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BY EMAIL

25th June 2018

Dear Retail Price Regulation Team,

Default Tariff Cap: Policy Consultation

Please find npower's response to the above consultation.

Whilst seeking to protect disengaged customers, it is essential that the cap is set at a level which minimises any negative impact on customer choice and current levels of engagement and competition. It must also enable suppliers to recover costs and manage risks and continue to invest and innovate. It is also essential to avoid unintended consequences such as penalising customers who engage in the market to seek out a good deal. In designing and setting the cap and consistent with good regulatory practice, Ofgem must be fully transparent in discharging its legal requirement under Clause 1(6) of the Tariff Cap Bill ("the Bill") and its more general legal requirement in relation to transparency. This extends to all assumptions, calculations, adjustments and decisions.

The UK requires a sensible regulatory framework to attract the investment required to transform our energy system and deliver positive outcomes for consumers. A poorly designed price cap would adversely impact investor confidence. The effect of a short term price cap, whilst providing disengaged customers with some relief from rising costs, should not put excessive financial pressure on suppliers as this helps neither consumers nor competition. It remains possible to have a cap that protects consumers, maintains engagement and supports investment.

As discussed in our responses to the working papers, we agree with Ofgem's proposed ruling out of a market basket option for setting and updating the cap. In our view, the bottom-up cost option would be the most robust and transparent approach for setting a cap that reflects the long-run costs of suppliers who serve the majority of Standard Variable Tariff (SVT) / legacy customers and incur the full range of policy costs. We do not think this approach creates excess work for Ofgem, as there would need to be an assessment of suppliers' cost data when making adjustments under a reference price approach. Whichever option Ofgem decides to implement, it must ensure that sufficient rigour has been applied within a challenging timescale and that the methodology is fully transparent.

We also agree with Ofgem's preferred option of updating the cap to reflect trends in costs data and indices. Consideration should be given to skip cap updates subject to a cumulative materiality threshold of c1%, rather than automatically following each six month review, as a more efficient process and smoother customer experience.

We commented extensively on the working papers and our detailed answers to the questions in the consultation appendices are appended to this letter.

Our key comments and concerns are summarised below:

Efficient supplier

We reiterate that it is inappropriate and flawed to benchmark smaller or mid-tier suppliers in a growth phase (with high levels of newly acquired direct debit / online customers on heavily discounted short term tariff products and facing lower policy obligation costs and cost to serve) with larger suppliers (with a range of different types of customers, including legacy and vulnerable, paying by different methods as required according to the duty to offer terms and facing the full costs of delivering the government's social and environmental obligations).

As a point of law, the Electricity Act 1989 (EA89) and Gas Act 1986 (GA86) continue to require the Authority to secure that licence holders are able to finance their activities, whilst promoting efficiency and economy. These acts are not being repealed and therefore still stand, there being no primacy in law to the Tariff Cap Bill. Efficiency must in law on implementation of the Tariff Cap Act be understood consistently with EA89 and GA86. Ofgem has in addition a legal duty of care to suppliers in this regard.

We do recognise that achieved efficiency for each element of suppliers' costs does provide relevant information but efficiency at the frontier must be examined in relation to the activity rather than simply using the value as an efficient cost proxy. As Ofgem has pointed out, there are numerous ways by which a supplier can reduce costs but not be suitable for an efficiency proxy. Examples are service reductions and taking excessive risk. For risk in particular, the taking of risk by one supplier passes the cost of that risk on to other suppliers. This creates a dispersion of costs, and the most expensive and not the cheapest supplier is the proper proxy. To the extent to which achieved costs provide some kind of proxy for efficiency, one method might be to take the cost at 75th centile (i.e. 25% of suppliers being more costly) for each cost item as the benchmark for that cost item.

Ofgem will of course be aware of the principal limitation of using achieved costs as a proxy. Since it is logically impossible for all suppliers to better the average cost, then the average cost cannot logically be a cost proxy without further examination.

In the absence of proven inefficiency, the proper proxy is therefore the most costly supplier overall. Whilst in the period before cost based price control, all suppliers have clearly been incentivised to become more efficient, Ofgem must base costs on the basis of this incentive to date. We recognise both that a cost base price control must not reduce efficiency incentives, and that even with the incentive to reduce costs that the extra costs of the least efficient supplier should flow to investors not customers. If short term costs must be driven below the efficient level in order to maintain short term financeability at the cap, this creates long run inefficiencies with costs that flow to consumers.

We understand the administrative convenience of using average costs for each line item. If this is done then to this must be added the cost dispersion. It is important to note Ofgem's duties under EA89 and GA86 here as these apply to all suppliers. Headroom must be set above the levels determined by EA89 and GA86. The incentive for all suppliers to become more efficient clearly remains and the most efficient suppliers can gain the most customers by pricing beneath the cap. The frontier provides a clear target for all suppliers.

The financial pressures of market conditions has been well publicised. Ofgem should satisfy itself that the cost base of any suppliers who form the basis of the efficiency benchmark are representative of a sustainable energy supply business. Ofgem will also be aware that a cheaper price may compromise service levels to the detriment of consumers or a moral hazard cost that is passed to other suppliers (for example via the taking of risks without guarantee of fulfilling responsibilities). We welcome Ofgem's review of its approach to licensing energy suppliers, to ensure that appropriate protections are in place against poor customer service and default, the *ex ante* cost of which falls to consumers and must be factored into the cap.

Smart costs

The extent to which progress has been made in installing smart meters is the key consideration on the face of the Bill when reviewing whether conditions for effective competition are in place to enable removal of the cap. It would be fundamentally wrong if the cap undermines the roll out of smart meters by not allowing the full recovery of costs reasonably incurred in the face of inefficiencies driven into the programme by government and Ofgem actions and inactions. Investment in smart (and energy efficiency) is essential in ensuring that the UK doesn't continue to be a place of relatively high domestic consumption, regardless of price, to the detriment of customers.

In principle, we believe that smart costs should be recognised as a policy cost given that this is a significant obligation driven by Government. We welcome Ofgem's proposal to separately index smart costs and provide for "pass through" of smart related industry charges. The programme is subject to specific risks and cost drivers. Price escalation is a real challenge particularly in field operations, where productivity, the availability of qualified engineers and portability and movement remain risks. Essentially everyone is reliant on a limited pool of resource.

It is essential and a matter of good regulatory practice that Ofgem is fully transparent in calculating the allowance for smart costs during 2019 and 2020. This includes full transparency of costs assumed to be within the baseline, from which the net cost change is calculated. BEIS model assumptions and non-confidential data should be made available for review. At this point Ofgem's modelling of smart costs is materially deficient in detail and hence we cannot answer this question in full.

One reason for the costs of smart to be fully recognised in the cap is the maintenance of the incentive to minimise inefficiencies driven into the programme by government and Ofgem action and inaction.

So large are the smart costs that we believe it essential that Ofgem conduct a specific and ongoing exercise, gathering supplier data. We would happy to provide such data and to contribute to any exercise that enables Ofgem to standardise the line items so that the understanding of costs is tractable and clear. We recognise that smart will create supplier savings to offset some of the gross costs and we would be happy to work with Ofgem on the calculation of these.

[…]

Overall, smart is very complex. In addition to the effect of wholesale costs, we believe that a true up via cost recovery provides a good solution. We note that many excess costs cannot be anticipated and occur as shocks. A recent example is DCC delays in the SMETS1/2 cutover. There has also been considerable volatility and uncertainty around AltHANCo costs, which are to a large extent still unknown.

Accordingly, if the anticipated cost for a price control period was £x but turned out at £y for reasons beyond suppliers control, then an uplift of £y-£x should be applied to the next price control. Ofgem is *required in law* both by EA89/GA86 and its duty of care in public office either to do this or provide sufficient uncertainly uplift (not included in the general headroom).

Whilst we agree in principle with pass through of smart industry charges, we are concerned that Ofgem refers to this as meaning adjustments made to reflect the average cost across suppliers for industry bodies (DCC, SEGB and SMICOP). This would not reflect the fact that costs such as DCC/SMICoP are being largely funded by larger suppliers i.e. higher costs per customer.

There is a considerable free ride issue in smart, in which medium (>250,000 customers) and large suppliers bear the full brunt of programme costs, and all suppliers can cherry pick consumers, for example just after smart install. This causes a consumer distributional issue which Ofgem has a primary duty to resolve. There are in fact solutions available to Ofgem, for example in regulatory oversight of Meter Asset Provider and Meter Operator costs.

Suppliers are obliged to meet "all reasonable steps" in rolling out smart meters. The meaning that Ofgem imputes to this term remains entirely unclear. To drive an efficient programme Ofgem must: i) align its view to the prevailing Cost Benefit Analyses of smart and ii) make its views detailed and transparent *ex ante*.

Wholesale risk

Some costs are a zero sum game, in which loss by one party is a gain by another. Risk however is a pure deadweight cost, meaning that no-one gains. The marketplace has a fairly well defined cost of risk and hence the risk cost uplift that is according to EA89 and GA86 *necessarily* applied to the cap flows as a pure loss to consumers. This would be at variance to Ofgem's primary duty to protect the interests of consumers.

Therefore, Ofgem is *required* to minimise the cost of risk flow through to consumers. This can be done by the use of the standard recovery mechanisms common in the regulated networks.

We note in addition that the wholesale costs of energy, and electricity in particular, is subject to cost shocks over and above the normal ebb and flow of markets. An example of this is Carbon Price Support. This has two specific effects. The first is that it creates "uncertainty" that is hard to characterise in addition to "risk" that is common and understood in markets. The second is that the nature of the shocks disrupts the normal term structure of the forward market, thereby adding additional basis risk that is greater if the structure of the price cap reset cannot be hedged accurately. Both of these effects add further to the deadweight cost of risk which must *necessarily* be included in the cap if the inter-year recovery is not applied. This cost flows to consumers.

Even after recovery, suppliers still have risk because (unlike the networks), the recovery mechanism must be standardised across the whole industry so that all suppliers face the same cap.

We recognise that there is no indexation basis that gets the cost of wholesale price risk to zero, but some bases have lower cost of risk than others. Ofgem is correct to recognise the risk to suppliers from the inability to perfectly match hedging to the wholesale index, but the current proposals do not address it adequately.. We have experienced the impact of this as a result of the PPM price cap and believe that suppliers are exposed to a significant expected cost […]. We have written to you separately asking Ofgem to consider a specific meeting with industry experts on this topic or a bilateral meeting. Given the technical nature of this and the absence of any need to reveal supplier specific information, we see no competition concerns on having such a meeting with Ofgem.

Ideally, the forward contract and price cap delivery periods should be aligned, whether they be 6 or 12 months. There is a balance to be struck between competing forces. For example a six monthly reset will cause a seasonal cycle, the strength of which depends on, for example, the relative prices of the Apr-Sep to Oct-Mar market prices, the switching rate from the cap, the take up of time of use tariffs, changing periodicity of demand, and consumer arbitrage by cyclic switching. As Ofgem is concerned about seasonal pricing, we would advocate a 6-2-12 annual model. A supplier is better able to manage demand forecasting risk than the current risk arising from the basis of the wholesale index. The latter is of a significantly higher magnitude. Alternatively, Ofgem could introduce a recovery mechanism: if the basis risk costs suppliers – and Ofgem can track this – then suppliers recoup this cost in the following cap period, whilst if the basis risk delivers a benefit, that benefit is passed through. In the absence of the regulatory standard (in retail as well as networks), the deadweight cost to consumers is reduced by a six monthly reset.

The existence of costs which cannot be hedged – that is, those over and above the baseload / peak assessment of commodity costs - also lends itself to the need for a recovery mechanism. Indeed, Ofgem appears to understate the cost of re-hedging in a market of varying demand and positive correlation between consumer demand and wholesale prices. We do not believe that Ofgem disputes either the demand variation or the correlation (these not being credibly disputable) and hence Ofgem must recognise the costs ex ante. In addition to this, Ofgem must observe EA89 and GA86 in recognising the effect of low frequency high impact events. This can be expressed on a "1 in 20 year" basis. In practice the required ex ante cost uplift is so high that a recovery mechanism is the only realistic way to contend with this. So, suppliers in a 1 in 20 (or worse) weather event would experience significant cash flow issues, but would recover the revenue in the next period. In a 1 in 20 year, we estimate that these costs represent 5-10% of the total commodity cost stack, whilst in an extreme year this could increase by a *further* 5-10%. The need for a recovery mechanism becomes more important over time as the Capacity Mechanism, Contracts for Difference, and other market interventions become more efficient.

We would also like to understand Ofgem's thoughts on the hybrid approach we have suggested on more than one occasion, most recently in our response to working paper #1.

Correction mechanism and inter-year recovery of over-under pricing relative to ex post costs

In a competitive market, suppliers have discretion over the extent to which ex-post cost pass throughs to consumers are smoothed in retail pricing. The lack of a mechanism in the cap to correct for uncertainty/error results in a deadweight cost to suppliers and ultimately customers. It is also incompatible with both duties to have regard to the need to finance activities.

This is particularly pertinent in relation to the wholesale, smart and other policy costs. We illustrate the volatility of Contract for Difference (CFD) costs in our response to Appendix 7. We have also highlighted the importance of a recovery mechanism in the index / headroom for Balancing Services Use of System (BSUoS) costs.

It has been the habit of Ofgem to apply Use of System cost shocks to suppliers when they could readily have eliminated these shocks by using the network recovery mechanisms and applying the cost increases to future years. This then reduces the recovery adjustments in the price cap.

It also important to note that recovery provides the right incentives for Ofgem. By way of example it remains our view that Ofgem did not act in the interests of consumers in the National Grid black start episode. Had Ofgem been required to make public explanation as part of a price change in price control then the decision to award the black start contract may have been different. As it stands, this cost might have fallen outside the cap.

There have been numerous other smaller episodes of a similar nature, for example the Balancing Service Use of System charges shocks.

Ofgem has in the past, and again proposes to, require suppliers to participate in mutualised insurance of the defaults of suppliers who exited the market without paying their customers money owed to them on account for energy bills. The legality and vires of that is not addressed here, but if Ofgem proposes to continue this, then this cost expectation line item must be added to use of system charges and recognised discretely in the cap.

Headroom

After a two year investigation, the CMA decided that explicit headroom was required in the Prepayment cap to enable competition to co-exist. We see no reason to disagree with the CMA's decision and therefore why it would not apply to the SVT/default cap. There is a significant risk that setting the cap too low will impact cost recovery, the ability to offer profitable tariffs below the cap and the savings required to sustain competition.

Headroom should be calculated on a Receipt of Bill basis, with suppliers free to discount Direct Debit.

Inadequate headroom could also thwart market entry, innovation and wider engagement.

The absence of a correction mechanism would merit a further uplift to headroom to mitigate supplier deadweight cost and support the financing of activities. If headroom is intended to support competition and manage the risk of uncertainty, there should be an explicit allowance for each.

It is important to note that headroom is required in addition to cost uncertainty. EA89, GA86 and Ofgem's duty of care in public office apply to all *actual* suppliers, not a *hypothetical* average or frontier efficiency supplier.

Payment differentials

Ofgem acknowledges the additional costs of supplying standard credit customers (£114) as being within the range calculated by the CMA (£88-£158). We broadly agree with this assessment and believe that current prices reflect a conservative (i.e. lower discount as Receipt of Bill tend to be less advantaged than Direct Debit customers) approach to compliance with the cost reflectivity obligation under SLC27.2A.

The cost reflective differential between ROB and DD is likely to change over time as in the absence of inter-year recovery, the cost of capital may rise, and bad debt rates may rise or fall, for example as a result of increased use by suppliers of credit reference agencies, and a firmer approach to debt and disconnection.

We believe that it is sufficient and simpler to have a fully cost reflective Receipt of Bill (ROB) cap, with no separate cap for Direct Debit (DD). This would not preclude suppliers from offering a discount for paying by Direct Debit. The price control should therefore be done on a ROB basis.

Regulated cross-subsidy in the form of forced socialisation creates numerous unknown and unintended consequences, distorts the competitive market by encouraging cherry picking and therefore must cause an uplift to the cap.

The proposed socialisation of costs is inconsistent with the allocation of risk/costs in other markets, such as insurance. For example, the premiums for young drivers reflect the risks associated with that customer cohort; the relatively higher premiums for contents insurance in higher risk postcodes. There is a risk of unintended consequences as offering ROB tariffs could be less attractive if suppliers are not recovering their costs, particularly if they have a high proportion of ROB customers. An effective discount of £22 would significantly dilute the incentive to switch payment methods in order to better budget for energy costs. The increase in overall costs from not encouraging customers to the most efficient payment method causes a cost that must be recovered in the cap and thereby a deadweight cost to consumers. It would also be a poor experience for existing direct debit customers to be notified that their current discount is effectively being reduced as a result of regulatory changes.

There could also be an impact on prices and payment method differentials for fixed tariffs as suppliers seek to recover costs, further undermining engagement and competition. Ofgem should clarify whether it would expect the same differential to apply in that segment of the market.

It may be that smart meters create a new hybrid of payment mechanisms. The relative cost reflectivity of these in the cap may need careful consideration.

Cost of Capital / margin

We reiterate that we disagreed with the CMA’s reliance on Return on Capital Employed, inappropriate for “asset light” supply businesses and understating the economic value on which to base allowed earnings. Ofgem’s calculations must be transparent and start from the cost benchmark of 10% Weighted Average Cost of Capital (pre-tax nominal) and not reverse engineer the calculation from a target EBIT margin, Ofgem has a legal requirement to do this properly.

Please contact myself or Paul Finch (contact details below) if you would like to discuss any particular point(s).

This version of our response is non-confidential and may be published.

Yours sincerely,

Chris Harris
Head of Regulation

Cc: Paul Finch, Regulatory Advisor (07795 353787 / paul.finch@npower.com)

APPENDICES: CONTENTS PAGE

Overview paper questions

Question 1: Which approach for setting a benchmark for efficient costs do you think would be most appropriate?

Bottom-up cost.

We remain of the view that Option 4 (bottom-up assessment) would be a more robust and transparent approach for such a significant market intervention. Please refer to our responses to your working papers for the issues that we believe would need to be addressed under either of the price reference options. In particular, flaws regarding policy costs; wholesale risks, smart costs, representative supplier/tariff sample.

Question 2: What are your views on the issues we should consider when setting the overall level of the cap, including the level of headroom?

Legislated duties, recovery mechanism, finance costs, effect on switching, cost completeness, universal service costs

Essentially, the cap should be reflective of the long-run costs of a wide sample of suppliers who serve the majority of Standard Variable Tariff (SVT) / legacy customer types and incur the full range of policy costs, including those costs for which there are numerous exemptions for smaller and newer suppliers. There must be full transparency of any adjustments for comparability purposes.

Ofgem will need to demonstrate how its design of the tariff cap, in the round, delivers the policy intent of balancing protection, competition and sustaining the ability of suppliers to finance their activities.

The CMA decided that explicit headroom was required in the Prepayment cap to enable competition to co-exist. We see no reason to disagree with the CMA's decision and therefore why it would not apply to the SVT/default cap. There is a significant risk that setting the cap too low will impact cost recovery and managing risks, the ability to offer profitable tariffs below the cap and the savings required to sustain competition. Please refer to our response to working paper #3.

Question 3: Do you agree with our approach to accounting for different costs, in particular additional costs of serving consumers paying by standard credit?

No, we do not agree with the proposed socialisation of costs.

Please see our answers to Appendices 8 Operating costs and 12 Payment differentials.

Question 4: Do you agree with our proposals for how we will use cost data to update the cap?

Yes

We broadly agree with Option C, updating the cap to reflect trends in cost data and indices. Please see our responses to individual appendices for detailed comments.

Question 5: Do you agree with our assessments of whether an exemption for tariffs that appear to support renewable energy is necessary and workable?

Yes

We agree that a derogation process is more appropriate than an exemption for renewable SVTs. This would enable individual cases to be assessed on their merits in order to safeguard consumers. The criteria and basis for granting each derogation should be transparent to ensure equitable treatment of suppliers. Ofgem should make clear and public the bases for derogation. Ofgem's caution on "appear to support" is well founded and no doubt some standardisation may be required for derogations, for example compliance with the Green Electricity Supply Code, a consistent approach to additionality and source provenance, the treatment of the various forms of carbon offsets, non renewable low carbon, and renewable gas.

Question 6: Do you have any views on what information we should use to assess the conditions for competition?

We welcome a focus on market framework/structure rather than outcomes, recognising that the existence of a cap may impact the latter. Consumer engagement remains a key area, both inter-supplier and intra-supplier switching.

Appendix 1: Market basket – npower's response

Question A1.1: Do you agree that we should not further consider the use of a market basket to set the initial level of the cap? We set out our reasoning in Chapter 3.

Yes.

We agree for the reasons set out by Ofgem and in our response to working paper #2.

Question A1.2: Do you agree that we should not further consider the use of a market basket to update the cap over time? We set out our reasoning in Chapter 4.

Yes.

We agree for the reasons set out by Ofgem and in our response to working paper #2.

Appendix 2: Adjusted version of the existing safeguard tariff – npower's response

Question A2.1: Do you agree with, or have views on, our approach to adjusting the CMA's methodology to make its benchmark appropriate for the default tariff cap? In particular, how we propose to address: additional standard credit costs, existing overheads and customer acquisition adjustments, and other potential adjustments to operating costs.

Standard credit Receipt of Bill (ROB) should be the benchmark, all costs, including overheads and cost to gain/lose customers must be recognised

We have commented extensively on the issues we see with the CMA's methodology. Where analysis and more recent data justifies an adjustment to the CMA's methodology, this should outweigh Ofgem's concern about previous experience and understanding of the methodology. For example, we agree with Ofgem being minded to adjust the existing safeguard tariff methodology to account for potential variations in smart metering costs, where material differences are identified.

Ofgem notes that it is yet to assess suppliers' data on realised overhead costs since 2015. For transparency, the results of Ofgem's analysis should be made available along with the rationale for decisions on whether or not to make adjustments to the CMA's benchmark.

We would like to understand how adjustments for non-efficiency differences would be applied in practice. As there can only be one cap, an average benchmark would not allow full cost recovery

Question A2.2: Do you agree with how we propose to adjust the benchmark at nil consumption?

Yes, we broadly agree.

The further Ofgem adds intentional cross-subsidy the more it distorts the market

Question A2.3: Do you agree with our proposed approach for updating the level of the adjusted safeguard tariff cap?

Yes.

We agree with an exogenous indexation approach (subject to addressing our concerns with the wholesale index).

Appendix 3: Updated competitive reference price – npower's response

Question A3.1 Do you agree with our proposed approach for an updated price reference approach? In particular, how we select price data and exclude suppliers or adjust data.

No.

We do not agree with excluding suppliers/tariffs on the basis of the proposed customer engagement criteria. We fundamentally disagree with the CMAs assertion of significant inefficiency, based on dispersion of costs, revenues and profits rather than business observation. SVT tariffs reflect the higher costs to serve legacy customers and are constrained by savings widely available, with evidence of significant SVT customer losses across the market. There is a risk that new entrant prices reflect cherry-picking of lower cost to serve and more profitable customers. We have made significant efforts to increase SVT customer engagement and suppliers with a high proportion of SVT customers should not be penalised. Accordingly, we agree that option 1 should not be adopted (only include fixed term tariffs in an updated benchmark) and we also welcome Ofgem's acknowledgement of the need to address the concern that some suppliers may be loss-making.

We also provided extensive commentary on this option in our response to working paper #5.

Question A3.2 Do you agree with the judgements we set out regarding consumer engagement, policy and wholesale costs, and constructing the benchmark?

No

See above comments on customer engagement. Please see our response to Appendix 6 for our comments and concerns regarding wholesales costs when constructing the benchmark.

Question A3.3 Do you agree that, under an updated competitive reference price approach, we should set the benchmark at nil consumption using the adjusted standing charges from the same suppliers included in the benchmark at typical consumption?

Yes.

This seems sensible in striking a balance between the recovery of efficient costs and protecting low volume users. However, standing charge should not be regarded as necessarily cost reflective. It is in part driven by consumer preference.

Question A3.4 Do you agree with our approach to weighting the benchmark at TDCV and nil consumption?

Yes, in broad terms.

Clearly Ofgem needs two points to form the cap in order to form the envelope of standing charge and the unit rate. This necessarily requires costs estimates at zero consumption and at some other consumption point. The ideal is average consumption, but this is not easy to form due to regional differences, demographic differences and inter-year trends and variations.

TDCV has some merit as a candidate volume benchmark. This is discretionarily set by Ofgem and there is some conflict of interest in TDCV truly reflecting trends in median consumption and any desire that there may be to reset the index below costs. To avoid politicisation of TDCV its methodology should be standardised, almost certainly using a weighted weather corrected trend-adjusted average of the last 5-10 years.

All things considered, TDCV is an expedient choice. Since it will then form an element of price control, transparency in the resetting of TDCV is essential.

The indices should be cost reflective unless there are compelling reasons not to be. It is manifestly the case that Warm Homes Discount for which suppliers are liable even for minimal consumption, must be included in the benchmark for zero consumption rather than TDCV. For actual zero consumption, suppliers still incur costs where the meter point remains registered but not WHD costs if there is no consumer live on supply (long term vacant, etc.)

However, we disagree that Ofgem is not minded to make exception for WHD as there are not insignificant costs (c£13 per DF customer) and should be properly indexed.

The nil consumption point, effectively driving the standing charge, is a matter of balance. As a general principle we believe that cost reflectivity should always be applied by the regulator as this makes the market more efficient (and therefore cheaper for consumers) and less distorted. However both commercial and social pressures drive down the standing charge. The commercial pressure is consumer dislike of standing charges and hence supplier accommodation of this and the social pressure is the income effect of energy intensity (i.e. poorer consumers on average pay a larger percentage of income on energy than better off consumers). This has driven down the Standing Charge / Unit Rate ratio on SVT and indeed the result of this is that SVT is commonly the cheapest tariff for lower consumption customers. Conversely, growing suppliers tend to have high SC/UR ratios to attract better off consumers. This also has the effect of not taking on less advantaged consumers who have a higher cost to serve. Finally, what the fixed costs of suppliers are, to form the SC benchmark, are in practice not clear.

Broadly speaking, since the price cap is a form of social intervention, to minimise the risk of unintended consequences of adverse distributional impact, it may be safest to follow current supplier practice of setting a low SC/UR ratio, as suppliers do now. It is difficult to tell how much negative effect on engagement of lower consumption customers this will have.

Appendix 4: Bottom up cost assessment – npower's response

Question A4.1: Do you agree with our assessment of the advantages and disadvantages of a bottom-up approach to estimating an efficient level of costs?

Yes, broadly

In our view, the bottom-up cost option would be the most robust and transparent approach for setting a cap that reflects the long-run efficient costs of suppliers who serve the majority of Standard Variable Tariff (SVT) / legacy customer types and incur the full range of policy costs. We do not think that the challenges highlighted by Ofgem are insurmountable and in any event, there would need to be an assessment of suppliers' cost data when making adjustments under a reference price approach. The view of efficient costs should accommodate a range of business models.

Whichever option Ofgem decides to implement, it must ensure that sufficient resource has been applied within a challenging timescale and that the methodology is fully transparent.

Question A4.2 Do you agree with our proposed approach to categorising different costs under a bottom-up cost assessment approach to setting the default tariff cap?

Yes, broadly speaking.

Table A.41 looks reasonable, although we question whether Capacity Market payments should be categorised as wholesale costs, rather than policy costs. Smart costs should be a separate line item given the need for transparency of what is included in the baseline. Energy Intensive Industry (EII) exemption costs also need to be added.

Appendix 5: Updating the cap over time – npower's response

Question A5.1: Do you agree with our proposal to update the cap in line with trends in exogenous cost drivers?

Yes.

As default fixed term tariffs will be subject to the cap, it follows that if costs increase a supplier should be permitted to increase the price of such tariffs. This would require an exemption from SLC22C.9.

Question A5.2: Do you agree with our proposed choice of cap and baseline periods?

On the cap period, there are arguments for 6 monthly reset (minimises tracking error) and 12 monthly resets (minimisation of costs). In the absence of the recovery mechanism (that we regard as essential to keep consumer costs down), then the balance falls in favour or 6 monthly resets.

We question Ofgem's assertion that 6 monthly reflects the approximate frequency that customers on most default tariffs have historically faced price changes (npower: Feb'15; Feb'16; March'17; June'18). […]. We understand that the requirement under the Tariff Cap Bill is to review the cap, not necessarily update it. Consideration should be given to skipping an update after a 6 monthly review, perhaps applying a cumulative materiality threshold (for example a change of over 1% since the last reset applied) in terms of the impact of cost movements on bills. Customer insight has previously indicated that our direct debit customers value payment stability. The costs of administering a price change (the so called "menu costs") must be recoverable under the cap.

In terms of the baseline period, under an adjusted version of the existing safeguard tariff we question whether First Utility and Ovo 2015 prices are sufficiently recent as a starting point. Their prices changes since then should be taken into account. Our analysis of the current Direct Debit prices of the CMA's benchmark suppliers suggests that prices are significantly above the cap level than if indexing were applied to the 2015 prices.

Question A5.3: Do you consider that further provision is required for us to re-open aspects of the design of the cap, beyond our licence modification powers – and if so, why?

Yes.

The baseline is set to the level that best balances consumer protection and the continuation of the market. The unknowns are considerable. It therefore seems likely that Ofgem may in practice need to adjust the indexation, to adjust this balance or to update costs correctly, or both. This should be done with no less transparency than the initial baseline and indexation. The ability of Ofgem unilaterally to reset prices both increases investment risk (in terms of moral hazard on Ofgem's part) and decreases it (by having a safety valve in case of excessive supplier exits).

Clearly, in the first instance the priority must be to forecast costs as accurately as possible for recovery during a cap period. This will not always be possible and some costs are more volatile than others (e.g. Contracts for Difference). In the absence of a price cap, suppliers can exercise discretion on whether to price through a correction and the timing of doing so. A price cap without an error correction mechanism denies suppliers this flexibility and increases risk. An unintended consequence could be the impact on fixed term contract prices.

As a minimum, suppliers should be able to apply to Ofgem for an adjustment to be made to the cap. We are concerned that relying on the licence modification process would be too cumbersome.

Some elements of the indexation may require minor technical adjustments. An example is the reconciliation run used for Balancing Service Use of System charges, as the “RF” run can have the effect of retrospective charges not captured in the cap.

To the extent that the price cap mechanics do not provide for error correction and mitigate uncertainty, there should be a separate, explicit allowance outside the headroom.

Appendix 6: Wholesale costs – npower's response

There are several elements here:

i) Unhedgeable risk and its cost;
ii) Standard hedge profile;
iii) "Swing" (volume variation)

The indexation should be such as to minimise the "basis" risk that cannot be hedged, since this causes a deadweight cost of risk to consumers.

Ofgem will need to set a standard hedge profile as it has done without the cap in forming the Supply Cost Indicators. Ofgem has not at this point published this profile and hence we cannot comment on it. Broadly speaking, the higher the cap the less the hedge profile is changed from current, and the lower the cap the closer the hedge profile is to purchasing 100% forward on the date of reset.

Swing risk is complex. A recovery mechanism is essential and in its absence both suppliers and Ofgem face considerable risk in a "1 in 20" winter. Ofgem has a duty of care in public office to suppliers to avoid unrecoverable negative cash flows in such a winter. Note also that swing risk is asymmetric and therefore the expectation of loss (i.e. not just the cost of risk) must be factored into the prices for all years. Furthermore, since prolonged extreme weather and supplier exits are highly correlated, the socialisation of default costs must in addition be factored into the swing cost.

QA6.1: do you agree with our approach to setting the wholesale allowance? In particular using 2015 for the base period of the adjusted safeguard tariff approach.

Adjusted version of existing Safeguard Tariff

In our response to working paper five, we advocated a bottom-up approach on the grounds of robustness and transparency. We continue to hold this position; we are particularly concerned by the assumption made by Ofgem in point 3.8 of Appendix 6 – that the reference price captures all relevant wholesale costs. As discussed in more detail in our answer to QA6.5, we believe that different approaches to managing and pricing said costs exist depending on suppliers' ability to assess risk, their risk appetite, and their ability to trade in the wholesale market. Moreover, we would press upon Ofgem the importance of using the most up-to-date cost information, seeing as shape costs have increased by approximately 50% since 2015 in reflection of the evolving UK fundamental picture.
Thus, we do not agree with the proposal to use 2015 for the base period of the adjusted safeguard tariff approach.

Updated reference price

In our response to working paper five, in an 'updated competitive reference price' scenario we suggested basing the reference price on tariffs which were on sale at that point in time rather than all 'live' tariffs. To clarify, in the case of the June 30th 2015 Competitive Benchmark, this would have been any product which was on sale on 30th June (so potentially launched several weeks before that date and / or on sale several weeks after the date). As such, these tariffs would very much represent (part of) the customer base – we did not fully understand the comment from Ofgem which suggested that they would not. In any case, we clarify our reasoning below.

A Fixed Term Contract (FTC) on sale today / at a particular point in time are broadly reflective of wholesale prices today / at that point in time. The competitive benchmark is based predominantly on FTCs (given the selection of First Utility and Ovo as the basis of the calculation) but, as it includes all live tariffs as at a particular date, some of which would have been priced and launched some months or even years prior to the date in question, the competitive benchmark is therefore detached from the prevailing market price.

This meant that, in a sustained period of falling wholesale market prices, the competitive benchmark level was higher than prevailing market prices when the June 30th 2015 competitive benchmark was observed. Since then, this wholesale trend has reversed; were the competitive benchmark to be re-stated as at 30th June 2017, for example, it will be below prevailing market prices as at that date.

This is similar to the point made by the CMA (14.162) of their Energy Market Investigation final report), which explained that the application of the wholesale energy cost index to the competitive benchmark was 'somewhat favourable' to suppliers because of the decline in wholesale costs since 2014. This is because the wholesale index was based on wholesale price observations from August 2014 to January 2015 i.e. the cost which would have applied for the price cap period 1 April 2015 to 30 September 2015, had it been in effect. Again, since mid-2015, the opposite was true, meaning a disadvantage.

The CMA's final report (14.185) identified this inconsistency between

i. the commodity cost achieved by the retrospective application of the wholesale index to the point at which the reference price is calculated, and
ii. the commodity cost associated with the products included in the competitive benchmark.

The difference is significant both when setting the initial level of the cap and when subsequently updating the cap. npower recommends that the two factors are aligned, not just to remove the disparity but to make the cap price achievable. It is possible that some suppliers have chosen to proactively align their SVT hedging strategy to the wholesale index prior to the details of the cap being published; this is because the PPM cap provided a point of reference upon which to base such a change (noting of course that taking an early view on the nature of the price cap in terms of structure, timing etc. is in itself risk-introducing). The same is clearly not true in the case of the competitive benchmark, as the relevant suppliers, tariffs and customer numbers are completely unknown at this point. **It is impossible for suppliers to retrospectively achieve the costs implied by the competitive benchmark price, yet the initial cap level will be determined by the competitive benchmark, not the wholesale index.**

Therefore, the recommendation is that the competitive benchmark is curtailed somewhat, so as to align to the wholesale index. In practice, were this to have applied to the original benchmark, this would have meant that no product launched prior to 1st April 2015 was included. **Not doing so would serve only to set the initial cap level unachievably low** (noting that this would **not** be rectified by subsequent cap updates – the disadvantage would be 'baked in' to the cap)**.**

npower did suggest another alternative in our submission to working paper five: base the competitive benchmark on tariffs on sale as at June 30th 2015 and, rather than applying the wholesale index, assume instead that these tariffs were hedged shortly before they were put on sale. Upon reflection, this alternative approach does place significant emphasis on wholesale prices on a particular day, which we recognise is a limitation. We prefer the option involving alignment of the wholesale index and the competitive benchmark, in the interest of consistency i.e. wholesale index is involved in both setting the initial level and subsequent updates.

Finally, to reiterate: a customer number-weighted benchmark tariff can be based on either of the two options above as easily as if it was based on all live tariffs; the only difference is that the number of tariffs included would be different.

Bottom-up cost assessment

In the case of the PPM cap, there is a substantial difference between billed and settled consumption for both commodities. This is because no separate settlement profile currently exists for PPM customers.

When calculating the wholesale index, Ofgem adopts a Winter / Summer gas demand split of 63% / 37% (based, we presume, on billed volume), […]. The equivalent power ratios are 53% Winter / 47% Summer (billed) and […]

It is recognised that said disparity will not be as pronounced when considering SVT customers, as consumption will be more in keeping with the overall Domestic pattern (ALP 01B): PPM is a relative outlier in this sense.

In the case of both reference price methodologies, this disparity is accounted for because it can be reasonably assumed that First Utility and Ovo have priced according to their settled consumption; thus, the risk is that individual suppliers‘ portfolios differ in terms of consumption patterns vs. First Utility and Ovo.

The same is not true in a bottom-up cost assessment scenario; here, suppliers are fully exposed to the disparity. Indeed, had the PPM cap been based on a bottom-up cost assessment, the impact on the two caps starting in 2017 (April 1st and October 1st of that year) would have been >£3.50 per dual fuel customer.

Therefore, in the event that a bottom-up cost assessment is preferred, we strongly advise that the summer / winter demand split used is representative of SVT. Furthermore, whilst this may be outside of the scope of this consultation, we would strongly encourage Ofgem to adjust the PPM cap once EUC 01P has been implemented, to reflect PPM-specific (rather than domestic average) consumption

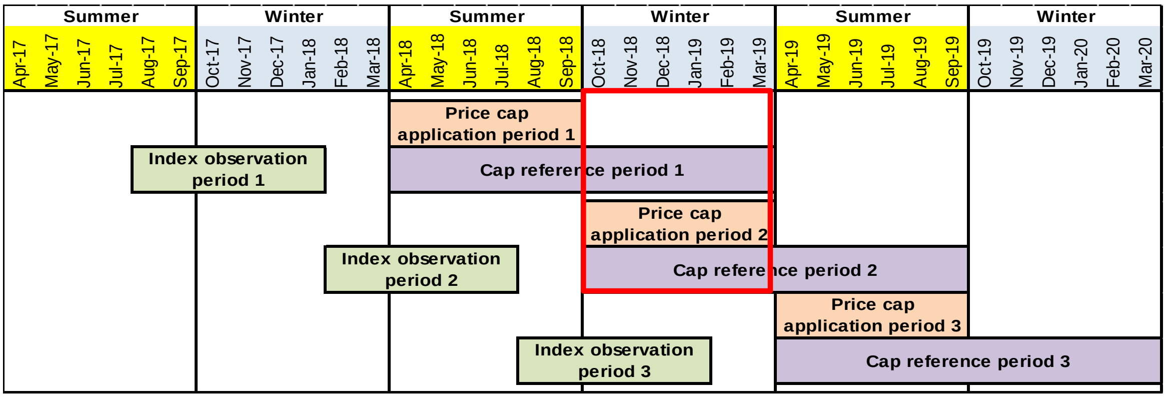
QA6.2: do you agree with our approach to updating the wholesale allowance?

No. The mechanism is a major concern due to the hedging risk which Ofgem has highlighted.
We support the alternative described in paragraph 4.9 of Appendix 6 (6-2-12 annual) for both setting the initial level of the cap and for subsequent updates.

This is covered in detail in Qs A6.1 and A6.3.

QA6.3: do you agree with our proposed approach to use a semi-annual cap period, compared with a 6-2-12 annual model, or shorter observation period? Please explain how the alternatives would affect you, if we were to choose those options instead.

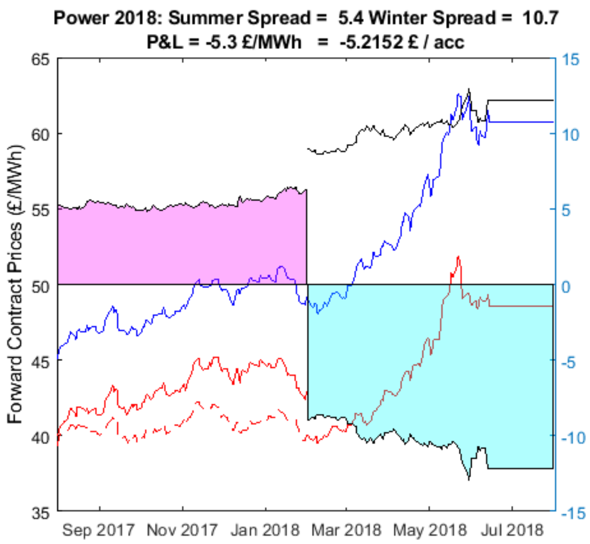
We welcome the fact that Ofgem acknowledges the risk introduced by a 6-2-12 semi-annual formula; as highlighted in our previous submissions, and in point 4.5 of Appendix 6, suppliers are exposed to price risk because the mechanism requires them to purchase wholesale products which are outside of the *price cap application* period (meaning that the products bought in *cap application period 1* are delivered in *cap application period 2*, but the price at which they were purchased them will not be factored into *cap application period 2 – see diagram below*).

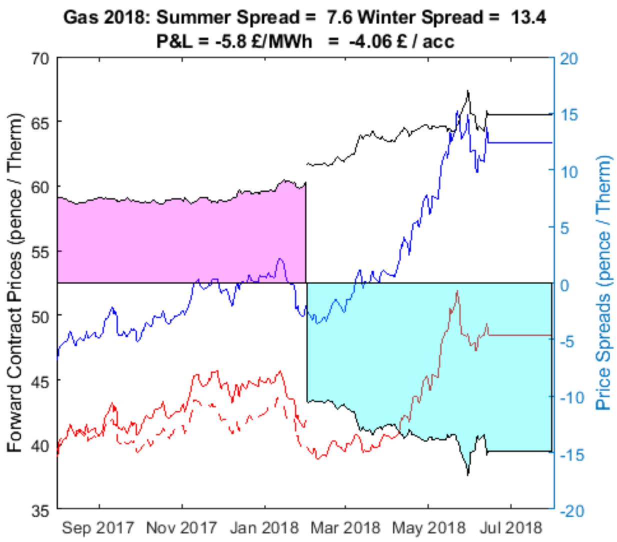


6-2-12 semi-annual mechanism requires the purchase of Winter 2018-19 during cap reference period 1, but this purchase overlaps with price cap application period 2.

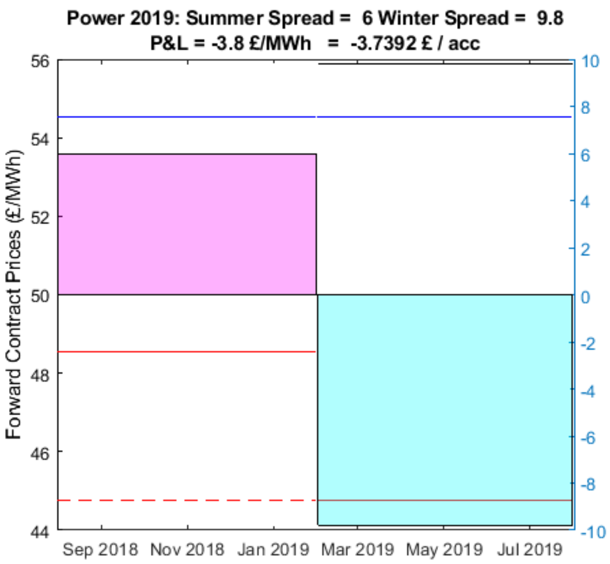
An alternative course of action on the part of a supplier is to purchase only the wholesale product which aligns to the price-cap setting period. This equates to purchasing a summer wholesale product **only** in a summer cap (based on average of summer and winter price, so supplier's cost is lower than allowed revenue) and a winter wholesale contract **only** a winter cap (based on average of winter and summer price, so supplier's cost is higher than allowed revenue). If the wholesale market were to remain completely static, each summer and winter cap should be equal and offsetting (so, on an annualised basis, the impact is zero). Thus, the price risk described earlier is exchanged for an exposure to the difference between seasonal prices i.e. price spreads. Our assessment is that this spread risk is lower than the outright price risk discussed in the previous paragraph.

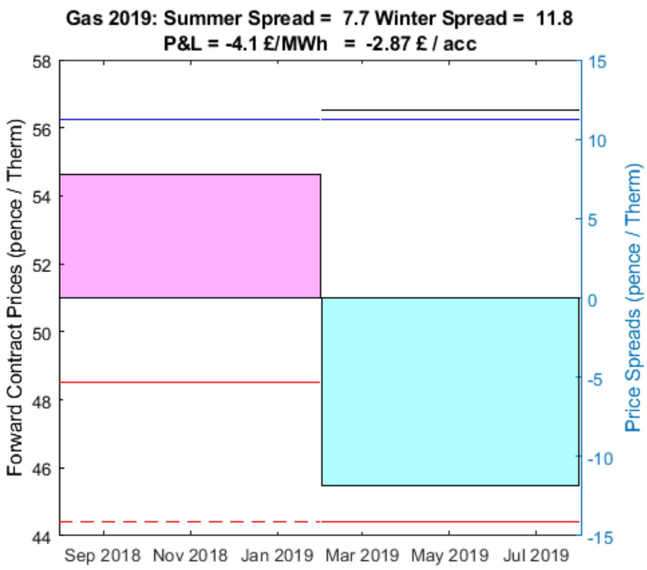
The charts below show the impact of following this alternative approach for the Prepayment (PPM) caps effective on 1st April 2018 and 1st October 2018, where the latter is still being calculated. The pink shaded area shows the development of the W18 vs S18 spread, and is a benefit, whilst the turquoise area shows S19 vs W18, and is a cost. With reference to the previous paragraph, the benefit and cost are **not** equal and offsetting. At time of writing (15th June) the shape of the forward curve (the difference in size of the two shaded areas) and price volatility within each indexation period (the slopes on each of the shaded areas) result in a combined adverse impact of >£9 per dual fuel account.





It is important to note that the shape of the forward curve introduces an expected cost to future PPM cap periods, even before indexation begins i.e. those applicable from April 1st 2019 and beyond, and by extension to the full market cap assuming that the PPM mechanism is retained. […]. Once within the relevant cap observation period, this could increase significantly due to price volatility. We believe that suppliers of all sizes are exposed to this cost.





We note that Ofgem suggested two alternative indexation models. We agree that the 6-2-12 annual alternative introduces a different risk to suppliers, in the form of greater exposure to customer number forecast accuracy. Whilst this may be true, we believe that

- this risk is dwarfed by that which is associated with the basis risk,
- customer number forecasting inaccuracy is a risk inherent in the retail energy supply business and is therefore one which it is reasonable to expect suppliers to manage. This is in contrast to indexation structures which cannot be accurately hedged, and

- crucially, the risks described in the 6-2-12 semi-annual method do not materialise in the annual method, because the price cap periods and the forward periods included in the index are aligned. We recognise that, when viewed in isolation, the less frequent price changes in the 6-2-12 annual method would be larger than in the semi-annual equivalent. However, the costs of the 6-2-12 semi-annual mechanism as described above are such that they would have to be recouped through pricing of other products.

The third option - a 6-2-6 semi-annual indexation method - introduces seasonal pricing, which is not desirable for customers. So, whilst this method can be hedged accurately, we would not support it. We do not agree with the suggestion that this would be detrimental to wholesale liquidity, firstly because of the relative proportion of total wholesale market activity attributable to retail. Moreover, we would suggest that the proposed wholesale index will force suppliers to shift their focus away from Y+2 and Y+3 where they may have previously been active, so it is the introduction of a price cap itself rather than this particular detail which is responsible for the majority of liquidity impact.

npower advocates the adoption of a 6-2-12 annual mechanism for the reasons discussed above. Alternatively, if Ofgem will not deviate from their minded-to position, we would strongly suggest that a recovery mechanism is introduced. The analysis above can be replicated and tracked transparently by Ofgem as part of the indexation process; if the forward curve costs suppliers, then suppliers recoup this cost in the following cap period but if the shape of the forward curve is beneficial, that benefit is passed through.

Finally, npower also seeks clarification on why Ofgem rejected the hybrid approach that was suggested most recently in our response to working paper 1:
(https://assets.publishing.service.gov.uk/media/58347537e5274a5918000000/prepayment_price_cap_draft_order_response_RWE_npower.pdf)]

QA6.4: Do you agree with our approach to modelling forward contracts? In particular: that initial shaping should be based on a 70-30 spilt between baseload and peakload, and the cap will be semi-annual. If not, please provide evidence to support alternative approaches.

The 70/30 split between baseload and peak is a reasonable approximation of a volume neutral hedge of domestic demand profiles over an annual period. However it is a poor fit to the actual HH demand shape and leaves both a large correction necessary to reflect the expected cost of purchasing a domestic profile and a large uncertainty in the outturn costs of trading the difference between the 70:30 approximation and actual demand shape in the short term markets, or leaving those differences to imbalance.

Within the limits imposed by the available wholesale market products we support the proposed split but we would recommend that, as discussed in our response to QA6.5, an explicit scaling factor is added to the baseline cost assessment to take account of both the expected additional costs and additional cost uncertainties in moving from this hedge to hedging actual customer demand outturn.

As a seasonal hedge does not reflect the eventual day-on-day shape and cost of demand profile across a season, we would recommend that allowance is also made for the resultant costs and additional cost uncertainties in moving from a seasonal hedge to hedging actual customer demand outturn.

We also note also that the weighting between summer and winter prices in the cap (53.1% Winter 46.9% Summer in the case of the Prepayment cap) must reflect the demand weighting of a PC1 profile […]. In a bottom-up cost assessment, this would significantly under-estimate the commodity cost for suppliers. We would therefore recommend using the latter numbers in the proposed indexation mechanism to reduce basis risk.

QA6.5: What are your views on the necessity and size of an additional allowance for shaping and imbalance costs? Please provide evidence to support this.

We believe that there are three significant additional costs over and above the baseload/peak assessment of commodity costs. These are:

- Expected Costs and Cost Variability of Shaping a domestic profile
- Expected Costs and Cost Variability of Imbalance
- Expected Costs and Cost/Income variability of Swing – weather driven demand and price impacts of customers not consuming the expected seasonal normal demand profile

Although this question does not address swing impacts, we include our views on this here since it is not covered elsewhere in the consultation and it is of critical importance for OFGEM to understand its significance, especially in the context of a low margin business such as domestic gas and electricity supply.

Overall, the combination of these costs add 5-10% to the commodity purchase costs of suppliers in an average year. In an extreme year there could be a further 5-10% addition to the costs over and above those in an average year.

The following table shows a rough breakdown of the commodity cost stack that we estimate for gas and electricity under a low risk (normal year) scenario and a high risk (extreme outcome) scenario. This highlights that these additional costs are both significant and highly volatile.

Electricity Costs		
	Typical Year	**Extreme Year**
Peak/Baseload Hedge	94.30%	86.04%
Adjustment to HH Shape	5.00%	4.56%
Swing + Imbalance + Shape Risk	0.70%	9.40%
	100.00%	100.00%
Gas Costs		
	Typical Year	**Extreme Year**
Baseload Hedge	84.4%	80.2%
Adjustment to Daily Shape	10.0%	9.50%
Swing + Imbalance + Shape Risk	5.6%	10.3%
	100.00%	100.00%

Shape Costs/Risks

We have partially addressed our concerns around shaping a domestic profile in our response to QA6.4 and QA6.1.

Different suppliers will manage shape in different ways dependent upon their ability to assess the potential risks, their own risk appetites and their ability to trade in the wholesale markets.

These choices will affect the level of costs and risks associated with trading and the amount of volume taken to imbalance to meet actual customer demand outturn. In different market scenarios, different approaches may be more or less beneficial, and would result in more or less price volatility for customers dependant on outturn events. It cannot be assumed that the pricing approach of one or two suppliers is representative of all behaviour (as discussed in our response to QA6.1).

For the purposes of discussion, it is important to separate these into two components. Firstly we have the theoretical cost of achieving the required shaped purchases and secondly we have the additional costs associated with the practicalities of achieving this shaped supply profile in the real world (e.g. trading costs, bid/offer spreads, liquidity etc.).

The theoretical cost of moving from a 70/30 baseload/peak trading position to a shaped position can be assessed by creating a synthetic forward curve at greater granularity than the products tradeable in the market (HH for power, daily for gas) and assessing the resultant total cost difference. This is usually done by shaping the prices of liquid forward curve products using historical outturn short-term market prices. In this way, a forward curve is produced that reflects the correct pricing for liquid market products but reflects the historical relative pricing of power purchased at greater granularity. There will be some variability in the assessed costs of shape between different market players depending upon their choice of historical data but all will agree that the theoretical cost of purchasing a domestic profile is higher than implied by a straight baseload/peak hedge. In our assessment, a Base/Peak hedge only assessment of cost underestimates the cost of shaped power by ~5% for a domestic profile for power. For gas, the underestimation is ~10% than implied by a baseload hedge

Over and above the true cost of the domestic shape profile, there are the costs associated with trading in the wholesale market to achieve this profile in the real world. These costs are associated with bid/offer spreads, demand forecasting uncertainty, churn etc. The size of these costs is very variable depending on hedging strategy and interacts with outturn weather conditions (i.e. swing) etc. but is consistently significantly higher than the equivalent costs associated with longer term baseload/peak hedging.

Finally, it should be recognised that shape costs, by their very nature, cannot be hedged to any great extent other than in the short term markets. This means that suppliers are exposed to significant variability in their outturn while they are obliged to take on such unhedgable price risk at the point of a customer joining them. Such uncertainty needs to be factored into any costs as an explicit risk allowance.

In any assessment of base costs, it is important to use the most up to date data since shape costs have increased significantly in recent years (~50% since 2015) as supply/demand fundamentals have changed in the UK. This is a good example of the significant challenges a domestic supplier has in assessing costs, especially during the period of energy market volatility and market transition we are currently seeing.

Imbalance Costs

The impact of imbalance costs depends heavily on each supplier’s approach to hedging and access to the short term markets. If a supplier is to take a very conservative approach to hedging all their exposures as much as possible in the wholesale market, then their resultant imbalance position will be small, while if a supplier chooses not to, or is unable to, hedge their positions in advance, then their imbalance position may be large. Further, the imbalance price is dependent on the actions undertaken by national Grid in their responsibility as balancer for the grid. As such, it is difficult to assess the cost of imbalance for any given supplier without defining an expected forward hedge expectation.

Our view is that it is reasonable for customers to expect us to minimise the potential volatility in their prices driven by outturn weather effects, and thus they would expect us, as reasonably practicable, to hedge their half hourly demand profile, minimising the volumes we leave to imbalance.

This, then, leaves imbalance as a function of forecast inaccuracy. As forecast accuracy is not perfect, some imbalance position is inevitable. As imbalance prices are generally the most volatile and are driven by different drivers than the wholesale markets in general, they are a source of significant uncertainty in outturn cost that needs to be factored into an appropriate risk premium in the assessment of baseline costs.

We strongly advise you to consider an appropriate allocation of expected costs to balance imbalance risk created through forecast error.

Swing Costs

Swing (short term changes in customer demand driven by weather) is a significant factor (particularly in gas) affecting the commodity costs of suppliers. Swing has two components:

- Volume of sales – in warm weather demand drops and thus income from customers is decreased and in cold weather the opposite happens. This is only partially compensated for by changes in the costs of purchase/sell-back of commodities and changes in other costs of supply
- Changes in short term wholesale price driven by unexpected changes in consumer demand

The impact sales volume will not be considered further here other than to note that in a warm year a tariff cap may under recover a supplier’s fixed costs.

The impact of wholesale driven price changes is two-fold:

Firstly, there is an expected cost (even in a normal weather year) caused by correlation between the short term market price and the short-term changes in demand caused by weather. In essence, in cold weather prices rise and so suppliers make a smaller than expected margin on extra sales, whilst in warm weather prices drop so that supplier’s make a slightly larger margin on fewer sales. Overall this results in a cost to suppliers since there will always be weather variability on a day by day basis. The total cost of this is ~1% of the total commodity purchase cost for suppliers.

Secondly, there is enormous year on year variability in the cost of swing impact on commodity costs. On a day by day basis weather outturn can result in the requirement to buy or sell substantial volumes of gas or power in the short term markets. For example, an extreme winter day can require a supplier to buy 50% more gas than expected and a warm winter day will require them to sell back 50% of already purchased gas. None of this volume can be hedged in advance and so commodity costs are exposed to any changes in underlying market prices between the setting of the tariff cap and delivery. This is typically partially offset by the extra/lower revenue achieved from sales. It is worth noting, however, that it is entirely possible that commodity costs will rise above the level of commodity costs allowed under a Price Cap mechanism, meaning suppliers, who are obliged to supply, could be selling every additional unit of sale over seasonal normal expected consumption to their customers at a loss, with no ability to recover these losses. Even when commodity costs do not exceed those rates set in a price cap world, the residual margin risk is still substantial and can amount to the equivalent of ~ 5% of a suppliers total commodity cost in an extreme year. The setting of a tariff cap without some allowance for this uncertainty could easily result in significant losses to suppliers in an extreme year.

Question A6.6: What are your views on the necessity and size of an additional allowance for transaction costs relating to brokers and collateral?

All retail supply businesses can choose to hedge their commodity price risk, or to leave such price risk to imbalance. In practice, under a price cap scenario, a retail business would be taking an extremely high risk to leave their commodity cost exposure to imbalance, and not hedge it (this causing system wide information imbalance and hence a cost to consumers from excessive procurement by National Grid of reserve). This is because the implicit allowable commodity cost could easily be exceeded through wholesale market moves, leading to a supply business supplying energy to customers at a loss.

Because the price cap model so strongly drives suppliers to hedge their commodity cost risk, it is reasonable to include an allowance for hedging commodity cost risks for brokerage, bid/offer spread costs and collateral charges.

[…]

Collateral charges are highly dependent on the credit rating of the supplier, but in all cases, are a cost a supplier will incur. We strongly recommend that OFGEM includes an allowance for commodity collateral costs, as we would expect them to be an ongoing expense for all retail businesses that are likely to transact in the wholesale market as part of managing their Price Cap price risk.

Question A6.7: do you agree that our approach to updating the benchmark for the first cap period is appropriate?

We have already explained our concerns with the indexation mechanism itself, so will not reiterate these here.

Broadly, we agree with the approach to updating for the first or ‘transitional’ cap period.

In our response to QA6.1 we highlighted the possibility that some suppliers may have chosen to make pre-emptive adjustments to their forward purchasing strategy before the structure of the price cap is known.

In the case of the transitional cap, whilst the principle of the wholesale index remains the same, the dates involved are of course slightly different; whereas a ‘normal’ cap applicable during winter involves observation of forward contracts between February 1st and 31st July, the observation period proposed transitional cap is two months later (April 1st to September 30th).

The most logical pre-emptive step as discussed in QA6.1 would have been to align to the same dates as the existing PPM wholesale index mechanism; those suppliers who took this step are now exposed to the two month difference in observation period, which given the relevant price history of the traded contracts which relate to a Winter 2018 cap would been somewhat favourable.

Indeed, suppliers who chose not to pre-emptively adjust their hedge positions may or may not carry a favourable commodity cost position into the first cap themselves, though this has to be balanced against both the lack of certainty about the specific design of the cap (i.e. the risk that it is not analogous to the PPM cap) and the unavoidable costs associated with Ofgem’s minded-to position.

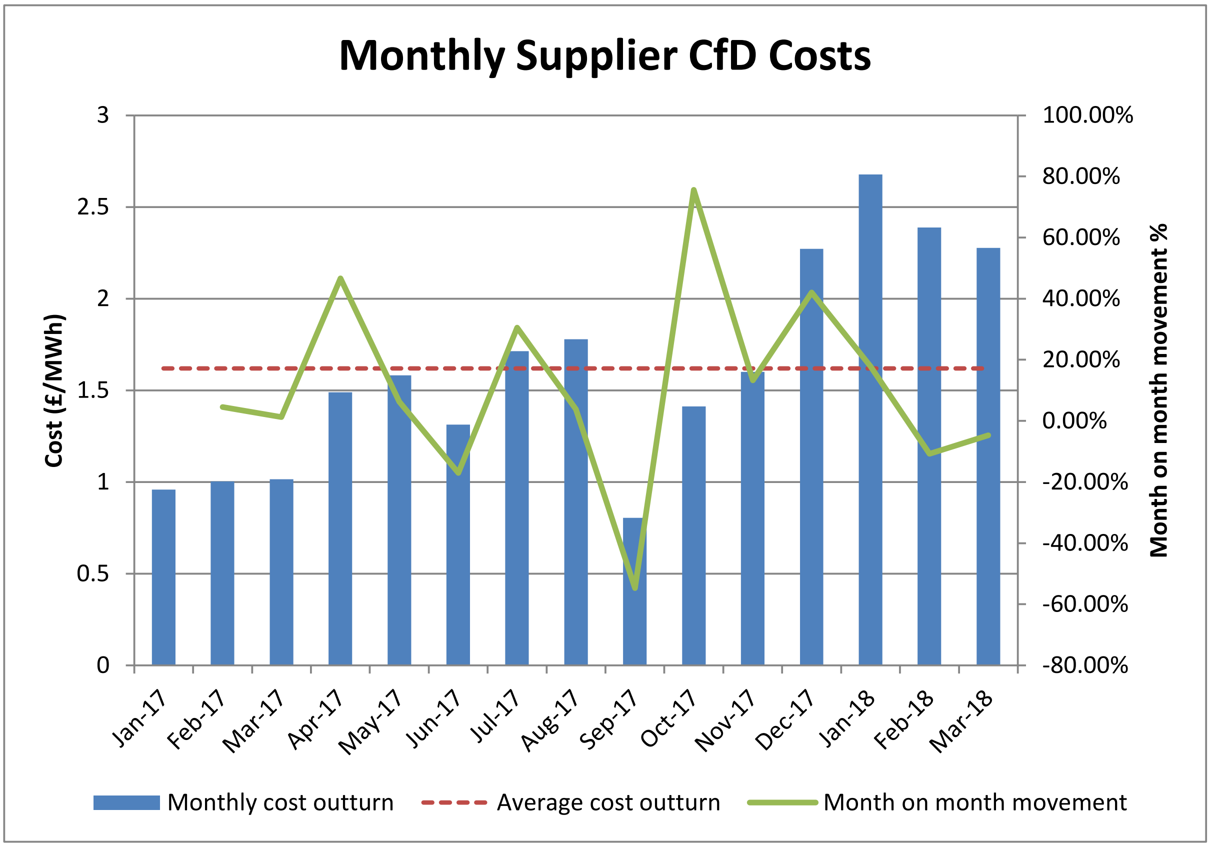
Appendix 7: Policy and Network costs – npower's response

Question A7.1 Do you agree with the way we propose to estimate the costs of each of the schemes for setting the baseline level of the cap?

Broadly speaking, yes.

The proposals for Renewables Obligation (RO) and Capacity Mechanism (CM) fix the cap on timescales when the costs have been largely fixed and so there is little residual risk to suppliers.

In calculating the base year costs of CfD, ideally OFGEM should seek to exclude known "one-off" events. For example, a major outage from a large biomass generator would significantly reduce outturn costs in the base year but would not expect to be repeated in future years. Having said this, it is not entirely clear that the base year costs will have any impact on the cap setting level for future years given that the mechanism proposed is essentially to calculate the costs for each season based on latest estimates and use this to set the cap level. If scaling factors are used, then as long as the same assumptions are made for the denominator of the scaling factor as were used for setting the base year cost then the correct costs will be achieved regardless of the assumptions made in the base year. For CfD, there are still substantial uncertainties in outturn costs versus the Interim Levy Rate (ILR forecasts). We strongly urge Ofgem to consider including an explicit risk premium in its assessment of these costs or a mechanism to allow reconciliation of costs from season to season. These uncertainties could lead to over or under recovery of costs by suppliers. To illustrate:



Monthly CFD cost outturn has been very volatile. For example, during the period between Jan-17 to Mar-18, month on month movements have been ranging from c +75% to -55%. Average outturn during this period has been £1.62/MWh whilst highest outturn was c £2.68/MWh, 65% higher than the average while lowest outturn was c £0.80/MWh, 50% lower than the average.

For CfD the latter could be achieved using the quarterly reconciled adjusted Interim Levy rates published by Low Carbon Contracts Company (LCCC) as part of their supplier cost reconciliation process. If we consider a price cap for a season composed of Q+1 and Q+2 that is set in quarter Q, then the adjusted ILRs will be available for Q-1 and Q-2 at the time of setting the cap. By calculating the cost difference for Q-1 and Q-2 against the original ILR values used in setting their relevant cap season costs, this cost could be added or subtracted from the total cost forecast for the new season and thus adjust the cap rate. So, for the first season of the price cap there would be no reconciliation. For the second season, the Q-1 quarter reconciliation would be included in the setting of the cap and for the third season onwards, the Q-1 and Q-2 quarters would be included in the reconciliation. In this way the reconciliation would be rolling and have minimal time lag.

For Feed in Tariff (FiT), Ofgem will be completing the Annual Levelisation process for the previous FiT year in September. It is important that this latest data is used when setting the cap in October as both total cost and chargeable volume base could potentially change (e.g.: changes in National Demand and amount of exempted volumes under GEE) at the annual levelisation compared to the view based on quarterly levelisation data for a given FiT year.

This will ensure that the baseline level of the cap is reflective of the latest outturn cost and future cap levels are forecasted based on the latest outturn.

We note that Table A7.1 does not recognise the Energy Companies Obligation (ECO) taper i.e. suppliers with 250-500k customers are partially obligated. Also, a new taper mechanism is proposed under the new ECO methodology where the cost per customer changes in direct proportion to market size (i.e. “personal allowance”).

In that context, could Ofgem please confirm what it means by the costs of a “fully obligated supplier”?

It is essential that Ofgem take into account the cross subsidy within ECO, as this drives consumers from obligated suppliers to non-obligated ones. This reduces the obligation base and increases the differential between suppliers. Indeed, differential obligation costs have been a key driver to the retail price differentials that CMA and Ofgem have cited as an issue. Ofgem must recognise this *ex ante*, as an ex post effect not captured in the price cap could render Ofgem in breach of its duty of care and EA89 and GS86.

Question A7.2 Do you agree with our proposed approach to forecasting the costs of each scheme?

Broadly speaking, yes.

For FiT, to increase visibility and confidence we would like to request the publication of OBR’s high-level forecasting methodology/approach. As per Table A7.4 under Appendix 7, in general for the October cap updates OBR’s March FiT forecast will be used while for the April update Office for Budget Responsibility (OBR’s) previous November’s forecast will be used. Whilst we recognise that the latest available OBR’s forecast is proposed to be used in the six monthly cap updates, it is worth noting that there could be a scenario where exogenous changes that happened since OBR's last forecast update may have a material impact on future FiT outturn which would not be reflected in OBR’s latest forecast due to timing, hence not taken into account in the cap. In such situation it would be important to adjust OBR’s forecast to reflect the impact of such exogenous changes to make sure future cap levels are reflective of future costs.

Paragraph 4.20 proposes to update the cap to reflect forecast trends in the costs suppliers incur in relation to ECO. This will be based on the estimate of annualised total scheme costs to suppliers, as included in the most recently published impact assessment for the ECO3 period. How and when the IA will be updated is unclear and it will be important to take into account volume & price in previous price cap periods, to avoid under/overstating future costs.

It is important that any “successor documents” used to forecast ECO costs are subject to the same level of governance and transparency as the the Department for Business, Energy and Industrial Strategy (BEIS) Impact Assessment (IA).

It would be helpful if in relation to Table 7.4, Ofgem could give a worked example for WHD. The revised scheme target comes in on 1st of April 2019. Ofgem should receive suppliers’ customer numbers and scheme targets from BEIS by February 2019, which may be challenging to implement for 1st April 19 due to the need to confirm the cap level to suppliers early February for a 1st April cap update. How would Ofgem ensure any difference is picked up in the next calculation from 1st October for the previous six month cap period?

Generally, there needs to be a mechanism to minimise the impact of lag in relation to policy costs, otherwise suppliers may not recover costs where obligations increase year on year. Further, a declining customer base will mean that if an obligation cost started in April 2019, a supplier would be unable to recover that shortfall despite having the obligation for the full scheme year based on market share as at December 2018.

If the cap comes in by the end of December 2018 would the cap actually be based on WHD spend for 18/19 e.g. £340m @ 47.65m meters = £7.13 per account rather than £6.70 in the consultation (Materiality £20m across all suppliers). Again, if for April – Sep 2019 it was based on £7.13 per account, it's likely the obligation could have increased to £7.25-£7.40 based on current methodology and depending on market share of non-obligated suppliers.

Whilst the calculation appears to be quite simple, it isn't and different scenarios could play out in the next 12 months which see annual spending ranging from around £6.80 per account to £7.40 which is around £30m materiality across all suppliers.

We also query whether it should be net of voluntary suppliers, who have chosen to be involved in the activity and more than likely if the wider vulnerable cap came in, would be obliged to comply with that cap and therefore costs should not be excluded.

The lowering of the socially unjust Warm Homes Discount threshold over time should be taken into account.

Question A7.3 Do you agree with the data sources that we propose to use to forecast the expected demand base for each scheme? Do you have any alternative suggestions which would more accurately track trends in eligible demand??

Broadly speaking, yes.

For Capacity Mechanism (CM), we note the importance of accurate forecasts of peak hours demand in allocating costs fairly to domestic consumers. We strongly recommend that Ofgem confirm that National Grid forecasts are consistent with actual metered data over the peak winter hours in recent years.

For Contract for Difference (CfD), we note that the eligible demand base needs to be adjusted both for Energy Intensive Industries (EII) and any Green Energy from abroad. The latter is included in supplier costs on a quarterly basis approximately one year in arrears. We recommend assuming that a volume of energy equal to the maximum allowable under the scheme is excluded from the demand estimate unless actual data, when it becomes available, suggests under-utilisation of the scheme. This will avoid a subsequent increase in actual charges once the lower charging base is confirmed.

For FiT , we would like to reiterate the importance of accurate national demand forecast in this calculation in the absence of a cost reconciliation mechanism post final outturn to make sure suppliers do not under or over recover. Also were the exemption for Energy Intensive Industries (EII) to be extended to FiT, we would like to suggest a review of BEIS's estimations against the actual exempted volumes under EII post first year of implementation and to make adjustments to the numbers used in this calculation where necessary.

Question A7.4 Do you agree with our proposal to use the existing model to estimate the network costs that suppliers incur?

Broadly, with some additions

As Ofgem acknowledges, there could be some risk to suppliers if there were changes to network charges within the charging year. We agree that such changes are rare but consider that provision should be included to reassess the level of the cap. Reviews should be considered at an interval of less than six months if published ex-ante network charges are revised within the charging year, so that the level of the cap continues to accurately reflect the network charge costs.

It is also important to consider adjustments that would be necessary if changes are made to network costs outside of use of system charging arrangements such as previously when the then Department for Energy and Climate change requested DNOs to take voluntary action to reduce network costs which was not made through use of system charges by all DNOs.

For BSUoS costs, which are not known ex-ante, we agree that the use of lagged historic price to set the allowance is an appropriate methodology. However, while the use of SF (first settlement run) data minimises the lag into pricing it introduces the risk that significant cost variances between SF (first formal settlement run) and RF (final settlement run) are not captured. For example the additional Black Start costs (£113mn cost to the industry of which £57mn was billed at RF). Where additional costs are to be included only at the RF billing run, appropriate adjustments should be made to SF data used to take account of this once known (i.e. in advance of publication of RF final settlement run).

Headroom: Network costs are excluded from the calculation of headroom and whilst this is appropriate for ex-ante published rates, we believe that headroom allowance is necessary to reflect uncertainty of future BSUoS costs. As such, BSUoS should not be excluded from the headroom calculations. More generally, headroom should not be used as a catch all for all forecasting errors in the cap calculation.

However, in the absence of the (essential) recovery mechanism for the cap, the recovery mechanism for the networks is inadequate. The recovery should be pushed forward by one year, so increased cost incurred by the network in year 0, would be recovered not in year 1 but year 2.

As noted above, if Ofgem proposed to continue to levy forced default mutualisation insurance payments by suppliers via the networks (the legality of which is not discussed here), and if there is no inter-year recovery mechanism, then Ofgem must include the expectation losses as a discrete line item next to distribution charges. Since the existence of the scheme increases the expectation of losses then this factor must also be taken into account.

Question A7.5 Do you have any views on the impact of using information on the average share of consumption that takes place in peak periods to estimate electricity transmission charges?

Yes

Transmission charge flow through to the cap should be cost reflective. The consumer incentives both in transmission charges and the capacity mechanism (and nominally in distribution charges) need to move to actual rather the projected use and hence appear ex post. Setting the cap without a recovery mechanism dilutes/eliminates the price signal to consumers, increases peak demand and thereby causes excess network build. The cost flow through would either put Ofgem in breach of EA89, GA86 and its duty of care or in violation of its duty to protect consumers, including in their wider interests with respect to climate change. The case for a recovery mechanism is compelling

Taking the peak consumption to be a % of the total consumption would not appear to be a particularly accurate proxy for E7 consumers as their peak consumption would be a proportion of their consumption on the day register. This would overestimate costs for users who have a greater than average proportion of their total usage during the night. Consideration should be given to setting the level of the cap with reference to day and night rates in order to avoid this simplification creating a cross subsidy.

Appendix 8: Operating costs – npower's response

Question A8.1 Do you agree with our proposed approach to estimating suppliers' operating costs (including our focus on total historical costs per customer, and estimating separate values for gas and electricity)?

In general terms we would agree with the concepts outlined in the paper regarding the focus on total costs and split by fuel. We would argue that to eliminate concerns about comparability further (above using total costs), these comparisons must be at the quality, granularity and auditability of the Consolidated Segmental Statements currently published – this would ensure consistency of the costs included and have the assurance of being externally audited by an independent third party.

One element of operating costs needs careful consideration. This is the costs of smart. Eventually, smart will decrease supplier costs due to savings in pedestrian reads and improvement in data, but the costs rise during roll-out before they fall.

Question A8.2 Should a variable component of this allowance be split out to reflect differences in bad debt costs between customers with higher and lower consumption?

Yes, on a cost reflective basis.

If debt costs are to be socialised across all customers, notwithstanding our concerns about the distortive effect of all deviations from cost reflectivity, it would seem fair to link a portion to consumption. Whilst we do not consider consumption itself to be directly correlated with a customer's likelihood to fall into arrears, there is logic that, should a customer fall into arrears, the higher their consumption, the higher their potential debt. There are other costs associated with the collection of debt that we believe would be more fairly apportioned on a per customer basis.

Broadly speaking, the more Ofgem socialises costs, the higher the cap must be as it drives up suppliers' costs due to cherry picking of higher margin customers, thereby somewhat defeating its purpose. The allocation of bad debt is not straightforward at all, even on an ex ante basis. For example, the more advantaged consumers tend to have lower bad debt and higher consumption. Another example is the relationship between prepayment and debt. Being on a prepayment meter reduces bad debt increases but many consumers are in debt when they have a PPM fitted. The allocation of ex ante bad debt between PPM and Receipt of Bill is therefore a matter of judgement. However, the overall relationship between bad debt and consumption is not clear, for example the cohort of low income high consuming customers. It is cost reflective to levy higher ex ante bad debt costs to less advantaged consumers, but there is a considerable social justice issue to consider. Our view in general is for credit reference agencies to be used more, so that less advantaged good payers get better terms. However this is hard to factor into the cap. The elevation of the cap to contend with bad debt could be considerable.

Question A8.3 Do you consider 2017 to be an appropriate period on which to base our benchmark, or are there reasons to think a longer period would be more representative?

Yes, 2017 is appropriate.

For the rationale outlined in the paper, regarding capturing the latest view of smart costs, 2017 appears an appropriate period to consider. Careful consideration will need to be given as to the amount of smart costs included in the initial baseline and the amount of costs included in the indexation to ensure all costs are fully covered. Any judgements and calculations in isolating these smart costs should be fully transparent.

Question A8.4 Do you consider that default tariff customers have higher or lower operating costs than other types of customers?

Higher operating costs.

We would expect the costs of default tariff customers to be higher in the areas of bad debt, customer service and metering. The main driver being the relative weighting of different payment types within the default tariff population, specifically a greater proportion of credit (and prepayment) customers. However, others factors may also drive higher costs for default customer, such as the prevalence of online account management typically being higher for non-default tariff customers – […]

Question A8.5 Do you agree with our proposal of where to exclude suppliers from our benchmarking analysis?

Yes, albeit that as Ofgem notes, the necessary exclusions make market based baseline and index impractical.

We agree in principle with the categories of exclusions from the benchmarking analysis. Our more specific views on the individual exclusions are as follows:

1. It may be more robust to exclude suppliers up to a limit of 500k, the point at which obligation exemptions fully cease;
2. It terms of reliability, perhaps a simplified and easier to adopt approach may be to only include the costs of those suppliers who publish an audited Consolidated Segmental Statement – this not only gives the assurance of an independent third party audit but would also aid comparability given the specific guidance on classification of costs. There would be nothing to preclude any supplier from publishing this information and therefore any supplier could be included subject to the other exclusions noted.

Question A8.6 Do you agree with our proposal of what to include in our definition of operating costs?

Yes – subject to our response to Appendix 10 on smart costs.

This should be checked ex post with respect to actual costs incurred

Question A8.7 Do you agree with our proposed approach to benchmarking operating costs under a bottom-up cost assessment?

Yes and no – It is essential to avoid the logical error of all suppliers beating the average.

We agree that there are number of factors that may impact operating costs outside of the simple bracket of efficiency as outlined in table A8.2. It will be important to accurately and transparently adjust for these factors and the proposal to analyse efficient costs for a supplier with ‘average’ characteristics seems sensible in principle, subject to how the definition of ‘average’ is determined.

It would also seem sensible to take an average of efficient costs over a number of suppliers to allow for any errors in adjustment when looking at a single supplier. We would also support the proposal made in an earlier response by another party that setting a wider initial headroom to allow suppliers time to reduce their costs to the determined efficient benchmark would be an appropriate alternative.

Question A8.8 Which if any of the factors listed in Table A8.2 do you think we should take into account when choosing our benchmark? Do you have any suggestions for how we could estimate the materiality of the impact of any of these factors on costs?

- Certainly factors (b), (c) and (d) and (g) through to (j) should be considered;
- In terms of company size, there may be many factors both favourable (lower reporting and regulatory burden) and adverse (economies of scale) and as such this may be complex to adjust accurately for;
- Customer service levels could perhaps be less subjectively catered for through the exclusion of those suppliers whose service falls below a specified acceptable level, as proposed earlier in the document;
- In terms of acquisition costs, it may be a simpler and more transparent approach to expense these fully rather than try to standardise for a suitable amortisation period.

Question A8.9 Do you agree with our proposal to use CPIH to index the allowance for operating costs within the default tariff cap?

Yes.

Question A8.10 Should the default tariff cap be reduced over time to reflect an expectation of general productivity improvements – and if so – at what level should this efficiency factor be set?

No

For the reasons stated in the document – smart savings will be captured separately, the short duration of the cap and consistency with the PPM methodology. Efficiency savings will automatically be captured.

Appendix 9: EBIT – npower's response

Question A9.1: Do you agree with our proposed approach to setting the EBIT margin?

No.

The starting point is not EBIT but WACC.

Unfortunately, both CMA and Ofgem have materially misunderstood the cost of capital and in order to comply with EA89 and GA86 this should be remedied when applied to the cap.

Our concerns over using ROCE for an asset light business as the basis for this determination of an efficient EBIT margin have been well documented in various responses to the CMA energy market investigation, not least in the provisional decision on remedies response. Our key concerns being:

- The under-statement of economic capital employed, most materially the notional capital held against a broad range of business risks faced by suppliers. Specifically it (i) fails to appreciate that the Six Large Energy Firms hold relatively larger amounts of capital because they operate with a lower probability of default than the mid-tier firms, which ultimately benefits consumers; (ii) underestimates the total costs of trading services; and (iii) understates regulatory collateral.
- It understates the value of a customer because it adopts an unnecessarily restrictive definition of the costs to acquire customers, excluding valuations based on market transactions, and underestimates average customer life
- It excludes the value of purchased goodwill and brand value in entirety to avoid the risk of capitalising the value of excess profits – this appears an extreme position
- It excludes the cost of pension deficit repairs, although noted elsewhere in these consultation papers that these may be considered as part of the operating cost benchmark
- The judgement and level of complexity involved in making the relevant adjustments to the economic capital employed in order to attempt to improve the reliability of ROCE as a measure for an asset light business

We would still view an analysis of % EBIT margins as a more relevant approach and note that the CMA previously suggested in its Provisional Findings document: "it is our preliminary view that comparators within the GB energy retail supply markets are likely to be more informative than those outside the GB energy retail markets" (paragraph 16) and "In relation to EBIT margins, the … evidence from independent suppliers suggests to us that competitive EBIT margins in energy supply are relatively low and likely to be 3% or less depending on the level of investment and the level of cost efficiency" (appendix 10.6, paragraph 17(a)).

With regards to applying the relevant EBIT %, i.e. with or without intermediary trading arrangements, dependent on the choice of initial benchmark seems sensible in principle. However, again in reference to our response to the CMA provisional decision on remedies, we note that the trading fee applied to estimate trading collateral requirements is understated because it fails to account for the value of the charges and warrants transferred to the trading intermediary from the Independent suppliers.

Question A9.2: Do you agree that it is acceptable to retain the WACC figure used by the CMA? If not, do you have views on the factors we would need to consider if we were updating the WACC?

Yes.

WACC is the key figure from which EBIT should be derived, and not vice versa. Ofgem should confirm this.

Question A9.3: Do you agree that we should maintain the CMA's estimates of the capital employed by energy suppliers? If not, please specify which element you think we would need to revalue.

No.

As stated in response to question A9.1 above, we believe the CMA methodology of determining capital employed materially understates the value of capital employed by a responsible energy supplier and involves an undue amount of judgement in adjusting the inputs compared to a simple analysis of % EBIT margins.

Question A9.4: Do you agree with our proposed approach to updating the EBIT margin?

No.

The WACC to EBIT conversion needs an overhaul to make it correct. Once set, i may make more sense to hold the EBIT margin as a fixed %, which therefore increases / decreases in £/customer terms in line with changes in the costs within the index. This is likely to be more relevant than indexing to CPI.

Appendix 10: Smart metering costs – npower's response

Question A10.1: Do you agree with our minded-to position to include a separate smart metering index to reflect the changes in costs from the baseline (2017) to the initial year of the cap (2018)?

Yes.

We agree with the proposal to separately index smart costs. However, we also believe that it is essential to have maximum transparency of the efficient level of costs / benefits included within the baseline, as the starting point from which to apply indexation.

In reality, due to considerable issues with DCC delays, supplier costs have risen significantly as a result. There is incentive for Ofgem to understate these issues by excluding their effect from the cap. To do so deliberately would be a serious offence by Ofgem in public office.

Question A10.2: Do you agree with our minded-to position to include an adjustment to the Reference Price (SMRPA) in the event a material difference is identified between the smart metering net costs of the suppliers making up the Reference Price and the model?

Yes.

We agree with proposal to include an adjustment to the reference price, subject to transparency regarding any delta and materiality judgement. There are many aspects to the overall financial impact of smart metering on suppliers that differences between suppliers making up the Reference Price and the model need to be reflected in the price cap. These differences include, amongst others, customer mix, rollout plans, level of SMETS 1 installations and premature removal charges.

The mechanism proposed creates a limited inter-year recovery mechanism. This reduces the risk of Ofgem breaching EA89, GA86 and its duty of care. However this does not obviate the need to get smart costs as right as possible ex ante. We remain strongly supportive of a discrete and thorough exercise in getting to grips with supplier gross and net smart costs in a consistent manner. We would be happy to participate in a data room exercise, recognising the need for third party involvement in confidential matters.

Question A10.3: Do you agree with our initial assessment for the Smart Metering Net Cost Change, including our inclusion and assessment of the costs of SEGB, SMICoP and DCC charges?

In principle, the overall approach to assessing the SMNCC looks logical, in that it calculates a baseline for the pass through costs and applies an uplift based on the latest available charges. However, it is not clear how soon changes to these costs will be reflected in the price cap**.** To the extent possible, it is essential that the SMNCC reflects changes in the Charging Statements as soon as they are available.

The current DCC charging statement would span the intial cap period to 31 March 2019. We anticipate an indicative statement in October 2018 to forecast 2019/20 charges, with actual charges published around the middle of March 2019 i.e. after the 5th working day in February when Ofgem plans to notify the cap level from 1st April. This presents a risk of under/over recovery and a need to true-up the costs for April-September.

The forecasts for some of these costs have been extremely volatile over the past few years. Although the projections of DCC fixed charges are becoming more robust, there remains a huge amount of uncertainty around AltHANCo costs, which are to a large extent still unknown. These costs have moved significantly between forecasts:

- In October 2017 the DCC forecast AltHAN costs for FY 19/20 to be £7.3m.
- In April 2018 the DCC forecast AltHAN costs for FY 19/20 to be £56.1m, nearly an eightfold increase.

[…]

Question A10.4: Do you agree with the judgements we have set out regarding smart costs, in particular our choice of data and model, identification of relevant costs and benefits, and approach to variation?

Judgement 1 – using the BEIS model seems sensible as a starting point, subject to maximum transparency regarding assumption, inputs, etc. We note in passing that government Impact Assessments and Cost Benefit Analyses on many policies such as smart have been substantially awry relative to outturn costs and benefits. This is to some extent inevitable due to the difficulty in predicting the future, but some model shortcomings were evident at the time of publication. The key will be how this is adapted to show only supplier benefits (50% of BEIS assumed benefits which is debatable), and the fact that some overall benefits (e.g. reduction in consumer usage) represent a loss to suppliers. Will Ofgem factor in that suppliers will have to recover fixed costs from a reduced average consumption / customer? In addition, there may well be other items in the BEIS model that Ofgem need to update which are not mentioned in section 2.11. These include updated installation costs, premature removal charges, and the increased costs to suppliers' infrastructure programme as a result of the two year delay in rolling out SMETS 2 meters.

Judgement 2 – The cost categories seem sensible, but the key point will be whether the costs in these categories are updated to reflect what has happened in the overall smart programme nationally since 2016, in particular the increased cost resulting from the delays to the national programme.

Judgement 3 – Whilst proving non-efficiency variations is difficult, Ofgem should keep an open mind on this issue. For example, npower have incurred considerable extra costs […] through being at the forefront on the SMETS 2 testing (we currently have over 50% of the SMETS 2 meters with less than 10% of the market share) but Ofgem are suggesting that this should not be reflected in any price cap. This does not create appropriate incentives for suppliers.

Question A10.5: Do you consider that there will be any significant change in the costs or benefits of smart metering from 2017 onwards? For example, installation costs or asset costs. Please provide evidence to support your view.

Yes

It is likely that there will be considerable changes in costs from 2017 onwards.
However the benefits post-date the costs and may happen after the sunset of the cap. In addition there is a distributional effect between suppliers, in which obligated suppliers incur all the costs, but non obligated suppliers receive disproportionate benefits. Using historic data, which will be based on SMETS 1 installations, is not an accurate basis for projecting the costs of SMETS 2 installations. The costs of SMETS 2 installations will be different from SMETS 1 installations in the following way:

- The commissioning times for SMETS 2 meters at volume are unknown, and will inevitably vary from those of SMETS 1 meters. This will impact the installation productivity in a way that is as yet unknown, but could be significant based on current commissioning issues in the Arqiva area.
- There is no track record for how long it may take to install SMETS 2 meters with a Dual Band Communications Hub (DBCH?). This could reduce productivity.
- There is no track record for how long it may take to install SMETS 2 meters which required an Alternative Home Area Network (HAN). This could reduce productivity.
- Asset cost may vary between Smart Metering Equipment Technical Specification (SMETS) 1 and SMETS 2 meters, although this will depend on individual suppliers' contracts.

About 30% of qualifying properties across industry do not have a technical solution available, these are being progressed and developed, but of course at this stage costs are uncertain – this needs to be factored in.

Question A10.6: Please comment on the proposed methodology for calculating the efficient cost of rolling out a smart meter, indicating a preference with supporting rationale, on the efficiency option (average cost approach, pure frontier cost approach, lower quartile approach)

As discussed in our covering letters, the second least efficient supplier represents the best solution, based on the largest suppliers who are likelier to have engaged in the smart metering rollout earlier in the process, and hence their costs are more reflective of the real cost of the rollout programme. We are particularly concerned that if the cost allowance was based on the lowest quartile of supplier costs then suppliers who have engaged more in the process, and incurred higher costs, would be penalised for getting on with the process earlier.

Question A10.7: Do you agree with our approach to updating smart costs? In particular, our intention to specifically index smart cost changes, based on net cost analysis (option 3), and whether any other approaches would be preferable to option 3.

Yes

We agree with Ofgem's minded-to position to use option 3 as this is would ensure that changes in smart costs are reflected in the cap. However, it will be important to understand how this will work in practice, and to get comfort that sudden increases in costs (e.g. AltHAN) will be included in the cap,

Appendix 11 Headroom – npower's response

Question A11.1: What are your views on headroom being a percentage? Do you think it should be applied to all cost components except for network cost? Alternatively, do you think headroom should be applied as a percentage to only controllable costs?

We believe headroom should be a percentage applied to all costs except for network costs as we agree that these are currently relatively certain. The exception is BSuoS costs which are known ex-post and black start costs ((£113mn cost to the industry of which £57mn was billed at RF), should either be catered for by way of a correction mechanism or the uncertainty factored into headroom.

Forced mutualisation of default levied by networks should be treated separately and have inter-year recovery applied.

Question A11.2: What are your views on whether we should change the level of headroom over time?

We do not believe that it would be appropriate to reduce headroom as suppliers already have incentives to improve efficiency, in order to compete, retain customers and deliver value for shareholders. There is evidence of significant cost cutting programmes across the industry.

The level of headroom may need to be revised if the cap has an adverse impact on the market and/or suppliers. Ofgem must follow consultation and transparency in doing so.

Question A11.3: Bearing in mind the analysis and scenarios presented, what are your views on the appropriate level of headroom to include in the default tariff cap?

This is a matter of policy.

There appears to be high risk that elements of cost and headroom will be reverse engineered so that tariffs change by an amount deemed politically acceptable in parliament. £100 per annum (on a Dual Fuel Receipt of Bill basis) appears to have some political currency. In our view, such a figure cannot be arrived at by following the proper process of cost evaluation and headroom setting.

The lack of any error correction mechanism would also warrant a further uplift to headroom. This could be considerable (several %) and is pure deadweight cost to consumers (i.e. no corresponding gain by suppliers)

Appendix 12 Payment method uplift – npower's response

Question A12.1: Do you agree with our proposed methodology for allocating additional costs between standard credit and direct debit customers?

No, the situation is more complicated than outlined

We agree with the allocation of costs which is broadly in line with the CMA's view and our assessment of the additional costs to serve standard credit customers. Our current prices reflect a conservative approach to compliance with the cost reflectivity obligation under SLC27.2A.

Ofgem should set the cap on a Receipt of Bill basis, allow suppliers to discount Direct Debit, and make clear its position on SLC27.2A.

Question A12.2: Do you agree with our proposed methodology for calculating the additional costs to serve and the socialisation level?

No.

We believe that the cap should be on standard credit ROB, with suppliers free to discount direct debit. This will in turn require a revision of SLC27.2a

We believe that it is sufficient and simpler to have a fully cost reflective Receipt of Bill (ROB) cap, with no separate cap for Direct Debit (DD). This would not preclude suppliers from continuing to offer a discount for paying by Direct Debit.

Ofgem's proposed socialisation of costs is inconsistent with the allocation of risk/costs in other markets, such as insurance. For example, the premiums for young drivers reflect the risks associated with that customer cohort; the relatively higher premiums for contents insurance in higher risk postcodes. There is a risk of unintended consequences as offering ROB tariffs could be less attractive if suppliers are not recovering their costs, particularly if they have a high proportion of ROB customers. An effective discount of £22 would significantly dilute the incentive to switch payment methods in order to better budget for energy costs.

There could also be an impact on prices and payment method differentials for fixed tariffs as suppliers seek to recover costs, further undermining engagement and competition. Ofgem should also clarify whether it would expect the same differential to apply in that segment of the market.

Appendix 13 Renewable tariff exemption – npower's response

Question A13.1: Do you agree with our minded-to positions not to provide exemptions for renewable electricity or gas tariffs?

Yes.

Question A13.2: What are your views on whether to provide a derogation for renewable electricity tariffs?

Yes, on a case by case basis.

We agree that a derogation process is more appropriate than an exemption for renewable SVTs. This would enable individual cases to be assessed on their merits in order to safeguard consumers. The criteria and basis for granting each derogation should be transparent to ensure equitable treatment of suppliers. Ofgem should make clear and public the bases for derogation, for example is there an actual or de facto on green premium.

Appendix 14 Initial view on impact assessment – npower's response

Question A14.1: What is your view on the overarching approach that is proposed for conducting the impact assessment? In particular, on the scope of the assessment, and material issues that we have not referred to. Please provide details of any relevant sources of data and evidence that you think should be considered.

The approach and scope seem reasonable and covers the ground we would expect. There will be read across to the risks identified by the CMA when deciding not to implement an SVT wide price cap, principally the risk of undermining the competitive process, with reduced incentives for suppliers to compete and customers to engage. Ofgem will need to ensure the design and level of the cap mitigates such risks.

Question A14.2: Do you consider that suppliers will incur a change in administration costs as a result of the default tariff cap? If so, please provide estimates with supporting evidence. Please specify whether any administration costs are fixed or variable. If variable, on what basis do these costs vary? For example, on a per customer basis.

Yes.

[…]

We do expect an increase in administration costs from the cap, because its change will cause all suppliers prices to change at the same time and create surges in enquiries, direct debit changes, and switches. This is only partly offset by the ability to plan around certain dates. […]

Question A14.3: Are you aware of any unintended consequences, in the form of detrimental impacts on customers that were observed as a result of the existing safeguard tariffs? If so, please provide details of these unintended consequences.

A relatively small number of low volume users' bills increased (within the cap), but we periodically review such accounts in order to provide a bill credit to mitigate any detriment. There is evidence of reduced price dispersion and lower available savings in the PPM market.

Question A14.4: Do you have reason to believe the default tariff cap could disproportionately impact any of the nine protected characteristics under the Equality Act 2010? Please provide any supporting evidence.

None that we are aware of.

Question A14.5: Do you have any additional information or data on the impact of the implementation of the existing safeguard tariffs on switching rates that would inform this analysis?

Industry commentators/analysts have highlighted how the PPM cap reduced PPM switching rates.

[…]