Anna Rossington
Deputy Director, Retail Price Regulation
Ofgem

8th October 2018

Dear Anna,

Default Tariff Cap: Response to Statutory Consultation

Thank you for the opportunity to respond. We have enclosed our view of how the build-up of cost is necessarily corrected to comply with the relevant legislation (principally the Electricity, Gas and Tariff Cap Acts)[1].

In this letter we feel that we must explain the damaging effects of Ofgem not complying with the legislation and Ofgem's duty of care in public office and the potentially dramatic consequences of setting the cap too low. We refer herein to the top down view of the level of the cap, which necessarily features in its proper setting, and which can readily be used to gauge the impact on profitability of the whole sector. **Overall, the cap appears understated by at least £50 per annum per dual fuel account.**

As is evidenced in the Consolidated Segmental Statements, npower has faced significant financial challenges, with our parent Innogy funding significant negative Earnings Before Interest and Tax (EBIT) in each of power and gas in each of the last three years.

During this time we have made enormous strides in our recovery and return to sustainability programmes to lower costs, drive efficiency and return to breakeven. With industry norm cost in sight and a strong customer service position, it is vitally important that the price cap does not preclude profitability even for an efficient supplier going forward.

It is our view that the proposed cap based on the lowest supplier cost risks plunging some, many or even most suppliers into loss. This is even before omissions and corrections in Ofgem's cost calculation, and the effect of cost and revenue variations beyond suppliers' control that far overwhelm the EBIT margin proposed, even if the Recovery mechanism, standard in price control, is neglected. Ofgem must not be indifferent to such an outcome. Ofgem's publication of a proposed cap level must not prejudice the outcome of a fair consultation under principles established in law.

As the policy and regulatory structure stands, many costs are in practice borne largely on Standard Variable Tariffs (SVTs) and slightly on Fixed Term Contracts. This is readily apparent given that depression of SVT to the proposed level, in the absence of a rise in FTCs, would approximate eliminate aggregate industry profit.

The exit of a supplier is not straightforward if in default. The reason is that there are numerous regulatory mechanisms that recycle the cost back to suppliers, and in practice the cost is borne largely on SVT. This has a domino effect that can eventually spiral if the marginal supplier is driven to exit by the cost socialisation.

The bottom up amendments are covered in the body of this document. Hidden in the technical detail are very large items. To take a single example, Unidentified Gas (UiG) is a very technical subject but the size of the error is in excess of 3% of the real and current cost of gas and outside the control of any individual supplier. In the context of an EBIT margin of 1.9%, this item alone (and it is one of many) erodes any margin or certainty in achieving positive EBIT. Omission of use of the expertise of Xoserve, who ran the Nexus programme, to forecast UiG, and the use of an idealised technical

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[1] See Table on page 5

figure (only loosely related to actual cost levied to suppliers) from the Allocation of Unidentified Gas Expert, seems reckless.

Ofgem's approach has unfortunately been less transparent than is commensurate for a level of scrutiny appropriate with a policy intervention of this magnitude and potentially dramatic consequences. In particular, the impediments placed in front of licensees to prevent effective use of the disclosure room. These include unreasonable limitations on access to the disclosure room; the insistence on a physical disclosure room; the short time available for analysis and in particular the wholly excessive use of redactions that has significantly undermined our ability to review the assumptions and calculations behind the complex modelling.

We believe that significant costs of the SMART program have not yet been included within the methodology. It seems perverse to us to base the costs on the lower cost 2017 Foundation period in which DCC problems delayed mass roll out, rather than fully recognise the true costs of SMART in a 2019 mass delivery period including the cost consequences of those delays. The SMART costs are potentially understated by at least £10 per meter, which equates to c£200m across the industry.

At a slightly more detailed level our key points on the consultation are listed here and expanded on in the body of the document;

i) **Corrections** - There are significant underestimates and omissions of costs, Some appear to be deliberate, e.g. those mentioned above; smart, and Unidentified Gas (UIG);
ii) **Adjustments** - There are numerous adjustments that appear to be completely arbitrary, such as the £5 dual fuel "efficiency factor" and 15% uplift to the practically impossible hypothetically efficient supplier;
iii) **Recovery** - The absence of the regulatory standard Recovery mechanism causes flowthrough of capital cost risk to consumers placing Ofgem in breach of its primary duty;
iv) **Headroom** – Ofgem still conflates modelling errors/uncertainty and true competitive headroom. To comply with the Acts these must be separated;
v) **EBIT margin** - Largely as a result of the absence of Recovery, the 1.9% EBIT figure remains manifestly incorrect in relation to the cited Weighted Average Cost of Capital;
vi) **Wholesale** – We describe below the issues and modelling errors causing significant underestimation of costs.

In conclusion, the sum of these issues amount to a loss of revenue to the industry of the same order as the total current domestic earnings. It is inconceivable that suppliers will be able to immediately change their cost structure and deliver important government programmes such as SMART and provide universal service to all customers; such changes take time. Similarly the non-SVT market *may* adjust in some way to mitigate some of this impact and it may not. To take that chance, and be indifferent to potentially dramatic consequences, requires careful reflection on the effect on future consumers and businesses providing thousands of jobs in the UK economy.

This redacted response is non-confidential.

Yours sincerely,

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Cc: Paul Finch, Regulatory Advisor

Contents

Having responded to the previous consultation, we summarise where we have made points before and expand where new questions and issues have arisen in consultation.

The themes are set out as below. Matters of detail are contained in the appendices.

Effect on financing, investment, innovation and exit

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 will adversely impact investor confidence. Stock market reaction to the statutory consultation largely reflects reduced uncertainty, rather than endorsement of the proposed cap level. 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.

Ofgem proposes a cap level of £1,136 and £1,219 on average for Direct Debit and Receipt of Bill customers respectively, at Typical Domestic Consumption Value (TDCV). Ofgem estimates that this equates to customer savings of about £1 billion. This is a stark figure in the context of combined Six Large Energy Firm (SLEF) EBIT of £924m[2] for 2017. **The headline average savings figure of £75, actually equates to a saving of £85 for Standard Variable Tariff (SVT) customers of the (SLEFs).**

In reality the saving in the first price control period is considerably higher than the £75 headline due to the recent increase in wholesale prices. These have not been fully factored into SVT prices for two reasons: i) the wholesale price changes, in part driven by international oil prices, have been recent, and hence not featured in SVT prices which tend to lag wholesale markets; ii) in the presence of impending price cap, it is a reasonable supposition that suppliers (including npower) have not made SVT changes that they might otherwise have done without the cap, since the period of higher prices would be short lived. **This effect is substantial – in the range of £15-£35, making the true reduction around £100.**

The cap increases the likelihood of supplier exits and defaults. At this point in time Ofgem has acted (ultra vires in many respects such as the mandated mutualisation of default cost insurance which in the finance sector was properly executed by legislation[3]) to socialise supplier default costs in all respects (e.g. energy costs, network and use of system costs, numerous obligations such as Feed In Tariff). A cap set too low risks a spiral in which suppliers are precipitated to default, the socialised costs of which precipitate other defaults, etc.

Whilst seeking to protect disengaged customers, it is essential that the cap is set at a level which mitigates any negative impact on customer choice and current levels of engagement and competition. It must enable suppliers, including those who have no policy exemptions, to recover costs, manage risks and continue to invest and innovate. It is also essential to mitigate unintended consequences such as penalising customers who engage in the market to seek out a good deal. We believe that it remains possible to refine the cap proposals to strike a better balance in satisfying the objectives of the Domestic Gas and Electricity (Tariff Cap) Act 2018 ("Tariff Cap Act") and wider energy legislation.

Accordingly, it will not surprise Ofgem that npower considers policy Option 2 too low. We do clearly recognise and accept of course that the primary legislation has been passed, and Ofgem also may not set the cap too high.

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[2] SLEF 2017 Consolidated Segmental Statements
[3] Financial Services and Markets Act 2000

However, we believe that in totality, an uplift to the proposed cap of at least £50 per annum per dual fuel account is justified to mitigate the costs and risks highlighted in our response, and deliver a cap that is fully compliant with the legislation (particularly in the absence of a Recovery mechanism).

A tabular breakdown of each uplift (above the proposed Ofgem cap allowances in its model) is provided below, with detailed rationale under each topic within this response.

Electricity		Model	Uplift	Resultant	**Gas**		Model	Uplift	Resultant
Wholesale	DF	192.51	0.00	192.51	Wholesale	DF	240.87	8.44	249.31
Wholesale	CM	11.08	0.00	11.08	Wholesale	CM	0.00	0.00	0.00
Policy costs	PC	116.17	0.00	116.17	Policy costs	PC	20.85	0.00	20.85
Network costs	NC	131.28	0.00	131.28	Network costs	NC	126.34	0.00	126.34
Operating costs	OC	81.13	2.50	83.63	Operating costs	OC	92.49	2.50	94.99
Operating costs	SMNCC	7.28	10.00	17.28	Operating costs	SMNCC	7.77	10.00	17.77
Operating costs	PAAC	4.66	0.00	4.66	Operating costs	PAAC	4.63	0.00	4.63
Operating costs	PAP	7.79	0.00	7.79	Operating costs	PAP	5.52	0.00	5.52
EBIT	E	10.49	0.00	10.49	EBIT	E	9.47	0.00	9.47
Headroom	H	6.24	11.76	18.00	Headroom	H	5.52	10.81	16.34
VAT	VAT	28.43	1.22	29.66	VAT	VAT	25.67	1.61	27.28
Total		597.05	25.49	622.54	Total		539.15	33.36	572.51

Dual Fuel	**1,195**
Ofgem Model	**1,136**
Total Uplift	**59**

2019 prices at Ofgem TDCV (Direct Debit). Certain zero uplifts in the table exclude additional risks and costs that need to be addressed (as explained below)

In summary:

i) Gas Wholesale Direct Fuel Costs uplift (£8.44) to mitigate the underestimated UiG risk (see page 6 and Appendix 2);

ii) Removal of the arbitrary £2.50 “Efficiency Factor” (see page 7 and Appendix 3);

iii) Smart Meter Net Cost Change uplift of at least £10 per meter (although we are concerned that this may need to be higher. For example, it is unclear to what extent supplier IT costs have been included). See page 9 and Appendix 5.

iv) Headroom uplift from 1.45% to 4%, commensurate with the Prepayment Cap, as we believe that this is required for competition given our concerns about the efficient benchmark and overall cap level. See page 9 and Appendix 6. Further, the proposed 1% (£3) allowance for wholesale and 1.45% (£12) for residual uncertainty are dwarfed by the wholesale risks we explain in our response (in the absence of a Recovery mechanism) and highlight below:

v) In the absence of a Recovery mechanism, the risk of a "one in twenty" year outturn of shape swing, and imbalance costs [✂], not included in the above table. See page 10 and Appendix 7;

vi) We have not included an uplift for Wholesale basis risk in the above table, as this is a fundamental issue of methodology / lack of a Recovery mechanism. Our current expectation is a cost of [✂] per dual fuel account for 2019. See page 11 and Appendix 7.

vii) We also highlight the one-off Wholesale cost (>£15 per dual fuel account) for the transitional cap period due to Ofgem's reversal of the originally proposed observation period. An allowance must be provided within the cap to ensure cost recovery.

viii) c£10-20 per dual fuel account to address the issues we identify in Appendix 3 in relation to efficient supplier costs (also not included in the above table).

Please see Appendix 1. Headline Figure

<u>Corrections</u>

In general, the analysis done is to Ofgem's credit given the compressed timescale of 6 rather than the normal 30[4] months. However, several corrections must be made to be consistent with the Acts[5]. The main ones are summarised below, with further detail in the appendices.

<u>Unidentified Gas (UiG)</u>

The allowance for UiG is currently:

i) Based on an aspirational estimate that is at odds with UiG levels experienced post-Nexus;
ii) Requiring proper attention given that it is a difficult and material subject;
iii) Light on explanation of rationale;
iv) Recklessly indifferent to our realistic expectation of the likely outcome.

At a high level, an alternative solution would be:

i) Not to use a hypothetical estimate of so-called 'permanent' UiG as calculated by the Allocation of Unidentified Gas Expert (AUGE), but rather to use the findings of the Central Data Service Providers (CDSP) UiG Task Force to establish a realistic projection, with error bands to the end of the price control period;
ii) To use a reasonable high case or have a Recovery mechanism.

If the allowance remains unchanged, we believe the risk of under-recovery will be c£8 per gas account (based on the differential between our forecast 2018 UiG exposure at 4.5% and the 0.96% proposed allowance).

4 Understanding Regulation" (2012) Baldwin, R., Cave, M. and Lodge, M. OUP
[5] EA89/GA86 as amended. UA00, Enterprise Act 02, Energy Acts 10/13

Please see Appendix 2.

Midata

The CPIH indexation does not take into account numerous cost increases due to scope increases in regulatory and government requirements. The omission creates the political incentive to place costs onto suppliers since these escape scrutiny. One of many such examples is the Midata initiative. We have always supported this but it does cost money and this money must come from somewhere.

As far as we are aware, the proposed cap level does not include costs related to the Midata initiative. Our initial forecast is a cost to npower of c£300k for implementation and £100k ongoing support costs. However, the new version of Midata is looking much more complex and if it requires a model akin to the DCC, costs will increase dramatically.

This is an example of the need to ensure future policy developments are factored into the cap (rather than relying on headroom). This example highlights the need to allow for the cumulative impact of what appear, in isolation, to be relatively immaterial costs.

Generally, we note that Ofgem escalates costs (capex and opex) at CPIH. However, this does not take into account the crescendo of regulatory changes and political initiatives over the next two to three years. Examples include faster reliable switching, development of half-hourly settlement, system and process changes to accommodate the development of the “Supplier Hub” regulatory model which must be updated, other changes relating to smart (e.g. smart combined with feed in tariff export), Midata and other data initiatives etc.

Warm Home Discount

We note that the costs in Ofgem’s table published 6th September are slightly incorrect, not quite reflecting the obligation letters on 31st September. Across the industry this amounts to c£3m. All errors should be corrected.

Adjustments

Efficient supplier

The method of construction of the costs of an efficient supplier is seriously incorrect and must be revisited. We have expanded on this in Appendix 3.

£5 efficiency factor

An allowance of £23 is proposed for the difference between frontier operating costs and the benchmark (set at lowest quartile less £5 Dual Fuel (DF) “efficiency factor”). As this would be below the costs of any of the SLEFs and given they supply c95% of SVT customers, the benchmark is clearly not fully reflective of the cost of serving these customers. Neither does it provide suppliers, above the lowest quartile, time to achieve further cost reductions (efficiency savings having been actively pursued already, there is danger that this cuts into investment and delivery). The *arbitrary and entirely unsubstantiated* efficiency factor of £5/DF effectively reduces the “headroom” in respect of a variation in efficient costs and inhibits the ability of an efficient supplier to compete.

This adjustment also seems partially based on the rationale that 2017 costs were higher than average. However, 2017 costs were higher than average due to increased smart costs that should be fully reflected in the cap.

The efficiency factor is in fact double counted because it is inherent in the CPIH indexation.

The £5 per Dual Fuel adjustment should be removed as Ofgem provides insufficient justification for this and it is double counted.

Please see Appendix 3.

Energy Companies Obligation (ECO)

The proposed methodology for ECO under the price cap mechanism adjusts for economies of scale. This is accounted for in the ECO 'Supplier Allowance' methodology and is therefore an unnecessary allowance in the price cap that will only penalise further the larger non-exempt suppliers.

The price cap proposal is to calculate an average allowance for the costs of the scheme by dividing the annualised cost of ECO by the total gross supply of all obligated suppliers at 31 December the previous calendar year. This approach is favoured over the alternative of dividing the annualised cost of ECO by the supply volumes of obligated suppliers net of the supplier allowance deductions. Appendix 5 par 2.45 states: "We note that while this may disadvantage larger suppliers, the impact may be offset to the extent that these suppliers are able to achieve economies of scale".

In their response to the ECO3 consultation BEIS state that the main objective to implementing the Supplier Allowance was that "larger suppliers'' obligations would increase disproportionately due to the proposed supplier allowance, leaving them adversely affected"[6] . The responses go on to say that the impact is "(an) increase in their obligations, expected to be less than one percentage point for the largest supplier"[7].

The rationale for making further adjustments for economies of scale in price recovery, above that which is factored in the obligation setting methodology, is unclear and in our view unnecessary.

Lack of a Recovery correction mechanism

We note that Ofgem might modify the licence condition to correct material systematic issues. We also welcome the proposal to include a provision within the licence conditions to allow Ofgem, subject to consultation, to make changes to the models used to update the wholesale, policy, networks and smart metering net cost components of the cap.

However, we remain hugely concerned that Ofgem do not propose to include a mechanism in the cap for correcting previous forecast errors, *especially where they have been flagged at this stage*. This is a fundamental error in the cap mechanism, out of keeping with standard regulatory practice in price control (for example in network regulation in Great Britain), and flowing a deadweight cost of risk into the economy. This is particularly pertinent in relation to wholesale, smart and other policy costs. We are very concerned about the recovery of outturn ECO3 costs (potentially subject to significant amendment) under the cap. There really is no excuse for not incorporating a Recovery mechanism.

[6] "Government Response to the ECO3 Consultation" pub. BEIS par. 11
[7] "Government Response to the ECO3 Consultation" pub. BEIS par. 13

Please see Appendix 4.

Smart Costs

This is also an area of high concern.

The calculations are highly opaque and apparently deliberately so.

There is significant political incentive to exclude smart costs from the cap so that any increase in programme costs caused by government and/or regulator are not subject to scrutiny and unwelcome attention. In turn, the exclusion and avoidance of scrutiny has significant political risk of increase in costs. A third effect, in the absence the Recovery mechanism, is the clear incentive for Ofgem to underestimate costs. The combination of these three effects could easily overwhelm the EBIT margin even of the average supplier. Clearly, in the absence of profits, the smart programme cannot be delivered at any aspirational timeframe. The potential here is to be recklessly indifferent to the outcome.

We believe a potential uplift of at least £10 per meter is required (and are concerned that this could be higher).

Please see Appendix 5 for our detailed response on Smart.

Whilst not within scope, we also remain concerned that the Prepayment Price Cap did not include a sufficient allowance for prepayment smart costs. If these costs are not included in the SVT cap in order for suppliers to efficiently recover costs, it will be important that the CMA addresses this in its review of the prepayment cap.

Headroom

Ofgem continues to conflate true competitive headroom (zero allowance, contrary to the CMA's approach) with the variation in efficient costs and a buffer for uncertainty, modelling errors, mis-forecasts, omissions and intentional under-estimates. To comply with the Electricity Act 1989 (EA89), Gas Act 1986 (GA86) as amended, and the Tariff Cap Act, these must be separated.

In our view, the £3 additional wholesale allowance and explicit headroom of £10 (1.45%) for residual uncertainty are recklessly insufficient. Our internal analysis indicates that this allowance for uncertainty would be consumed by forecast uncertainty and volatility (excluding wholesale basis risk), leaving no headroom for a supplier at the efficient benchmark to compete and incentivise switching. This is compounded by Ofgem's incorrect approach to EBIT.

It is manifestly inappropriate to conflate headroom with the £23 "allowance" for establishing the efficient benchmark above the frontier.

A cap with no competitive headroom drives up uncapped tariffs, causing them to converge. Stimulus to switch is lost and the whole market converges to a single price control. This will inevitably have major impacts on churn and customer engagement where research suggests the majority of customers have a threshold savings to embark on switching. By way of example suppose that the threshold is £100, the currently available saving is £150, the cap reduces the current tariff £75 and raises the gain tariff by £50[8]. The consumer who would have switched but did not because the cap took the saving below threshold i.e. would have saved £150 but ends up

[8] For the avoidance of any doubt, an entirely figurative number is chosen here, and no inference whatsoever should be read into it

saving £75 due to the cap, i.e. a lost opportunity of £75. We do of course recognise that other consumers, who had a higher threshold or simply had no intention to switch, do save the £75.

A readily conceivable outcome is substantial reduction in switching, with two key drivers to tariff differentiation: i) cost differences between exempt and non-exempt suppliers spiralling as the obligation base shrinks; ii) risk seeking supplier behaviour being subsidised by mutualisation of default by irresponsible suppliers. This situation is not satisfactory to any responsible stakeholder, nor is it sustainable.

We believe that Ofgem should allow competitive headroom of 4% commensurate with the CMA's allowance under the Prepayment price cap (and as further mitigation of significant wholesale risks). This equates to an uplift of £23 per dual fuel account.

Please see Appendix 6.

Wholesale Costs

This is a complex topic and Ofgem's current proposals significantly increase costs and risk on two fronts. We have summarised our views below, and provided further detail on some elements in Appendix 7.

Shaping, forecast error and Imbalance costs

We reiterate the significant financial magnitude of the volatility (year on year variability of cost), in relation to a variety of wholesale basis risks, namely:

i) Shape risk (market risk arising from wholesale hedging forward product granularity not matching supply requirements);
ii) 'Swing' risk (weather and other volume variability);

iii) Imbalance cost (changes to near term demand forecast and the difference between final forecast and nominated out-turn). Our own quantification was tabulated in detail in response to QA6.5 of the Policy Consultation.

We express our concern that your evaluation of a provision for these 'risks' falls significantly short not just on our forecast, but actual incurred costs in the past few years. In our forecasts, we assess a one in twenty year conditional expectation of cost. In reality in the past few years, we have seen extreme 'tail' events beyond this level, driving one or more of these costs. Recent examples include: the 'Beast from the East' weather system driving very high 'Swing' costs; a sustained period of French nuclear shutdowns leading to exporting during the winter having a dramatic impact on UK 'shape risk' costs; and the scope for the new balancing regime which includes the Reserve Scarcity Pricing mechanism to have dramatic spikes in cost. In many such extreme events we see large impacts in more than one of these costs i.e. in extreme events we see abnormally high correlations of amplified costs across different elements of the cost stack, including those listed above. For example, shocks to market price shape and increased 'peakiness' also brings with it much higher spot volatility and scope for balancing spikes.

The 1% allowance for additional risk and uncertainty is intended to cover volatile demand due to weather, as well as basis risk, volatility around gas losses, and modelling uncertainty; however, we evaluate that a one in twenty year outturn of shape swing, and imbalance costs would in effect necessitate a shaping, forecast and imbalance allowance of [✂] (Gas) and [✂] (Power). The shortfall between this requirement and the proposed allowance [✂] for power and [✂] for gas -

would thus (more than) consume the *entire* additional allowance for uncertainty, leaving no means by which to recover the other elements, which are themselves significant".

As proposed, in the absence of Recovery, the cap design provides scant protection for these highly volatile costs and yet does not appear to recognise the full potential Cost of Risk. The cap method is based on historic data. For these types of risk, we find that forecasting risks using simulation models provides more insight into the underlying exposures and their range. Basing a view of these costs on a particular window of history in the data does not give a feel for the true volatility and severe impact on profitability. The cap mechanism provides no scope for claw back in an adverse outturn of these costs.

Transitional cap arrangements

We were extremely surprised and disappointed that Ofgem have reversed their proposal to adjust the observation period for the transitional cap. We do recognise that this is an evolving process and that things can change, but do expect Ofgem to understand that suppliers have to make hedge decisions and naturally look to statements by the regulator to inform these. This regulatory uncertainty brings a deadweight cost of risk that flows to consumers and in this case an actual cost.

The decision to reverse this proposal appears due at least in part to a misconception about supplier hedging behaviour; it will result in a substantial cost to suppliers. This cost can be readily replicated by Ofgem since both the previous Ofgem 18 month reference hedge and the hedge (with a churn reduction assumption) for the mooted observation period are both known. We calculate that a supplier reacting to regulatory signals will have achieved a commodity cost for delivery in the transitional cap period of >10% higher than that implied by the February to July observation period, which equates to >£15 per dual fuel account (£10-11 gas and £5-6 power). The details of these calculations are included in Appendix 7. All other things being equal, setting the transitional cap level artificially low will also drive a larger price increase for customers when the April 2019 cap level is confirmed.

Unless Ofgem reverts to an April to September observation period for the transitional cap (as initially proposed in its Policy Consultation), the cap would need to be uplifted in line with the values listed above to offset the detrimental impact of Ofgem's decision and ensure cost recovery.

Wholesale indexation methodology: basis risk

We are pleased to note that Ofgem recognises part of the basis risk introduced by the hedge tenor and supply delivery period mismatch involved in the 6-2-12 semi-annual approach. However, it is disappointing that Ofgem has not grasped the full extent of the said risk: we expect a cost of [✂] dual fuel [✂] across the Apr-19 and Oct-19 caps, based on 26th September wholesale market prices, due to the prevailing (backwardated) shape of the forward curve. This will change - both prior to *and* during the relevant indexation periods - and is explained in more detail in Appendix 7.

It is our belief that we have considered every possible hedge strategy referred to in the *apparent basis risk* section of Appendix 4 of Ofgem's Statutory Consultation, and, as Ofgem acknowledges, none of these remove this cost. It is possible to "lock in" the cost at the prevailing level (to remove exposure to subsequent volatility around the [✂] dual fuel cost above) but, under standard accounting rules, the hedge which achieves this creates significant earnings volatility [✂] based on today's npower SVT volumes and seven years of back-testing) which thereby increases capital costs. These costs should be recognised.

Once again in the context of the 1% “additional risk and uncertainty” allowance, the current cost of basis risk described above equates to [✂] of the core direct fuel allowance. This leaves a [✂] unrecovered loss and leaves nothing to cover volatile demand due to weather, volatility around gas losses or modelling uncertainty. This being said, it is important to stress that suppliers’ exposure to the cost of basis risk is the result of flawed methodology, rather than an insufficient allowance: we have an *expectation* as at a particular point in time [✂] per dual fuel account, above) but it is not possible to forecast how this will outturn in order to make some allowance for it. As such, if the regulator remains committed to the 6-2-12 semi-annual approach, the associated basis risk cost (or benefit) should be subject to a recovery mechanism.

On balance, our belief is that a “6-2-12 annual” approach is preferable because it removes said basis risk entirely.

Payment differential / discount structure

As proposed, the cap would result in a Direct Debit (DD) discount structure with both fixed and variable elements. npower, along with other suppliers, currently applies a DD discount to the fixed (standing charge) element only. We are concerned that the proposed change would cause significant complexity and confusion in communicating a revised discount to customers. It would also require system changes at significant cost.

Bad debt and working capital are variable costs and would naturally sit within the unit cost if we priced purely against the cost stack. As a general rule we believe that everything should be cost reflective. Nevertheless, there is some customer merit in leaving the Receipt of Bill to Direct Debit Differential in the Standing Charge:

i) In Fixed Term Contracts, the differential tends to be on Standing Charge and hence the regulated and unregulated prices / discounts go more out of kilter;
ii) Tariff comparisons and communicating savings are harder when there are two differences, Unit Rate and Standing Charge;
iii) The differential is less stable over time e.g. consumption changes;
iv) The change in method will take some explaining to customers, with the potential for some confusion;
v) It is more difficult to communicate the precise variation to charges which would occur as a result of the customer being moved from Direct Debit to Receipt of Bill;
vi) A change in tariff structure makes it more likely that some bills will rise as a result of the cap;
vii) There will be an uncertain distributional outcome from increasing the differential in unit rate at the expense of the standing change;
viii) The relative competition for DD and ROB customers will change and the distributional outcomes are unknown.

In Ofgem’s calculations it is not clear why in calculating bad debt and admin costs 6 SLEF’s, 3 mediums and 1 small supplier are used, whereas for working capital 5 large suppliers & 2 mediums are used, The differential is considered for all suppliers over 100k. This is unclear.

[redacted]

Safeguard tariff customer transition to Direct Debit cap

We are concerned that a requirement to move Safeguard/WHD customers immediately onto the Direct Debit cap, could potentially result in 3 price increases for some customers (i.e. October'18; Jan'19; April'19). As such, there is merit in deferring the transition to the Direct Debit cap until April 2019. Ofgem should consider this impact and provide a view.

It is our understanding that SVT WHD customers identified post-31 March 2019 would be protected by either the Direct Debit or Standard Credit (Receipt of Bill) cap, dependent on their payment method. Could Ofgem clarify whether it expects WHD customers identified pre-31 March 2019 to continue to be protected by the SVT Direct Debit cap for the duration of the cap?

Appendices

Appendix 1: Proposed cap level / EBIT (impact on investment, financeability and risk of supplier exit)

On Ofgem's figures, based on 2017 financial data (Consolidated Segmental Statements), five of the six largest suppliers would be operating at negative or subnormal profit levels following the implementation of the default tariff cap. In order for these suppliers to achieve normal profit they would need to increase the price of their fixed tariffs, or if competitive constraints within the market do not allow for these suppliers to increase prices of fixed tariffs without losing customers (many to suppliers exempt from numerous obligations), then it is likely that these suppliers will seek to cut controllable costs. This may have an impact on customer service levels and/or innovation. (For reference, extracts below from Ofgem's Draft Impact Assessment)

We struggle to see how Ofgem's view is compatible with its Electricity and Gas Act duties to have regard to protecting the interests of customers (in a broader sense), the need for licence holders to finance activities and for suppliers to maintain service levels in compliance with Standards of Conduct. In addition Ofgem has a duty of care in public office not to be recklessly indifferent to unforeseen *and foreseen and forewarned* effects on licensees, particularly where shortcomings and omissions in the analysis have been pointed out and in addition where safety valve mechanisms, *which are standard in price controls* such as Recovery, have been *deliberately ignored*.

The current level of prevailing Fixed Term Contract prices in the market should not be regarded as sustainable and therefore is not valid as a cost proxy. This is readily apparent by considering:

i) Aggregate industry earnings;
ii) The rapid rate of attrition from higher to lower priced tariffs.

Ofgem is already testing the requirements of the Electricity/Gas Acts in relation to specific charges (such as warrant costs) and the requirement for suppliers to be able to finance their activities. At this point these are untested in court but this should not be taken to mean that Ofgem is intra vires.

The cap represents a serious challenge to the sustainable financing of energy supply and the investment and innovation required to improve service levels, deliver significant programmes like Smart and ECO and the transition to a low-carbon energy system. Significant efficiencies have been made or committed to within npower and publicly across the industry.

Extracts from Ofgem's Draft Impact Assessment

4.70 As we present in paragraphs 4.55 to 4.66 above, our analysis suggests that five of the six largest suppliers will be operating at negative or subnormal profit levels following the implementation of the default tariff cap. Similarly, we expect that some small suppliers will be operating at subnormal profits as a direct result of the cap. If these suppliers are unable to offset the reduction in profitability, either through increased fixed tariff prices or through reduced costs (either by improving efficiency or cutting controllable costs), then they will make losses. This could result in some suppliers exiting the market.

4.93 Within our analysis we have assessed the extent to which suppliers would need to improve efficiency to become as efficient as the most efficient large supplier. The results of our analysis suggest that at our proposed cap level, there will be some suppliers who despite improving efficiency to the same level as the most efficient large supplier operating within the market, would *still make negative or subnormal profit. In order for these suppliers to achieve normal profit under the default tariff cap they would need to increase the price of their fixed tariffs. If competitive constraints within the market do not allow for these suppliers to increase prices of fixed tariffs without losing customers, then it is likely that these suppliers seek to cut controllable costs. This may have an impact on customer service levels or innovation (we assess these impacts in Chapter 6). Alternatively, this could lead to an increased likelihood of these suppliers exiting the market.*

Ofgem have relied upon the CMA assessment of a 1.9% allowable EBIT predicated on an analysis of Return on Capital Employed (ROCE).

The CMA analysis had serious deficiencies. We have challenged numerous times that this ROCE analysis is flawed due to the degree of judgement required in estimating capital employed for an asset light business. As it happened, these created more of a perception problem (of excess risk adjusted return) than a practical problem in relation to the CMA remedies. Hence challenges to the methodology (which require only standard finance theory) to the CMA were dropped by us and we presume others.

The decision to impose a default tariff cap was not made within the CMA consultation and hence there was not particular need to press the challenge on the capital calculation   Had the cap been properly considered within the actual two year CMA investigation, there would have been the need and opportunity for the CMA to look more deeply into this. *The CMA assumptions, methods and coefficients, made for one purpose, may not be regarded as safe for a different purpose that is much more sensitive to their correctness*. A detailed paper was written by npower as part of the CMA market investigation

Therefore, Ofgem would be unsafe in relying on the flawed CMA methodology. In addition it was apparent that the CMA took its benchmarks from markets with recovery mechanisms.

We believe a return at this level is not sufficient to support the investment required by suppliers to support change in the industry and foster innovation, and is at odds with previous Ofgem analysis that suggested a 3% EBIT was an acceptable return for a *vertically integrated* supplier. The acceptable return for a vertically integrated supplier is of no relevance to an independent supplier.

Estimating ROCE for an asset light business is challenging and requires too great a degree of estimation / judgement to be reliable. Key areas of uncertainty are, for example; market capitalisation (risk adjusted return on equity is the key but the retail component of total market capitalisation is commonly uncertain), goodwill yet to be amortised, pension deficit treatment.

The cap increases the likelihood of supplier exits and defaults. At this point in time Ofgem has acted (ultra vires in many respects such as the mandated mutualisation of default cost insurance which in the finance sector was properly executed by legislation[9]) to socialise supplier default costs in all respects (e.g. energy costs, network and use of system costs, numerous obligations such as Feed In Tariff). A cap set too low risks a spiral in which suppliers are precipitated to default, the socialised costs of which precipitate other defaults etc.

[9] Financial Services and Markets Act 2000

Appendix 2: Unidentified Gas (UIG)

The allowance for UiG is currently:

i) Based on an aspirational estimate that is at odds with UiG levels experienced post-Nexus;
ii) Requiring proper attention given that it is a difficult and material subject;
iii) Light on explanation of rationale;
iv) Indifferent to our realistic expectation of the likely outcome.

At a high level, an alternative solution would be:

i) Not to use a hypothetical estimate of so-called ‘permanent’ UiG as calculated by the Allocation of Unidentified Gas Expert (AUGE), but rather to use the findings of the Central Data Service Providers (CDSP) UiG Task Force to establish a realistic projection, with error bands to the end of the price control period;
ii) To use a reasonable high case or have a recovery mechanism.

National UiG to-date and potential impact of future change

- During the first 12 months following Nexus implementation, national UiG charged was 5.1% of total throughput, with domestic shippers incurring higher % values of UiG as a result of AUGE weighting factors.

- We note with interest that Xoserve has recently published some analysis showing that, had the coming ‘uplifted’ Annual Load Profiles (ALPs) and DAFs (Daily Adjustment Factors) been applied in allocation since Nexus go-live, then levels of UiG at ‘Delivery Day +5’ (D+5) would have been an average c2.5% nationally. Uniform Network Code (UNC) modification 644 “Improvements to nomination and reconciliation through the introduction of new EUC bands and improvements for the ALP and DAF “and the resulting Data Services Contract (DSC) change reference XRN4665 effect these changes.

- The Central Data Service Provider (CDSP) analysis is too complex to summarise in this response so a link is provided below.

  https://www.xoserve.com/wp-content/uploads/Iss-13-Simulation-of-impact-of-Uplift-Factors-on-UIG.pdf

- Despite these changes to demand estimation being implemented for the start of gas year 2018/19 there are no available data that forecast (at an industry level) what reconciliation will do to this newly reduced UiG volume at D+5 (reconciliation might increase UiG % rather than decrease it).

- Aside from this ‘unknown’, there are also outstanding issues with the CDSP central system, with new defects relating to settlement-specific processes such as Annual Quantity and reconciliation being raised some 17 months after Nexus - to what extent these issues impact on the overall UiG position has not yet been properly quantified.

- New ALPs and DAFs aside, there remains much for the industry to do to reduce levels of UiG towards the AUGE estimate of permanent UiG (if that is achievable) as the new Nexus regimes “catches up” historic losses and post-reconciled volumes reach a steady state. We recognise that the industry has a role to play. However UIG is to a large extent a “public bad”, experienced by efficient suppliers and inefficient suppliers alike. It is therefore highly questionable as to whether there is the vires in the Act, to remain compliant with EA89/GA86 in charging this cost to efficient suppliers.

npower exposure to date

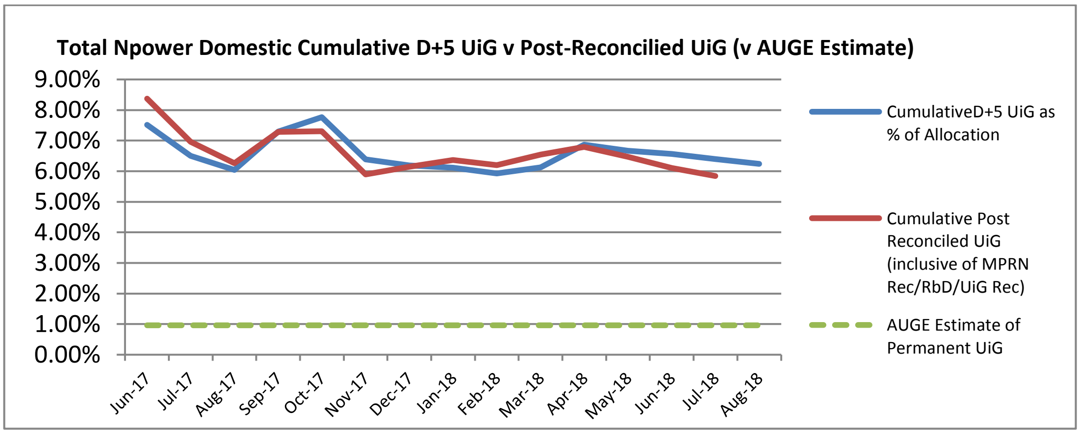
Normally we would regard this as confidential but given Ofgem's approach to the "public bad" of UIG we are prepared to show our figures for the last 18 months:

- After 17 months post-Nexus implementation, npower's total cumulative exposure to UiG has reduced from 6.2% of total allocated volume (D+5) to 5.84% via the reconciliation process.

- The graph below shows an incremental (monthly) cumulative view of D+5 and post-reconciled UG as a % of total volume for our domestic business since Nexus implementation.

- It demonstrates that reconciliation has, thus far, only slightly reduced the amount of UiG (as a % of total volume) npower is exposed to.

- **We expect that our overall exposure across 2018 will be c.4.5%** - inclusive of the expected impact of uplifted ALPs and DAFs and the amount of volume likely (based on post Nexus patterns to date) to be reconciled back to npower via UiG reconciliation.



Ofgem Rationale for UiG Allowance

- The central rationale for the proposed cap allowance is that a final state of UiG will be 0.96% and that this can be achieved via the reconciliation of profiled demand with metered consumption.

- On p.29 of the document linked here:https://www.ofgem.gov.uk/system/files/docs/2018/09/appendix_4_-_wholesale_costs.pdf

  Ofgem states its rationale for allowing 0.96% in the price cap for UiG:

"3.42. We agree that the default tariff cap should provide an allowance for the underlying losses. Gas losses are a physical feature of the network and not something an efficient supplier can avoid, therefore there is a need for some kind of allowance. However, we do not agree with those

[redacted]

suppliers claiming that gas losses are uncontrollable. There are actions suppliers could take – for example to tackle theft (one of the largest causes of UIG) which would reduce the level of these costs. ***Moreover, at an individual level, an efficient supplier could (through their shipper) utilise the new gas settlement arrangements to control their exposure to UIG costs through the submission of more regular meter reads into the central gas systems.*** *(emboldened here) We have calculated our estimate of UIG at 0.96%, and we propose to use this figure as the basis for an allowance. We have used publically sources (Allocation of Unidentified Gas Expert, or AUGE) to derive this factor".*

- In particular, the (crucial) sentence highlighted above is only true if all shippers and the central settlement system are collectively and simultaneously operating efficiently. Given the number of outstanding issues that Xoserve's UiG task force (propelled by UNC Mod 658) "CDSP to identify and develop improvements to LDZ settlement processes" is investigating, and the multiple outstanding UK Link defects that impact critical settlement processes such as Annual Quantity and Volume Amendment (reconciliation), neither optimum shipper performance nor central system stability has yet been achieved.

- npower does not consider such a future state is likely in the short / medium term. Nor do we consider 0.96% as being a credible state of permanency. As such, we do not agree that an efficient shipper can materially mitigate the levels of UiG it attracts, with actual levels considerably in excess of 0.96% *despite the actions of an efficient shipper*.

- Despite recent trends where UiG reconciliation has reduced the cumulative amount of UiG volume for the domestic market, we observe that in the very latest amendment invoice, Meter Point Reconciliation (dictated by Larger Supply Point reconciliation) has reversed this trend, and as a result we are moving further away from the allotted 0.96% rather than closer to it. We believe that not only have D+5 UiG trends not been fully understood, UiG reconciliation trends are even less clear.

Industry Change

- npower believes that there are multiple root causes of so called 'temporary' and 'permanent' UiG and has been active in attempting to mitigate these issues via raising industry changes and donating resource to the relevant industry committees (Performance Assurance Committee, Demand Estimation Sub-Committee, Data Service Contract Change Management Committee, etc).

- npower has worked hard to help resolve these systematic issues. Via our active participation in PAC and the DCS committees, we have raised the following UNC modifications (mods) and DSC Changes:

    - Mod 652 *Introduction of winter read/consumption reports and associated obligations*
    - Mod 657s *Adding Annual Quantity (AQ) reporting to the Performance Assurance Report Register Schedule reporting suite*
    - Mod 664 *Transfer of Sites with Low Read Submission Performance from Supply Meter Point Class 2 and 3 into Class 4*
    - XRN4690 *Actual read following estimated transfer read calculating AQ of 1*

- These are all UiG-related, and have been designed to address shipper performance issues that impact UiG, or to resolve issues with the CDSP system that lead to under demand estimation (a contributor to UiG).

- We note in passing that Ofgem simultaneously expects us to work towards resolving issues such as UiG but recognises no cost of doing so (code participation being carved out of operational expenditure costs).

- npower has also supported industry changes that seek to address the root causes of UIG as we understand them.

- Along with inaccuracies in Non-Daily Metered profiles, transitional (Nexus) data issues and CDSP system defects, we note that the current Performance Assurance Committee (PAC) Risk Register includes 17 performance- related items that would all impact UiG either in allocation or reconciliation. 15 of these risks have controls that are currently 'Not Effective' with the remaining 2 having a status of 'Partially Effective'. npower believes that it will take considerable time for the industry to work through these issues to the extent where any impact on UiG will be mitigated in a material way.

- PAF risk register:

  http://www.gasgovernance.co.uk/sites/default/files/ggf/page/2018-09/Risk%20Register%20PAC%20V2018.01%2020180911.xlsx

- npower considers that it will take time to resolve all of the outstanding (and potentially as yet unknown) causes of temporary UiG, and until this is achieved, we expect our exposure to UiG to be unavoidable and at similar levels to those seen so far.

UiG Task Force

- The CDSP task force as dictated by UNC modification 658 (*CDSP to identify and develop improvements to Local Distribution Zone settlement processes*) has already identified 23 issues on its evolving view of things that impact UiG https://www.xoserve.com/wp-content/uploads/UIG-Investigation-Log-2018_09_20.xlsx

- Part of the CDSPs remit is to quantify the issues in terms of to what extent each of them impact on UiG and to produce a robust means for the industry to forecast exposure to UiG levels and volatility.

- Until this work concludes, to what extent temporary UiG can be become permanent is unknown, as is the pace at which each issue can be mitigated / resolved (as some resolutions might require extensive industry change, as opposed to being 'quick wins').

- The task force is set to deliver incremental findings via the monthly DSC Change Committee and wider industry communication, aiming to close before the start of the new financial year.

Conclusion

- There are multiple complex root causes for temporary levels of UiG, making it very difficult to predict when and where UiG will 'crystallise'.

- Via the Data Service Contract (DSC), shippers (incorporated as costs to suppliers) have provided £1.1m funding for Xoserve to stand up a UiG-task force which will incorporate 'machine learning', Artificial Intelligence and issues analysis) which will seek to identify improvements to current processes and systems. It is likely that any recommendations resulting from this activity will require industry / system / code / behavioural change that is unlikely to all be achievable in the short term or at once.

- npower considers appropriating an allowance in the price cap based on the AUGE estimate of ‘permanent’ UiG is premature, unfair on organisations that will be burdened with an unavoidable cost to operate, and at odds with historic, current and future levels of UiG.

- We believe the allowance should be set a reasonable, achievable level for the price control period, that includes careful consideration of the points we raise above

If the allowance remains unchanged, we believe the risk of under-recovery will be in the region of c£8 per gas account (based on the differential between our forecast 2018 UiG exposure at 4.5%and the 0.96% proposed allowance).

Appendix 3: Efficient supplier & £5 efficiency factor

The £5 incentive

The efficient supplier benchmark for the purpose of determining the operating cost allowance in the cap is set at a methodologically incurred lower quartile cost of 10 suppliers less a fairly arbitrary £5/DF (dual fuel).

The £5 reduction is incorrect for two reasons:

i) It is expressed as an incentive to suppliers commensurate with Ofgem's duty to promote efficiency. With the cap already removing the entirety of industry profits Ofgem must assume that even if there were not sufficient incentive before to be efficient, it will be under the cap and that no further exhortation is needed. The application of £5 reduction is a significant misreading of Ofgem's duty to promote efficiency. In apparently discharging this obligation by a random figure which achieves no efficiency saving, Ofgem abrogates its responsibility actually to do something constructive in improving aggregate welfare, such as making joint programmes more efficient.

ii) It is a double count – the Use of the CPIH index factors in economy wide efficiency improvements over time.

Quartile calculation

Note from Table A2.1
*2. **For standard credit we use the lower quartile to set efficient costs** – for Standard Credit customers (not shown here) the uplift is £9 higher than had we used the frontier supplier (taken across all cost categories combined). **If we were to take the frontier cost for each additional cost component separately, then the frontier benchmark for both direct debit and standard credit cap be lower.***

We do note that overall, Ofgem is correct in principle to attempt not to take the top quartile performance factor by factor but top quartile overall (actually the average of the top and second is slightly higher, i.e. lower cost than top quartile).

However, in fact a number of factors do find their way in to a factor by factor approach and hence the cost is in fact downward biased.

Consider for example, exceptional items. By their nature they feature irregularly, yet few companies escape them completely. Indeed one way of achieving top quartile performance in companies has been to restructure, and hence take exceptional charges. By excluding exceptional charges, Ofgem has effectively isolated higher performer costs from lower performer cost and hence taken factor costs individually. It is plain to see that a cost that all, or nearly all companies face over time is excluded completely.

Similarly, for all sorts of reasons including simply the way that accountings earnings phase (for example the accounting earnings volatility in the 6-2-12 index perfectly hedged!), companies have good and bad years. It is correct to take the average. However, by taking a one year sample and the top quartile, again the cost is downwardly biased. The effect is the same as taking a factor cost by factor cost approach.

The same applies in several specific areas such as pension deficit repair charges, different customer types, different capex/opex ratios.

Supplier enforcement penalties also have the same effect. In addition, Ofgem proposes to exclude penalties. We understand the motivation, but it is flawed. For example, most suppliers settle cases early without formal conclusion of fault (just unilateral acceptance). It may be cheaper to settle than contest even in the absence of proven fault. We believe that safety provides the best analogy. The target for fatalities can never be other than zero. Indeed the target for “near misses”, “lost time accidents” and “slips and trips”, must also be zero. Yet no company can attain these and hence performance is measured ex post relative to industry performance as well as to the zero targets. For enforcement, whilst emphatically not stating that enforcement penalties are simply a cost of doing business, it is a historic reality that at the median, all suppliers have experienced penalties. The treatment of penalties is truly a difficult question, and whilst we do not agree with Ofgem’s approach and do believe that the cost will in any event flow to the cost of equity, we are not minded to oppose it.

Because the factor cost by factor cost approach has in practice found its way into the cap, the effect needs explaining;

Consider an Olympic decathlon. There are 12 athletes. Their points in each event are shown below.

	Points in event											total	rank
Athlete	1	2	3	4	5	6	7	8	9	10			
A	3	11	3	1	12	12	10	5	3	10		70	5
B	5	5	6	5	2	11	12	10	11	2		69	6
C	9	8	7	9	8	7	8	8	9	8		81	1
D	8	9	8	7	9	9	7	7	7	9		80	2
E	7	7	9	8	7	8	9	9	8	7		79	3
F	2	3	11	2	11	10	1	3	5	1		49	11
G	6	6	5	10	4	5	11	12	2	11		72	4
H	12	2	12	3	3	1	3	1	1	12		50	10
I	11	4	1	6	5	2	6	2	6	4		47	12
J	4	10	4	4	10	4	2	11	10	5		64	7
K	1	12	2	12	6	3	4	6	4	6		56	9
L	10	1	10	11	1	6	5	4	12	3		63	8

Table 1 Event rankings and event and total scores for 12 decathletes

For each event (equivalent to the cost category of the cap), the average number of points of the top quartile is 11.

As we can see, Athlete C won the gold medal, despite not being in the top quartile for any event. The average number of points of the top quartile is 8 – quite a long way from 11.
Clearly the correlation between event ranking and individual discipline ranking is important. There are some positive correlations (e.g. sprint and long jump) and negative ones (e.g. high jump and shot put).

Relationship between factor cost leadership and total cost leadership

We may expect a broad correlation between factor cost efficiencies. So a firm efficient on one cost is likely to be efficient on another. However, this is only true if all firms are identical in all factors other than efficiencies. Where firms are more automated (high capex/opex ratios), then the "lumpy" nature of capex and depreciation makes the selection of lowest capex in any one year a downward bias of average capex.

Companies have different business models. Using the decathlon example, what makes an athlete the best shot putter may impact their performance in the high hurdles.

Consider for example, firms with the same costs but different ratios of labour (opex) to capital (capex depreciation). We can see this below for firms A to G.

	A	B	C	D	E	F	G	H	I	J	K	L
opex	12	11	10	9	8	7	6	5	4	3	2	1
capex	0	1	2	3	4	5	6	7	8	9	10	11
totex	12	12	12	12	12	12	12	12	12	12	12	12

Table 2 12 firms with different degrees of automation and the same total costs

The average of the top quartiles in opex and capex costs are 1 each and hence the total cost constructed from these is 2. However, all firms here are equally efficient.
This is demonstrated below.

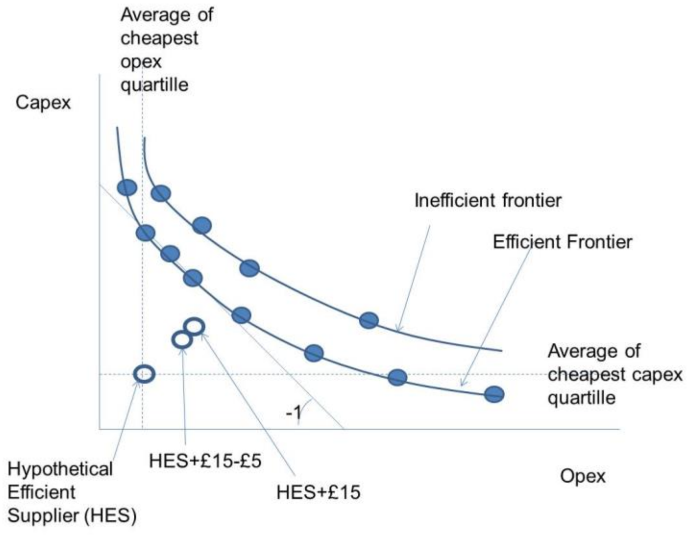


Figure 1 The Efficient Frontier as described by Ofgem, showing the hypothetical efficient supplier. The figure shows the inefficient frontier that is most relevant under EA89/GA86

Here we have expressed operational expenditure (opex) and economic depreciation on capital expenditure as substitutes, with each firm determine its degree of automation and their marginal costs at the margin are the same.

We can easily see that constructing a Hypothetical Efficient Supplier (HES) (not an Ofgem term) from the averages of the top quartile of the two cost factors creates a supplier that is theoretically as well as practically impossible.

This is recognised by Ofgem in the 15% uplift but it is readily apparent that with either few or many cost factors that this is inadequate. However the true level can be calculated. In the absence of factor cost to total cost correlation then it can be calculated from the factor cost dispersions. Correlations do decrease this but the calculation is unsafe if these are not evaluated.

It is easy to see how a hypothetical energy supplier with zero costs can be constructed by taking the lower of the costs for each factor for a fully automated supplier (zero opex) and a fully manual supplier (zero capex)

Ofgem has borrowed from financial theory in constructing the efficient frontier in this context. However, a further correction should be applied. In financial theory the absolute cost of capital (£/year) is determined by the market capitalisation and debt gearing. An inefficient firm moves to the efficient frontier via loss of share price (thereby reducing the absolute earnings needed to achieve the market rate for risk adjusted return on equity). For capital assets and goodwill their valuation in stock market terms moves up and down to reflect market value[10], not a book value based on depreciated cost. This is standard and was recognised by the CMA in the Energy Market Investigation in the valuation of power stations.

This method is not apposite here because the core mechanism couples the absolute cost of capital not to the market capitalisation and gearing but bottom up from the operational costs and a standard rate of capital (including working capital) built from the idealised business model rather than from the market.

Indeed it is clear from EA89 and GA86 that the benchmark should be the *inefficient* frontier as shown in the figure above, as inefficient firms disappear from the market.

The £5 efficiency saving is also incorrect because it is double counted, since efficiency savings are already included in the CPIH index unless there is a specific reason, which has not been advanced, to believe that the energy supply sector can develop efficiency savings faster than other sectors such as consumer electronics, data or photovoltaic panels.

<u>Measurement effects</u>

As Ofgem correctly notes, companies measure costs in different ways according to purpose and belief. The example cited is in the allocation of bad debt according to payment type. There is a tension between fairness and pure forward looking cost reflectivity. If two companies allocate bad debt costs differently between payment mechanisms and lowest quartile is used for each then a misleading efficient cost of bad debt arises.

There are several factors in which allocation makes a difference and renders the factor cost quartile approach unsafe. Not all of these are obvious. For example, high bad debt run rates reduce capital cost allocation.

<u>The Electricity Act 1989 and Gas Act 1986 (as amended by the Energy Acts)</u>

The Tariff Cap Act (TCA18) did not repeal EA89 and GA86. Hence it remains that case that Ofgem may not *in law* set prices below costs. We do recognise that EA89/GA86 does not give free rein to

[10] Sometimes called Tobin Q. It is closely related to stock alpha, which is zero in a market with perfect information

companies to be profligate, but Ofgem must also recognise the current strong incentives to be efficient to maximise investor returns. Therefore TCA18, and Ofgem's implementation of it, must *interpret* and not change the definitions in EA89/GA86.

We do recognise that efficiency does play a role in the interpretation of EA98/GA86. However, it is clearly not in keeping with these to interpret efficiency at the most efficient end. The interpretation is *clearly* at the least efficient end.

<u>Benchmarking of efficiency</u>

Both CMA and Ofgem apply efficiency at a desktop level, rather than through detailed examination of business process.

Ofgem in particular uses only the dispersion of actual costs and considers performance below top quartile as prima facie evidence of inefficiency where costs are higher than the top quartile average (i.e. even a top quartile performance can be deemed inefficient). In fact the reverse is the case. This approach to efficiency is *prima facie incorrect* because it is logically impossible (apart from the trivial case of identical costs) for all suppliers to have top quartile costs.

We do recognise that the presence of a top quartile performance in a particular cost factor, may be circumstantial evidence that achieving that cost for that factor may be possible. However, as noted above, without proper examination, the cost factor may appear lower than reality due to either a business model effect (e.g. opex/capex ratio) or a measurement effect (bad debt allocation). Without examining the cost, it is unsafe to assume actual top quartile performance.

<u>Overall</u>

If Ofgem implicitly takes a factor cost by factor cost approach for some cost elements then the average rather than the average of the top quartile is the correct figure to use. With allowed margin so tiny there is no room for error.

The Electricity and Gas Acts remain in force. Therefore, the efficiency benchmark should in law be the least efficient in aggregate across all cost factors.

Market forces do indeed operate at both ends of the efficiency spectrum. In a normal market, the least efficient firm will dwindle and exit and the most efficient firm will grow.

Appendix 4: Recovery mechanism / clawback

This is a fundamental error in the cap mechanism, out of keeping with standard regulatory practice in price control (for example in network regulation in Great Britain), and flowing a deadweight cost of risk into the economy. There really is no excuse for not using the Recovery mechanism.

The Recovery mechanism is simple. If a cost factor out-turns above/below forecast then the next price control is elevated/reduced to recover the difference. Whilst there does remain volatility in accounting earnings, which has a deadweight cost of credit premium, the bulk of the cost of risk is reduced greatly with a benefit to the economy (this is “win-win” not a zero sum game).

We do recognise that large Recovery adjustments can distort the competitive market because the regulated price is forced higher or lower than the prevailing market price. However, if the regulator’s misforecast is small then the effect is small and if the regulator’s misforecast is large then absence of Recovery puts the regulator in breach of EA89/GA86. Hence the need for recovery is overwhelming.

Some of the cost factors in the cap are manifestly wrong, and will be proven so. In the face of figures and argumentation provided at this point in time, it is reckless to ignore these and use made-up figures with no basis. Recovery all but eliminates this problem.

In ***Smart*** in particular, the absence of Recovery provides significant moral hazard, since government and the regulator may wish to avoid opprobrium from avoidable cost over-runs and therefore hide the smart cost outside the cap. This is turn reduces the incentives to control costs. Hence suppliers’ revenues fall and costs rise. The Smart model remains opaque, notwithstanding the disclosure room with limited access and significant impediment placed in front of suppliers that made calculation more or less impossible.

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[11] costs, which are to a large extent still unknown.

There is also significant volatility in relation to ***Shape risk*** (market risk arising from wholesale hedging forward product granularity not matching supply requirements); ‘Swing’ risk (weather and other volume variability); Imbalance cost (changes to near term demand forecast and the difference between final forecast and nominated out-turn). In addition. In addition to this, extreme price events, usually caused by extreme weather (e.g. “1 in 20” year weather) incurs cost over and above the normal cost of risk due to; i) higher likelihood (so called “fat tails”), ii) increased correlation of volume and price, iii) the cost of investor loss aversion, iv) correlation effects (extreme weather causes systemic effects)

We reiterate the magnitude of the volatility (year on year variability of cost), which we covered thoroughly in response to QA6.5 of the Policy Consultation. As proposed, in the absence of Recovery, the cap design provides scant protection for these highly volatile costs and yet does not recognise the Cost of Risk. The cap method is based on historic data. For these types of risk, we find that risk simulations provide more insight into the underlying exposures and their range. Basing a view of these costs on a particular window of history in the data does not give a feel for the true volatility and severe impact on profitability. The cap mechanism provides no scope for claw back in an adverse outturn of these costs. There are many drivers and ample scope for significant outturn of costs, e.g. trends in market, prolonged extreme weather, systematic plant outages.

[11] In smart meters, the standard Home Area Network (HAN) solution does not work for all. Hence the need for coordinated procurement of Alternative (Alt) standardised solutions

In relation to ***ECO***, at time of this response BEIS are yet to publish their Impact Assessment for ECO3, nearly three months after the publication of the consultation response. We are concerned that BEIS's costs assumptions that are material to the Price Cap are not transparent and are not validated.

In addition, we understand that BEIS will make additional changes to ECO3 in 2019 to implement improvements to quality and standards (the Each Home Counts Quality Mark, PAS 2030 and PAS 2035). The impact of these changes on the cost of ECO delivery is likely to be considerable, so there is a risk that ECO3 targets cannot be delivered to the Impact Assessment cost of £640m. Based on current industry discussions and proposals we are very concerned that the costs of ECO amendments in 2019 could be significant and are not fully understood by BEIS.

Therefore, we see a potential for escalating compliance costs under ECO from 2019, dependent upon the proposals that BEIS will introduce in 2019 (and implement under negative resolution) and the accuracy of the accompanying Impact Assessment. We would like assurance that Ofgem will have vires to make allowance under the price cap mechanism to adjust for excess costs incurred by obligated suppliers if they are unable to comply with ECO at the Impact Assessment price.

This is one of the cost factors that requires a Recovery mechanism. The risk is the same as for other cost factors, for example an exposure to deliberate under-estimation by Ofgem-BEIS and thence the clear incentive to increase costs to an inefficient and opaque extent because public scrutiny is escaped due to the omission of the change in ECO costs to the change in the cap.

The lack of a mechanism in the cap to correct for under-recovery results in deadweight cost of risk to suppliers and ultimately customers. It is incompatible with Ofgem's duties to have regard to the need to finance activities, particularly when coupled with a low margin. Ofgem's arguments for not correcting forecasting errors are weak. We do recognise that the recovery mechanism, in a price control can cause a slight decoupling to prevailing uncapped prices but we see any policy concern with this as small compared to the deadweight cost of risk. In practice, there are some similarities to the ex-post cost pass-through by suppliers in a competitive market.

The assertion that in the long run, non-systematic forecast error should net out, is unsubstantiated.

In fact it is incorrect on several counts, for example:

i) The relation between profitability and optimum tariff is concave, i.e. if a supplier overprices one year (and loses volume) and underprices the next year (and gains volume), the net effect is loss relative to optimum on both occasions;
ii) There is strong incentive for various parties (regulator, government, civil service, service providers to these) to underestimate costs.

Appendix 5: Smart costs

Summary Framework

We welcome the proposal to identify smart metering costs as a separate element of the price cap, and the decision to separate smart costs between pass-through and non-pass-through. Whilst this is a positive step, we have a number of comments and significant concerns, which are outlined below, about the approach and the detail behind some of the assumptions.

The methodology used in the calculation of smart metering costs is a relative, rather than absolute, calculation. Whilst we understand the theory behind this, the methodology requires assuming that the 2017 cost submissions are reflective of smart costs at that point, and then specifically identifying cost movements. It also requires unpicking some costs from 2017 that are now defined as pass-through, and then reapplying those costs in the new category. This process has added unnecessary complexity, and we have had to spend a considerable amount of time in the consultation period reviewing these cost movements to attempt to identify that they have correctly been moved from non-pass-through to pass-through. The restrictions of the data disclosure room have meant that we have not been able to do this, and therefore we have no assurance that the principles behind the SMNCC have been applied in practice.

We believe that going forward it would be preferable to calculate the smart costs as an absolute number, rather than referencing to a baseline period that was very different to where we will be in late 2019.

Whilst the relative principle has been used in the prepayment price cap, there has been significantly more movement in smart metering as the programme rolls out, and therefore we believe that an absolute method would be more appropriate. Therefore, we suggest that when Ofgem reviews smart for the cap periods from October 2019 this methodology is used. In particular, we would like assurance that the choice of methodology will not be influenced by any desire to avoid revealing the true cost of smart metering to consumers.

Pass-Through Costs

As mentioned above, we welcome the decision to include smart related industry costs as a straight pass-through for the purposes of calculating the price cap. These are unavoidable costs over which suppliers have no discretion, and are in principle no different to network charges or social / environment obligations. As with several other factors, Ofgem's minded to decision not to follow standard best practice in price control by having a Recovery mechanism, the absence of Recovery of cost true up from forecast to actual causes perverse incentives to under-forecast and the further effect of increasing costs (having escaped public scrutiny)

We have some comments on the detail of the pass-through costs as they are outlined in the consultation:

- The use of a relative methodology adds unnecessary complexity to the process given that the absolute charges are available for the cap period. These are laid out in Annex 5, and could be used as an absolute number. The need to reference back to 2017 is also made more complicated by the lack of a like for like comparison for some costs. Particular examples are Dual Band Comms Hubs (DBCH[12]) and Alt HAN costs, which were not specifically identified in the DCC charges prior to 2018.

[12] Where the local geography and fabric of the home does not work well for one of the two standard radio frequencies

[redacted]

- Our concerns on the relative methodology are exacerbated by a comment that appears a number of times in Annex A of Appendix 7, which at best can be described as misleading. This comment states that "DCC Charges are included in the SMNCC as pass-through charges". This is incorrect – it is only the movement of DCC charges since the April – September 2017 charging period that is included. The same principle applies to Smart Energy GB costs. These costs from 2017 should remain within the baseline non-pass-through costs, but due to the restrictions and redactions of the data disclosure room we have been unable to ascertain whether this is the case. Therefore, we are concerned that the principle of pass-through costs has not been applied in practice and that these costs are not fully included in the price cap;

- Our concerns about the volatility of DCC charges, and in particular the Alt HAN costs have not been addressed. We believe that for the principle of "pass-through" to work in practice there has to be a reconciliation with actual charges. Anything less means that these costs are no longer "pass-through". We are particularly concerned by the somewhat cavalier approach in paragraph 3.41 that suggests that because historic changes between DCC draft and final charging statements is "relatively low" they can be ignored. An efficient supplier cannot afford to simply ignore "relatively low" cost variances. In addition, the comment at the end of paragraph 3.41 is extraordinary – no supplier is likely to adjust standard variable and default tariffs as a result of DCC charges on their own, but when considering tariff changes ALL costs, including DCC charges, will be factored into the decision.

- Finally, there appears to be some small discrepancies between the DCC charges shown in Annex 5 and the DCC published statements:

    - The baseline charging period should, we understand, be the final DCC Charging statement for 2017/18, as published in March 2017. This shows electricity fixed charge to be £0.463 per month and gas fixed charge to be £0.350 per month. The charges shown in Annex 5 as the baseline are £0.473 and £0.358 respectively. We suggest that the numbers in the March 2017 published charging statement are used as the baseline.
    - The latest charging statement from DCC for 2018/19 (published in September 2018) are also slightly different from Annex 5, so we are assuming that these will be corrected for the first cap period (January to March 2019) and that the values for the second cap period (April to September 2019) will be based on the draft DCC Charging Statement for 2019/20 to be published in December 2019.

<u>Comments on Non-Pass-Through Costs</u>

It has been particularly challenging to assess whether the proposed non-pass-through element of the SMNCC is an accurate reflection of the principles outlined in the consultation due to the rules and restrictions of the data disclosure room. However, based on the information we have been able to obtain, together with the consultation proposal, we have identified five specific areas of concern which are outlined below:

<u>Productivity Assumptions</u>

We note the 40% productivity assumption increase that has been applied to the insourced variable costs, and that this has been applied on the basis of assumptions provided in supplier returns. However, based on the information available in the data disclosure room we cannot be comfortable that this is an accurate reflection of supplier returns. We have the following concerns regarding the calculation of this increase:

[redacted]

- The 40% assumption is stated to be based on the average of six suppliers. However, as npower did not submit a 2017 figure, this is not the case unless data was used from five other large suppliers and complemented from information of one of the small or medium suppliers.
- It is unclear if the other five suppliers provided both 2017 and 2018 data, and if one or more suppliers did provide data for both years whether the sample is large enough for this assumption to be relied upon.
- It is unclear how robust this figure is, and it is unclear how it would be impacted if npower's 2017 figures are included, or if mid-tier suppliers are included.

Aside for these concerns around the methodology we are surprised that any supplier would be forecasting such productivity improvements at a time when the industry is transitioning from SMETS 1 to SMETS 2 meter rollout. In our Large Supplier Rollout Plan for 2018 we indicated that productivity would be impacted negatively in 2018 due to the national issues with SMETS 2. We are concerned that suppliers who predicted such productivity increases did not have a realistic view of the challenges facing the industry with the SMETS 2 rollout.

Furthermore, those productivity assumptions that were made were put together some time ago, either in late 2017 or early 2018. These were made on the basis of the industry rollout plans at that point in time, and assumed that SMETS 2 meters would be in mass rollout by late 2018 and early 2019. The assumptions on which the productivity improvements were made have moved on during 2018, and it is absolutely the case that the industry end to end testing of SMETS 2 meters has continued to experience multiple issues. Some examples of these are:

- Inconsistent communications in the Arqiva / North region – differing outcomes on the same service request /command to the same Comms Hub (CH) when sent minutes/hours apart. This leads to a lack of confidence in or being able to prove overall stability/readiness for next stage of roll out.

- Communications drop in the Arqiva / North region – Communications to CH working fine and then drops off the network and doesn't return until the next day/days after. This leads to a lack of confidence in or being able to prove overall stability/readiness for next stage of roll out.

- Traditional Registration Data Update Feed in Data Services Provider (Core DCC) – customers who have changed supplier but the core registration data in DCC still shows the old supplier. Unable to install against the meter point (MPAN/MRPN).

- End to End (E2E) Change of Supplier spanning DCC – there are a number of issues in DCC's change of supplier process on both the loss and gain journeys, meaning the overall solution doesn't work.

- Parallel Processing in the Arqiva / North region – The Arqiva implemented solution is unable to communicate to multiple devices in parallel. This impacts when 2 Service Users or 2 engineers are performing an install in the same area and possibly when an installer is completing parallel work finishing off commissioning a meter whilst starting the Prepayment activities under our install process.

- Due to the ongoing issues with the Telefonica and Central & South Region (C&S) Toshiba Comms Hubs the testing on the C&S Wistron NeWeb Corporation (WNC – manufacturer of one of the C&S CHs) has been put on hold to allow the resources to focus on the primary variants in the deployment environment. Once confidence is established in the gas side of

Telefonica / Toshiba this will be back in play, and hence allow us to release all the currently quarantined WNC CHs.

- The consistency, timeliness and reliability of Gas SR6.21 certificate exchange process.

- Although improved, there is continued instability between the Gas Smart Meter (GSME) and the Gas Proxy function (GPF) CH on both the Arqiva and Toshiba CH variants which contributes to overall Dual Fuel confidence / stability.

We have been at the forefront of the SMETS 2 development, incurring significant extra costs in the process, and during 2018 have had proportionately more SMETS 2 installations than almost any other supplier. We are, therefore, in a good position to judge the state of the industry and the readiness for mass rollout of SMETS 2 meters. We believe it is completely unreasonable, and irrational, to assume a productivity improvement for the early stages of the SMETS 2 rollout, with no basis in evidence. If anything, the first cap period covering Q1 of 2019 should make an allowance for the productivity impact of the SMETS 2 rollout, whilst the second cap period should hold the 2017 productivity levels constant. Productivity assumptions beyond this should be part of the review of SMNCC in 2019. We believe that the impact of this productivity assumption is that it is reducing the SMNCC by around £0.50 per meter per year based on SMETS 2 costs being annualised over 15 years, which equates to around £5 per meter over its asset life.

[✂]. Our MAP contracts are not fully aligned to the assumptions used in the modelling and the impact of this is over £1 per meter per year and this should be added to the SMNCC.

It is important to stress that our concerns around productivity are not based on internal inefficiencies, but an assessment of the impact of national issues identified above that are beyond our control. Over the past few years these issues have added enormous costs to suppliers which have had to be passed on to consumers, and we believe that this will continue into 2019 and hence must be reflected in the SVT cap.

<u>SMETS 1 Costs & Pass-Through Methodology</u>

The methodology that has been proposed implies that certain costs, in particular those relating to SMETS 1 meters, have been removed from the baseline costs on the basis these will be charged by the DCC, and that "DCC charges are included in the SNMCC as pass-through costs". As mentioned above, we have particular concern with this statement, as it is only the movement in DCC charges from 2017 that are included in SMNCC. There is considerable ambiguity around this whole area, and this has not been helped by the fact that key information from the data disclosure room has been redacted.

We have a fundamental concern that the principles of the consultation are not being followed. The SMNCC calculation is based around the 2017 cost submission being the baseline, with all calculations being a movement from this position. If DCC and Smart Energy GB allowances in the SMNCC pass-through costs are only the movement from 2017 (and the calculations in Annex 5 confirm this) then we do not understand why any costs included in the 2017 baseline are being removed. There are numerous references to downward adjustments to the model in Annex A of Appendix 7. We therefore believe that the industry costs, in particular those relating to DCC and Smart Energy GB, are not fully reflected in the price cap, and that the pass-through principle is not being correctly adopted.

A particular concern within this is the treatment of SMETS 1 meters, where there is reference to a downward adjustment in 2019, and removal from 2020. As a supplier with around [✂] SMETS 1 meter installations by the end of 2018 we will continue to incur charges for communication hubs

[redacted]

[✂] per year) and data processing [✂] per year) until these meters are adopted by the DCC. Based on the current DCC proposals for Enrolment & Adoption (E&A) migration, the npower group of customers will not migrate until either Q4 2019 or Q1 2020, both of which are outside the two cap periods covered by the SMNCC. As mentioned above, the data disclosure room restrictions have meant that we have not been able to ascertain the assumptions around E&A, but we do not believe there should be any downward adjustment for SMETS 1 meter costs until after the first two cap periods, and that full allowance for the additional £11 communications and data costs of SMETS 1 meters should be made. With [✂] such meters, this comes to an annualised cost of [✂], which equates to over £2 per meter over all our customer base.

We also believe that there is an error in the calculation of the volume of SMETS 1 Communication Hubs in 2018, which in turn feeds through to 2019. We believe the model incorrectly calculates that half of all communication hubs installed in 2018 are SMETS 1, and half are SMETS 2. This incorrectly reduces SMNCC by around £0.50 per meter, and clearly this is inconsistent with the overall modelling assumptions around SMETS 1 and 2 deployment. We trust that this will be corrected in the final proposal.

Finally, we have been unable to verify whether the assumptions used in Annex 5 for the calculation of the pass-through elements of SMNCC are consistent with the changes made to the model in the calculation of non-pass-through costs. This adds to our concern that genuine, and unavoidable, smart metering costs are not being included in the price cap.

<u>Industry IT Costs</u>

We do not believe that the additional supplier IT costs, which are outside our control and driven by industry-wide issues that are noted above, have been adequately reflected in the calculation of non-pass-through costs.

The consultation references an industry-wide increase in supplier IT costs in paragraphs 3.44 to 3.49 of Appendix 7. We have not been able to ascertain what this allowance is, and the assumptions underpinning it, as all the key assumptions that would help us to do this have been redacted from the data disclosure room. Therefore we have no evidence to ascertain whether the allowance adequately reflects the costs incurred, and in particular we cannot determine whether the additional costs that have been incurred from the ongoing delays to SMETS 2 installation have been captured.

Furthermore, we note that the estimate of additional costs is based on a BEIS estimate, and we have no way of knowing whether this fully captures supplier costs. We note that in 2013 BEIS estimated industry-wide IT costs from programme delays would be £30m which has turned out to be a significant understatement. Without understanding the numbers and assumptions behind the additional costs we are at risk of understating externally driven, and non-controllable, costs from the price cap.

Finally, we have not been able to ascertain whether the accounting treatment of supplier IT costs is appropriate, and reflects the actual treatment by suppliers. Paragraph 4.31 of Appendix 7 states that the cost of system changes are capitalised over a 15 year period. It is not clear from our analysis of the data disclosure room what the capitalisation period is, and what percentage of supplier IT costs are not capitalised (i.e. are operating costs). Supplier IT costs are not capitalised over a 15 year period (5 to 10 years being general accounting practice) and a significant minority of supplier IT costs [✂] are not capitalised. We have not seen evidence to suggest that the accounting policy assumption match those of suppliers in relation to IT costs. All this information should have been available in the data disclosure room, and the fact that it has all been redacted is, in our view, highly unsatisfactory.

Furthermore, we are particularly disappointment in the Ofgem response to our question as to why these data has been redacted. The response essentially justifies redacting information on the basis that it is not in the public domain. This seems to imply a logic that suggests that only publically available information is available for disclosure, in which case it begs the question as to why there are confidentiality requirements in place at all. We consider the decision to redact this information as being deliberately obstructive. It has significantly undermined our ability to review the information in the data disclosure room, as well as our confidence in the overall process.

We believe that the impact of supplier IT opex costs and depreciation is around [✂] per meter in 2019, based on a total cost of around [✂] in operating IT costs and depreciation. We believe that this number should be reflected in the SMNCC, but have no way of determining the extent to which it is. Depending on a supplier's accounting policies, we believe that these costs could be between £3-7 per meter.

<u>Supplier Benefits</u>

Smart metering brings with it both benefits and costs to suppliers. The balance of benefits and costs will vary depending on where a supplier in on the rollout profile. Generally the costs are incurred in the earlier stages of the rollout, whilst the benefits are incurred towards the end and afterwards.

We note in paragraph 4.23 of Appendix 7 that additional costs relating to the smart meter rollout have been specifically excluded from the SMNCC, even though such cost increases will inevitably occur. The consultation approach, whilst agreeing that such costs are in theory like to occur (paragraph 4.37) places the burden of proof on suppliers to provide evidence that such cost increases will occur, despite the inherent problems associated with proving a future event.

Whilst supplier cost increases are excluded, no such exclusion is made for supplier benefits, as outlined in paragraphs 3.28 to 3.31. The benefits in the model are based on theoretical assumptions from the BEIS model that are at least two years out of date and assumed a very different rollout path than is currently taking place. The consultation appears to take those benefits as confirmed facts, not to be challenged, despite the uncertainties that surround them. Our analysis of the Data Room showed that there is downward movement on the SMNCC caused by the supplier benefits in the BEIS model, but again we cannot determine the actual amount as the figure has been redacted.

We are particularly concerned with the BEIS assumption that all benefits are realised in the year the smart meters are installed. There is no logical sense in this assumption given that installations are phased throughout the year. For example, the model assumes that if a smart meter is installed in December 2019, then the full benefit of two meter reads per year (£6 per meter) are included for 2019. The impact of this incorrect assumption alone for meter reading, customer enquiries and debt handling equates to [✂] based on our installations for 2019. This works out at just over [✂] per meter across our entire portfolio, so this assumption alone is incorrectly pushing down the SMNCC by at least [✂] per meter. If a sensible assumption of a one-year delay in realising the benefits were to be applied, then the SMNCC would increase by around £3 per meter, and we believe that assumption should be applied.

We have been unable to ascertain what the validity of the assumptions are behind these benefits – as mentioned above the model appears to take the out of date BEIS assumptions without in any way challenging them. In addition, for customer enquiries, and particularly debt handling, there is inevitably a time lag between the installation of a smart meter and the benefits, and this lag should be included in any benefits modelling.

Finally, there is a consistency issue in that the consultation accepts the principle that suppliers have incurred additional IT costs as a result in changes to the industry-wide rollout (although as mentioned above it is difficult to ascertain what actual allowance has been made). It therefore follows that if there is an acceptance that industry delays have an impact on suppliers IT costs then they will also have an impact on the timing of supplier benefits beyond just updating the deployment profile. In order for smart metering non-pass-through costs to be a fair reflection of costs incurred by an efficient supplier then it is essential that the timing and scale of the supplier benefits in the BEIS model are updated to reflect the latest industry-wide circumstances.

PRC Costs

The cost of Premature Removal Charges (PRCs) caused by the smart metering programme is, and will continue to be, significant to all suppliers. For that reason the treatment of these costs in the price cap is of particular importance. We note the detailed treatment of these costs in the SMNCC as outlined in paragraphs 3.50 to 3.60, and welcome the fact that the consultation recognises the importance of these costs.

However, our analysis of the Data Room has shown that the SMNCC is extremely sensitive to the modelling assumptions, in particular the average age of traditional meters in 2011, and to the assumption that PRCs only apply to meters up to 15 years. The reality is that these costs are significant, and uncertain, and are caused as a result of suppliers meeting their smart metering licence obligations. The consultation appears to expect efficient suppliers to simply absorb these uncertainties. We believe that this is unreasonable, and that only a post-event true-up of PRC costs is going to fairly reflect the costs and risks associated with this issue.

The analysis from the data suggests that the PRC impact in 2019 is around half the PRC figure of 2017 even though the number of displaced dumb meters is four times as many. This has the effect of reducing the SMNCC. Whilst we accept that the aging of meters will have some downward impact on PRC charges (offset by the higher volume of displacement) we cannot understand how ageing meters with an asset life of 15 years by two years can have the effect of halving the PRC value. We can only assume that the combination of all the modelling assumptions and the modelling methodology has produced this illogical outcome. Particular concerns around the mechanics of the model include:

- Under-estimating the number of traditional meters expiring through use of the incorrect starting year. This incorrectly reduces SMNCC by £0.50 per meter.
- The counterfactual cost of the traditional meter, where the logic and rationale underpinning the calculation of the PRC is unclear.
- The application of the PRC calculation, and an apparent double count of the average dumb meter cost.
- The application of a recertification assumption, and the result that it increases the average age of meters, reducing the SMNCC as a result. This incorrectly reduces SMNCC by between £1 and £2 per meter.

Overall, whilst we welcome the recognition by Ofgem of PRC costs and their complexity, we are concerned about the mechanics of the model, together with some of the starting assumptions, and consequently do not have confidence in the results. As mentioned above, this has a large potential impact on the SMNCC.

We do not accept that there should be a downward adjustment to the SMNCC for PRC charges, and consequently believe that the most appropriate way forward is to exclude the downward adjustment for the price cap period to September 2019, and undertake a post-event reconciliation of PRC charges in 2019, as part of the overall SMNCC review, and include this in subsequent price caps.

It is important to note that we incur PRC and even stock stranding costs through no fault of our own. To take a single example, in 2018 we had to guess whether DCC would miss another target. In order not to stall the rollout due to inability to connect to the DCC, we ordered extra SMETS1 stock. Despite repeated assurances to the contrary, the DCC did in fact miss the deadline and we were saved by our prescience. If the DCC had achieved the deadline then we would have been stranded with the stock. Similar situations may arise in future, which would incur costs to suppliers not included in the cap, and yet not caused by them.

Finally, there is no allowance for PRC costs for SMETS 1 meters. Whilst we accept that the vast majority of SMETS 1 meters will be successfully adopted by the DCC, there will inevitably be some meters that cannot be upgraded to be compliant, and hence have to be replaced. In essence the consultation is assuming a 100% success rate in adopting SMETS 1 meters, without explicitly saying so, or saying why such a rate is the most likely outcome. We believe that a [✂] success rate is a challenging but realistic assumption, based on our experiences to date in Over The Air (OTA) upgrades. Such a rate would cost npower around [✂], or just over [✂] per meter spread over our portfolio. Consequently, we believe that an allowance of £1 per meter needs to be made in the SMNCC for PRC costs for SMETS 1 meters.

<u>Overall Impact on SMNCC</u>

In summary, we believe that the following increases need to be made to the per meter SMNCC to reflect our concerns:

- Productivity assumption — £0.50
- SMETS 1 Comms Hub Error — £0.50
- Asset life assumptions — £1.00
- SMETS 1 Comms Hub Rental — £2.00
- Supplier IT Costs — potentially £3-7
- Supplier Benefits deferral — £3.00
- PRC corrections — £2.00
- SMETS 1 PRC Charges — £1.00

Overall, we believe that the SMNCC is potentially understated by at least £10 per meter, although it is impossible to determine the exact amount due to the extensive restrictions of the data disclosure room.

[redacted]

Appendix 6: Headroom

Ofgem continues to conflate true competitive headroom (zero allowance, contrary to the CMA's approach) with the variation in efficient costs and a buffer for uncertainty and volatility, modelling errors, mis-forecasts, omissions and intentional under-estimates. To comply with the Electricity Act 1989 (EA89), Gas Act 1986 (GA86), and the Tariff Cap Act 2018, these must be separated and allowed.

It is manifestly inappropriate to conflate headroom with the £23 "allowance" for establishing Ofgem's view of the efficient benchmark above the frontier, including the recovery of legacy costs.

In our view and as illustrated throughout this response, the £3 additional wholesale allowance and explicit headroom of £10 (1.45%) for residual uncertainty are recklessly insufficient. Our internal analysis indicates that this allowance for uncertainty would be consumed by forecast uncertainty and volatility (excluding wholesale basis risk), leaving no headroom for a supplier at the efficient benchmark to compete and incentivise switching.

An uplift in headroom of £23 per dual fuel account is required to enable an efficient supplier to compete and mitigate significant uncertainty.

We also have the following comments:

1. **Assessment of Variation in Efficient Costs**

An allowance of £23 is provided, representing the difference between the frontier operating costs and the benchmark, set at frontier +15% (or lowest quartile less £5/DF).

Firstly, this benchmark is set below the costs of any of the SLEFs, which given they supply c95% of SVT customers, indicating that such a low threshold is not fully reflective of the cost of serving these customers. One key factor in this seems to be that Ofgem have not considered any variation in supplying an SVT customer over an FTC customer, above the differentiation in costs due to payment type. We estimate this variation in cost is in the region of [✂] – and is not purely confined to payment method differentials.

We believe there is still a residual difference which can be estimated and built into the cap

The key drivers of this differential are:

1. More SVT customer manage their accounts offline;
2. SVT customers incur higher debt costs[13] –;
3. SVT customers (noting 1) have a higher propensity to call us (meter reads, billing queries, etc)
4. SVT customers are more likely to be vulnerable[14] and hence incur extra costs

Ofgem's counter argument is that such customers would incur lower sales and marketing costs having been with us for a number of years. However, we actually incur considerable costs trying to engage these customers and marketing costs are incurred to both attract and retain customers.

[13] Default cap Policy Consultation Appendix 12, para 1.2
[14] Default Cap Draft Impact Assessment para 5.103

Ofgem note that the suppliers within their sample that have the 'hardest' and 'easiest' to serve direct debit customers were the two lowest cost suppliers, which would suggest portfolio make-up has little impact. However, it should be noted that:

1. Both these suppliers are not one of the SLEFs;
2. A greater proportion of the 'harder' to serve customers are likely to be in the ROB population, which is skewed towards the SLEFs;
3. The payment method allowance is partially socialised, which would therefore penalise the SLEFs who would be overweight in ROB customers

Ofgem apply an efficiency adjustment of £5/DF to its selected lower quartile benchmark for 2017. This effectively reduces the "headroom" due to variation in efficient costs. The £5/DF adjustment seems partially based on the rationale that 2017 costs were higher than average, however in our view 2017 costs were higher than average due to increased smart costs that should be fully reflected in the cap.

A number of factors are listed as potentially impacting variation in operating costs:

Table A6.6: Possible drivers of variation in operating costs – customer base feature

Customer base feature	Description	Position in May consultation
Proportion of vulnerable customers	Customers with lower incomes or otherwise in vulnerable circumstances may be more costly to serve. The proportion of a supplier's customers in vulnerable situations is likely to have an impact on operating costs.	We proposed to consider this further, with reference to, for example, variation in the number of customers of different suppliers on the priority services register (PSR), and evidence on the additional cost of supplying these customers.
Proportion of customers serviced online	Customers that manage their accounts online may be cheaper to serve. The proportion of a supplier's customers that manage their account online is likely to have an impact on operating costs.	We proposed not to make a specific adjustment, given the difficulties in developing a robust estimate of the incremental cost of supplying an offline customer, the likelihood of strong correlations with other characteristics (such as payment method and vulnerability), and uncertainty about the extent to which the proportion of offline customers is outside a supplier's control. Instead, we proposed to consider this in the round when setting the overall benchmark.
Proportion of dual fuel and electricity-only customers	Dual fuel customers may be cheaper to serve, due to - for example - the economics of only having to send a single bill. Electricity-only customers may be more expensive to serve due to the nature of their metering arrangements.	We said that we may want to consider this factor when setting the benchmark, but noted that would depend on whether the evidence supported that this had a material impact on costs.

We acknowledge that it is hard to assess these variations but believe that £23 per dual fuel customer is highly likely to be insufficient, especially noting the omission of the extra costs of serving an SVT customer vs an FTC customer, potentially [✂] per account. Further, our internal analysis indicates that the conservative additional cost of servicing an offline customer is [✂] per account, around half of which is due to mailing costs and the remainder due to increase propensity to call the call centre, for example to submit meter reads, rather than self-serve online.

Finally, regarding the treatment of smart costs, the efficient benchmark for these costs in 2017 is deemed to be included in the costs of the lowest quartile supplier. There is a real risk here that the costs of one supplier may be materially different to others due to rollout strategy / maturity, investment to date and capitalisation policy, and scale in the case of fixed costs. See Appendix 5 for our comments and concerns on Smart.

2. Incentives to Switch

In our view, an efficient supplier would not have any headroom, after the risks and costs outlined above, to offer discounted products to the cap and make a sustainable return.

A cap with no headroom drives up uncapped tariffs, causing them to converge to the cap. Stimulus to switch is lost and the whole market converges to a single price control. This will inevitably have major impacts on churn and customer engagement where research suggests the majority of customers require at least £100 savings to incentivise switching.

A readily conceivable outcome is substantial reduction in switching, with two key drivers to tariff differentiation; i) cost differences between exempt and non-exempt suppliers spiralling as the obligation base shrinks, ii) risk seeking supplier behaviour being subsidised by mutualisation of default by irresponsible suppliers. This situation is not satisfactory to any responsible stakeholder, nor is it sustainable.

We note that the CMA allowed £30 (Dual Fuel) true competitive headroom (i.e. not with uncertainties conflated into it) whilst this figure appears to be £0 here - £36 comprising £23 (variation in opex) + £3 (wholesale uncertainty) + £10 headroom (residual uncertainty).

1.6. We propose to set the overall direct debit baseline cap at £1,007, which includes £10 of headroom on top of our 2017 baseline for the efficient benchmark. Under our proposed methodology, the benchmark already contains allowances for uncertainty and variation in efficient costs. Taking the benchmark and headroom allowance together, we propose to include £36 (excluding VAT impact) in our baseline for uncertainty and variation in efficient costs. In part, this follows our consideration of the need to have due regard to the financeability of an efficient supplier. This level of 'headroom' (comparing the cap level to the efficient frontier) is in the middle of the range we presented in our May consultation.

Appendix 7: Wholesale indexation methodology

Transitional Cap decision: proposal reversal

(numbers refer to paragraphs in appendix 4 of the statutory consultation unless otherwise stated)

We were extremely surprised and disappointed to note that Ofgem have reversed their proposal to adjust the observation period for the transitional cap. Doing so is an example of the detrimental impact of regulatory uncertainty, evidence for which we will provide later in our response. Moreover, the rationale for the change in Ofgem's position is not at all clear, particularly as i. "the majority of suppliers agreed that the proposal was appropriate" and "… any deviation from these proposals represented more uncertainty…" (**4.7**). Moreover, Ofgem states that "… whatever period we choose, some suppliers are likely to over recover their costs, and some may under-recover" (**4.19**): so why change from the policy consultation proposal? Our comments below firstly discuss important overarching principles before addressing the transitional cap specifically.

The purpose of hedging is to ensure that costs and revenue are aligned. A rational supplier adjusts their hedging strategy in light of the best information available to them. Through the proposed allowance, Ofgem dictates allowable revenue to suppliers so the hedge against this is to mirror the formula used to set said costs. Thus, the allowance and hedging strategy are virtually one and the same (**4.15**). Indeed, Ofgem stated in May that (in the context of the transitional cap) that "suppliers may attempt to adjust their position to the hedge once this approach is confirmed" (**Policy Consultation Appendix 6, 5.48**) – the indexation method and hedging strategy are basically interchangeable. We agree with Ofgem's assertion that "[The allowance's] primary function is to set an allowance that gives a realistic allowance to cover the costs that suppliers might incur delivering energy (**4.15**), but evidently disagree with Ofgem on what those costs are.

In the context of a market-wide price cap, the only point of reference since draft legislation was published in October 2017 – and indeed since the CMA method was implemented for prepayment customers – was/is the existing prepayment cap / safeguard tariff; indeed, in March of this year, Ofgem gave a clear signal, stating that "… our current expectation is that we would use a version of the existing model to set an allowance for wholesale costs, whether in the context of a bottom-up cost assessment, or to update any cap for trends in wholesale costs over time". (**Working paper 1, 5.32**).

We recognise that, at this point, no final decision had been made on the structure of the cap so it could be considered premature to align fully to suppliers' best view of the likely structure but it is almost inconceivable that any suppliers still hedge "a very long time in advance" (**4.20**), or rather, that they have not adjusted their hedge strategy and / or position over time in line with legislative and political developments; the definition of "existing strategies" (**4.17**) should be used carefully. It follows that suppliers may have done this gradually, in line with increasing clarity on format, timing and so on, but also to avoid the need for disruptively large buy or sell transactions. Given Ofgem's valid desire to avoid wholesale market distortion, we can only assume that Ofgem would support this.

Crucially, Ofgem recognised in May that "Suppliers have strong incentives to follow a buying strategy that matches the index we choose. This is to reduce their exposure and risk from being away from the costs used to calculate the level of the cap" (**Policy Consultation Appendix 6, 4.4**). We agree. This contradicts - and indeed we entirely disagree with - the suggestion (**4.17**) that it is "[un]likely that suppliers would seek to undo previous actions to align to the model for setting the initial periods of the default tariff cap": such "undoing" behaviour is precisely what hedging *is*, so the statement suggests a conflation of risk management and simple procurement, and a misunderstanding of how a rational supplier behaves.

Hedge strategy data captured in 2016 and/or as part of the consultation (**4.16**) does not necessarily reflect the hedge strategy today; historical tendencies are particularly irrelevant, due in no small part to Ofgem's clear and consistent preference for the 6-2-12 semi-annual method, which – as explained above – is entirely at odds with the adoption of a long (i.e. two / three years forward) hedging strategy by a supplier. We therefore believe that reverting to a more "retrospective" index based on a historic, partial and potentially inaccurate view of supplier hedging behaviour does not stack up, and arguably penalises those suppliers who have done the most to align their hedging activity with Ofgem's preferred approach (and the aims of the cap in general).

Referring specifically to the transitional cap, there were four pieces of information surrounding the proposed change to the observation period which we believe made it highly likely that the proposal would be adopted, and therefore justified incorporating it into our hedge:

1. The already-mentioned "strong incentives… to match the index" sentiment gave a signal to act.

2. The proposal represented the first change of any real substance to the underlying methodology since the 6-2-12 formula first came to light, and was taken very seriously as a result.

3. As this information was released in (late) May of this year, there was ample time for suppliers to take action and align to the implied hedge; this was in their interests because of the implications of not doing so that we have already covered i.e. deviation of costs and revenue. Indeed, the policy consultation stated that "[The change] was in response to comments on our early working papers that suppliers were worried they would have already started hedging for the first default tariff cap period, potentially on a different hedging strategy and wanted as much notice as possible". (**Policy Consultation Appendix 6, 1.21**)

4. The timing of subsequent publications / consultations would mean that there was not time for a supplier to make a meaningful adjustment later down the line (e.g. after the release of the statutory consultation) as the observation window would have closed by that point.

Ofgem's decision to reverse this proposal – due at least part to a misconception about supplier behaviour – will result in a substantial cost to npower (because of price development since May of this year).

We calculate that a supplier that adjusted their hedging in line with Ofgem's statements on cap structure would have paid £62.58/MWh for Q1 power and 66.38p/th for Q1 gas, compared to £56.93/MWh and 59.92p/th, which is the average price of Q1 observed in a February to July window (using npower forward curve data – there may be slight differences between these values and those of ICIS Heren). This is based on:

- The reasonable assumption that a supplier had aligned their Q1 purchasing to the PPM methodology prior to the start of indexation for the Q1 cap (which, prior to May's Policy Consultation was the only available point of reference);
- That, upon publication of the Policy Consultation, they adjusted their Q1 hedge position to align to the April to September observation window, in order to mitigate the risk that their commodity cost and the new expectation of the level at which the Q1 cap would be set would deviate (which required selling volume back to the market, to move from a hedge position of 63% of their forecast volume to 30%), and;
- That, upon publication of the Statutory Consultation, they adjusted their Q1 hedge position again to revert to the February to July observation window, again in order to mitigate the risk of further deviation of commodity cost and cap level (which required them to move from

87% to 100% of their forecast volume, but, as the observation window was in the past, it clearly was not able to retrospectively achieve the relevant prices).

All things being equal, setting the cap artificially low will also drive a larger price increase for customers when the April 2019 cap level is confirmed. This can be quantified using Ofgem's illustrative *wholesale cost allowance methodology* model.

<u>Basis Risk</u>

We are pleased to note that Ofgem recognises part of the basis risk introduced by 6-2-12 semi-annual approach (2.11) – that is, that

i) the under-recovery during a winter cap (where a supplier buys a winter forward contract against an index that is the average of winter and summer forward prices) and
ii) the over-recovery during a summer cap (where the supplier buys a summer forward contract against an average of a summer and winter forward prices).

are not equal and opposite because summer-winter price spreads are not constant.

We also note, and agree with, the implication that suppliers will align their hedging to the chosen wholesale indexation mechanism, though this is at odds with the statement that "in general, suppliers buy energy for SVT customers over a much longer period, reducing how quickly cost increases or decreases are passed on to customers" (2.10). We have already addressed this assumption, which we believe to be flawed, in our comments on the transitional cap change.

However, it is disappointing that Ofgem has not grasped the full extent of the basis risk - the other impact being that of backwardation or contango – and have as a result dramatically underestimated the impact of it. Before considering the extent to which summer/winter spreads have changed during a particular observation period, we must assess our starting point i.e. the forward curve before price observation commences.

[✂]

Following the logic above derives an impact of approximately [✂] (power account) and approximately [✂] (gas account} for the two caps which start in 2019, which Ofgem can compare to the "worst case" scenario (2.35) of £15/dual fuel account. Based on npower's SVT portfolio, this drives an adverse impact of [✂] – a cost, not a risk. To reiterate, this is the case when there is zero volatility and is driven by the shape of the forward curve before indexation commences. Of course, in the real world, we expect some degree of price volatility; the £/account impacts would therefore move around accordingly and, as Ofgem asserts, we assume that this impact is as likely to go up as down ("we consider it implausible that the summer-winter spread would consistently shift in a single direction" (2.36) – but up and down from a starting point of a cost of approx. [✂]/account.

As mentioned in our policy consultation, the effect of a market in contango would be the opposite: suppliers would benefit. This is why, in our response to the Policy Consultation, if Ofgem insisted on adopting the 6-2-12 semi-annual method, npower advocated a mechanism for recovering the cost or benefit which results from this effect.

All of the above assumes a 'simple' hedge of buying only the season matching the cap application period. Ofgem is partly correct to suggest (2.39) that a supplier can manage basis risk. We agree that, as Ofgem states, "at the time the default tariff is announced, the 6-2-12 semi-annual model creates an expected profit or loss from that point" and that a supplier "could hedge in a way that locks in that profit or loss from that point, exposing themselves to no additional basis risk" (price spread volatility). npower has also identified a hedge which achieves this result. This method would therefore lock in the [✂] impact in 2019 described above but it would not remove said impact - only the impact of spread volatility during the indexation period (and even then, as customer numbers are not static and forecasts are not perfect, there is further risk: Ofgem has made an allowance for this, however).

The “lock in” hedge that Ofgem refers to involves the following steps, and a worked example is included below:

[✂]

[✂]. This directly contradicts the suggestion that suppliers would buy further into the future (2.18, point 4) than they do currently under the annual method. An additional complication is the fact that the cash hedge element of the structure does not deliver in the same financial year as the cap period to which it applies, which drives substantial volatility in the operating result of a non-vertically integrated supplier such as npower.

Ofgem identifies that it would be possible to structure a deal with a third party (2.40). Because of the accounting restrictions described above, we investigated whether a third party could replicate the “lock in” hedge on our behalf. One party was willing to provide a quote for such a structure, for gas only, though the price included a premium for managing this risk of an additional [✂].

We will not repeat our rationale for adopting the 6-2-12 annual method, even though it remains our preference, on balance. One point that we do wish to raise afresh is that the annual method exposes suppliers to weather effects more than the semi-annual approach; weather is an effect which suppliers deal with only in the short term horizon. Suppliers hedge according to seasonal normal weather until forecasts become reliable (<2 weeks prior to delivery). We will also not reiterate our rationale for ruling out the 6-2-6 approach – Ofgem is right to have done so.

Finally, we continue to struggle with the idea of discounting the 6-2-12 annual method on the grounds that volume risk that it would introduce (2.28). Whilst we do not disagree that volume risk will indeed be greater in an annual scenario, forecasting customer numbers is a fundamental part of operating in the energy retail market; suppliers of all sizes who acquire customers by offering competitively-priced fixed term contracts have to forecast subsequent alignment to SVT (and new FTCs) once those fixed deals expire as a matter of course. They will also undoubtedly forecast “in-term” (prior to product expiry) movement from existing products to both their own new launches and those of competitors depending on the price position of each, so this logic can be extended to the capped tariff. We acknowledge that the removal of (re)pricing as a mitigation “lever” is a new challenge but, as we said in our Policy Consultation response, it is one which is reasonable to impose upon suppliers. It is certainly preferable to manage this risk than the basis risk, which as clearly demonstrated imposes a cost which suppliers cannot manage.