863.5	20%
Mobile	£ (monthly)	63.0	38.5	39%	48.0	20%
Fixed-line telephone	£ (1st year)	367.7	180.0	51%	223.2	19%
Electricity services	£ (annual personal projection)	646.6	393.4	39%	484.7	19%
Internet provision	£ (1st year)	270.8	180.9	33%	218.4	17%
TV subscription	£ (1st year)	294.0	180.9	38%	212.8	15%
Credit cards	% (APR)	18.9	15.9	16%	17.9	11%
Private life insurance	£ (monthly)	12.2	9.7	21%	10.6	8%

57 High to low saving is defined as (High price – Low price) / High price.
58 Median to low saving is defined as (Median price – Low price)/Median price.

4. The level of dispersion in electricity and gas (19% and 20% median to low saving respectively) is around the middle of the pack and very close to that observed in fixed line telecoms, mobile, investment products and mortgages.

Methodology

5. The survey was carried out in January 2015. Prices were obtained for representative products by searching price comparison websites and other sources of price quotations. The representative product assumptions were as follows:

- Vehicle insurance-Ford Fiesta 2013-14 Petrol 1.6L Manual 5 doors ST
- Home insurance-£350,000 three-bedroom house
- TV, broadband, fixed-line, gas and electricity-Oxford postcode
- Mortgages-property value of £200,000 and amount borrowed of £160,000
- Mobile-Apple iPhone 6 64GB deals
- Investment products-pensions on a nil commission basis and a total annual contribution of £1.5m with no transfer payment
- Personal loans-£10,000 over three years for a car purchase
- Credit cards-cards with a higher than 5/10 approval rating
- Life insurance-£200,000 cover for over 25 years

Data points

6. For reference, details of the firm and product details on which the low, median and high prices are based are detailed below:

Product	High price provider	Median price provider	Low price provider
Saving accounts	HSBC (0.05% AER)	Lloyds Bank (0.75% AER)	Virgin money (1.35% AER)
Credit cards	Multiple providers (18.9%)	Multiple providers (17.9%)	MBNA (15.9%)
Vehicle insurance	SureThing! (£1573.34 p.a.)	Nationwide (£621.16 p.a.)	Esure (£265.35 p.a.)
Home insurance	One (£349.99 p.a)	Fresh home (£162.05 p.a.)	Swiftcover (£93.79 p.a.)
TV subscription	John Lewis (£294.00 for 1st year)	Talktalk (£207.15) and EE (£218.40)	plusnet (£180.90 for 1st year)
Personal loans	UlsterBank (9.8% APR)	RBS (4.9% APR) and Carloan4U (5.9% APR)	Hitachi (4.1% APR)
Fixed-line telephone	DirectSave telecom (£367.65 for 1st year)	EE (£218.40) and John Lewis (£228.00)	Fuel broadband (£180.00 for 1st year)
Investment products	F&C (0.47%)	Blackrock (0.16%)	Fidelity (0.07%)
Internet provision	BT (£270.83 for 1st year)	EE (£218.40)	Plusnet (£180.87 for 1st year)
Electricity services	First:utility (646.60 p.a.)	Eon (£484.73 p.a.))	Eon (£393.43 p.a.)

Product	High price provider	Median price provider	Low price provider
Mobile	O2 (£63.00 p.m.)	O2 (£48.00 p.m.)	Mobile Phones Direct (£38.50 p.m.)
Gas services	Utilita (£1021.00 p.a)	Eon (£863.48 p.a.)	Scottish Power (£689.35 p.a.)
Mortgages	Furnace Building Society (5.3% APR)	Platform and Principality (4.8% APR)	Nationwide (3.7% APR)
Private life insurance	PruProtect (£12.19 p.m.)	Aviva and Ageas (£10.56 p.m.)	Beagle Street (£9.69 p.m.)

ANNEX 2

COMMENTS ON COST PASS-THROUGH WORKING PAPER

Introduction

1. This annex provides our comments on the CMA's cost pass-through working paper. Our response covers a number of areas that are relevant to the CMA's second phase of cost pass-through analysis:
   - use of quantitative rather than qualitative or other simple forms of analysis to draw conclusions;
   - controlling for regulatory change;
   - firm-level analysis;
   - robustness of results to alternative hedging strategies;
   - role of gas price volatility; and
   - investigation into the relationship between SVT and non-standard tariff prices.

Use of quantitative analysis to draw conclusions

2. In addition to the initial descriptive analysis, we understand that the CMA plans to adopt an analytical approach to assess cost pass-through. We are supportive of this, and consider that the results of quantitative analysis should take precedence over any conclusions drawn from qualitative analyses. While qualitative approaches are useful for shaping the methods used in an econometric analysis, they are not a substitute. Inferences made on complex economic issues from qualitative studies can be highly subjective, and may fail correctly to isolate the effects of factors other than cost (for example, regulatory interventions) that could affect price dynamics.

3. We understand that the CMA also wishes to assess the extent to which the rockets and feathers hypothesis applies in practice, but considers that an econometric analysis of SVT may not be appropriate due to the low number of price changes observed during the time period covered by the CMA's dataset. We acknowledge that a high level of confidence in the results of this analysis would require a good number of observed upward and downward price changes, but we consider that an econometric approach is likely to be considerably more informative in this case than qualitative analysis.

4. A graphical or simple analysis would also be subject to the same underlying constraints related to a low number of observed price changes, and specifically price decreases. Inference from a small number of data points is inherently uncertain and the issue is not avoided by failing to engage with the statistics. A suitably well specified quantitative analysis would make explicit the error range (and thus the appropriate level of confidence in the analysis) while the degree of confidence in a qualitative analysis instead depends on subjective judgement. Moreover, as discussed above, simple analyses cannot rigorously control for multiple factors and may therefore produce results that are subject to bias and therefore not reliable.

Controlling for regulatory change

5. We understand that the CMA recognises that the nature of competition has changed over time, due in large part to regulatory interventions (e.g. SLC 25A) and intends to investigate the impact of this. We consider that any analysis of competition, including cost pass-through analysis, should directly take regulatory changes into account in the model specifications. For example, it may be the case that there is a structural break in the relationship between price and cost as a result of such regulatory

change. Oxera's rockets and feathers analysis (see **Annex 3**) suggests that regulatory change may be an important driver that needs to be accounted for in understanding the relationship between prices and costs.

6. Whilst it may not be possible to estimate the impact of SLC 25A or other regulatory changes by comparing domestic prices to those of a control group, the change in regulation should be adequately controlled for in order to ensure reliable results. This could be done, for example, by allowing for a structural break in the estimated relationship between price and cost at the time when a regulatory change occurred, or representing a particular change through an appropriate variable in the model specification (as in the Oxera rockets and feathers analysis).

Firm-level analysis

7. We consider that it may be useful to carry out a firm-level cost pass-through analysis, as suggested by the CMA. Firms change their prices at different times and may have different forecasts of industry costs. It could therefore be informative to investigate the extent to which firm-level cost forecasts explain each firm's pricing and cost pass-through. If sufficient firm-specific cost variation is identified, this could be informative in assessing the level of competition in the market and any resulting analysis should be conducted quantitatively.

Robustness of results to other hedging strategies

8. The CMA considers a number of cost benchmarks, including Ofgem's SMI that assumes an 18-month hedging strategy. We consider that any econometric analysis should include sensitivities to test the robustness of the results to a number of hedging strategies, for example Ofgem's other SMI cost benchmarks. This may be particularly useful given that the CMA has found that prices lag behind corresponding movements in the one-year index, as this may indicate that a 12-month hedging strategy is too short relative to the hedging strategies pursued by energy suppliers.

Relevance of volatile gas prices

9. The CMA has indicated that the day-ahead price index may be less relevant for investigating cost pass-through because it is impacted by short-term shocks. We agree that purchasing day-ahead products represents a relatively small part of most suppliers' hedging strategy. However, the volatility of day-ahead gas prices may be relevant for understanding the relationship between retail prices and costs as it could affect firms' pricing and hedging decisions. It would therefore be prudent to consider the day-ahead gas price index, or more specifically its volatility, as a further factor in the CMA's econometric analysis.

Relationship between SVT and non-standard tariff prices

10. The CMA has explained that it intends to assess the pass-through rates for SVT prices and non-standard tariffs separately and that it intends to compare these in order to determine whether the intensity of competition is different in the SVT and product segments of the energy retail market. While this may be an informative exercise, the current methodology does not allow for interaction between the SVT and non-standard tariffs. It short, it appears to presuppose that the two markets are separate, which is a key empirical question, not presently addressed in the UIS and which we do not believe to be correct (paragraph 5.23 *et seq*.).

11. We consider that it is important to model cost pass-through in a way that captures the relationship between SVT and standard tariff prices. This is because customers frequently transition between SVT and product segments of the market, for example when they come to the end of their current product deal and may remain on the SVT for some time before transitioning on to another product. The price difference between the SVT and the products available in the market would be expected to

affect a customer's decision on whether to choose a product or to remain on the SVT. Hence the way in which suppliers price their standard and other products is likely to be affected by their assessment of the customer response to those prices, and the transition of customers between products and SVTs, both within and between suppliers.

12. The assessment of the relationship between SVT prices and non-standard tariff prices is particularly relevant to the issue of UMP over SVT customers. The CMA could investigate whether there is a relationship between SVT prices and non-standard tariff prices (perhaps for a given product) at the same time as investigating cost pass-through in the SVT and non-standard product segments of the market using a system model such as a vector error correction model (**VECM**). A threshold VECM model could also be used to control for issues such as menu costs.

ANNEX 3

OXERA ROCKETS AND FEATHERS REPORT

(Provided as a separate document)

ANNEX 4

SCOTTISHPOWER LETTER TO DECC IN RELATION TO ECO, 6 SEPTEMBER 2013

(Provided as a separate document)

Ofgem’s ‘rockets and feathers’ analysis: results from an updated approach

Note prepared for ScottishPower

18 March 2015

Executive summary

In its State of the Market Assessment, one of Ofgem’s propositions was that suppliers raised prices in response to an increase in wholesale costs faster than they reduced prices in response to a fall in wholesale costs (‘rockets and feathers’ pricing).[1] In support of this hypothesis, Ofgem cited a model that it claimed demonstrates that prices respond faster to cost increases than they do to cost decreases, based on the data shown in Figure 1 below.[2] In August 2014, Oxera submitted a summary report highlighting technical concerns with this evidence, in particular with respect to how the results had been interpreted.[3] In October 2014, the CMA provided Oxera with the data and model underpinning the 2014 analysis.[4] This allowed Oxera to repeat the analysis, addressing the concerns that had been raised in the August critique.

[1] Ofgem (2014), ‘State of the Market Assessment’, 27 March, p. 72. The State of the Market assessment, while published by Ofgem, was a joint assessment by Ofgem, the Competition and Markets Authority (CMA) and the Office of Fair Trading (OFT). In this paper we refer to ‘Ofgem’ for notational convenience.

[2] See Ofgem (2014), ‘State of the Market Assessment: supplementary appendices’, 15 April, appendix 2.

[3] Oxera (2014), ‘Critique of Ofgem’s ‘rockets and feathers’ analyses: summary of findings’, report prepared for ScottishPower, 21 August.

[4] The files received were ‘Dataset_R&F.xls’ and ‘ECM RF.do’.

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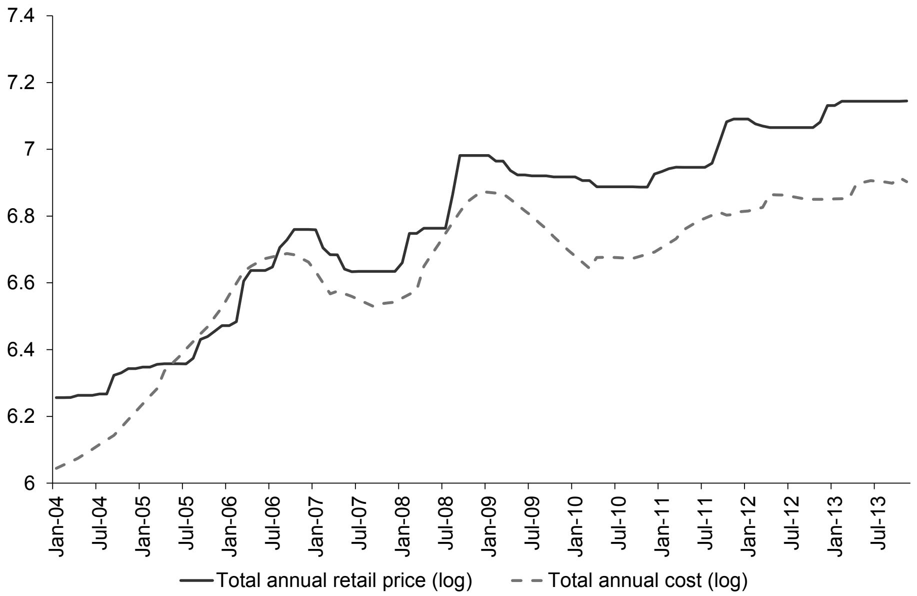
Figure 1 Comparison of standard variable tariff and total cost index in Ofgem 2014 dataset



Source: Oxera analysis of Ofgem 2014 data.

Ofgem's analysis uses an 'error correction model'. This econometric technique separates the pricing dynamics into a long-run, underlying 'equilibrium price' (which is related to suppliers' cost of providing energy) and short-run departures from that equilibrium price (driven by the fact energy prices cannot adjust immediately or completely to short-term changes in costs). Ofgem used this technique to investigate whether retail energy prices respond faster to wholesale energy cost increases or decreases. The hypothesis is that when prices are below their long-run equilibrium they rise quickly (like a rocket) but when they were above their equilibrium price they fall slowly (like a feather).

While the use of an 'error correction model' framework in this context is appropriate in theory, Oxera identified the following technical issues with the analysis.

- Some of the statistical tests used by Ofgem assume that prices adjusted at the same rate upwards and downward (in contradiction to its own conclusions).
- Ofgem excluded a crucial data point from the final analysis without justification.
- Ofgem failed to consider how the long- and short-run price dynamics combined to give an overall direction of prices—short- and long-run adjustments were considered only in isolation.
- Ofgem's model of the long-run relationship between price and costs was not economically coherent, assuming that the equilibrium price level could change to a new level each year, without explanation, regardless of what happened to costs.

With respect to the latter point, the chosen model of the equilibrium price is critical in understanding not only how prices evolve in the UK energy market, but also assessing whether rockets and feather dynamics apply in this market.

Because of its importance, alongside correcting the shortcomings noted above, Oxera has considered two possibilities for the equilibrium relationship in this note.

First, the model for equilibrium standard variable tariff prices is determined by a mix of wholesale energy and other costs, and the two categories of cost are allowed to have differing impacts on energy prices. This modified version of the model used by Ofgem in its 2014 analysis is not ideal as a theoretical presentation of energy prices. In particular, it implies that prices are related to wholesale costs *multiplied* by other costs (instead of the two cost categories being added together, as might be expected). While this is a reasonable approximation for small changes in costs, there have been substantial cost movements across the period considered (2003–14). This may partly explain why the results are not in line with expectations. The results suggests that prices are highly sensitive to 'other' costs (i.e. costs aside from purchase of wholesale energy), to the extent that a £1 change in other costs leads to a much greater than £1 change in prices. This does not appear realistic. The model also fails to account for important regulatory changes in this market noted by the CMA.[5]

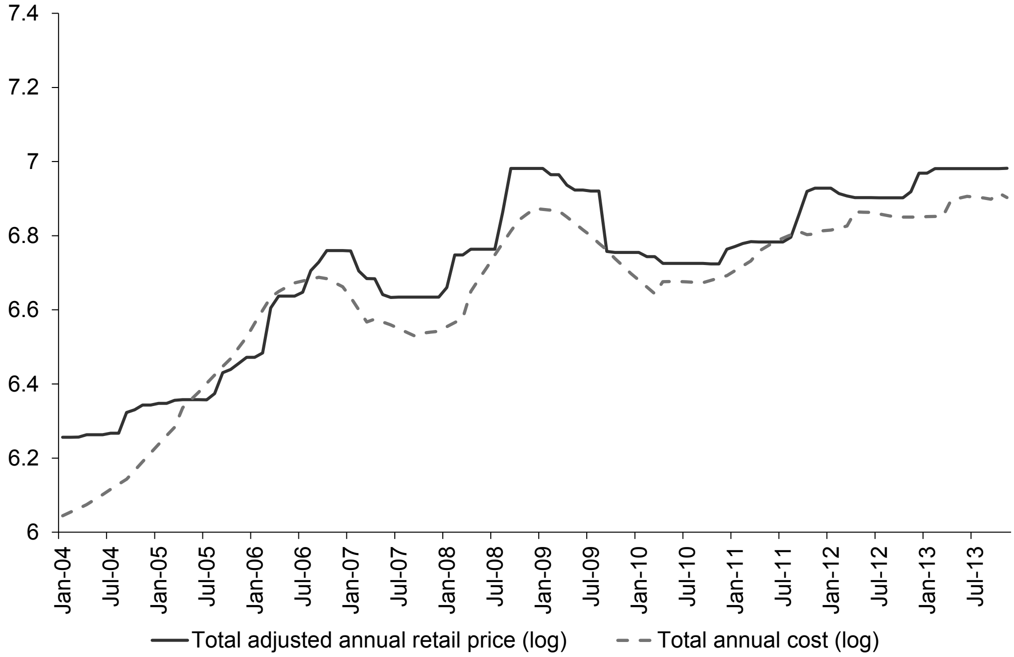
As a sensitivity, Oxera has therefore developed an alternative version of the model for equilibrium standard variable tariff (SVT) prices. In this model, price is related to the total cost and the difference in the regulatory environment which followed Ofgem's introduction of SLC25A in 2009.[6] Not only does this model give a more intuitive relationship between these prices and costs, but it also shows an impact from the regulatory changes since 2009 (starting with SLC25A) that is consistent with the narrative in existing academic literature (also noted by the CMA); namely that the market response to the regulatory change by shifting the focus of competitive activity to product tariffs, increased the long-run prices of standard variable tariffs.

This model provides an alternative possible explanation for the observed trend in standard variable tariff prices since 2009. Rather than any evidence of asymmetric adjustment of these prices to costs, the movement can be understood as a change in the relationship between SVT prices and cost, concurrent with the cost fall at this time. This can be seen by comparing Figures 1 and 2. Figure 1 gives an impression of asymmetric adjustment primarily due to the different response of standard tariff prices to the movement in cost in 2009. Figure 2 below shows that when costs are compared to 'adjusted' prices (i.e. removing the impact of regulatory changes as estimated in our analysis) there is little evidence of asymmetry in the underlying price dynamics.

[5] Competition and Markets Authority (2015), 'Energy Market Investigation – updated issues statement', 18 February, paras 145–163.

[6] To be specific, we include a dummy variable in the long-run price model that takes value one for all time periods after the introduction of SLC25A and value zero for all periods before the introduction of SLC25A. This allows the estimate equilibrium price level to shift following the regulatory change.

Figure 2 Comparison of retail price and total cost index in Ofgem 2014 dataset, removing estimated impact of regulatory changes since 2009



Source: Oxera analysis of Ofgem 2014 data.

It is true, however, that whichever model of equilibrium price is adopted, once Oxera's concerns with Ofgem's analysis are addressed, we find no evidence of rockets and feather dynamics in the pricing of standard variable tariffs in the UK energy market.

1 Key findings

1.1 This note provides an update to Ofgem's 'rockets and feathers' analysis presented in the State of the Market assessment.[7] Based on the same data that Ofgem used, it corrects the main flaws in the original analysis as identified in our 'August critique'.[8] The note examines the extent to which rockets and feathers pricing has applied in practice in the UK energy market (an issue that the CMA has stated that it intends to assess further).[9]

1.2 With the updated analysis, the asymmetric price response from standard variable tariff (SVT) prices to cost shocks identified by Ofgem is no longer evident. Regardless of whether the rockets and feathers hypothesis is tested through simple comparison of adjustment terms (as per Ofgem's 2014 analysis) or consideration of the impulse response function (Oxera's preferred method), SVT prices are, if anything, found to respond faster to cost decreases than cost increases.

[7] Ofgem (2014), 'State of the Market Assessment', 27 March, p. 72. The State of the Market assessment, while published by Ofgem, was a joint assessment by Ofgem, the Competition and Markets Authority (CMA) and the Office of Fair Trading (OFT). In this paper we refer to 'Ofgem' for notational convenience.

[8] Oxera (2014), 'Critique of Ofgem's 'rockets and feathers' analyses: summary of findings', report prepared for ScottishPower, 21 August.

[9] Competition and Markets Authority (2015), 'Energy Market Investigation – updated issues statement', 18 February, para. 127.

1.3 As noted by the CMA, there have been several important regulatory changes since 2009, the effects of which were not included in Ofgem's 2014 analysis.[10] As a sensitivity, we have also tested an alternative hypothesis—i.e. that changes in the equilibrium price can be explained in terms of the total cost and the long-run impact of regulatory interventions, starting with Ofgem's introduction of SLC25A in 2009. This approach is successful in explaining the movement in the equilibrium SVT price over time,[11] and also shows no rockets and feathers dynamic in UK energy pricing.

1.4 The evidence from the dataset used by Ofgem in its 2014 analysis therefore does not provide any reliable support for the hypothesis that there has been rockets and feathers pricing in the standard variable tariffs offered in the UK energy market.

2 Introduction

2.1 In its State of the Market Assessment, one of Ofgem's propositions was that suppliers raised prices in response to an increase in wholesale costs faster than they reduced prices in response to a fall in wholesale costs ('rockets and feathers' pricing).[12] In support of this, Ofgem cited an error correction model (the 'Ofgem 2014 analysis') which was claimed to demonstrate a 'statistically significant asymmetry in the length of response to decreases in wholesale cost'.[13] This was a follow-up to an earlier analysis (the 'Ofgem 2011 analysis').[14]

2.2 Such asymmetry in pricing could be interpreted in a number of ways. Ofgem claimed that the asymmetry could be a symptom of a lack of effective competition (including tacit coordination), while noting that there may be other feasible explanations, such as an asymmetric media response to upward and downward price changes. Oxera has previous noted that asymmetric price movements have been found to be prevalent in markets outside energy—for example, those detailed in Peltzman (2000), a study which found no correlation between asymmetric price responses and the level of competition in the markets examined.[15] For this reason, even if the Ofgem 2014 results were robust, 'rockets and feathers' pricing dynamics may not be evidence of a competitive problem in the energy market.

2.3 In August 2014, Oxera submitted a summary report highlighting concerns with this evidence (our 'August critique').[16] The Ofgem 2011 analysis was found to contain substantial econometric errors, and we therefore concluded that it could not be relied on. While the 2014 analysis addressed many of these issues, a number of material technical shortcomings remained, in particular with respect to

[10] Competition and Markets Authority (2015), 'Energy Market Investigation – updated issues statement', 18 February, paras 154–163. In addition, SLC 25 (Marketing to Domestic Customers) introduced onerous requirements on suppliers undertaking doorstep sales.

[11] In the sense that a co-integrating relationship was found between price, total cost and a dummy for regulatory changes.

[12] Ofgem (2014), 'State of the Market Assessment', 27 March, p. 72.

[13] See Ofgem (2014), 'State of the Market Assessment: supplementary appendices', 15 April, appendix 2, p. 13.

[14] Ofgem (2011), 'Do energy bills respond faster to rising costs than falling costs?', 21 March.

[15] Peltzman, S. (2000), 'Prices rise faster than they fall', *The Journal of Political Economy*, **108**:3, June, pp. 466–502.

[16] Oxera (2014), 'Critique of Ofgem's 'rockets and feathers' analyses: summary of findings', report prepared for ScottishPower, 21 August.

the econometric specifications employed and the way the results were interpreted.

2.4 On 2 October 2014, the CMA provided Oxera with the data and econometric modelling that underpinned the 2014 analysis.[17] This has resolved some ambiguity in the methods used and allowed Oxera to repeat the analysis, addressing a number of the concerns that had been raised in our August critique.

2.5 This note presents the results of the updated analysis:

- section 3 sets out the methodology employed in the note, and in particular the changes made from the Ofgem 2014 analysis;
- section 4 presents the results of the updated Ofgem models, with comparison to the earlier results presented by Ofgem;[18]
- as a sensitivity, section 5 presents an alternative long-run specification, based on total costs and a recognition of the regulatory changes that occurred, commencing with the introduction of SLC25A in 2009;
- section 6 concludes.

3 Methodology

3.A Overall approach

3.1 In this note, we have (wherever the data allows) corrected the issues in the Ofgem 2014 analysis that we considered to be most material. Otherwise, we have followed an approach that is consistent with that advanced by Ofgem.

3.2 In our August critique, four key concerns were identified with Ofgem's 2014 analysis.[19] These are set out below, alongside details of how we have addressed the concerns in the updated analysis. In section 3.E, we note a further adjustment—the removal of an outlier dummy—made following a review of the underlying data (which was not available to us at the time of writing our August critique).

3.B Symmetric unit root tests

3.3 The error correction model was employed by Ofgem on the premise that there is a long-run stable relationship between SVT energy prices and costs (a 'co-integrating' relationship). It is this relationship that makes the analysis possible.

3.4 In ascertaining the existence of this long-run relationship, Ofgem employed tests based on a *symmetric* adjustment to equilibrium, even though its analysis purported to show *asymmetric* adjustment.[20] In this note, we use an alternative testing procedure that allows for the type of asymmetric adjustment to

[17] The files received were 'Dataset_R&F.xls' and 'ECM RF.do'.

[18] Sections 4.A and 4.B are technical in nature and require a working knowledge of the error correction model framework. For a non-technical discussion of the updated results, section 4.C can be read individually.

[19] Oxera (2014), 'Critique of Ofgem's "rockets and feathers" analyses: summary of findings', report prepared for ScottishPower, 21 August, section 1.D.

[20] In particular, the standard Dickey–Fuller 'unit root' test was employed, which implicitly assumes symmetric adjustment. Strictly, the test considers a null hypothesis of non-stationarity (unit root) against an alternative hypothesis of stationarity with symmetric adjustment. See Enders, W. and Granger, C.W.J. (1998), 'Unit-root tests and asymmetric adjustment with an example using the term structure of interest rates', *Journal of Business & Economic Statistics*, **16**, pp. 304–11.

equilibrium that Ofgem wanted to test (as described by Enders and Siklos, 2001).[21]

3.C Yearly and quarterly dummies

3.5 In its specification of the long-run co-integrating relationship, Ofgem included, without stating a justification, quarterly and yearly dummies, which Oxera understood to have affected the resulting estimate of this relationship (based on the description of the method provided in the State of the Market Assessment[22]).

3.6 In non-technical terms, yearly dummies (a control variable for each year from 2004 to 2013) allow for the equilibrium price to vary each year, completely independently of adjustments made in previous years and the underlying costs. Three quarterly dummies allow for seasonal differences, meaning that the equilibrium SVT price level can vary each quarter, relative to costs. However this seasonal adjustment is assumed to be the same for any given quarter each year.[23]

3.7 The inclusion of yearly dummies means that the equilibrium value of the price can change each year, *independently of the movement in wholesale and other costs*. This is a particular issue, as price changes for standard variable tariffs do not happen with much greater frequency than once a year; hence the year dummies are potentially identifying the price changes that were made in that year, rather than any underlying equilibrium. We have therefore removed these dummy variables from the updated analysis.

3.8 There is a reasonable rationale for the inclusion of quarterly dummies. For example, if there was an additive seasonal effect on prices that was not adequately controlled for by the cost variables, including quarterly dummies would be a reasonable approach. While Ofgem does not make the case explicitly, it may be that seasonality in wholesale prices affects the relationship between retail standard variable tariffs and retail costs. We therefore include the quarterly dummies in our long-run specification.[24]

3.D Hedging

3.9 In its earlier analysis in 2011, Ofgem assessed the results from four hedging strategies, as this assumption was considered to be ‘crucial to the test for asymmetry’.[25] This sensitivity check was not conducted in the 2014 analysis.

3.10 The data provided to Oxera included only wholesale cost data based on an assumption of an 18-month hedging strategy. Without further data, we are not able to conduct this sensitivity check.

[21] Enders, W. and Siklos, P.L. (2001), ‘Cointegration and threshold adjustment’, *Journal of Business & Economic Statistics*, **19**:2, pp. 166–76.

[22] Ofgem (2014), ‘State of the Market Assessment: supplementary appendices’, 15 April, appendix 2; para. 1.16.

[23] So, for example, the seasonal adjustment for quarter 4 in 2008 is the same as that for quarter 4 of 2009. It is correct that only three quarter dummies are considered; the fourth quarter represents the baseline for the analysis.

[24] The results presented in section 4 are not materially affected by whether these seasonal dummies are included.

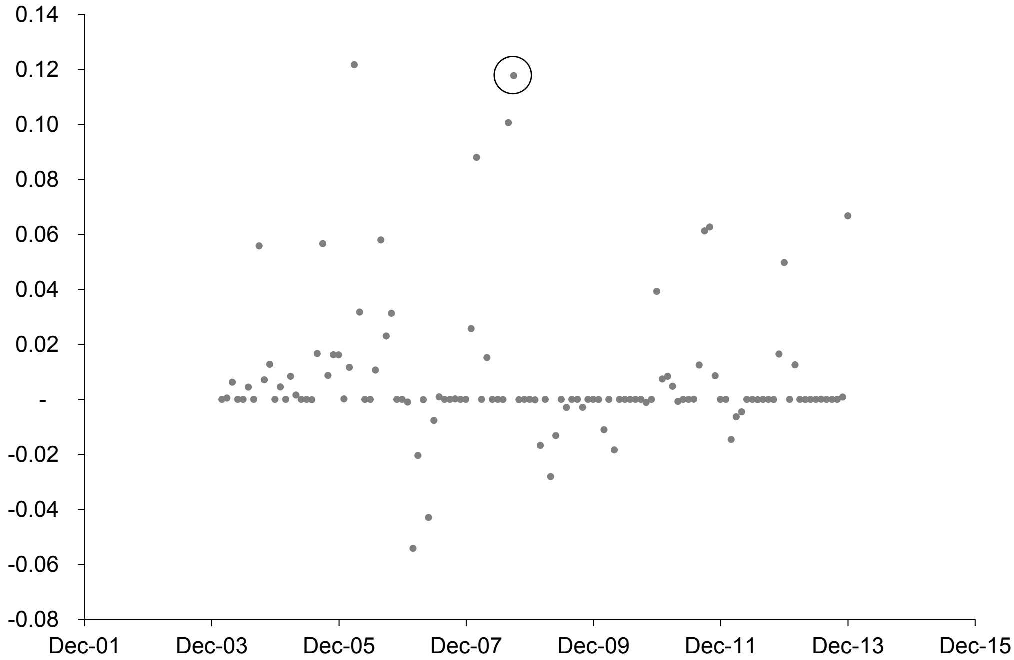
[25] Ofgem (2011), ‘Do energy bills respond faster to rising costs than falling costs?’, 21 March, para. 1.14.

3.E Exclusion of a data point

3.11 In the 2014 analysis, Ofgem included an ‘outlier dummy’ which removed a single data point from the analysis (September 2008). This was to ‘control for the spike in prices’ in this period.[26] Oxera has been able to review this methodological assumption based on the underlying data received from the CMA.

3.12 As shown in the figure below, the change in prices in September 2008, while high, was not out of line with the variation in the rest of the dataset (the excluded data point is circled). In logarithmic terms (as considered in the model), it was not even the highest price change in the dataset. Its exclusion therefore appears arbitrary.

Figure 3.1 Change in log price over time in the Ofgem 2014 dataset



Note: Logarithmic changes can be approximately interpreted as proportionate changes—i.e. a 0.01 log change implies an approximate 1% change in price. The data point excluded by Ofgem is circled.

Source: Oxera analysis of Ofgem 2014 analysis dataset.

3.13 The accompanying cost data shows that this price rise came after a sustained period of wholesale cost rises (a cumulative rise of 40% from the start of 2008 to September 2008). The basis on which Ofgem concludes that this was a spurious outlier, rather than an informative observation of market prices, is therefore unclear. Furthermore, Ofgem’s treatment of this data point is inconsistent: while it is excluded in the final error correction model, it is included when Ofgem estimates the long-run relationship.

3.14 As the removal of this point does not appear to be justified by the data, we exclude the outlier dummy from the error correction model in this note, and thus include the full dataset in the analysis.

[26] See Ofgem (2014), ‘State of the Market Assessment: supplementary appendices’, 15 April, appendix 2, p. 11.

3.F Interaction of short- and long-run dynamics

3.15 By considering the short- and long-run coefficients separately, and basing its conclusion of rockets and feathers pricing on the long-run adjustment coefficient only, Ofgem failed to consider the *combined* impact of the short-run and long-run dynamics. Both are relevant in giving a full view of how price adjusts to shocks in wholesale cost.

3.16 The implications for price dynamics of the entire estimated model can be considered through graphical illustrations ('impulse response functions') that show how the price adjusts in response to upward and downward cost shocks of identical size. Following this approach in our critique, we found that, when the entire Ofgem 2014 model was taken into account, Ofgem's conclusion of rockets and feathers did not appear justified.

3.17 In this note we consider both the individual adjustment terms (in line with Ofgem's 2014 analysis) and, graphically, the overall price response.

3.G Summary of changes

3.18 The changes described in this section are the only changes Oxera has made to the 2014 analysis; other details, such as the specification of the error correction models, are unchanged. We consider this appropriate, given that the aim of this note is to highlight the impact of correcting the shortcomings identified in our earlier critique.[27] However, as a sensitivity we also consider an alternative specification for the long-run relationship; this is discussed in section 5. For the core analysis, the changes described in this section are summarised in Table 3.1.

Table 3.1 Changes made to the Ofgem 2014 analysis for the analysis in this note

	Ofgem 2014 analysis	**Oxera analysis**
Data	Market-wide monthly data, including annualised retail prices, wholesale and other costs	Unchanged
Long-run relationship	Includes quarterly and yearly dummies	Includes quarterly dummies only
Unit root tests	Assumes symmetric relationship	Allows for asymmetric relationship
Outliers	September 2008 excluded (using outlier dummy)	No data points excluded
Hedging period sensitivity	Not considered	Not considered (owing to lack of data)
Error correction model	Asymmetric, allowing for 1–2 lagged differences	Unchanged
Price dynamics	Considered by separate comparison of coefficients (equilibrium adjustment and short-run response to wholesale prices)	Comparison of coefficients and graphical analysis using entire estimated model

Source: Oxera analysis.

[27] Oxera (2014), 'Critique of Ofgem's "rockets and feathers" analyses: summary of findings', report prepared for ScottishPower, 21 August.

4 Results of updated Ofgem analysis

4.1 This section presents the parameter estimates from the econometric analysis in the long-run (section 4.A) and error correction (section 4.B) models, before considering (in section 4.C) the implications for rockets and feathers pricing in the UK energy market. Sections 4.A and 4.B include technical discussion of the results and assume a working knowledge of regression analysis and the error correction model framework. Readers seeking only a non-technical discussion of the final results can proceed directly to section 4.C.

4.A Long-run relationship and co-integration

4.2 Following the changes made to the Ofgem 2014 analysis, the specification employed in estimating the long-run relationship is:

$$\log(retail\ price_t) = \alpha + \beta \log(wholesale\ cost_t) + \gamma \log(other\ cost_t) + \sum_{i=1}^{i=3} quarter_t^i + \epsilon_t$$

4.3 This 'log-log' specification represents a non-standard specification for the relationship between prices and costs. When expressed in natural (non-logarithmic) form, it implies that the SVT price is related to wholesale costs *multiplied* by the other costs, as opposed to the more standard assumption that price is related to wholesale costs *added* to other costs.

4.4 Indeed, this is the specification frequently employed when investigating material inputs in a 'Cobb-Douglas' production function, which assumes substitutability of between inputs.[28] It is clear this is a poor analogy in this case; suppliers cannot choose to purchase less wholesale energy and spend more on social obligations to get the same output. Oxera therefore considers that, while it may be a valid approximation for estimating the impact of small cost changes, it lacks economic coherence when considered in the context of the large cost changes observed in the Ofgem 2014 dataset. This issue is revisited in section 5.

4.5 In Table 4.1, the resulting estimates from this specification are compared with the long-run relationship estimated in the Ofgem 2014 analysis.

Table 4.1 Long-run relationship in rockets and feathers analysis (robust standard errors in parentheses)

Estimation of log(retail price)	Ofgem 2014 analysis	Oxera analysis
Log (wholesale cost)	0.463 (0.0439)	0.362 (0.0230)
Log (other costs)	-0.0245 (0.157)	0.899 (0.0292)
Yearly dummies	Included	Excluded
Quarterly dummies	Included	Included
Observations	119	119
Result of symmetric co-integration test (Dickey–Fuller, 12 lags, following Ofgem 2014)	Co-integrated	Co-integrated
Result of asymmetric co-integration test (as Enders and Siklos 2001)[1]	Not conducted by Ofgem	Co-integrated

Note: All co-integration tests conducted using 95% critical values. Yearly and quarterly dummies individual coefficients not shown. [1] The number of lags in the test specification was selected using the Bayes Information Criterion. The test statistic employed was the F-statistic from a Threshold

[28] Cobb, C.W. and Douglas, P. H. (1928), 'A Theory of Production', *American Economic Review* ,**18** (Supplement), pp. 139–65.

Auto Regression (TAR) adjustment model, compared with the critical values presented in Table 1 of Enders and Siklos (2001).

Source: Oxera analysis of Ofgem 2014 data.

4.6 Three observations are immediately apparent:

- The updated specification (excluding year dummies) still represents a co-integrating relationship between prices and costs.
- The ‘other cost’ coefficient was negative and insignificant in the Ofgem model, implying, implausibly, that increases in other (non-wholesale) costs had a negligible (and possibly negative) impact on retail prices. In the Oxera specification the coefficient is positive (and significant), which is more in line with the theoretical expectation that changes in other costs will, at least to some extent, be passed through to prices.
- Even in the Oxera specification, the level of this ‘other cost’ coefficient of approximately 0.9 implies that every 1.0% change in other costs will result in a roughly 0.9% change in equilibrium retail price. This is now higher than expected, given the proportion of total cost (roughly 40% in the Ofgem 2014 dataset) made up from ‘other’ costs.[29] This coefficient implies a ‘pass–on’ of these other costs of considerably more than 100%.

4.B Error correction model

4.7 Aside from the exclusion of a single ‘outlier dummy’ (see section 3.E), the specification of the error correction model considered in this note is unchanged from the Ofgem 2014 analysis. The results are shown in Table 4.2.

[29] Alongside other operating costs, these include network costs, environmental costs and social obligations. See Ofgem (2014), ‘State of the Market Assessment: supplementary appendices’, 15 April, appendix 2, p. 8.

Table 4.2 Estimated error correction models

Error correction model: estimation of change in log(retail SVT price)	Ofgem 2014 analysis (1 lag)	Ofgem 2014 analysis (2 lags)	Oxera analysis (1 lag)	Oxera analysis (2 lags)
Long-run adjustments				
Adjustment when above equilibrium (t-1) (a)	0.0138	0.0231	-0.148	-0.124
Adjustment when below equilibrium (t-1) (b)	-0.652***	-0.653***	-0.183	-0.177
Short-run adjustments				
Δlog(retail_price) (positive, t-1)	0.228***	0.234***	0.348**	0.365**
Δlog(retail_price) (positive, t-2)		-0.0309		-0.0998
Δlog(retail_price) (negative, t-1)	0.152	0.134	0.0994	0.0919
Δlog(retail_price) (negative, t-2)		0.133		0.0423
Δlog(wholesale cost) (positive, t) (c)	0.169	0.166	0.174	0.203
Δlog(wholesale cost) (positive, t-1)	-0.322*	-0.300	-0.0348	-0.0392
Δlog(wholesale cost) (positive, t-2)		-0.0325		-0.00906
Δlog(wholesale cost) (negative, t) (d)	0.236	0.281	0.113	0.126
Δlog(wholesale cost) (negative, t-1)	0.140	-0.00477	0.163	0.0586
Δlog(wholesale cost) (negative, t-2)		0.115		0.135
Δlog (other cost) (t)	-0.0422	-0.0307	–0.0530	-0.0376
Outlier dummy	0.0999***	0.0994***		
Observations	117	116	117	116

Note: Coefficient significant at ***1%, **5% and *10% level. (t) indicates contemporaneous change. (t-1) indicates change in previous month, and (t-2) indicates change two months previously. Robust standard errors have been employed (not shown). For all four specifications, standard diagnostic tests were conducted and passed. These included the Ramsey RESET test of specification and the Ljung–Box test for serial correlation of residuals.

Source: Oxera analysis of Ofgem 2014 data.

4.8 Given the small number of changes we have made, it is not surprising that there are qualitative similarities between the Ofgem 2014 error correction model and the Oxera update. Short-run coefficients usually have the same sign and in many cases are of similar magnitude. Of these, only the lagged price change is consistently statistically significant.

4.9 Ofgem's conclusion of a finding of rockets and feathers pricing was based on the difference between the two long-run coefficients. In its analysis it finds that, when SVT prices are below their equilibrium level in relation to costs, prices will increase (based on the significant negative coefficient on the adjustment when below equilibrium), but that when these prices are above their equilibrium level in relation to costs, there is no reduction in price (the equivalent coefficient on the opposite adjustment term is not significant). It is this combination of coefficients that formed the basis for Ofgem's finding of rockets and feathers in UK SVT retail energy pricing, as described in detail in section 4.C.

4.10 The CMA has since raised concerns that there are too few price changes in the standard variable tariff to support an econometric analysis of this nature.[30] While we agree that this issue increases the uncertainty around the point estimates, it would still be expected that, if there were rockets and feathers pricing in this market, some evidence of it would be found in these estimations. Price changes

[30] Competition and Markets Authority (2015), 'Energy Market Investigation Working Paper: Cost Pass Through', 23 February, para. 42.

are non-zero for the majority of the observations (75 of 119), and no severe issues of multicollinearity are found based on post-estimation diagnostics.[31]

4.11 In considering rockets and feathers pricing, it is therefore relevant that, once the changes recommended by Oxera have been made, the positive and negative adjustment coefficients are similar (as shown in Table 4.2). In the following section we show that, using formal statistical tests, this similarity of the coefficients undermines Ofgem's conclusion of rockets and feathers pricing in this market.

4.C Rockets and feathers

4.C.2 Testing for symmetry in individual coefficients

4.12 In the Ofgem 2014 analysis, the hypothesis of rockets and feathers pricing was tested by conducting a formal test (an 'F-test') of the equality of (i) the two long-run adjustment coefficients;[32] and (ii) the two contemporaneous short-term adjustment coefficients, which measure the immediate sensitivity of price to wholesale costs. The table below presents the results of this test in the Ofgem 2014 analysis, and the restated results once the changes recommended in this note are made. It is seen that, following these changes, *the statistically significant difference between the positive and negative adjustment terms disappears*.

Table 4.3 Testing equality of coefficients (Ofgem's test for rockets and feathers)

	Ofgem 2014 analysis (1 lag)	Ofgem 2014 analysis (2 lags)	Oxera analysis (1 lag)	Oxera analysis (2 lags)
Test of equality of equilibrium adjustment F-test of (a) = (b), p-value	0.011	0.010	0.882	0.819
Significant difference	Yes (at 5%)	Yes (at 5%)	No	No
Test of equality of equilibrium adjustment F-test of (c) = (d), p-value	0.838	0.753	0.884	0.873
Significant difference	No	No	No	No

Note: The p-value in each case can be interpreted as the probability of the coefficient estimates being observed, if it is assumed that the true coefficients are equal. By statistical convention, we reject this assumption when the p-value is less than 0.05. (a), (b), (c) and (d) refer to the coefficients in Table 4.2.

Source: Oxera analysis of Ofgem 2014 data.

4.13 The statistical test presented in Table 4.3 was the basis on which Ofgem supported its conclusion of rockets and feathers pricing. Oxera therefore concludes that this finding is an artefact of the shortcomings in Ofgem's methodology, as outlined in section 3.

4.C.3 Impulse response functions

4.14 It was noted in our August critique that a complete analysis of the pricing dynamics implied by an error correction model cannot only depend on statistical tests of individual coefficients, but should consider the model as a whole. To

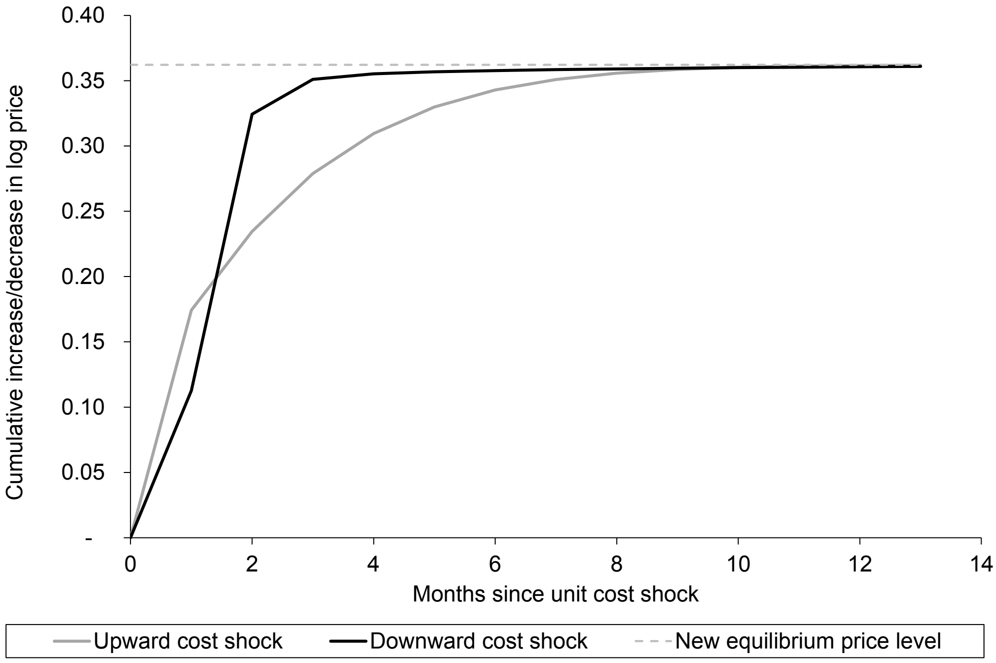
[31] The variance inflation factor is above 10 for only one coefficient in the updated specifications—i.e. the positive lagged change in wholesale costs in the two lag equation, where it is 13.9.

[32] Marked (a) and (b) in Table 4.2.

illustrate the dynamics implied by the updated models presented in this note, we employ the 'impulse response functions' resulting from the two models (for one and two lags respectively).

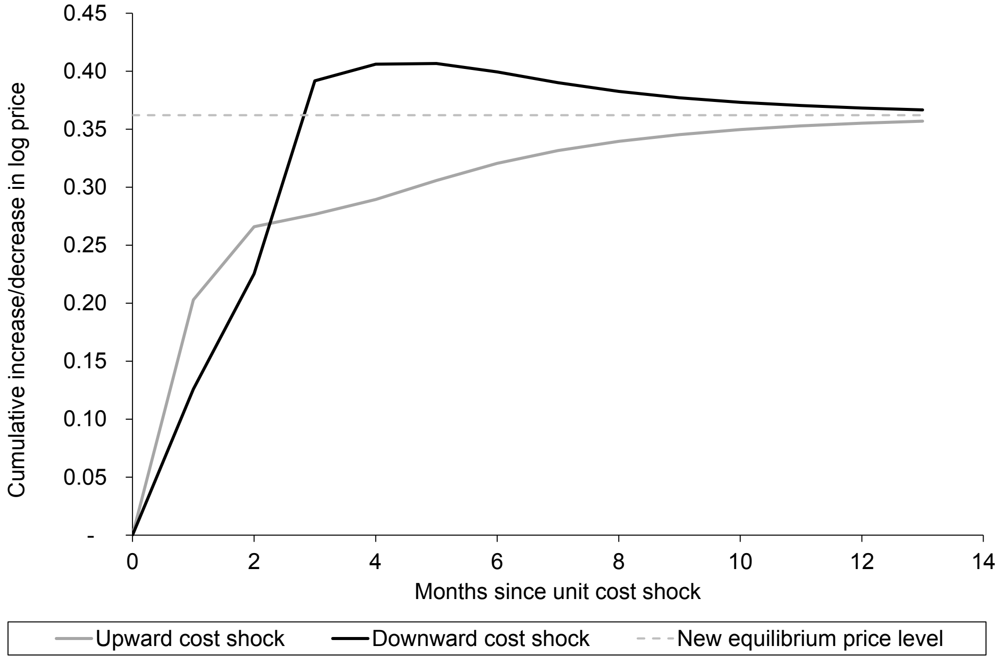
4.15 The impulse response functions present two trends. The first illustrates the cumulative *increase* in log price that results from a permanent unit increase in wholesale costs. For comparison, the second illustrates the change that results from a permanent unit decrease in wholesale cost alongside the first (the scale is reversed, so, for the second line, the axis represents the cumulative *decrease* in log price). See Figures 4.1 and 4.2.

Figure 4.1 Impulse response function for updated model (one lag)



Source: Oxera analysis of Ofgem 2014 data.

Figure 4.2 Impulse response function for updated model (two lags)



Source: Oxera analysis of Ofgem 2014 data.

4.16 There is little indication in these figures of a slower adjustment of SVT prices to wholesale cost decreases than wholesale cost increases. Indeed, in both models the overall speed of adjustment to decreases in wholesale costs is, if anything, faster than the speed of response to increases in wholesale costs. In the 'two-lag' model an 'overcorrection' is observed in response to a cost decrease, with prices falling below their equilibrium levels before slowly returning. However, given the degree of uncertainty in the estimates of the short-run coefficients, the detailed adjustment profile is indicative only.

4.17 Nevertheless, these figures serve to illustrate that, once updated for the shortcomings identified in section 3, neither of the error correction models within the Ofgem 2014 analysis provides any evidence of rockets and feathers pricing in the UK energy market.

5 An alternative long-run price relationship

5.1 In section 4 it was noted that, given minimal changes to Ofgem's approach, the issue of an unfeasible implied (negative) relationship between price and other costs was resolved. However, the level of 'pass-on' implied by the new approach for other (non-wholesale) costs at over 100% is higher than expected, indicated the model may still be mis-specified. One possible reason for this is that the coefficient on the 'other cost' measure is being affected by the other changes that have happened in the market since 2009.

5.2 In this section, we consider an alternative approach motivated by existing literature concerning the regulatory changes that have occurred since 2009 (starting with the introduction of SLC25A) in the UK energy market.[33] We show that the trend in UK SVT energy prices can be explained in terms of total costs and the long-run impact of these interventions that have reduced price

[33] See Competition and Markets Authority (2015), 'Energy Market Investigation – updated issues statement', 18 February, para. 157.

discrimination. In this framework, we find the data is consistent with (i) an impact on SVT prices from these regulatory interventions; and (ii) no evidence of rockets and feathers pricing.

5.3 Section 5A motivates this sensitivity with a brief overview of the main regulatory changes since 2009, starting with SLC25A, and trends in SVT prices and total cost in the Ofgem dataset. Section 5B gives a technical description of the long-run specification that we have employed and the resulting error correction model. Section 5C interprets these results.

5.A Regulatory changes post-2009, including SLC25A, and the UK energy retail market

5.4 In September 2009, Ofgem introduced a new energy supply licence condition (SLC25A), which had the aim of 'preventing undue discrimination' by energy providers.[34] In particular, it sought to place strict limits on the extent to which suppliers could charge a higher SVT price in the area where they were traditionally an incumbent compared to elsewhere in the country.[35] The clause was allowed to lapse in 2012, but Ofgem indicated that 'if at any time we have compelling evidence to suggest pricing practices which are unjustified are returning to the market, we may commence a full review of this area and consider developing new licence conditions to address our concerns.'[36] On this basis, energy suppliers have indicated to the CMA that they continued to adhere to its principles after 2012.[37]

5.5 In January 2010, Ofgem introduced SLC 25: Marketing to Domestic Customers. Requirements under this licence condition included keeping accurate records on competitor pricing to ensure full and complete pricing comparisons were provided to customers. The introduction of these requirements, and the subsequent enforcement action taken by Ofgem, led to an effective withdrawal of energy suppliers from doorstep sales.

5.6 Moreover, in 2013, following the Retail Market Review, Ofgem introduced limitations on the number of tariffs a supplier could offer to a given customer in order to simplify choice.[38] While not intended to restrict regional tariff differentiation, this further limited the extent to which suppliers could price-discriminate in general, constraining the range of tariffs that could be offered to potential customers.[39]

5.7 Evidence of a long-run effect of SLC25A (and anti-price-discrimination regulation in general) on the nature of competition in the UK energy market has been well documented.[40] In particular, as suppliers were unable to offer lower standard

[34] See Ofgem (2009), 'Addressing under discrimination – Final Impact Assessment' Ref 73/09 , 26 June.

[35] For an overview, see Oxera (2012), 'Ofgem's anti-competitive practice', *Agenda,* May.

[36] Ofgem (2012), 'Decision on Standard Condition 25A in the Gas and Electricity Supply Licences', letter to holders of Gas and Electricity Supply Licences, 26 October.

[37] Competition and Markets Authority (2015), 'Energy Market Investigation – updated issues statement', 18 February. In December 2014 Ofgem wrote to suppliers to confirm that they were no longer bound by SLC25A 'in any way'. However, as this event occurred after the final point in the rockets and feathers dataset, it is not considered in this paper.

[38] Ofgem (2013), 'Ofgem starts countdown to a simpler, clearer and fairer energy market', press release, 21 February.

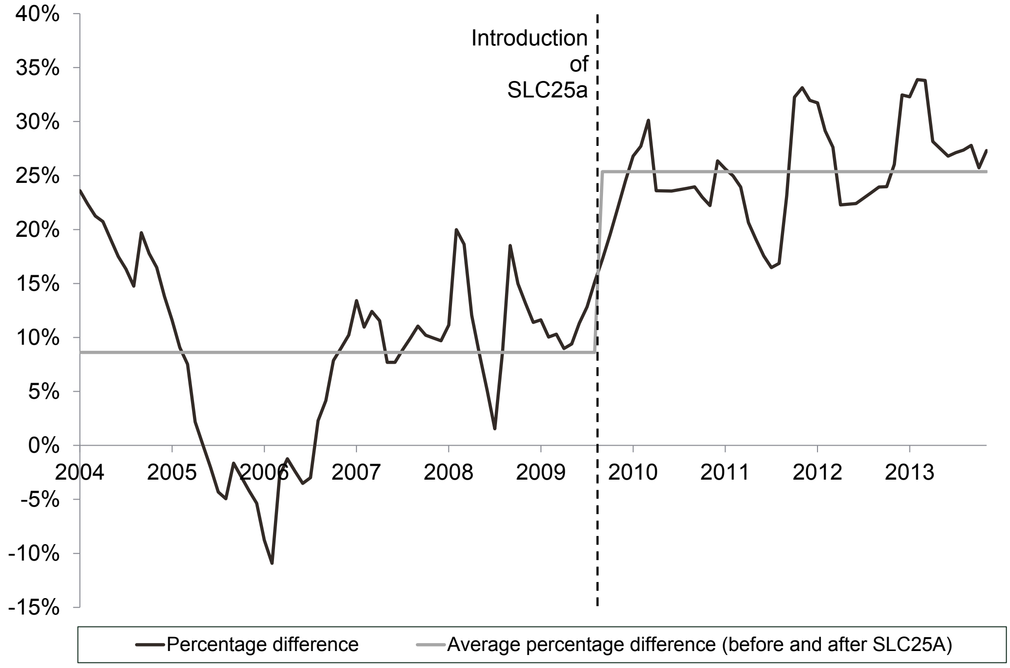
[39] See Waddams Price, C. and Zhu, M. (2013), 'Pricing in the UK retail energy market, 2005 – 2013', CCP Working Paper 13-12, December, p. 16.

[40] See Waddams Price, C. and Zhu, M. (2013), 'Pricing in the UK retail energy market, 2005 – 2013', CCP Working Paper 13-12, December, p. 16; Oxera (2012), 'Ofgem's anti-competitive practice', *Agenda,* May; Littlechild, S. (2012), 'Ofgem's retail choice', a response to Ofgem's consultation on SLC25A; 28 May; and

tariffs to target growth outside of their incumbency regions, the effect has been to move the focus of this competition from standard variable tariffs to special offer and product tariffs.[41]

5.8 On this basis, it might be expected that, in the Ofgem 2014 dataset (which is limited to standard variable tariff prices only), a change in the average pricing dynamic for this set of tariffs would be observed from the point of the introduction of SLC25A. This is illustrated in Figure 5.1. The effect is consistent with a 'step change' in the pricing of standard variable tariffs relative to total cost, starting from this date. As SVTs represent only a portion of the tariff offerings in the market, an understanding of the overall market pricing dynamics post-2009 would need to investigate how other tariffs developed at this time. This observation motivates our alternative price specification, discussed in the following section.

Figure 5.1 UK energy industry difference beteen price and cost indices for standard variable tariffs (Ofgem 2014 data)



Note: Percentage difference expressed as price less wholesale and other costs, divided by price as defined in the Ofgem 2014 dataset.

Source: Oxera analysis of Ofgem 2014 dataset.

5.B Alternative specifications using total cost

5.B.2 Long-run relationship

5.9 This subsection repeats the analysis of section 4, but changes the specification to test the impact of the regulatory interventions discussed above. As a minimal specification, we consider a relationship between SVT price and total cost given by the following:

Yarrow, G. (2009), 'Addressing undue discrimination: final proposals' Response to Ofgem's consultation, 13 May.

[41] Waddams Price, C. and Zhu, M. (2013), 'Pricing in the UK retail energy market, 2005 – 2013', CCP Working Paper 13-12, December, p. 15.

$$\log(retail\ price_t) = \alpha + \beta \log(total\ cost_t) + \gamma\ SLC25a_t + \sum_{i=1}^{i=3} quarter_t^i + \epsilon_t$$

5.10 ‘Total cost’ is defined as the sum of wholesale and other costs in the Ofgem 2014 dataset. ‘SLC25A’ is a dummy variable taking value one after the introduction of SLC25A in September 2009, and value zero otherwise. Quarterly dummies to allow for seasonality are included, consistent with the Ofgem 2014 analysis.

5.11 The use of the total cost (rather than wholesale and other costs separately) in this context has two main advantages.

- First, it reflects a more realistic relationship between price and cost, relating SVT prices to the sum of wholesale and other costs, as opposed to the non-standard relationship inherent in the Ofgem 2014 specification (see paragraph 4.4 above).
- Second, it allows for a simpler technical specification, thus reducing concern associated with possible multiple co-integrating relationships between variables and increasing the power of any test of co-integration.

5.12 Replacing the wholesale and other cost measures with a single measure of total cost alone, we find that the SVT price variable and total cost measure are not, in themselves, co-integrated. However, by adding the dummy variable to allow for the 2009 regulatory change, we do find a co-integrating relationship, which gives a more economically coherent interpretation. The resulting estimation is shown in Table 5.1.

Table 5.1 Long-run relationship in rockets and feathers analysis (alternative specification, robust standard errors in parentheses)

Estimation of log(retail SVT price)	Oxera alternative specification
Log (total cost)	0.934 (0.0230)
SLC25A	0.163 (0.0136)
Yearly dummies	Excluded
Quarterly dummies	Included
Observations	119
Result of symmetric co-integration test (Dickey–Fuller, 12 lags, following Ofgem 2014)	Co-integrated
Result of asymmetric co-integration test (as Enders and Siklos 2001)[1]	Co-integrated

Note: All co-integration tests conducted using 95% critical values. Yearly and quarterly dummies individual coefficients not shown. [1] The number of lags in the test specification was selected using the Bayes Information Criterion. The test statistic employed was the F-statistic from a TAR adjustment model, compared with the critical values presented in Table 1 of Enders and Siklos (2001).

Source: Oxera analysis of Ofgem 2014 data.

5.13 This specification has an advantage over that considered in section 4, in that the coefficients have economically consistent implications. The coefficient of total cost (0.9) approximately implies that, for every 1.0% change in total costs, the SVT price changes by 0.9%. The coefficient on the SLC25A variable suggests that standard variable prices were 17.7% higher after the introduction of SLC25A than would have been expected based on the previous trend in costs alone. While not definitive evidence, this observation is consistent with a shift in the focus of competition from standard variable to other tariffs, in line with the discussion set out in section 5.A.

5.B.3 Error correction model

5.14 The error correction model resulting from the long-run relationship above is estimated in Table 5.2. The specification of this model is unchanged except in so far as the short-run dynamics now depend on ‘total costs’ (rather than wholesale energy and other costs separately).

Table 5.2 Estimated error correction models (alternative specification)

Error correction model: estimation of change in log(retail SVT price)	Oxera analysis alternative specification (1 lag)	Oxera analysis alternative specification (2 lags)
Long-run adjustments		
Adjustment when above equilibrium (t-1) (a*)	-0.146	-0.116
Adjustment when below equilibrium (t-1) (b*)	-0.113	-0.120
Short-run adjustments		
Δlog(retail_price) (positive, t-1)	0.312*	0.342*
Δlog(retail_price) (positive, t-2)		-0.153
Δlog(retail_price) (negative, t-1)	0.105	0.107
Δlog(retail_price) (negative, t-2)		0.010
Δlog(total cost) (positive, t) (c*)	0.118	0.165
Δlog(total cost) (positive, t-1)	0.040	0.053
Δlog(total cost) (positive, t-2)		-0.063
Δlog(total cost) (negative, t) (d*)	0.370	0.419
Δlog(total cost) (negative, t-1)	0.278	-0.012
Δlog(total cost) (negative, t-2)		0.351
Observations	117	116

Note: Robust standard errors were employed. Coefficient significant at ***1%, **5% and *10% level. (t) indicates contemporaneous change. (t-1) indicates change in previous month, and (t-2) indicates change two months previously. Robust standard errors have been employed (not shown). For all four specifications, standard diagnostic tests were conducted and passed. The exception is the Ramsey RESET test, which fails at the 5% level in the case of the two-lag model. Variance inflation factors are not greater than 10 for any variable. SLC25A is expected to affect the long-run price level only; its effect is therefore captured through the long-run adjustments and is not reflected in the short-run adjustment coefficients.

Source: Oxera analysis of Ofgem 2014 data.

5.15 Consistent with the results of section 4, only the lagged SVT price change is statistically significant. Also consistent with section 4, the positive and negative adjustment coefficients (marked a* and b*) are of similar magnitude. For the short-run dynamics (marked c* and d*), the price appears, if anything, more reactive to cost falls than to cost rises. Again, with this change to the specification of the long-run equilibrium relationship between costs and SVT prices, there is no evidence of rockets and feathers pricing, and we replicate Ofgem’s formal tests in the following subsection.

5.C Rockets and feathers under alternative specification

5.16 This section conducts and explains the formal tests for rockets and feathers pricing, based on the assumption that the underlying price trend is determined by total costs and the impact of anti-price-discrimination regulations since 2009, starting with SLC25A. We will show that, while this represents a very different explanation of SVT prices to that in the previous section, the implication for rockets and feathers is unchanged, with no evidence of asymmetric adjustment of prices in the UK energy market.

5.C.4 Testing for symmetry of coefficients

5.17 In common with section 4, we repeat Ofgem's 2014 test for rockets and feathers by separately comparing the short- and long-run adjustment coefficients and conducting a formal test to identify whether there is any evidence that the two are asymmetric. The table below presents the results of this test. It can be seen that, consistent with the results of section 4, there is no evidence of rockets and feathers pricing using the alternative specification including the dummy from 2009.

Table 5.3 Testing equality of coefficients in the alternative specification (Ofgem's test for rockets and feathers)

	Oxera analysis (1 lag)	Oxera analysis (2 lags)
Test of equality of equilibrium adjustment F-test of (a*) = (b*), p-value	0.877	0.986
Significant difference	No	No
Test of equality of equilibrium adjustment F-test of (c*) = (d*), p-value	0.543	0.604
Significant difference	No	No

Note: The p-value in each case can be interpreted as the probability of the coefficient estimates being observed, if it is assumed that the true coefficients are equal. By statistical convention, we reject this assumption when the p-value is less than 0.05. (a*), (b*), (c*) and (d*) refer to the coefficients in Table 5.2.

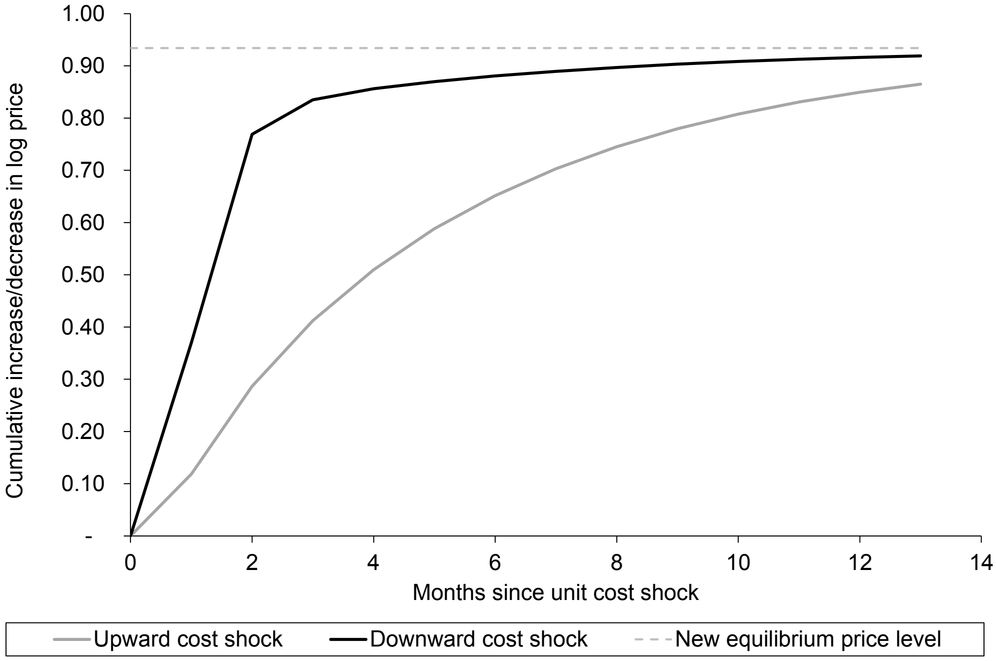
Source: Oxera analysis of Ofgem 2014 data.

5.C.5 Impulse response functions

5.18 We also test for a rockets and feathers dynamic in pricing considering the effect of short- and long-run dynamics together. To illustrate the price movements implied by the updated models presented in Table 5.2, we again use impulse response functions. These show the response to a price change implied by the updated models (for one- and two-lagged differences).

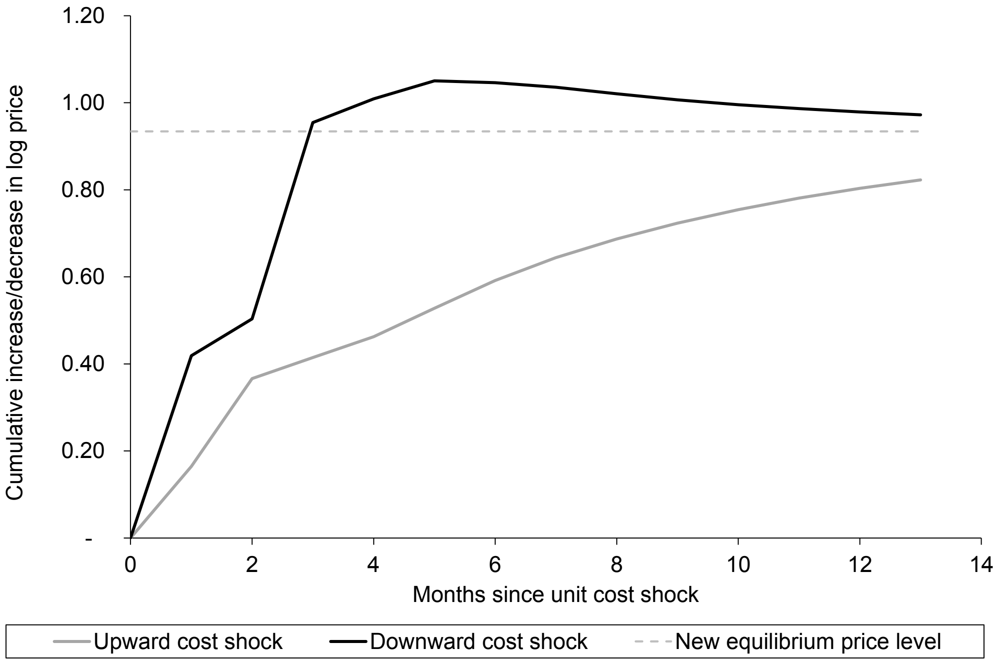
5.19 As in section 4, each of the figures below (one for each specification in Table 5.2) presents two trends. The first trend illustrates the cumulative *increase* in log SVT price that results from a permanent unit increase in total costs. For comparison, the second trend illustrates the change that results from a permanent unit decrease in total cost alongside the first (the scale is reversed, so, for the second line, the axis represents the cumulative *decrease* in log SVT price). See Figures 5.2 and 5.3.

Figure 5.2 Impulse response function for alternative model including impact of SLC25A (one lag)



Source: Oxera analysis of Ofgem 2014 data.

Figure 5.3 Impulse response function for alternative model including impact of SLC25A (two lags)



Source: Oxera analysis of Ofgem 2014 data.

5.20 There is no indication in these figures that SVT prices adjust faster to increases in total cost than they do to decreases. Indeed, for both the one-lag and two-lag models, the adjustment is *faster* in the case of a cost decrease. The implied time for adjustment to upward cost shocks is longer than indicated in section 4, with almost half the adjustment remaining six months after the cost shock. This might be considered consistent with a reluctance on the part of suppliers to raise prices in the short run given the negative media attention that follows any such increase. However, given the wide margin of error in the estimation of the short-run coefficients, these results can be considered indicative only.

5.21 In the previous section it was assumed that the equilibrium standard variable price depended on a 'split' relationship between wholesale and other costs. In this section we have made the alternative assumption that it depends on total cost and the influence of regulatory changes since 2009. This has not affected the conclusion with respect to the dynamics of price responses; whichever assumption is adopted, we find no evidence of rockets and feathers pricing in the UK energy market.

6 Conclusions

6.1 This note has updated the econometric method presented in the Ofgem 2014 analysis, making changes to address the technical concerns raised in our August critique. Specifically:

- unit root tests no longer implicitly assume symmetric adjustment to equilibrium;
- yearly dummies are no longer included in the estimation of the long-run co-integrating relationship between energy prices and costs;
- a single data point that was excluded arbitrarily (through the exclusion of one outlier dummy) has been added back into the analysis.

6.2 Consistent with our earlier August critique, the rockets and feathers hypothesis is tested by considering (i) individual coefficients in the model; and (ii) the overall SVT price dynamic implied by the model, as illustrated through impulse response functions. Whichever test is used, no evidence of rockets and feathers pricing is found in the updated analysis.

6.3 We therefore find that Ofgem's positive results in the 2014 analysis were an artefact of the methodological shortcomings identified in this note, and Ofgem's analysis cannot be considered to reliably support a conclusion of rockets and feathers pricing in the UK energy market.

6.4 As a sensitivity, we have also considered the pricing dynamics under an alternative specification of the long-run relationship between costs and SVT prices of standard variable tariffs. In this analysis, we assumed that the equilibrium SVT price for energy was explained by both (i) the total cost; and (ii) the long-run impact of regulatory interventions designed to reduce price-discrimination, starting with the introduction of SLC25A in 2009. We found that:

- a co-integrating relationship between standard variable tariff price and total cost can be achieved by allowing the level of equilibrium price to shift following the introduction of SLC25Ain 2009;
- the estimated increase in standard variable price following the introduction of SLC25A is consistent with a shift in the focus of competition to the other 'product' tariffs from 2009.

In this alternative framework, we continue to find no evidence of rockets and feathers dynamics in SVT energy pricing. In addition, the results demonstrate that looking at the dynamic of costs and standard variable tariffs in isolation may lead to erroneous conclusions as this ignores the effect of a shift in the focus of competition to ‘product’ tariffs following the introduction of SLC25A.

SCOTTISHPOWER

Rupert Steele OBE
Director of Regulation

Siobhan Stanger
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6 September 2013

Dear Siobhan,

Energy Companies Obligation (ECO) – Threshold and Taper Policy

Thank you for your letter dated 12 August. As you know, we have for some time been concerned that the current threshold and taper policy does not work well, causing barriers to growth for medium sized suppliers and significant distortions to competition affecting others (and consumers). We therefore welcome the fact that DECC are looking at the policy again, including collecting evidence in relation to ECO delivery and the operation of the current 'threshold and taper'.

<u>Fixed costs involved in delivering ECO</u>

We have analysed the roles of our team delivering ECO in order to apportion the staff and related administration costs between fixed costs and those that are proportionate to the volume of measures delivered. In broad terms, we estimate that about 20% of our administrative costs are fixed and that the remainder scale with the size of the programme.

More precisely, we have identified 12 Full Time Equivalent (FTE) roles in our organisation that we believe are ECO overheads that do not scale with volume. Using a notional annual full cost of £100,000 per FTE (to include salaries, accommodation, pensions, HR, IT, and all other on-costs), we therefore estimate the non-scale costs of running an ECO programme to be about £1.2 million each year.

The problem is that an exemption is a poor solution for dealing with the impact of these costs on suppliers of different sizes. It would clearly be desirable in terms of avoiding disadvantage to small suppliers and potential new entrants for the non-scale costs of an obligated small supplier to be non-material in the annual bill. If that was defined as £5 per dual fuel customer per year, it would require around 240,000 dual fuel customers over which to spread the fixed cost. But exempting suppliers also excludes the scalable costs of c. £50 per dual fuel customer per year (or maybe nearer £65 based on our recent view of the ECO programme's costs). This provides a substantial and unjustified cross subsidy in favour of non-obligated suppliers, together with significant barriers to growth for mid-sized suppliers who are on the taper and face a doubled marginal cost of ECO. Changes in the design will be needed to achieve a result which fairly allocates both the fixed and variable costs of ECO.

We can see two broad approaches to creating a more cost reflective and less distorting approach:

(a) Reduce the threshold and extend the taper

One approach would be to reduce the threshold to say 100,000 accounts and extend the taper to say 1 million accounts beyond that point. The result of this would be that all suppliers over 100,000 accounts would have to participate, but that the taper would ensure that the fixed costs were more than compensated for by a reduced obligation, until the overhead fell to around £1 per customer per year. The marginal cost of ECO on the taper would only be 1.1 times the cost of ECO for a major supplier, thus greatly mitigating the barrier to growth.

(b) Substantially abolish the threshold and introduce a trade-out mechanism

In this option, the obligation would apply to all suppliers, excluding the energy equivalent of the first say 1,000 customers, with companies up to say 400,000 customers having the right to trade out the obligation by making monthly payments at a reasonable estimate of the cost, with the proceeds being shared by the major utilities who would deliver the obligation on behalf of those who have opted to trade out. The result would be that companies would only have to undertake the obligation directly once the non-scalable cost was below around £3 per dual fuel account per year, but there would be no taper effects acting as a barrier to growth.

We think this may be achievable without primary legislation by a combination of secondary legislation and licence conditions, but the chief difficulty may be identifying a suitable trade-out price. A key data source could be the weighted average unit cost of delivering ECO, calculated monthly from suppliers' cost returns to Ofgem. It would also be possible to look at the brokerage auctions, though the auctions would need to be sufficiently liquid (and delivery sufficiently assured) to ensure that the price is robust.

We think that both these options have the potential to provide a balanced approach which protects smaller suppliers, avoids barriers to growth for mid-sized suppliers, and prevents the distortions to competition that arise from an exemption regime that is not cost-reflective. Distortions to competition are not in consumer interests, as they lead to a misallocation of resources and higher aggregate costs.

I attach at Annex A a note giving answers to your questions. Annex B describes option (b) above in more detail. In addition, you may use, on confidential terms, any information in our returns to Ofgem.

I hope that this information is useful and we look forward to discussing our thoughts with you.

Yours sincerely,

Rupert Steele
Director of Regulation

Annex A

Threshold and Taper

ScottishPower Response to Questions

1) The practical impact of the overall ECO "threshold", as set out in Articles 4 and 5 of the ECO Order 2012, on your business, and particularly how the size of your company affects (or would affect) delivery of the ECO.

ScottishPower has a retail market share of around 10% and while this makes us one of the smaller large suppliers, our scale is substantially above the threshold. The impact of the threshold on us therefore arises by virtue of its effect on competition and our customers.

The threshold has the effect that, while customers of all suppliers are eligible to benefit from ECO programmes, only customers of obligated suppliers are required to contribute to the cost. This difference in charges is quite material in scale – around £50 per dual fuel customer per year, based on DECC's impact assessment costs, or around £65 per dual fuel customer per year based on the cost estimate we gave the Energy and Climate Change Committee in evidence on 5 March 2013.

This difference is providing a competitive advantage to those suppliers who fall below the threshold, as they are able to offer significantly reduced tariffs to their customers or can operate with higher costs or profits while matching obligated suppliers' pricing. Such distortions of competition are likely to result in an inefficient allocation of resources and higher overall costs for consumers. They are also unfair to obligated suppliers.

As detailed in our covering letter, we do not consider that adjustments to the ECO that cost reflectively deal with the difficulties of a small supplier administering ECO are necessarily a distortion of competition. However any such adjustment needs to address both the fixed and variable costs of ECO and deal with them fairly.

In terms of the variable costs, we do not see any evidence that these would differ materially by size of supplier. The unit of delivery for ECO is quite small relative to obligation levels for medium or large suppliers as evidenced by brokerage lots or typical insulation contracts or partnerships. Larger scale procurement of ECO will not achieve material economies of scale since it is likely to lead mainly to more rather than larger packages of work. Indeed, there is an argument that larger suppliers may be at a disadvantage as the scale of their obligation may make it harder for them to pick and choose the best packages of work to buy.

In terms of the fixed administrative costs, which we estimate at about £1.2 m per year, these bear more heavily on smaller suppliers. At our scale, these costs are insignificant, being equivalent to about 45p per year per dual fuel account, but for smaller suppliers they could be a burden. We estimate that, on the assumption that the smaller supplier is paying the variable costs in full, the fixed costs cease to be competitively material once a small supplier has around 240,000 dual fuel customers (as at this level the difference is around £5 per dual fuel account per year). If the smaller supplier is relieved of the variable cost as well, we estimate that an exemption of only 18,000-24,000 dual fuel accounts is needed depending on the view taken about the costs of the ECO programme.

2) The practical impact of the "taper" mechanism, as set out in Article 11 of the ECO Order 2012, on your business.

The taper mechanism itself does not have a direct impact on our business as we are significantly above the taper range, but it does have an effect on the competitive dynamics we face.

This is because, for those suppliers within the taper, the current design results in a double marginal cost impact from the ECO programme[1], which is likely to act as a significant barrier to growth for medium sized suppliers. Such suppliers may still be financially advantaged by the combination of threshold and taper but, unless they can effectively segment their customer base, they will be disadvantaged in competing with larger suppliers and, especially, with other smaller suppliers that are below the taper.

3) Current and projected number of customer accounts (2013 to 2017).

We currently have in the order of 5.5 million customer accounts (counting dual fuel as two). For more precise information please refer to the customer number notification, provided to Ofgem (on a confidential basis) on 1st February 2013, for the purposes of our Phase 2 ECO determination.

Our business has been growing over the past year and whilst our intention is to continue to grow our customer base out to 2017 and beyond, this will be dependent on our competitive success in the market.

4) Current and projected annual gas and/or electricity supply levels (total and per customer, for the same time period as above).

For details of our annual gas and/or electricity supply levels please refer to the customer number notification, provided to Ofgem (on a confidential basis) on 1st February 2013, for the purposes of our Phase 2 ECO determination. The 'per customer' mean levels can be determined by dividing the total supply by the number of customer accounts for each fuel type.

It is important in this area to distinguish between median and mean values. This is because the distribution of energy consumption is asymmetric, with a tail of high consumers that results in the mean consumption level being significantly higher than the median. The typical Ofgem consumption levels used for price comparisons are median figures; Ofgem's Supply Market Indicators are based on means.

A further complication is that the published figures used by Ofgem are subject to review as a result of significant reductions in demand of both fuels, but especially gas. See the mean and median values given in Ofgem's recent proposals on revising the Typical Domestic Consumption Values, page 9[2].

Allowing for some extrapolation from the 2011 figures quoted by Ofgem to the present date, our supply levels are broadly in line with the numbers given. Any differences are unlikely to have a material impact on the economics of our ECO programme.

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[1] The double marginal cost occurs because between 250,000 and 500,000 customer accounts, suppliers go from no obligation to an obligation that is proportionate to 500,000 customer accounts. The effect is that they must pay double the cost for each additional customer.

[2] https://www.ofgem.gov.uk/ofgem-publications/74735/tdcv-review-consultation.pdf

Our future levels of supply per customer are likely to be influenced by, amongst other things, the success of energy efficiency programmes and the speed with which the UK economy recovers from recession.

5) Your business model, for example, the share of your customers who are dual fuel.

A little over two thirds of our total customer accounts are part of dual fuel deals. We find that customers are generally attracted to the simplicity of dual fuel deals, as well as the discounts that are offered. However, the growth of dual fuel is limited by the significant number of premises that do not have a gas supply.

6) Steps taken to lower costs, for example, by using the brokerage mechanism, and how this lowers your costs of compliance.

We are very focussed on minimising our cost to deliver ECO. A company that is able to deliver ECO cheaper than its rivals will have a competitive advantage which will enable it to grow its business or make additional profit. Similarly, if we fail to deliver ECO efficiently, we will lose ground to our rivals or have to accept weak financial returns.

We believe that a key route to lowering ECO costs is to develop strategic partnerships that enable a streamlined management framework. This approach will allow us to minimise total delivery costs, whilst maximising carbon and heating cost savings. In parallel, we have been actively looking to secure complementary funding streams, either through customer or third party contributions, such as Scottish Government/Housing Association funding, which will minimise our overall cost to deliver the programme.

Brokerage could also be an important route to the efficient delivery of ECO. We are currently purchasing lots through the Brokerage mechanism and monitoring performance. Should this prove to be a cost effective delivery route, taking account of the total delivery costs including quality assurance and delivery support as well as any savings in our administrative costs, this channel will grow as part of our portfolio for delivering our obligation.

7) Total actual and projected delivery costs related to ECO delivery (to March 2015).

We have provided actual cost information (on a confidential basis) in May 2013 as part of our ECO cost reporting notification to Ofgem (Table C) for the period ‘forward projection 2013’ and request that you refer to this information.

As part of that notification, we highlighted our 2013 projection for gas and electricity supply, so that a percentage cost recovery via our domestic customer bills could be calculated. It was highlighted in the submission that it should not be assumed that the percentage provided will be the actual percentage that is passed through to domestic customer bills in any particular period as this is wholly dependent on market conditions.

The costs provided as part of the most recent notification should be treated with caution as ScottishPower’s early progress against target has focussed on lower cost measures. Previous experience of delivery of CERT and CESP obligations has demonstrated that as suppliers progress towards the target end date delivery costs increase accordingly, particularly in relation to the more challenging elements of sub-obligations and ring fenced targets such as CSCO Rural.

In a Select Committee hearing on 5 March 2013, we discussed our views on the cost of ECO, suggesting that the programme would cost the industry as a whole £1.7 billion to £1.8 billion each year (as compared with DECC's estimate of £1.3 billion). As our market share is around 10%, the cost for us is likely to be of the order of £170 million - £180 million a year based on these estimates. This works out at about £65 annually per dual fuel account.

We will aim to take these costs (as they are refined in the light of experience with the programme) into account in setting domestic tariffs, recognising that our pricing decisions are dependent on market conditions.

8) How costs are broken down into administration and delivery costs.

We estimate that 97% to 98% of our total ECO costs are delivery costs, with the remainder being administration costs.

For more detailed information, please refer to the information supplied (on a confidential basis) to Ofgem as part of the standard cost reporting notification and reporting processes for Q1 (April submission) and Q2 (July submission) for details of current costs.

9) How administration costs are broken down into fixed costs (including set-up costs and non-variable recurring costs) and variable costs (which vary proportionately with the level of compliance).

As detailed in the covering letter, we estimate that c.20% of our administration costs are fixed and the remainder scale with the size of the programme.

We have identified 12 Full Time Equivalent (FTE) roles in our organisation that we believe are ECO overheads that do not scale with volume. Using a notional annual full cost of £100,000 per FTE (to include salaries, accommodation, pensions, HR, IT, and all other on-costs), we therefore estimate the non-scale costs of running an ECO programme to be about £1.2 million each year. This is probably an upper bound – for many organisations (including ourselves) the relevant full FTE costs may fall somewhat below £100,000.

Please refer to the information supplied to Ofgem (on a confidential basis) as part of the standard cost reporting notification and reporting processes for Q1 (April submission) and Q2 (July submission) for details of current costs.

10) Estimates of the impact on your customers' energy bills attributed to ECO delivery.

Please refer to response to Q7 above.

Annex B

ECO trade-out option

The key components of the ECO trade-out option are outlined below:

- The overall size of the ECO remains the same.
- Every supplier has the overall target split among them on a proportionate basis, according to the kWh of gas and electricity supplied to domestic customers, as per current practice but ignoring the first 3,500 MW of electricity and 14,000 MW of gas so as to exempt the very smallest suppliers with less than c. 1000 customers (without creating threshold problems or material marginal cost effects).
- Those suppliers who have less than 400,000 customer accounts have the choice to either deliver their target or pay the larger suppliers (through a pooled trade) the trade-out price in monthly instalments.
- Larger suppliers (perhaps above 1 million accounts) would be obliged by licence condition to accept their share of trade-out transactions; but a small supplier and a large one would be able to agree a bilateral trade outside the trade-out mechanism
- The trade-out price is a fixed price per tonne of carbon (for each of CERO and CSCO) and per heating cost point reduction (for HHCRO).
- DECC or Ofgem calculate the trade-out price and adjust it on a monthly/quarterly basis by using weighted average costs (based on quarterly reported cost information already provided by all suppliers participating in delivery) and/or the average brokerage price (providing that there is sufficient volume, depth and delivery assurance in the brokerage market for it to be reliable as a price indicator).
- The suppliers participating in delivery would have their target uplifted by the sum of their shares of the trade-out transactions and they should receive the recycled monies on the same proportionate basis.
- The ECO administrator would need to maintain a central trade-out register. It would probably be sensible to employ a central agent to collect and distribute the monies. Provision for this could be made in the licence condition obliging large suppliers to accept trade-out transactions.

Benefits of this option

By structuring the trade-out option in this way:

(a) Small suppliers are relieved of the disproportionate fixed costs of administering ECO delivery (by the time they reach 400,000 customers, the fixed cost is of the order of £3 in a dual fuel bill – not material in competitive terms);

(b) Medium sized suppliers are protected from the double marginal cost taper effects and do not actually have to undertake the programmes until they reach 400,000 customers;

(c) Large suppliers are not hampered by non cost-reflective benefits to their rivals or distortions of competition which could also harm consumers; and

(d) Suppliers of all sizes get a fair deal, provided that the trade-out price is set fairly.