Consultation

Price Cap – Consultation on possible wholesale cost adjustment

Subject	Details
Publication date:	16 May 2022
Response deadline:	14 June 2022
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We are consulting to seek views and evidence on whether suppliers are incurring additional efficient wholesale costs, beyond existing allowances in the default tariff cap – and to engage with stakeholders on whether any adjustment is necessary. We would like views from people with an interest in the level of the default tariff cap. We particularly welcome responses from domestic energy suppliers and consumer groups. We would also welcome responses from other stakeholders and the public.

This document outlines the scope, purpose and questions of the consultation and how you can get involved. Once the consultation is closed, we will consider all responses. We want to be transparent in our consultations. We will publish the non-confidential responses we receive alongside a decision on next steps on our website at Ofgem.gov.uk/consultations. If you want your response – in whole or in part – to be considered confidential, please tell us in your response and explain why. Please clearly mark the parts of your response that you consider to be confidential, and if possible, put the confidential material in separate appendices to your response.

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Executive summary

We introduced the default tariff cap ('cap') on 1 January 2019, which protects households on standard variable and default tariffs (which we refer to collectively as 'default tariffs'). The cap ensures that default tariff customers pay a fair price for their energy, reflecting its underlying costs.

We are consulting to seek views and evidence on whether suppliers are incurring additional efficient wholesale costs, beyond existing allowances in the cap – and to engage with stakeholders on whether any adjustment is necessary.

Explaining the potential issues

Wholesale prices reached record highs in winter 2021, followed by further increases and volatile conditions in spring 2022. This situation has the potential to create additional costs for suppliers in two areas.

- Suppliers may incur **unexpected standard variable tariff (SVT) demand costs** when more customers than expected move to or remain on SVTs, to the extent that they need to buy additional energy at a cost above the cap wholesale allowance. These costs have historically been low and covered by existing uncertainty mechanisms – but this might no longer be the case due to wholesale price increases.
- Suppliers incur **shaping and imbalance costs** from refining their hedged positions to meet customers' demand. This activity occurs close to the time of consumption, and is affected by wholesale prices at that time. While we include an allowance in the cap for shaping and imbalance costs, wholesale price increases could push costs above it.

In February 2022, we decided to introduce an adjustment to the cap for these two areas (and backwardation) in relation to costs for cap period seven. This consultation now considers costs for the two areas relating to cap periods eight (April 2022 – September 2022) and nine (October 2022 – March 2023), pending enduring changes to the cap being fully implemented. We are addressing future backwardation costs separately through our consultation 'Price cap - Statutory consultation on changes to the wholesale methodology'. Although this consultation notes that we are reviewing the calculation of backwardation costs (see Chapter 2 for an explanation) in cap period seven (October 2021 – March 2022).

Purpose of this consultation

We are consulting to seek views and evidence on whether suppliers are incurring additional wholesale costs in these areas, beyond existing allowances in the cap. We have already considered the results of a Request for Information (RFI). Our analysis, while not conclusive and subject to uncertainty on future changes to market prices, has shown sufficient potential evidence to justify a full consultation.

We then need to consider whether to adjust the cap. When doing so, we are considering whether there is a material and systematic change to suppliers' costs, in line with our general approach to considering adjustments to the cap methodology. This consultation is therefore also an opportunity to engage with stakeholders on whether any adjustment is necessary.

It is important to emphasise that we do not currently have a minded to position on whether an adjustment is required. We may decide that no adjustment is required – for example, due to costs not being material, the level of uncertainty around costs, offsetting allowances, or the impact on default tariff customers from introducing an adjustment to the cap.

Initial views

While we do not have a minded to position, we have initial views about the relative importance of different cost areas.

- At this stage, the area with the most (although still inconclusive) evidence of material additional costs is **unexpected SVT demand costs for cap period eight**. This is therefore the main subject of this consultation.
- There are three areas covered in the RFI where we currently do not consider that there is sufficient evidence that suppliers are incurring material additional costs. These are **shaping and imbalance costs for cap period eight**, and **both cost areas for cap period nine**.

We are also of the view that any adjustment would be applied over a 12-month period and be included in the adjustment allowance (Annex 8 to the cap licence conditions).

Next steps

We are requesting responses and any further evidence by 14 June 2022. We intend to issue a decision in August 2022. If we decide to adjust the cap, this will take effect from 1 October 2022 (cap period nine).

1. Consultation process

Consultation stages

1.1. We are consulting to seek views and evidence on whether suppliers are incurring additional wholesale costs, beyond existing allowances in the default tariff cap ('cap') – and to engage with stakeholders on whether any adjustment is necessary.

1.2. We invite stakeholders to submit comments on any aspect of this consultation on, or before, **14 June 2022**.

1.3. Responses to this consultation, and any supporting evidence, can be submitted to Ofgem by emailing RetailPriceRegulation@ofgem.gov.uk. We will publish non-confidential responses on our website at www.ofgem.gov.uk/consultations.

1.4. We are also happy to speak to stakeholders during the consultation period, to understand their initial views. If you would like to arrange a call, please contact us through retailpriceregulation@ofgem.gov.uk.

1.5. We intend to publish a decision in August 2022, so that, if needed, any changes may come into effect from 1 October 2022 (cap period nine).

Related publications

1.6. The main documents related to this consultation are:

- 2018 decision on the cap methodology ('2018 decision'): https://www.ofgem.gov.uk/publications/default-tariff-cap-decision-overview.

- November 2021 consultation on additional wholesale costs for cap period seven ('November 2021 wholesale consultation'): https://www.ofgem.gov.uk/publications/price-cap-consultation-potential-impact-increased-wholesale-volatility-default-tariff-cap.

- February 2022 decision on additional wholesale costs for cap period seven ('February 2022 wholesale decision'): https://www.ofgem.gov.uk/publications/price-cap-decision-potential-impact-increased-wholesale-volatility-default-tariff-cap.

- February 2022 guidance on treatment of reasonable risk management practices in future default tariff cap proposals ('February 2022 guidance letter'): https://www.ofgem.gov.uk/publications/price-cap-guidance-treatment-reasonable-risk-management-practices-future-default-tariff-cap-proposals.

- May 2022 statutory consultation on changes to the wholesale methodology ('changes to the wholesale methodology': https://www.ofgem.gov.uk/publications/price-cap-statutory-consultation-changes-wholesale-methodology.

How to respond

1.7. We want to hear from anyone interested in this consultation. Please send your response to RetailPriceRegulation@ofgem.gov.uk.

1.8. We do not ask specific questions in this document. Rather, we welcome views on any of the matters discussed in this consultation.

Your response, data and confidentiality

1.9. You can ask us to keep your response, or parts of your response, confidential. We will respect this, subject to obligations to disclose information, for example, under the Freedom of Information Act 2000, the Environmental Information Regulations 2004, statutory directions, court orders, government regulations or where you give us explicit permission to disclose. If you do want us to keep your response confidential, please clearly mark this on your response and explain why.

1.10. If you wish us to keep part of your response confidential, please clearly mark those parts of your response that you *do* wish to be kept confidential and those that you *do not* wish to be kept confidential. Please put the confidential material in a separate appendix to your response. If necessary, we'll get in touch with you to discuss which parts of the information in your response should be kept confidential, and which can be published. We might ask for reasons why.

1.11. If the information you give in your response contains personal data under the General Data Protection Regulation (Regulation (EU) 2016/679) as retained in domestic law following the UK's withdrawal from the European Union ('UK GDPR'), the Gas and Electricity Markets Authority will be the data controller for the purposes of GDPR.

Ofgem uses the information in responses in performing its statutory functions and in accordance with section 105 of the Utilities Act 2000. Please refer to our Privacy Notice on consultations, see Appendix 5.

1.12. If you wish to respond confidentially, we'll keep your response itself confidential, but we will publish the number (but not the names) of confidential responses we receive. We won't link responses to respondents if we publish a summary of responses, and we will evaluate each response on its own merits, without undermining your right to confidentiality.

General feedback

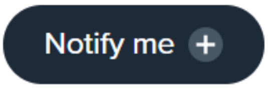
1.13. We believe that consultation is at the heart of good policy development. We welcome any comments about how we've run this consultation. We'd also like to get your answers to these questions:

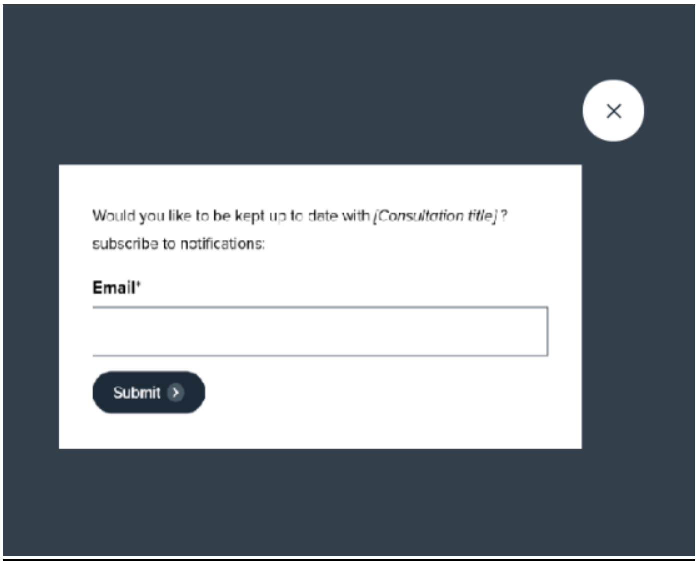
1. Do you have any comments about the overall process of this consultation?
2. Do you have any comments about its tone and content?
3. Was it easy to read and understand? Or could it have been better written?
4. Were its conclusions balanced?
5. Did it make reasoned recommendations for improvement?
6. Any further comments?

Please send any general feedback comments to stakeholders@ofgem.gov.uk.

How to track the progress of the consultation

You can track the progress of a consultation, from upcoming to decision status, using the 'notify me' function on a consultation page when published on our website [Ofgem.gov.uk/consultations.](Ofgem.gov.uk/consultations)





Once subscribed to notifications for a particular consultation, you will receive an email to notify you when its status has changed. Our consultation stages are:

Upcoming ► Open ► Closed (awaiting decision) ► Closed (with decision)

2. Introduction

Section summary

This chapter provides context on relevant allowances in the cap and how suppliers' costs could have changed due to recent wholesale price movements. It explains the consequent scope of the consultation. It also covers the statutory framework and our approach to considering adjustments to the cap.

What are we consulting on?

The cap

2.1. We introduced the cap on 1 January 2019, which protects households on standard variable and default tariffs (which we refer to collectively as 'default tariffs'). The cap ensures default tariff customers pay a fair price for the energy they consume, reflecting its underlying costs.

The issue

2.2. Following increases in wholesale prices over recent months, we are examining whether suppliers are incurring increased efficient[1] wholesale costs, which are not reflected in the cap methodology. We are considering costs for cap period eight (April to September 2022) and cap period nine (October 2022 to March 2023). This consultation considers the evidence available at this stage, sets out our current thinking on the need for any adjustment to the cap and invites responses and additional data to help our considerations.

[1] We focus on efficient costs because the relevant legislation requires us to protect default tariff customers and to have regard to the need to provide incentives for suppliers to improve their efficiency. See the 'Statutory framework' section below.

Context

Wholesale cost allowances in the cap

2.3. Wholesale costs account for the largest portion of a customer's bill. There are currently[2] three parts to our assessment of wholesale costs in the cap.

- **Core direct fuel allowance:** we estimate the majority of wholesale costs based on forward contracts for electricity and gas. We measure the prices of these contracts over a period of time before a cap period, which we refer to as an observation window.

- **Additional direct fuel allowances:** we uplift the core direct fuel allowance by an additional set percentage. This percentage reflects the expected costs of converting less granular forward contracts to more granular contracts closer to delivery, forecast error and imbalance. The percentage also reflects transaction costs. It also includes an uplift for additional risks ('additional risk allowance'), which we set at 1% in our 2018 decision. We apply this uplift because wholesale costs are a volatile and uncertain element of suppliers' costs, and this uncertainty could lead to additional costs which are not covered by the other wholesale allowances. We also apply regional electricity losses and unidentified gas before calculating the final direct fuel allowance.

- **Capacity market payments:** we also provide an allowance for the capacity market (CM) scheme, designed to ensure electricity security of supply.

2.4. We calculate and update the core direct fuel allowance and CM allowance each time we update the cap. This means that unexpected changes in direct fuel costs and CM costs are reflected in the cap level each time it is updated.

2.5. The additional direct fuel allowances are indexed as a fixed percentage of direct fuel costs, rather than calculated. At the time we introduced the cap, we estimated the costs associated with shaping, forecast error and imbalance costs, based on historical cost data. Table 1 includes a summary of the additional direct fuel allowances. We set

[2] Through our consultation on changes to the wholesale methodology, we are proposing to add a backwardation allowance as a new element to the wholesale cost allowance.

out more detail on how we calculated these additional direct fuel allowances in Appendix 4 to our 2018 decision.[3]

Table 1: Summary of additional direct fuel allowances for electricity and gas (as a percentage of the core direct fuel allowance)

Allowance	Electricity (single rate and multi-register)	Gas
Shaping, forecast error and imbalance costs	6.0%	4.3%
Transaction costs	0.4%	0.3%
Additional risk and uncertainty	1.0%	1.0%
Total	**7.4%**	**5.6%**

February 2022 wholesale decision

2.6. Our February 2022 wholesale decision sets out that suppliers' efficient costs materially departed from the cap allowances during cap period seven (October 2021 – March 2022). We concluded that a cap level increase of £61 per customer in cap periods eight and nine was required to ensure suppliers could recover their efficient costs related to cap period seven.

2.7. We implemented this adjustment through a change to the additional risk allowance. We changed the value so as to recover the adjustment, in addition to the original 1% value.

2.8. We did not make an upfront adjustment for costs relating to cap period eight. At a high level, this reflected the uncertainty about future costs. Our February 2022 wholesale decision sets out our considerations in detail.[4]

[3] Ofgem (2018), Default tariff cap: Decision – overview. Appendix 4 – Wholesale. https://www.ofgem.gov.uk/publications/default-tariff-cap-decision-overview
[4] Ofgem (2022), Price Cap - Decision on the potential impact of increased wholesale volatility on the default tariff cap, paragraphs 2.29 to 2.30. https://www.ofgem.gov.uk/publications/price-cap-decision-potential-impact-increased-wholesale-volatility-default-tariff-cap

2.9. Alongside our February 2022 wholesale decision, we published the February 2022 guidance letter. This sets out guidance for suppliers to support them in making prudent risk management decisions. We noted that, in our February 2022 wholesale decision, we had not adjusted the allowance for the effectiveness of suppliers' demand forecasting and hedging strategies, "as the market circumstances were unprecedented." However, we said: "Going forward, we expect suppliers to respond to the now-known risks of customer demand variance and will take that into account if we make a future allowance for unexpected customer demand."[5]

Recent wholesale price movements

2.10. Wholesale prices increased during summer 2021, followed by a significant acceleration in September 2021. Prices increased further in December 2021.

2.11. These price increases provided the context for our February 2022 wholesale decision on costs relating to cap period seven. However, these price increases also affect cap period eight. Suppliers will have started to incur wholesale costs for cap period eight from the start of the observation window in August 2021.

2.12. Since our February 2022 wholesale decision, wholesale gas price volatility has unexpectedly increased further. These further changes in wholesale prices could affect wholesale costs for the current cap period (ie cap period eight). They could also affect wholesale costs for cap period nine, where the observation window started in February 2022.

Consultation scope

2.13. This document sets out our considerations on whether (and if so, how) to adjust the cap from cap period nine, to account for any additional wholesale costs beyond the cap allowance methodology. These costs could relate to cap periods eight and nine.

2.14. Specifically, this consultation focuses on costs incurred across two areas.

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[5] Ofgem (2022), Price Cap - Guidance on treatment of reasonable risk management practices in future default tariff cap proposals, p4.
https://www.ofgem.gov.uk/publications/price-cap-guidance-treatment-reasonable-risk-management-practices-future-default-tariff-cap-proposals

- **Unexpected standard variable tariff (SVT) demand:** increases in wholesale prices may erode or eliminate the savings available on fixed-term contracts (FTC) relative to SVTs. This may increase the number of customers on SVTs, beyond the number that suppliers expected and hedged for. Suppliers may therefore need to buy energy to meet this unexpected SVT demand at prices above those used to set the cap level.

- **Shaping and imbalance costs:** while suppliers buy energy in the forward markets, they incur further costs to refine their positions close to delivery. These costs are likely to depend on the prevailing wholesale prices, and so may increase with them.

2.15. We provide further information on these areas in Chapters 3 and 4, respectively.

2.16. We are not considering backwardation[6] through this consultation. For an update on cap period seven backwardation costs, see below. We are addressing costs relating to backwardation for future cap periods separately through our consultation 'Price cap - Statutory consultation on changes to the wholesale methodology' (we refer to this as 'changes to the wholesale methodology').

Review of cap period seven backwardation estimate

2.17. In our February 2022 wholesale decision, we set out a decision to allow an allowance for backwardation costs especially related to cap period seven. We set this cost allowance at the weighted average level based on the evidence submitted by suppliers, offset against a 'deadband'.[7]

2.18. Following engagement with industry stakeholders after the publication of this decision, we consider it prudent to conduct a further and more detailed review of the approach to calculate backwardation costs specific to cap period seven. We commit to conducting a review of the evidence provided by suppliers related to backwardation

[6] For an explanation of backwardation, see: Ofgem (2022), Decision on the potential impact of increased wholesale volatility on the default tariff cap, paragraphs 4.4 to 4.7.
https://www.ofgem.gov.uk/publications/price-cap-decision-potential-impact-increased-wholesale-volatility-default-tariff-cap
[7] Further detail on the backwardation allowance for cap period seven and the use of a 'deadband' can be found in Section 4 of the February 2022 Wholesale Decision.

estimates for cap period seven, including engagement with suppliers where relevant, to ensure the estimate was in line with the evidence. This review will be specific to the evidence submitted as part of the November 2021 wholesale consultation process. We will not be asking for (or considering) further evidence outside of the consultation process. We will publish the outcome of this review as part of the decision to this consultation.

Statutory framework

2.19. We set the cap with reference to the Domestic Gas and Electricity (Tariff Cap) Act 2018 ('the Act'). The objective of the Act is to protect current and future default tariff customers. We consider protecting customers to mean that prices reflect underlying efficient costs. In doing so, we must have regard to four matters:

- the need to create incentives for holders of supply licences to improve their efficiency;
- the need to set the cap at a level that enables holders of supply licences to compete effectively for domestic supply contracts;
- the need to maintain incentives for domestic customers to switch to different domestic supply contracts; and
- the need to ensure that holders of supply licences who operate efficiently are able to finance activities authorised by the licence.

2.20. The requirement to have regard to the four matters identified in section 1(6) of the Act does not mean that we must achieve all of these. In setting the cap, our primary consideration is the protection of existing and future consumers who pay standard variable and default rates. In reaching decisions on particular aspects of the cap, the weight to be given to each of these considerations is a matter of judgment. Often a balance must be struck between competing considerations.

2.21. In setting the cap, we may not make different provisions for different holders of supply licences.[8] This means that we must set one cap level for all suppliers.

Approach to considering adjustments to the cap

2.22. In our 2018 decision, we said that: "if in the future we consider there are material systematic issues that require correction, we might modify the licence. This would allow us to make any changes required to correct how the cap was updated, if it systematically and materially departed from an efficient level of costs." We also said that: "The type of specific systematic errors for which we would adjust the cap would need to be unforeseen, clear, material, and necessitate changes."[9]

2.23. We have applied this test when considering changes to the cap. As set out in our November 2021 wholesale consultation: "We broadly consider the case for amending the cap methodology against the test of whether a change in the costs facing suppliers is material and systematic, considering the market as a whole."[10]

[8] Domestic Gas and Electricity (Tariff Cap) Act 2018, section 2(2). http://www.legislation.gov.uk/ukpga/2018/21/section/2/enacted
[9] Ofgem (2018), Default Tariff Cap decision – Overview, paragraphs 3.14 and 3.16. https://www.ofgem.gov.uk/publications/default-tariff-cap-decision-overview
[10] Ofgem (2021), Price Cap – Consultation on the potential impact of increased wholesale volatility on the default tariff cap, paragraph 4.16. https://www.ofgem.gov.uk/publications/price-cap-consultation-potential-impact-increased-wholesale-volatility-default-tariff-cap

3. Unexpected SVT demand

Section summary

We explain the issue of unexpected SVT demand and how we gathered data to consider this. We discuss options for benchmarking suppliers' costs. We set out suppliers' reported costs. We discuss potential offsets against other allowances. We set out our initial views on whether an adjustment may be needed.

Context

3.1. Suppliers may incur unexpected SVT demand costs when they need to buy additional energy for SVT customers, which are unexpected and unhedged. Below we explain both these concepts in general terms.

Unexpected

3.2. To align with the core direct fuel cost methodology for a given cap period, a supplier would need to purchase energy for SVT customers over the observation window for that cap period. To achieve this, a supplier would need to have a forecast – from the start of the observation window – of its expected SVT customer numbers over the course of that cap period. We would expect that such forecasts would take into account the expected number of customers moving from FTC to SVT, and of customers leaving the SVT (for a new FTC or to switch to another supplier).

3.3. However, SVT customer number forecasts may change between the start of the observation window and the end of the cap period, including due to changes in wholesale prices.

3.4. Changes in relative prices of FTCs and SVTs, due to changes in wholesale prices, can affect how customers move between these tariffs. For instance, increases in wholesale prices may erode or eliminate the savings available on FTCs. This may make it more likely that customers will end up on SVTs. FTC customers may be more likely to default onto the SVT when their existing contracts expire. SVT customers may be less likely to consider moving to FTCs or switching supplier.

3.5. This increase in SVT customers would be unexpected, given that suppliers cannot reliably predict future changes in wholesale prices. The risk of unexpected SVT demand has been small historically (before cap period seven). However, given the recent scale of wholesale price increases, the volume of unexpected SVT demand has risen significantly.

3.6. It is worth noting that the unexpected movement is measured relative to the tariff a supplier expected a customer to be on, rather than a customer's current tariff. This means that, in principle, there could be several rounds of unexpected SVT demand over time, even if many customers have already moved to SVTs.

Unhedged

3.7. When a supplier's forecasts change, it is unable to buy more energy at historical prices to reflect its revised forecast. If wholesale prices have increased, then a supplier might need to buy additional energy at a price higher than used to set the cap. This would be the case if it had not bought energy for its expected FTC customers – for example, if it did not buy energy for FTC customers until this demand is considered 'firm' (eg at the point of contract).

3.8. However, a supplier does not necessarily need to buy additional energy. In some cases, a supplier may have already started to buy energy for its expected FTC customers. Any such hedging would mitigate the impact of increased wholesale prices, as a supplier would be able to net off its under-hedged SVT position with an over-hedged FTC position.

Previous decision

3.9. In our February 2022 decision, we decided to include an allowance for unexpected SVT demand costs of £41 per dual fuel customer.[11] This additional allowance reflected the additional unexpected SVT demand costs incurred by suppliers for cap period seven.

[11] Ofgem (2022), Price Cap - Decision on the potential impact of increased wholesale volatility on the default tariff cap, paragraphs 3.0 to 3.2. https://www.ofgem.gov.uk/publications/price-cap-decision-potential-impact-increased-wholesale-volatility-default-tariff-cap

We set this adjustment based on data suppliers provided in response to the November 2021 wholesale consultation.[12]

Information considered

Rationale for gathering data

3.10. As explained in Chapter 2, wholesale prices have increased significantly since September 2021. Beyond the impact on cap period seven, which we covered in our February 2022 decision, the rise in wholesale prices is also relevant to both cap period eight (where the observation period began on 1 August 2021) and cap period nine (where the observation window began on 1 February 2022).

3.11. Alongside this consultation, we have published a consultation on our changes to the wholesale methodology. Primarily this proposes moving to quarterly updates, under which the wholesale cost allowance is updated more frequently to reduce the risks from changing wholesale prices. However, these proposed changes would not affect cap period eight, and cap period nine would be a transitional period.

3.12. The increase in wholesale prices created the possibility that suppliers have incurred unexpected SVT demand costs in relation to cap periods eight and nine, for the reasons set out in the previous section. Given the scale and pace of wholesale price increases (and the increased associated uncertainty around future prices), it was possible that the costs were material.

3.13. To help us understand the situation further, we therefore decided to issue a Request for Information (RFI) to suppliers. This was to gather evidence on the potential impact on suppliers' wholesale costs, enabling us to monitor these impacts.

[12] Ofgem (2021), Price Cap – Consultation on the potential impact of increased wholesale volatility on the default tariff cap
https://www.ofgem.gov.uk/publications/price-cap-consultation-potential-impact-increased-wholesale-volatility-default-tariff-cap

March 2022 RFI: Specific wholesale cost components

RFI process

3.14. The RFI covered two specific wholesale costs: unexpected SVT demand costs (covered in this chapter) and shaping and imbalance costs (covered in Chapter 4). We asked about costs that suppliers expect to face during cap periods eight (April 2022-September 2022) and nine (October 2022-March 2023).

3.15. Any adjustment would reflect a mixture of incurred and expected costs. The precise balance would differ between cap periods eight and nine, as a greater proportion of cap period nine costs would be forecasts at the point of taking a decision in August 2022. The degree of clarity around the costs is one reason we might reach different conclusions for cap period eight and cap period nine costs about whether an adjustment is required at that point.

3.16. We issued the RFI as a mandatory RFI, to suppliers with over 100,000 domestic customers. This was a total of 11 suppliers. We considered that issuing a mandatory RFI would support the completeness and consistency of our evidence base.

3.17. Given the scale of recent wholesale price movements, we prioritised gathering evidence swiftly. We issued the RFI immediately rather than sharing a draft RFI in advance. We had also set a two-week response period for the RFI. While we consider that our approach was appropriate, we recognise that it may have led to limitations on the details that suppliers were able to provide. This is one reason why we are using this consultation as an opportunity for suppliers to provide further evidence – see the end of this chapter.

Evidence provided

3.18. We discuss the evidence provided in Appendix 1. In summary, the data included in our analysis has good coverage, for both cap periods eight and nine.

3.19. However, there are inherent uncertainties around the estimates. We cover these uncertainties in the section 'Reported unexpected SVT demand costs' below.

Benchmarking suppliers' costs

Context

3.20. The aim of carrying out benchmarking is to assess an efficient level of costs, while taking into account that suppliers' costs may also vary for reasons unrelated to efficiency. The stringency of the benchmark is therefore a key issue. We could set the benchmark at different levels:

- a **frontier benchmark** would use the supplier with the lowest costs;
- we generally use a benchmark at or near the **lower quartile** in the cap.[13] This is the cost of the supplier that is halfway (in number of suppliers) between the suppliers with the lowest and median (ie midpoint) costs; and
- we could select an average benchmark, such as a **weighted average**. This would consider costs across suppliers, and therefore incorporate each of their circumstances into the calculation. If some suppliers have higher costs or lower costs, due to factors outside their control, the weighted average will reflect the average situation across all suppliers.

3.21. These general options are all available for benchmarking unexpected SVT demand costs. However, these mechanistic benchmarks are not the only way of addressing efficiency. In principle, we could exclude cost estimates provided by suppliers where we consider them to be outliers. We could also apply a discount (in percentage or absolute terms) to one of the benchmarks above, reflecting a judgement about the relative impact of efficiency and non-efficiency factors.

3.22. When comparing benchmarking options, we are interested in the potential reasons for differences in costs between suppliers. Common factors could increase suppliers' costs. However, to the extent that these affect suppliers equally, they would not affect the impact of different benchmark choices.

[13] For example, we set the operating cost benchmark at the lower quartile minus £5. We also used a lower quartile to set the payment method uplift.

Initial view

3.23. We have not reached a minded to position on the benchmark to use for unexpected SVT demand costs, as this will depend on the final evidence available to us for the decision.

3.24. At this stage, we recognise that the starting proportion of customers on different tariff types (a non-efficiency factor) will affect these costs, with possible lesser impacts from other non-efficiency issues. However, suppliers already had significant levels of unexpected SVT demand in cap period seven. With this experience and additional time to respond, suppliers should have been able to manage these costs more efficiently for cap periods eight and nine. We are therefore continuing to consider whether a benchmark below the weighted average would help to protect customers.

Considerations

3.25. In this section, we describe the non-efficiency and efficiency factors that could affect unexpected SVT demand costs. We then set out our initial thinking on the balance between these factors.

Non-efficiency factors for unexpected SVT demand costs

3.26. Non-efficiency factors would affect suppliers' costs, but would be outside (or largely outside) suppliers' control.

3.27. The main non-efficiency factor we have identified is a **supplier's starting proportion of FTC customers** (ie before a wholesale price shock). All else being equal, a supplier with a greater proportion of FTC customers would have incurred higher unexpected SVT demand costs (than a supplier with a lower proportion). This is because it would have more customers moving unexpectedly between FTCs and SVTs as a result of rising wholesale prices.

3.28. A supplier would have been unable to change its starting proportion of FTC customers in response to a wholesale price shock, so this factor is outside a supplier's control in the short-term. We recognise that a supplier's starting proportion of FTC customers will reflect business decisions that it has made over a sustained period, so it is not entirely outside its control. However, we consider that having a high proportion of FTC customers is at least a neutral feature of a supplier's business rather than a sign of pre-existing inefficiency.[14]

3.29. The **level of engagement of a supplier's customer base** may also impact its unexpected SVT demand costs, by affecting the expected flow of customers from SVTs to FTCs in normal circumstances. Engaged customers might be more likely to spend a short amount of time on an SVT than less engaged customers (when FTCs are cheaper than SVTs). We might therefore expect suppliers with a more engaged customer base to have expected a larger proportion of their starting stock of SVT customers to move away from SVTs in normal circumstances (compared to suppliers with a less engaged customer base). After a wholesale price shock, the change in expected customer flows could increase the amount of unexpected SVT demand.

3.30. While we are using data suppliers provided in response to an RFI, there may be **methodological differences** in how suppliers have prepared their estimates. This reflects the challenge of determining whether additional SVT demand was unexpected and unhedged. In principle, we would not want to select a more stringent benchmark when this reflected suppliers underestimating costs, rather than genuine cost variations. We do not currently consider that this is an important non-efficiency factor for cap period eight unexpected SVT demand costs, because suppliers' evidence largely relates to costs which they have already incurred. This reduces the need for suppliers to develop a methodology to estimate these costs. Methodological differences may be more significant for cap period nine, where costs depend on forecasts.

3.31. We also recognise that there may be some **natural variation** in suppliers' costs (ie noise). Some natural variation may be particularly likely in the context of an uncertain environment with rapidly changing wholesale prices. For example, small differences in the timing of suppliers purchasing additional volumes could affect the costs incurred if wholesale prices changed.

[14] We do not consider that having a high proportion of FTC customers is by definition a desirable feature of a supplier's business. We recognise that there has been sustained interest from Ofgem in encouraging suppliers to engage their customer bases, including by moving to FTCs. However, an individual supplier's proportion of FTC customers will also reflect the extent to which it has chosen to acquire customers (which until recently would have largely been through FTCs).

Efficiency factors for unexpected SVT demand costs

3.32. Efficiency factors would affect suppliers' costs, and would be within (or largely within) a supplier's control. As with any business activity, when a cost is controllable, efficient suppliers would be expected to incur lower costs.

3.33. We consider that efficiency has a particular interpretation in the context of considering whether to provide an adjustment to the cap. Suppliers may adopt approaches with different degrees of riskiness. Some behaviours may or may not be inefficient in the sense of having higher expected costs in the long run, but may still increase the variability of outturn costs. Suppliers are subject to the cap, and we expect suppliers to manage risks prudently in this context. We do not consider that it would protect default tariff customers to compensate suppliers through an adjustment for incurring high costs as a result of risky strategies. This is because customers would be unlikely to benefit from an offsetting adjustment in circumstances where the strategies led to low costs.

3.34. We expect that an efficient supplier would **update its customer number forecasts frequently**, and would consider forecasting more frequently in volatile market conditions to better manage risks. Frequent forecasting would increase the likelihood that its forecasts are more accurate. In response to the RFI, we did not identify any particular concerns about suppliers' approaches in this area, and there was some evidence of suppliers acting more quickly in current market circumstances.

3.35. We also expect that an efficient supplier would **adjust its traded position reasonably frequently** in response to changes in forecast customer numbers. However, we recognise that a supplier may also want to avoid the risk of 'over-trading' (eg due to transaction costs or the risk of making losses on market fluctuations). Again, we did not identify particular concerns about suppliers' approaches based on the RFI data. Some suppliers said that market liquidity was a factor affecting the speed of their adjustments. We accept that suppliers will consider liquidity when executing trades, though suppliers have to manage the competing aims of achieving the best possible prices and mitigating risks promptly.

3.36. We expect that an efficient supplier would **aim to hedge for its expected SVT customer numbers**. If a supplier was not doing so, this could be a sign of inefficiency, unless there was a clear justification. In response to the RFI, there were cases where suppliers indicated that they had not hedged to their expected SVT customer numbers, at least at particular points in time. We recognise that suppliers were seeking to manage an uncertain situation, including policy uncertainty on the Market Stabilisation Charge, which mitigates the impact of falling wholesale prices. However, at this stage, we do not have sufficient evidence to conclude that suppliers' approaches were efficient.

3.37. In the current market circumstances, we expect an efficient supplier to have at least considered whether to adjust its **hedging strategy for FTC customers**, to more closely align with the cap wholesale indexation methodology, or to change their assumptions on the likelihood of customers moving onto, or staying on, the SVT. This would reduce the impact of SVT drift. We recognise that suppliers' hedging strategies for fixed tariffs will also be affected by competitive dynamics. We also recognise that historically some suppliers may have aimed to buy energy close to the point of sale, so as to ensure a competitive offering. We are therefore particularly interested in understanding whether and how suppliers have considered changing their hedging approach for FTCs.

3.38. The efficiency factors above are not exhaustive. Forecasting demand and purchasing energy as a consequence are core activities for a supplier. Even where suppliers have similar strategies, there may be differences in **delivery efficiency**. For example, suppliers may vary in how accurately they forecast demand. Differences in delivery efficiency may affect suppliers' costs.

Initial thinking on choice of benchmark

3.39. While we have not reached a minded to position on which benchmark to select, we intend to discard the option of a frontier benchmark. This is because non-efficiency factors are likely to affect suppliers' costs, particularly the starting proportion of FTC customers. A frontier benchmark would therefore be likely to underestimate suppliers' efficient costs.

3.40. Our eventual approach could be a lower quartile benchmark, a weighted average benchmark, or an intermediate approach between these. We explain below some of the key considerations which may affect our ultimate decision.

3.41. We intend to consider any further data submitted by suppliers, along with the explanations provided. Should we have concerns about the data provided, we will seek to engage with suppliers as far as feasible in the time available. However, where we cannot resolve concerns, we intend to adapt our benchmarking approach to reduce or remove the impact of data with concerns.

3.42. We intend to consider the justifications suppliers provide for the efficiency of their approaches given the increased time since the initial wholesale price increase. The February 2022 guidance letter sets out our expectation that suppliers would respond to the circumstances. We encourage suppliers to provide clear explanations about how they have responded to this challenge. We also welcome views from other stakeholders on what they would expect an efficient supplier response to be.

3.43. We intend to consider carefully how to avoid any adjustment leading to customers bearing the impact of suppliers adopting risky strategies. We are particularly interested in receiving full explanations from suppliers who did not reflect their revised forecasts of expected SVT customer numbers in their energy purchases, to understand why they consider that this was a prudent strategy. Unless we find such responses persuasive, we intend to take appropriate corrective action through our benchmarking approach.

Reported unexpected SVT demand costs

3.44. We have conducted an initial analysis of the cost of unexpected and unhedged SVT demand using the information provided to us by suppliers through the RFI described above.

3.45. This analysis is based on the information available to date. We offer this as an initial and illustrative estimate only**.** The analysis is subject to change depending on any additional evidence received. This additional evidence could include revisions as more actual data becomes available.

3.46. These initial estimates are subject to a number of risks and uncertainties. These include:

- part of the data being forecasts, and therefore subject to change as a result of wholesale price fluctuations (with any reduction in wholesale prices for cap period eight likely leading to outturn costs being lower than suppliers' forecasts);
- differences in suppliers' methodologies; and

- differences in the level of information suppliers provided to allow us to validate their estimates.[15]

3.47. In this section, we present costs based on a weighted average benchmark, as this represents the upper bound for the costs we could include in any adjustment. This does not indicate that we have a minded to position to adopt a weighted average benchmark.

3.48. We have provided details on how we conducted the calculations in Appendix 1.

Cap period eight

3.49. Based on suppliers' reported data, the weighted average expected cost per dual fuel customer at benchmark consumption[16] for cap period eight is approximately £8 for prepayment meters (PPM) and £42 for non-PPM.[17] Table 2 sets out our summary of the potential unexpected SVT demand cost impact facing suppliers for cap period eight by fuel and payment type.

Table 2: Reported unexpected SVT demand costs in cap period eight (weighted average) – pounds per SVT customer during cap period eight

Fuel	Estimate of additional impact for PPM	Estimate of additional impact for non-PPM
Gas	£5	£23
Electricity	£3	£19
Dual fuel	**£8**	**£42**

Notes: Figures at benchmark consumption levels. Figures are costs over six months, rather than annualised costs. Non-PPM includes both direct debit and standard credit. Figures may not sum exactly due to rounding.

3.50. Based on the available data, unexpected demand costs are larger for non-PPM customers than PPM customers. This aligns with what we would expect. Very few PPM

[15] While we have engaged with suppliers where relevant to ask follow-up questions about their RFI responses, the scope of this has been limited by the time available.
[16] We use the term benchmark consumption to refer to the average annual consumption values we use when setting the cap (3,100kWh for single rate electricity and 12,000kWh for gas).
[17] For cap period eight the lower quartile expected cost per SVT customer at benchmark consumption is estimated to be approximately £0 for PPM and £3 for non-PPM. For further discussion please see Appendix 1.

customers are on FTCs, which significantly reduces the number of customers who could unexpectedly move to SVTs.

Cap period nine

3.51. Based on suppliers' reported data, the weighted average expected cost per dual fuel customer at benchmark consumption for cap period nine is approximately £1 for PPM and £3 for non-PPM.[18] Table 3 sets out our summary of the potential unexpected SVT demand cost impact facing suppliers for cap period nine by fuel and payment type.

Table 3: Reported unexpected SVT demand costs in cap period nine (weighted average) – pounds per SVT customer during cap period nine

Fuel	Estimate of additional impact for PPM	Estimate of additional impact for non-PPM
Gas	£0	£2
Electricity	£1	£1
Dual fuel	**£1**	**£3**

Note: Figures at benchmark consumption levels. Figures are costs over six months, rather than annualised costs. Non-PPM includes both direct debit and standard credit. Figures may not sum exactly due to rounding.

3.52. Reported unexpected SVT demand costs are significantly lower for cap period nine than for cap period eight. There are two reasons for this.

- Costs are likely to be low. Many customers have already moved from FTC to SVT, reducing the potential additional movement of customers from FTCs. While the most recent wholesale price increases may have created unexpected SVT demand, the wholesale price increases occurred at an early stage of the observation window for cap period nine. This means that suppliers would still largely be able to purchase in line with the core direct fuel cost allowance methodology for any unexpected SVT demand. The difference to date between the core direct fuel cost for cap period nine and current forward prices remains fairly low.

[18] For cap period nine the lower quartile expected cost per SVT customer at benchmark consumption is estimated to be approximately £0 for PPM and £0 for non-PPM. For further discussion please see Appendix 1.

- Current estimates will also be low because suppliers do not know how wholesale prices will move in future. By their nature, unexpected SVT demand costs are driven by changes in wholesale prices, which cannot be reliably predicted.

3.53. As for cap period eight, reported unexpected SVT demand costs are lower for PPM than for non-PPM customers. Again, this would be due to the small proportion of FTC customers for PPM.

Existing specific allowances

3.54. Unexpected SVT demand has always been a cost to suppliers. However, these costs have been small historically (before cap period seven) and likely to be captured within existing uncertainty mechanisms in the cap.

3.55. In particular, we took the potential for unexpected SVT demand into account when setting the headroom allowance in the cap. In our 2018 decision, we noted that suppliers "face a demand volume risk when purchasing their energy wholesale in advance of delivery." We referred to this as "a relatively small upward uncertain cost pressure", noting a supplier's estimate of this cost.[19] We also gave regard to this issue when setting the additional risk allowance.[20]

3.56. Given the scale of the cost, we took unexpected SVT demand into account through uncertainty allowances, rather than by creating a specific allowance.

3.57. Given the recent size of wholesale price increases, unexpected SVT demand costs are likely to be higher than historically. Therefore, a significant proportion of the costs reported above will be incremental, as these costs may not be covered by the uncertainty allowances. However, this is before consideration of any offset costs, which is discussed in the next section.

[19] Ofgem (2018), Default tariff cap: decision – Appendix 2 – Cap level analysis and headroom, paragraph 3.72.
https://www.ofgem.gov.uk/publications/default-tariff-cap-decision-overview
[20] Ofgem (2018), Default tariff cap: decision – Appendix 4 – Wholesale costs, paragraph 3.106.
https://www.ofgem.gov.uk/publications/default-tariff-cap-decision-overview

Offsets

Context

3.58. We do not want to consider the impact of increased wholesale prices on suppliers' unexpected SVT demand costs in isolation. To understand whether suppliers' efficient costs have materially and systematically departed from the allowances in the cap,[21] we need to consider whether there have been any other changes as a result of increased wholesale prices, which could offset unexpected SVT demand costs. The overarching principle is to protect default tariff customers, by ensuring that the cap level does not exceed suppliers' efficient costs.

3.59. We are specifically considering costs linked to higher wholesale prices. We are not re-examining the cap in its entirety. We do not consider that we need to reconsider all elements of the methodology when considering changes to one element. In the current circumstances, such an approach would also prevent us from making any kind of timely adjustment.

Proposal

3.60. We propose to offset unexpected SVT demand costs against a proportion of the 1% additional risk allowance.

3.61. We propose to offset unexpected SVT demand costs against an estimate of the cost savings suppliers have experienced from reduced switching as a consequence of higher wholesale prices.

3.62. We propose to consider the Contracts for Difference (CfD) benefit in the round when deciding whether an adjustment is required for cap period eight, but we will not offset this explicitly.

3.63. There are other cap allowances (eg headroom) which scale with increasing wholesale costs. At this stage, we do not consider that there is clear evidence that the costs they

[21] For cap period eight, we have already set the allowances in the cap, and so these are known. For cap period nine, we will determine the allowances based on the prescribed cap methodology (subject to any changes).

cover all scale at the same pace. We could consider offsetting against these allowances if there is evidence that the relevant costs have not scaled at a similar pace.

Considerations

1% additional risk allowance

3.64. In our 2018 decision, we provided the additional wholesale risk allowance to account for additional uncertainty and volatility in suppliers' wholesale costs (beyond what is already provided for in the other wholesale allowances and headroom). In summary, we said that we had given regard to: specific risks identified by suppliers, the potential for unforeseen shocks, and the potential for errors in our modelling.[22]

3.65. This 1% additional risk allowance is currently worth around £3 per dual fuel customer over the six months of cap period eight. Please see Appendix 2 for further information on how we have estimated this benefit. The benefit is higher in annualised terms (around £9 per dual fuel customer), but the actual amount received over the course of a year will depend on how the core direct fuel allowance changes for cap period nine.

3.66. To ensure customers are protected, we would not allow suppliers to benefit from an adjustment, to the extent that this duplicated the 1% additional risk allowance already included in the cap. There is clearly an overlap. Part of the rationale for the 1% additional risk allowance was the potential for unexpected shocks. An adjustment for unexpected SVT demand would respond to unexpected increases in wholesale prices. The question is the extent of this overlap.

3.67. The additional risk allowance is intended to reflect costs over time, rather than costs in a specific cap period.[23] However, in the February 2022 wholesale decision, we decided not to take into account the 1% additional risk allowance from either cap periods one to six or cap period seven.[24] We are therefore considering only the 1% additional risk allowance for the cap periods where we are considering an adjustment.

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[22] Ofgem (2018), Default tariff cap: decision – overview. Appendix 4 – wholesale, paragraph 2.32. https://www.ofgem.gov.uk/publications/default-tariff-cap-decision-overview
[23] Ofgem (2018), Default tariff cap: decision – overview. Appendix 4 – wholesale, paragraph 2.31. https://www.ofgem.gov.uk/publications/default-tariff-cap-decision-overview
[24] Ofgem (2022), Price Cap - Decision on the potential impact of increased wholesale volatility on the

3.68. Given the additional risk allowance is intended to reflect costs over time, the 1% additional risk allowance for a given cap period (eg cap period eight) can be seen as partly for risks in that cap period, but largely for risks in other cap periods.

- In a given cap period, there would be duplication between the 1% additional risk allowance and any adjustment. We recognise that any adjustment would be subject to uncertainty, meaning that outturn costs might not be fully covered by the adjustment. However, we would not try to cover suppliers' costs in all possible circumstances, as this would not protect customers. We also recognise that elements of the 1% additional risk allowance might be needed to cover other sources of risks. However, there are factors which reduce the likely need for this. First, the risk of extreme weather events is lower in a summer cap period like cap period eight, and one of the higher risk summer months is already complete (ie April). Second, by the time of our cap period eight decision, we will have more clarity about whether there have been further unforeseen shocks during cap period eight (which will largely be complete by that point).

- Our initial view is that we should not offset the portion of the 1% additional risk allowance which relates to risks in cap periods after any adjustment. For future cap periods where we do not make an adjustment, there would be no duplication between the 1% additional risk allowance and an adjustment.

3.69. To translate this into a proportion to offset, one possible approximation would be to consider the 1% additional risk allowance in a given cap period as relating to risks over the life of the cap (currently five years). If we consider that we can broadly offset the risks for cap period eight (lasting six months), then this would provide a floor of offsetting 10% of the 1% additional risk allowance recovered during cap period eight.

3.70. We particularly welcome any feedback on the proportion of the 1% additional risk allowance to offset – both the amount to offset and the methodology to justify this.

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default tariff cap, paragraphs 2.24 and 2.29.
https://www.ofgem.gov.uk/publications/price-cap-decision-potential-impact-increased-wholesale-volatility-default-tariff-cap

Switching costs

3.71. Switching rates have fallen significantly, relative to historical levels. This is because the cap has been the cheapest tariff available for many customers, removing their financial incentive to switch suppliers.

3.72. Suppliers may therefore have seen reduced switching costs due to:

- lower commission paid to intermediaries on completion of a switch; and
- internal administrative costs savings – although these will depend on the extent to which staff and resources can be reallocated temporarily.

3.73. Given the change in switching rates is linked to changes in wholesale costs, it seems appropriate to take this into account as a potential offset.

3.74. We have developed an initial estimate for the switching benefit. We estimate that the reduction in switching costs over the six months of cap period eight ranges could be roughly £1.90 to £2.70 per dual fuel customer. In annualised terms these estimates would double (around £3.80 to £5.40), provided that the change in switching is applied over a full year. Please see Appendix 2 for further information on how we have estimated this benefit.

3.75. To help us consider this area further, we particularly welcome:

- evidence from suppliers on the likely size of the benefit; and
- input from stakeholders on whether there are any other operating costs which have increased or decreased as a direct result of changes in wholesale prices, and which could therefore offset or add to any reduction in switching costs.

CfD benefit

3.76. In the February 2022 wholesale decision, we noted that suppliers will receive a benefit in cap period eight from negative CfD costs, which are not currently reflected in the cap methodology.[25] We only expect this benefit to occur in cap period eight, as we are currently consulting on amending the CfD cap methodology to better reflect the costs faced by suppliers.[26]

3.77. In the February 2022 wholesale decision, we said that we did not propose to claw back this benefit to suppliers through a negative adjustment.[27] We do not intend to change this position.

3.78. However, in the February 2022 wholesale decision, we noted the CfD benefit as one of the factors which we took into account when deciding not to make an ex-ante adjustment for cap period eight costs.[28] We propose to take the same approach when deciding whether to make an adjustment for cap period eight following this consultation. We intend to consider the CfD benefit alongside suppliers' reported cost increases and all factors covered in the sections above to understand whether there is a case for adjusting the cap. We consider that this approach will help support the cap reflecting efficient costs, and therefore protect customers in line with the Act's objective.

3.79. When considering the materiality of the CfD benefit, we intend to take into account the latest estimates of these costs, as well as the evidence we have received from suppliers on the extent to which they hedge CfD costs.

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[25] Ofgem (2022), Price Cap - Decision on the potential impact of increased wholesale volatility on the default tariff cap, paragraph 6.9. https://www.ofgem.gov.uk/publications/price-cap-decision-potential-impact-increased-wholesale-volatility-default-tariff-cap

[26] Ofgem (2022), Consultation on amending the methodology for setting the Contracts for Difference (CfD) cap allowance. https://www.ofgem.gov.uk/publications/consultation-amending-methodology-setting-contracts-difference-cfd-cap-allowance

[27] Ofgem (2022), Price Cap - Decision on the potential impact of increased wholesale volatility on the default tariff cap, paragraph 6.11. https://www.ofgem.gov.uk/publications/price-cap-decision-potential-impact-increased-wholesale-volatility-default-tariff-cap

[28] Ofgem (2022), Price Cap - Decision on the potential impact of increased wholesale volatility on the default tariff cap, paragraphs 2.29 and 2.30. https://www.ofgem.gov.uk/publications/price-cap-decision-potential-impact-increased-wholesale-volatility-default-tariff-cap

Other allowances

3.80. There are several allowances which are indexed based on other cap components. Increases in wholesale costs have therefore led to increases in these allowances. These are the payment method uplift (in part), Earnings Before Interest and Tax (EBIT) and headroom allowances.

3.81. There is some uncertainty about whether the costs covered by these allowances have increased at the same rate as the allowances themselves. We welcome further input from stakeholders on this. Should stakeholders identify cases where they consider that an allowance[29] is likely to have increased faster or slower than suppliers' efficient costs, they should identify them in response to this consultation, with as much supporting detail as possible.

3.82. As noted above, we took the potential for unexpected SVT demand into account when setting the headroom allowance, as well as when setting the 1% additional risk allowance. The headroom and 1% additional risk allowances are complementary to one another. Both allowances would be relevant to the case for offsetting an adjustment for SVT demand.[30] We will consider stakeholder feedback before determining an appropriate position in the round.

Whether to adjust for unexpected SVT demand

Context

3.83. In this section, we consider the case for introducing an adjustment for unexpected SVT demand costs in cap period nine. We are therefore not considering whether to carry out an adjustment at any point in time. More evidence may become available at a later stage, particularly for costs related to cap period nine.

[29] Stakeholders' comments should focus on an allowance in its entirety. For example, stakeholders' comments should not identify aspects of an allowance which may have increased faster than efficient costs, without also considering whether there are aspects of an allowance which may have increased more slowly than efficient costs.
[30] We could also decide to offset part of the headroom allowance for reasons unrelated to unexpected SVT demand, which is a separate issue.

Initial views

3.84. For cap period eight, our initial view is that there is a possibility that suppliers are incurring material additional costs. However, there are a number of uncertainties around this. In particular, we need to consider how best to benchmark suppliers' costs. We also need to consider whether to offset any existing allowances or benefits against the potential cost increase.

3.85. For cap period nine, our initial view is that the scale of reported costs is not sufficient to consider an adjustment. We welcome any updated data from suppliers in response to this consultation. However, for us to consider an adjustment to take effect in cap period nine, we would need to have sufficient confidence that suppliers were likely to incur material costs.

Considerations

Considerations for cap period eight

3.86. Suppliers have reported significant unexpected SVT demand costs for non-PPM customers in cap period eight and a smaller amount of costs for PPM customers. There is no specific existing allowance for unexpected SVT demand costs, and the potential cost offsets are small.

3.87. This means that there is a possibility that an adjustment could be appropriate.

- The costs involved could be material, at least for non-PPM customers. Given the differences in reported costs between non-PPM and PPM customers, it is possible that we would reach different conclusions on whether an adjustment is required for these customer segments. When considering whether to make any adjustment for PPM customers, we would take into account that these customers are more likely on average to be in vulnerable situations than credit customers as a whole.[31]

[31] BEIS (2019), Fuel Poverty Factsheet, Slide 3.
https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/966517/Fuel_Poverty_Factsheet_2019_data.pdf

- The costs would also be systematic. Although we expect these costs to be temporary, we would not expect suppliers to receive an offsetting benefit from unexpected SVT demand at any other point in time.

3.88. However, we consider that there are (at least) the following key sources of uncertainty which will affect our eventual decision on whether to carry out an adjustment:

- whether the cost data provided is sufficiently reliable to justify an adjustment;
- how we should benchmark costs to reflect the balance between efficiency and non-efficiency factors;
- which costs we should offset; and
- whether, in the round, an adjustment is in default tariff customers' interests.

3.89. To the extent that suppliers' reported costs include forecasts for future energy purchases, this element would change over time depending on changes in wholesale prices. For example, if the wholesale price for the remainder of cap period eight fell to the wholesale index value used to set the core direct fuel cost allowance for cap period eight, then suppliers would not incur costs for any further unexpected SVT demand. In that situation, the outturn costs would therefore be lower than the reported costs. We intend to monitor wholesale prices as they evolve over cap period eight, and consider how any price changes may affect the need for, or scale of, any adjustment.

Considerations for cap period nine

3.90. Suppliers have not reported significant costs for cap period nine. We, therefore, do not currently consider that an adjustment for cap period nine is likely to be necessary, as the costs do not appear to be material at this stage.

3.91. We recognise that we requested data at an early point in the observation window for cap period nine. Suppliers' reported data is therefore largely based on forecasts, which are subject to significant uncertainty. We, therefore, encourage suppliers to provide us with updated evidence on unexpected SVT demand costs for cap period nine.

3.92. However, there will still be uncertainty about cap period nine unexpected SVT demand costs at the point of our decision, due to the potential for wholesale price changes during cap period nine. While suppliers will be able to report the costs they have incurred, any forecasts will remain uncertain. For us to consider an adjustment to take effect in cap period nine, we would need to have sufficient confidence that suppliers were likely to incur material costs.

3.93. We also welcome any feedback on the points mentioned above for cap period eight, insofar as these would also be relevant to any adjustment for cap period nine costs.

Next steps

3.94. As part of refining our evidence base, we encourage suppliers to provide updated cost estimates as part of their responses to this consultation. We would welcome any such data by the closing date of this consultation.

3.95. To enable us to analyse any such data at pace, suppliers should submit such data in the same template format as the quantitative questions in the RFI.[32] Suppliers should also provide written explanations of how they have updated their analysis.

3.96. We recognise that the RFI response period was short. We consider that the further opportunity to submit data will give suppliers time to prepare more evidence and refine their estimates accordingly.

3.97. We are conscious that only some suppliers may submit further data. One reason could be asymmetric information - suppliers may be more likely to resubmit evidence if their forecasts of costs have increased. This creates some risk of an upward bias.

3.98. We currently intend to mitigate this risk by reserving the right to place more weight on the responses which we consider are most reliable. We also intend to consider the rationale given for any cost increases between submissions.

3.99. While a further RFI would mitigate the risk of upward bias, we are conscious of the need to keep requests proportionate. We, therefore, do not intend to progress an RFI at this point. Should stakeholders disagree with this position, they should contact us as soon as possible after the publication of this consultation with their reasoning. This

[32] If there are any suppliers who did not receive the RFI but would like to submit data, please contact us to obtain a copy of the template.

would give us a chance to reconsider the position, while still being able to deliver any adjustment in time for cap period nine.

4. Shaping and imbalance

Section summary

We explain the issue of shaping and imbalance costs and how we gathered data to consider this. We discuss options for benchmarking suppliers' costs. We set out suppliers' reported costs. We set out our initial views on whether an adjustment may be needed.

Context

Defining shaping and imbalance costs

4.1. Suppliers purchase energy in forward markets using less granular products. The products which are largely traded involve a flat volume over a long period (a season or quarter). For electricity, the products available are generally either a flat volume across each day (baseload) or a flat volume across the daytime on weekdays (peak).

4.2. However, customers' demand varies over time – at monthly, weekly, daily and (for electricity only) half-hourly granularity. Suppliers need to buy energy to reflect the pattern of their customers' demand, or otherwise face imbalance charges.

4.3. Suppliers must therefore refine their hedged positions from less to more granular contracts. They incur shaping and imbalance costs in doing so.

Impact of wholesale price changes on shaping and imbalance costs

4.4. Suppliers generally carry out shaping much nearer to delivery than their hedging. This is when more granular products are available,[33] and when there is more clarity about their customers' likely demand. Given that shaping and imbalance occur near to delivery, the costs of these activities will depend on wholesale prices at this time.

[33] By 'available', we mean that these products are traded to a degree in the market – ie that there is some liquidity. Liquidity is a measure of the ability to buy or sell a product without causing a major change in its price and without incurring significant transaction costs.

4.5. Therefore, if wholesale prices increase, shaping and imbalance costs are also likely to increase.

Existing allowances

4.6. As set out in Chapter 2, the cap includes existing allowances for shaping and imbalance. We define these in relation to the core direct fuel costs, which depend on wholesale prices during the observation window. Any increase in wholesale prices during or after the observation window could therefore mean that the prevailing wholesale price level at the point of shaping is higher than the wholesale price used to define the shaping allowance.

Previous decision

4.7. In our February 2022 wholesale decision, we concluded that increased wholesale prices had caused electricity shaping and imbalance costs to be materially higher than the cap methodology had accounted for in cap period seven. We, therefore, decided to set an additional allowance of £12 for electricity shaping and imbalance costs, to be recovered across cap periods eight and nine.[34] We did not set an additional allowance for gas. Our decision was based on supplier-provided data in response to the November 2021 wholesale consultation.

Information considered

Rationale for gathering data

4.8. We decided to gather data because of recent increases in wholesale prices. The rationale is therefore equivalent to that set out for unexpected SVT demand in Chapter 3.

[34] Ofgem (2022), Price Cap - Decision on the potential impact of increased wholesale volatility on the default tariff cap. https://www.ofgem.gov.uk/publications/price-cap-decision-potential-impact-increased-wholesale-volatility-default-tariff-cap

March 2022 RFI: Specific wholesale cost components

RFI process

4.9. This is the same as set out in Chapter 3.

Evidence provided

4.10. We discuss the evidence provided in Appendix 3. In summary, the data included in our analysis has modest coverage, for both cap periods eight and nine.

4.11. We consider that estimating shaping and imbalance costs is more challenging than estimating unexpected SVT demand costs. These costs are incurred close to delivery, so most of the costs had not been incurred at the time of the RFI. Suppliers, therefore, had to forecast these forward-looking costs to a greater extent rather than reporting known costs.

4.12. This means that suppliers had to use methodologies to estimate their costs. These methodologies may vary between suppliers (in terms of scope and approach) and have different pros and cons. Therefore, the variation in reported costs between suppliers may reflect methodology differences, rather than necessarily genuine differences in costs. We explain some of the observed differences at a high level in Appendix 3.

4.13. This is not intended as a criticism of suppliers. It is inevitably challenging to forecast costs in a complex area. We also recognise that suppliers had to provide these estimates in a short period of time.

4.14. We cover further uncertainties around the estimates in the section 'Reported unexpected SVT demand costs' below.

Benchmarking suppliers' costs

Context

4.15. The same general benchmarking considerations apply as set out in Chapter 3.

4.16. In line with the approach in Chapter 3, we are interested in the potential reasons for differences in costs between suppliers. We recognise that there will be common cost drivers which are outside all suppliers' control (eg wholesale prices or weather). There may also be specific common challenges in current market circumstances - suppliers have told us that product liquidity and uncertainty of customer demand are particular challenges at present which affect shaping costs. However, to the extent that these affect suppliers equally, they would not affect the impact of different benchmark choices.

Initial view

4.17. We have not reached a minded to position on the benchmark to use for shaping and imbalance costs, as this will depend on the final evidence available to us for the decision.

4.18. At this stage, we do not consider that the current data quality is sufficient to support the use of a lower quartile. This is because variation in the costs reported is likely to be driven by differences in the methodological approaches used to estimate the costs.

Considerations

Non-efficiency factors for shaping and imbalance costs

4.19. The main non-efficiency factor is **methodological differences** in how suppliers have prepared their estimates. As set out above, we consider that these differences are potentially significant for shaping and imbalance costs, given the need to forecast costs.

4.20. We also recognise that there may be some **natural variation** in suppliers' costs (ie noise). For example, in a context of volatile spot prices, demand forecasting errors might be particularly expensive on certain days.

4.21. At this stage, we have not identified reasons why a supplier's **customer base** would be a significant driver of its shaping and imbalance costs.

Efficiency factors for shaping and imbalance costs

4.22. Suppliers could reduce their shaping and imbalance costs by more **accurately forecasting customer demand**. An efficient supplier would make use of the information available to forecast and would consider the frequency of its forecasts. We consider this to be within a supplier's control. However, we received limited information on this area in response to the RFI.

4.23. Suppliers could also achieve efficiency through their **trading approaches**. An efficient supplier may make use of a number of markets (ie trading at different timeframes) to try to manage risks. Carrying out all shaping at a late stage (eg day-ahead) could be inefficient, especially in volatile market conditions. An efficient supplier may also trade more frequently – eg in response to revised forecasts. Information from the RFI does not suggest evidence of manifestly inefficient approaches, and some suppliers show evidence of having adapted their approaches in response to recent market circumstances.

4.24. As a complex and ongoing activity, there will be a variety of other features of a supplier's business which affects its shaping and imbalance costs. These will affect its **delivery efficiency**.

Initial thinking on choice of benchmark

4.25. Managing shaping and imbalance risks is a core business activity for suppliers. We expect that there is the potential for some suppliers to deliver this activity more efficiently than others. In normal circumstances, we would therefore be likely to use a lower quartile, in line with our general approach in the cap.

4.26. However, given the methodological variations in the current data, we could not be confident that variations in costs were at least as likely to be driven by efficiency factors as non-efficiency factors. While this could affect our benchmarking approach, it could also affect whether we have sufficient confidence in the data to make an adjustment for implementation in cap period nine.

Reported shaping and imbalance costs

4.27. We have conducted an initial analysis of the cost of shaping and imbalance using the information provided to us by suppliers through the RFI described above.

4.28. This analysis is based on the information available to date. <u>We offer this as an initial and illustrative estimate only</u>**.** The analysis is subject to change depending on any additional evidence received. This additional evidence could include revisions as more actual data becomes available.

4.29. These initial estimates are subject to a number of risks and uncertainties. These include:

- the data largely being a forecast, and therefore subject to change as a result of wholesale price fluctuations;
- near-term demand uncertainty, especially due to weather;
- differences in suppliers' methodologies; and
- differences in the information provided to allow us to validate the estimates provided.

4.30. In this section, we present costs based on a weighted average benchmark, as this represents the upper bound for the costs we could include in any adjustment. This does not indicate that we have a minded to position to adopt a weighted average benchmark.

4.31. We also note that the data used in the initial analysis represents less than half of the SVT customer base. We set out reasons for this low coverage in Appendix 3.

4.32. We have provided details on how we conducted the calculations in Appendix 3.

Cap period eight

4.33. Based on suppliers' reported data, the weighted average expected cost per dual fuel customer at the benchmark level of consumption for cap period eight is approximately £22 for PPM and £17 for non-PPM.[35] Table 4 sets out our summary of the potential shaping and imbalance cost impact facing suppliers for cap period eight by fuel for non-PPM customers.

4.34. Table 5 shows the equivalent information for PPM customers. The differences in the benchmarked PPM and non-PPM figures are due to differences in weighting across suppliers and not due to differences in the cost per customer figure for individual suppliers. We have explained this in Appendix 3. We welcome any feedback on the extent to which it would be appropriate to set different allowances for PPM and non-

[35] For cap period eight the lower quartile expected cost per SVT customer at benchmark consumption is estimated to be approximately £6 per dual fuel SVT customer for both PPM and non-PPM. For further discussion please see Appendix 3.

PPM due to the impact of the different weighting when calculating the weighted average.

Table 4: Reported shaping and imbalance costs in cap period eight (weighted average), shown against existing allowances – Non-PPM – pounds per customer during cap period eight

	Estimate of cost	Price cap allowance	Difference between estimated costs and price cap allowances
Gas	£6	£5	£0
Electricity	£11	£10	£0
Dual fuel	**£17**	**£16**	**£1**

Notes: Figures at benchmark consumption levels. Figures are costs over six months, rather than annualised costs.[36] Non-PPM includes both direct debit and standard credit. Figures may not sum exactly due to rounding.

Table 5: Reported shaping and imbalance costs in cap period eight (weighted average), shown against existing allowances – PPM – pounds per customer during cap period eight

	Estimate of cost	Price cap allowance	Difference between estimated costs and price cap allowances
Gas	£6	£6	£0
Electricity	£16	£10	£6
Dual fuel	**£22**	**£17**	**£6**

Notes: Figures at benchmark consumption levels. Figures are costs over six months, rather than annualised costs. Figures may not sum exactly due to rounding

[36] In annualised terms the price cap allowance, for both payment types, would be £22 for gas and £24 for electricity.

4.35. There is a small difference between the expected cost per customer and the allowance in the cap for cap period eight.[37] The expected cost is approximately £6 higher for PPM and £1 higher for non-PPM.

Cap period nine

4.36. Based on suppliers' reported data, the weighted average expected cost per dual fuel customer at the benchmark level of consumption for cap period nine is approximately £73 for PPM and £66 for non-PPM.[38] Table 6 sets out our summary of the potential shaping and imbalance cost impact facing suppliers for cap period nine by fuel for non-PPM customers. Table 7 shows the equivalent information for PPM customers.

4.37. We should treat these estimates with caution due to the limitations highlighted earlier in this chapter.

4.38. We have not provided an estimated cap allowance for cap period nine. This is because the observation window is still open, meaning that the final value of the core direct fuel cost allowance is not known.

4.39. We note that allowances would change for future cap periods, given our proposal to move to quarterly cap updates. This means that the seasonal to quarterly shaping allowance within the additional wholesale cost allowance for electricity would no longer be required. However, this would not have a significant impact on the results above.

[37] We included seasonal to monthly shaping, monthly peak/baseload to hourly shaping, rehedging day ahead and imbalance items within the additional wholesale allowances to calculate the allowance set for electricity shaping and imbalance costs for cap period eight. We included quarterly to monthly shaping, rehedging day ahead and imbalance items within the additional wholesale allowances to calculate the allowance set for gas shaping and imbalance costs for cap period eight.

[38] For cap period nine the lower quartile expected cost per SVT customer at benchmark consumption is estimated to be approximately £11 per dual fuel SVT customer for both PPM and non-PPM. For further discussion please see Appendix 3.

Table 6: Reported shaping and imbalance costs in cap period nine (weighted average) – Non-PPM - pounds per customer during cap period nine

	Estimate of cost
Gas	£41
Electricity	£25
Dual fuel	**£66**

Notes: Figures at benchmark consumption levels. Figures are costs over six months, rather than annualised costs. Non-PPM includes both direct debit and standard credit.

Table 7: Reported shaping and imbalance costs in cap period eight (weighted average) – PPM - pounds per customer during cap period nine

	Estimate of cost
Gas	£43
Electricity	£30
Dual fuel	**£73**

Notes: Figures at benchmark consumption levels. Figures are costs over six months, rather than annualised costs.

Existing specific allowances

4.40. We would consider whether suppliers have incurred additional costs above those covered by the shaping and imbalance allowance in the cap. We would therefore deduct the shaping and imbalance allowance from the reported shaping and imbalance costs. This is to avoid duplication.

Offsets

4.41. In Chapter 3, we discussed other potential cost items covered in the cap that we could potentially use to offset additional wholesale costs. As we propose to use certain allowances to offset unexpected SVT demand costs, we do not consider it appropriate to also offset additional shaping and imbalance costs against these allowances. This is to avoid double counting.

4.42. In any event, we have not considered potential offsets in depth at this stage for shaping and imbalance, given that the shaping allowances broadly cover the reported costs for cap period eight.

Whether to adjust for shaping and imbalance costs

Context

4.43. In this section, we consider the case for introducing an adjustment for shaping and imbalance costs to take effect in cap period nine. We are therefore not considering whether to carry out an adjustment at any other point in time. More evidence may become available at a later stage, particularly for costs relating to cap period nine.

Initial view

4.44. For cap period eight, our initial view is to not adjust for shaping and imbalance costs. This is because we consider that the additional costs reported by suppliers are not material and systematic.

4.45. For cap period nine, our initial view is that there is too much uncertainty around market conditions and suppliers' estimates to justify an adjustment.

Considerations

Considerations for cap period eight

4.46. While suppliers reported costs above the cap allowance, we do not consider that this difference is currently material. Given this small difference, we also do not consider that the impact is systematic, as variation in costs could balance out over time.

4.47. In addition, the cap methodology already includes a headroom allowance as an additional way to manage risk and uncertainty. The headroom allowance is therefore one of the features in the cap design to manage unexpected changes in costs.[39] This reduces the case for changes to the cap methodology

4.48. Furthermore, we do not have sufficient confidence in the data available at this stage, given the potential for methodology differences between suppliers and given that the included suppliers only cover a minority of SVT customers.

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[39] Ofgem (2018), Default tariff cap: Ddecision – overview document, paragraph 3.11.
https://www.ofgem.gov.uk/publications/default-tariff-cap-decision-overview

Considerations for cap period nine

4.49. Our current view is that the estimates for cap nine are subject to a significant degree of uncertainty. There are also significant questions about the methodological consistency between suppliers. We, therefore, do not consider that the estimates for cap period nine are sufficiently reliable to set an adjustment.

4.50. Based on the initial views, discussed above, we also note that the indexed shaping and imbalance allowance for cap period eight broadly covers costs, even under rising wholesale prices. This may provide a default position that the same would also be true for cap period nine.

4.51. Our initial view is therefore that we do not consider that an adjustment is required at this stage.

Reviewing the additional direct fuel allowances for shaping and imbalance costs

4.52. In our February 2022 wholesale decision, we set out our intention to consult on amending the additional direct fuel allowance for shaping and imbalance costs.[40] Currently, we are carrying out a statutory consultation on changes to the cap wholesale methodology, including proposals for quarterly cap updates. Given these proposed reforms, please let us know if you consider a review of the additional direct fuel allowances for shaping and imbalance costs is required as a consequence.

Next steps

4.53. In line with the approach set out in Chapter 3, we welcome any further evidence from suppliers on shaping and imbalance costs. The same considerations apply as set out in Chapter 3.

[40] Ofgem (2022), Price Cap - Decision on the potential impact of increased wholesale volatility on the default tariff cap, paragraph 7.2. https://www.ofgem.gov.uk/publications/price-cap-decision-potential-impact-increased-wholesale-volatility-default-tariff-cap

5. Implementation

Section summary

We explain which cap model we would adjust, in the event that we were making an adjustment. We explain whether we would make any adjustment as a fixed amount, or true this up later. We explain the length of time over which we would recover any amount.

5.1. In this chapter, we set out our current thinking on how we would implement an adjustment, if we concluded that one was required.

5.2. The inclusion of this chapter does not imply that we are intending to apply an adjustment. The purpose of including this chapter is to allow stakeholders to comment on the issues raised, so we are prepared to implement an adjustment if necessary.

5.3. We cover the following issues:

- **the format of any adjustment** – ie which cap model we would adjust;
- **the nature of any adjustment** – ie whether this would be a fixed amount, or whether we would true it up later by making a further adjustment once more data became available; and
- the duration over which to apply any adjustment.

Format of adjustment

Context

5.4. We would need to include any adjustment in one of the cap models (ie the annexes to Standard Licence Condition 28AD of the electricity and gas supply licences (SLC 28AD)). We could include the adjustment in:

- the additional risk allowance, which sits within the wholesale cost allowance model (Annex 2 to SLC 28AD – the 'Annex 2 model'); or

- the adjustment allowance (Annex 8 to SLC 28AD – the 'Annex 8 model').

5.5. In the February 2022 wholesale decision, we included the adjustment for cap period seven in the additional risk allowance. This was on the basis that we included this allowance within the cap methodology to account for uncertainty and volatility in wholesale costs.[41]

5.6. The section is about which model to use to reflect any adjustments for costs related to cap periods eight and nine. We are not intending to change the location of the existing adjustment to reflect cap period seven costs – this will remain in the additional risk allowance.

Proposal

5.7. We propose that any adjustment would be included in the adjustment allowance (Annex 8) model. We consider that this is the simplest approach, because it allows us to define the adjustment in absolute terms, rather than converting it into a percentage.

5.8. If required, we propose to set separate adjustments by fuel, payment type (PPM/non-PPM), and electricity region. The separate adjustments by region would be to account for regional variation in electricity losses only. We do not propose to set separate adjustments by electricity meter type (single-rate/multi-register), as we do not consider the additional complexity would be proportionate. As wholesale costs vary with consumption, we propose to set an adjustment at benchmark consumption only, meaning that the adjustment would apply to the implied unit rate within the cap.

5.9. We also propose to edit the wholesale cost allowance model (the Annex 2 model), so that – as intended – the increased additional risk allowance from the February 2022 decision does not apply beyond cap period nine.

[41] Ofgem (2022), Price Cap - Decision on the potential impact of increased wholesale volatility on the default tariff cap, paragraph 2.12.
https://www.ofgem.gov.uk/publications/price-cap-decision-potential-impact-increased-wholesale-volatility-default-tariff-cap

Considerations

High-level comparison of options

5.10. Conceptually, the costs under consideration would fit within the additional risk allowance. Both unexpected SVT demand and shaping and imbalance costs are wholesale-related costs. The additional risk allowance is intended to reflect wholesale costs which are not covered by the other allowances within the cap.

5.11. However, using the additional risk allowance poses practical challenges. We would want the adjustment to reflect an absolute cost, but the additional risk allowance is set as a percentage of the core direct fuel cost. We would need to go through extra calculation steps to convert the additional costs to a percentage. We could only finalise these calculations once the core direct fuel cost is known – ie when the observation window is complete. This is just before announcing the cap level.

5.12. In contrast, the adjustment allowance is set in absolute terms, rather than as a percentage of other cap components. This reduces the need for additional calculation steps.

5.13. We, therefore, propose to use the adjustment allowance, as this is the most practical option.

Number of adjustments

5.14. We propose to set separate adjustments by fuel, payment type (PPM/non-PPM), and electricity region. We have cost data split by the first two categories and would like to make adjustments which vary in the same way. The third category reflects that electricity losses vary regionally.[42]

5.15. We do not propose to set separate adjustments by electricity meter type (single-rate/multi-register). Costs per customer might vary between these meter types – either due to different consumption levels or due to different unit costs of purchasing energy. However, we do not have data on the cost differences between these meter types. Any variation in costs should also largely average out over an individual

[42] We would apply electricity losses to the adjustment, because these increase the amount of wholesale energy that suppliers need to purchase.

supplier's portfolio. We, therefore, do not consider the additional complexity of calculating separate adjustments would be proportionate.

5.16. We propose to define the adjustment at benchmark consumption only (and not at nil consumption), meaning that the adjustment would apply to the implied unit rate within the cap. This reflects that wholesale costs depend on how much energy a customer uses.

Model implications

5.17. As we do not have a proposal to apply an adjustment, we have not published draft models alongside this consultation. However, Appendix 4 provides a description of the modelling changes that we propose to make to Annex 8, in the event that we conclude that an adjustment is necessary.

5.18. Given our proposal to use the adjustment allowance, we would not be including further costs within the additional risk allowance. (The only exception is that, if we made any changes to the cap period seven backwardation allowance, we would include this when recalculating the percentage adjustment in the Annex 2 model from our February 2022 wholesale decision). However, the existing percentage values within the Annex 2 model are set as single percentage values for all cap periods and would therefore apply indefinitely. This does not reflect the policy intent of our February 2022 wholesale decision.[43] We would only want the increased wholesale additional risk allowance from the February 2022 wholesale decision to apply to the end of cap period nine, as the cap period seven wholesale costs would be recovered by this point.

5.19. We, therefore, propose to create a profile of percentage allowances in the Annex 2 model, reverting to the original 1% additional risk allowance from cap period ten onwards. We propose to make this change regardless of whether we conclude a further adjustment is required, as this change reflects the policy intent of our February 2022 wholesale decision.

[43] Ofgem (2022), Price Cap - Decision on the potential impact of increased wholesale volatility on the default tariff cap, paragraph 1.0. https://www.ofgem.gov.uk/publications/price-cap-decision-potential-impact-increased-wholesale-volatility-default-tariff-cap

Nature of adjustment

Context

5.20. Any adjustment for additional wholesale costs would be subject to a degree of uncertainty because it would partly be based on expected costs.

- For cap period eight, many costs would be actuals. However, cap period eight would still be in progress at the point we took a decision, so costs for the remainder of cap period eight would be expectations. Some costs could also be expectations due to the lag between the provision of data and the decision.

- For cap period nine, we would have some actual data on unexpected SVT demand costs. This is because the observation window would be largely complete. However, suppliers could incur further costs in the remainder of the observation window, or during cap period nine. Shaping and imbalance costs would largely be based on expectations, as suppliers mostly incur these costs close to delivery.

5.21. We therefore need to consider whether any adjustment should be an initial value subject to further refinement in a later cap period (a 'float and true-up') or whether any adjustment should be a fixed value.

5.22. We do not generally include true-ups within the cap. In our 2018 decision, we decided to "not include a mechanism in the cap for correcting previous forecast errors."[44] However, we did decide to adopt a float and true-up approach for debt-related costs linked to COVID-19. When explaining our decision, we said: "It is very uncertain what the total debt-related costs of COVID-19 will ultimately be."[45]

[44] Ofgem (2018), Default tariff cap: decision - overview, paragraph 3.17. https://www.ofgem.gov.uk/publications/default-tariff-cap-decision-overview
[45] Ofgem (2021), Decision on the potential impact of COVID-19 on the default tariff cap, p6. https://www.ofgem.gov.uk/publications/decision-potential-impact-covid-19-default-tariff-cap

Proposal

5.23. We propose that any adjustment would be a fixed amount. We consider that this is more proportionate than a float and true-up.

Considerations

Accuracy

5.24. A float and true-up could support accuracy, as further information will become available on suppliers' costs over time. As noted above, any adjustment would be partly based on forecast data. Forecasting costs is inevitably challenging when these depend on volatile wholesale prices. Actual data would therefore be more accurate.

5.25. This accuracy could benefit customers or suppliers. It would reduce the risk that customers pay more than the actual costs. It would also reduce the risk that suppliers under-recover their actual costs.

5.26. The improvement in accuracy from using a float and true-up would be greater for cap period nine than for cap period eight. For cap period nine, we would be using a greater proportion of forecast data and there would be a longer period for wholesale prices to change after setting the allowance.

Timeliness

5.27. For a float and true-up, we would need to gather further data to set the true-up. We would be able to gather such data (on actual costs) after the end of a cap period.

5.28. However, it would be challenging to apply the true-up in time for the next cap announcement – ie in a timeframe which is shorter than six months. We would need time to gather and analyse the data. We would then need to consult, consider responses and determine the revised cap level.

5.29. It is therefore more likely that any true-up would start to apply a year after the end of the cap period to which the costs related. For example, any true-up for cap period eight costs would likely only take effect from cap period eleven (currently October to December 2023).

5.30. We consider that this lag would reduce the benefits of a true-up. In particular, it would increase the scope for changes in the numbers of default tariff customers, which could reduce the degree to which any amount recovered through the adjustment reflects the costs incurred by individual suppliers.

Resource impacts

5.31. Carrying out a true-up would have resource impacts on suppliers (to provide data and respond to the consultation), and other stakeholders (to respond to the consultation).

5.32. We are conscious that stakeholders need to engage with a range of policy developments. For suppliers, this runs alongside responding to a range of information requests. We, therefore, need to bear in mind this wider context when determining how to prioritise any true-up. Our aim is to achieve the best possible outcome for customers across our work programme, so we want to manage the demands on stakeholders to achieve this.

Conclusion

5.33. While we recognise that a true-up could offer benefits in terms of accuracy, we consider that these benefits are unlikely to justify the additional resource impacts. This is particularly evident given our initial view that an adjustment is unlikely to be justified for cap period nine, where costs are more uncertain. We, therefore, do not consider that a true-up would be proportionate.

5.34. While we previously adopted a float and true-up approach for the debt-related costs linked to COVID-19, those costs were particularly uncertain, because it takes time to determine whether debts will be repaid or not. We consider that the situation for debt-related costs linked to COVID-19 was therefore different to this case.

Duration over which to apply adjustment

Context

5.35. If we identified an amount of costs from a given cap period to recover through an adjustment, one question would be how long this adjustment should last. This duration affects the speed at which customers would pay for these costs, and therefore how fast suppliers would recover them. It does not affect the total amount of costs to recover.[46]

5.36. We could apply any adjustment:

- for one cap period (currently six months);
- for one year; and
- for a period longer than one year.[47]

5.37. In the February 2022 wholesale decision, we decided to apply the adjustment over 12 months (ie two cap periods). We said that a 12-month recovery period was more appropriate than a six-month period to limit the impact on customer bills.[48]

Proposal

5.38. We propose to apply any adjustment over a 12-month period. We consider that this protects customers better than a shorter recovery period, while ensuring that suppliers can recover costs in an appropriate timeframe.

Considerations

5.39. As a general point, a shorter recovery period has a negative immediate impact on customers' bills, but a positive immediate impact on suppliers' finances.

5.40. In this consultation, we are considering the possibility of an adjustment starting in cap period nine. The negative impact on customers' bills from a shorter recovery period

[46] The total amount of costs would change in nominal terms if we adjusted for inflation. However, we do not currently intend to do this, given that any adjustment would apply at the same time as, or shortly after, the costs were incurred.
[47] In principle, any move to quarterly cap updates could create more options. However, in practice these options would either be undesirable (eg recovering costs within three months would increase customers' bills significantly) or only marginally different from those above.
[48] Ofgem (2022), Price Cap - Decision on the potential impact of increased wholesale volatility on the default tariff cap, paragraph 2.14.
https://www.ofgem.gov.uk/publications/price-cap-decision-potential-impact-increased-wholesale-volatility-default-tariff-cap

would therefore coincide with customers paying the remainder of the adjustment for additional wholesale costs incurred in cap period seven.

5.41. Customers’ ability to manage the impact of higher energy prices is likely to be reduced by wider cost of living pressures beyond energy. We are also conscious that bill increases will have particular impacts on customers in vulnerable situations.

5.42. Recovery over a shorter period benefits suppliers, by allowing them to receive money more quickly. This would help to improve their financial situations – with particular impacts on any suppliers experiencing financing constraints. However, many suppliers have significant access to working capital (eg through parent companies), and such suppliers supply a significant proportion of default tariff customers. In general, we consider that suppliers will have the tools to manage temporary cashflow issues in the normal course of business. The benefits from a shorter adjustment might therefore only have direct impacts on a minority of suppliers, but would affect all default tariff customers. Under the Act, we must protect default tariff customers, whereas we must “have regard to” financeability. This means that we would need compelling evidence to conclude that a benefit to the financeability of a minority of suppliers was sufficient to outweigh the negative impacts of a shorter recovery period on customers.

5.43. We recognise that market exit of some suppliers can have indirect effects across the market, eg through mutualisation payments. Some of these costs would be reflected in the cap, and would therefore not have a permanent impact on other suppliers. Where costs are passed onto customers, it is in their interest for us to reduce these costs where possible. However, when taking a decision to protect customers, we have to weigh up the certain impact of higher immediate bills (due to a shorter recovery period) against the possibility of higher bills at some future point (to the extent that the recovery period affected the risk of supplier exits and consequent mutualisation payments). We would need clear evidence that a shorter recovery period was likely to deliver significant benefits to customers.

5.44. If the cost to recover was particularly large, then applying the adjustment over a longer time period could help to mitigate the impact on customers’ bills. However, a longer recovery lag (in the context of a large cost) would increase the cashflow impact on suppliers and could theoretically increase the number of suppliers facing financing constraints.

5.45. Given our proposal above to apply the adjustment through the Annex 8 model, there would be a small consequential increase in the size of the EBIT and headroom allowances.[49] This increase could either be used to offset some of the cost of the allowance, or to provide an additional allowance to mitigate any further costs related to the slight delay in recovery. We welcome further input from stakeholders on this.

5.46. Based on the factors above, we consider that recovery over 12 months protects customers better than a recovery period shorter than this, while ensuring that suppliers can recover costs in an appropriate timeframe.

[49] The cap methodology calculates the EBIT and headroom allowances as a percentage of other allowances, including the adjustment allowance.

Appendices

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Appendix 1 – Detail on unexpected SVT demand analysis

Supplier evidence submitted

1.1. Ten out of eleven suppliers responded to the unexpected SVT demand cost question. The remaining supplier provided a nil return due to its wholesale purchasing arrangements. We have included this case as a zero value in our calculations.

1.2. Of the ten suppliers, we excluded one supplier from our cap period eight analysis and two for our cap period nine analysis. We excluded suppliers due to:

- **incomplete data**: a supplier considered that it was unable to provide cost forecasts at this stage for cap period nine given uncertainties; and

- **inrepresentative data**: a supplier forecasted costs which were unrepresentative given its unique circumstances.

1.3. The included data represents a significant majority of the SVT customer base for both cap periods – albeit with more data for cap period eight than cap period nine.

1.4. Suppliers provided evidence regarding the split of unexpected SVT demand costs between fuels (gas and electricity) and payment types (PPM and non-PPM). A small number of suppliers did not provide cost estimates by payment type but did provide justifications. Where necessary, we have made assumptions based on suppliers' responses to allocate total costs between payment types.[50]

1.5. We have sought to avoid suppliers including any costs which they will reasonably recover through the supplier of last resort (SoLR) levy claims process. We currently consider that this is met.

Variation in suppliers' methodologies

1.6. In the March 2022 RFI, we asked suppliers to provide the methodologies used to calculate their reported estimates. Suppliers provided varying levels of detail to allow us

[50] Similarly, one supplier did not provide average annual consumption values by payment type. In this case, we have assumed that the average consumption is the same across payment types.

to understand their estimates. Based on the information received, we understand that suppliers have taken different calculation approaches. However, we have not identified fundamental differences between approaches (for the suppliers who provided detailed explanations).

1.7. In our calculations, we have not made any adjustment to the reported figures considering these methodological differences.

Weighted average methodology

Calculation of cost per customer at benchmark level of consumption

1.8. As part of the RFI template, we included automated calculations to convert suppliers' estimates from their own annual average consumption level to benchmark consumption.[51] This is one of the refinements that we were able to make through issuing a standardised RFI.

1.9. We calculated the number of expected SVT customers by fuel (gas and electricity) and payment type (PPM and non-PPM), as described in the section below.

1.10. For each of the suppliers that provided cost estimates (split by fuel and payment type), we have divided each cost estimate by the respective numbers of expected SVT customers. We did this to estimate the cost per SVT customer.

Calculation of customer numbers

1.11. Our main data source was the expected numbers of default electricity and gas accounts in the relevant timeframe from the Financial Responsibility Principle RFI (version dated 11 April 2022).

1.12. However, the data in this RFI does not include a payment type split. We therefore used the data provided by each supplier in the Customer Account and Tariff October 2021 RFI to calculate the weights of PPM and non-PPM SVT customers. We then applied these

[51] Benchmark consumption is based on the consumption values of 3,100 kWh for electricity and 12,000 kWh for gas.

weights to the expected SVT customer numbers from the Financial Responsibility Principle RFI.

1.13. We note that the weights are based on October 2021 data, so may not reflect the latest situation. However, we would not expect these proportions to change significantly over this period.

1.14. We also assumed that the proportion of customers using credit or PPM remain static over time. However, the customer numbers themselves are not static over time, as suppliers provided a profile of expected customer numbers.

Calculation of weighted average costs

1.15. Using the cost per SVT customer figures, we applied weights based on suppliers' numbers of SVT customers (for the relevant fuel and payment type) to calculate the weighted average costs. Please refer to Chapter 3 for the initial estimates.

Lower quartile methodology

1.16. The lower quartile methodology was the same as for the weighted average, except as described below.

Calculation of lower quartile costs

1.17. Before calculating the lower quartile of each supplier's cost per SVT customer figures, we excluded suppliers who are PPM-focussed from the non-PPM lower quartile calculation. This was to reduce the risk of suppliers with few or no non-PPM customers affecting the calculation.

1.18. We then took the lower quartile.

1.19. We have calculated the lower quartile dual fuel costs for both PPM and non-PPM. For PPM customers, the lower quartile was £0 per dual fuel customer in both cap periods eight and nine. For non-PPM customers, the lower quartile was £3 per SVT dual fuel non-PPM account in cap period eight and £0 for cap period nine.

Appendix 2 – Detail on cost offset analysis

1.1. In Chapter 3, we present estimates for two potential cost offsets for cap period eight. This appendix provides an overview of how we calculated these estimates.

1% additional risk allowance

1.2. We calculated the annual core direct fuel cost by multiplying the wholesale index value (in £/MWh) by the benchmark consumption used in the cap (in MWh). In annual terms, the 1% additional risk allowance is then equal to 1% of the annual core direct fuel cost.

1.3. We calculated the value of the 1% additional risk allowance over cap period eight (a summer season), by multiplying by the proportion of consumption in summer. We used the seasonal consumption value from the Annex 2 cap model.

1.4. The size of the potential offset could then be some fraction of this cap period eight value.

Switching benefit

1.5. We used two different approaches to estimate the switching benefit – a bottom-up approach and a top-down approach. These approaches form the range of estimates set out in Chapter 3.

Bottom-up approach

1.6. This approach had three main elements: the change in switching since 2017; the proportion of switches completed through price comparison websites (PCWs); and the commission per switch.

1.7. We estimated the change in switching using industry data on electricity switching.[52] We used a 2017 baseline, because this was the year of the data used to calculate the operating cost allowance in the cap. The data source used included both domestic and

[52] We do not consider that it is a significant limitation that the data only covers electricity, because the majority of domestic switches are dual fuel, so switching rates should be similar across fuels.

non-domestic switches in 2017, so we used the same scope when looking at the most recent switching data (the first three months of 2022). We consider that this is acceptable because of the small relative size of the non-domestic segment. We estimated 2022 switching by assuming that switching continued at the same rate over the remainder of the year as in the first three months.[53]

1.8. We estimated the proportion of switches completed through PCWs using Ofgem survey data from 2019. This is the most recent point when the relevant questions were included.[54] In any case, this sits between 2017 and 2022, and may therefore be a broadly appropriate assumption for both years.

1.9. We used public statements by PCWs from 2015 as an estimate of the PCW commission per fuel switched. There is limited data available publicly on PCW commission, due to commercial confidentiality. As part of responses to this consultation, we welcome any more recent data from suppliers that would help us to refine this estimate.

1.10. We multiplied the three main elements together to calculate an annual benefit from reduced switching (in £). We converted this to a benefit per meter point, using the number of domestic and non-domestic meter points (for consistency with the switching data).

1.11. We converted this to a benefit (per meter point) over a six-month cap period, by dividing the annual benefit by two. We converted to a dual fuel benefit (over a six-month cap period) by multiplying by two. Finally, we adjusted for inflation between the year of the cost figures and 2022.

[53] Given that our estimate of the switching benefit relates to cap period eight, in effect we are only assuming that switching would continue at the same rate over cap period eight. We consider it reasonable to assume that switching is likely to remain low during cap period eight, given current wholesale prices mean that the cap is the cheapest tariff available.

[54] We used the percentage of customers who found out about deals through a PCW when they last switched, and, of customers who switched through a PCW, the percentage who completed the switch through a PCW. We multiplied these figures together. This is because a commission would not be payable when a customer found out about deals through a PCW, but completed the switch in another way.

Top-down approach

1.12. This approach used data on operating costs that suppliers provided in response to a 2018 RFI, at the point we were designing the cap. As part of this RFI, suppliers provided data on third party commissions in 2017. The scope of this data may be slightly broader than under the bottom-up approach, as the RFI defined third party commission costs as "brokers' costs and intermediaries' sales commissions."

1.13. We took the lower quartile of this data for the suppliers included in the 2018 operating cost analysis. We used a lower quartile to broadly align with the efficiency benchmark we used to calculate the operating cost allowance.[55] This gives us a cost per dual fuel customer.

1.14. We used the same switching data as described in the bottom-up approach. We converted this to a percentage change in switching. We applied this to the cost per dual fuel customer, to give an estimate of the annual saving per dual fuel customer.

1.15. We converted this annual saving to a benefit during a six-month cap period, by dividing by two. Finally, we adjusted for inflation between 2017 (the year of the cost data) and 2022.

[55] We set the operating cost benchmark at the lower quartile minus £5. We do not consider it necessary to take the £5 deduction into account, as it represents a small proportion of the overall operating cost allowance.

Appendix 3 – Detail on shaping and imbalance analysis

Supplier evidence submitted

Responses and exclusions

1.1. Nine out of eleven suppliers responded to the shaping and imbalance costs questions. One supplier provided a nil return due to its wholesale purchasing arrangements. We have included this case as a zero value in our calculations. We have also treated another supplier's response as a nil return, as the supplier provided a duplicate figure to its response to the unexpected SVT demand question. We have excluded that case from our calculations, as we do not have information about what the supplier's costs were.

1.2. Out of the nine suppliers, we excluded four suppliers from our analysis. We excluded suppliers due to:

- **incomplete data**: some suppliers were unable to provide cost forecasts, were unable to provide a central estimate for their cost forecasts and/or have only provided costs they have incurred until the point the RFI was issued;
- **unrepresentative data**: a supplier forecasted costs which were unrepresentative given its unique circumstances; and
- **lack of confidence in the calculation methodology**: one supplier forecasted costs using the existing shaping and imbalance percentages from the cap model. We consider that this creates a circularity when trying to assess whether the existing allowances are sufficient.

1.3. The data used in the analysis therefore only represents 42% of the SVT customer base.

Explanation for the variation in reported costs

1.4. For the suppliers included in our analysis, there were significant variations in reported costs. While there were potential outliers on both the low side and the high side, the overall impact would be to increase the weighted average, especially for cap period nine.

1.5. In our RFI, we asked suppliers to provide the methodologies used to calculate the reported estimates. Based on the responses, we observed the following inconsistencies (not exhaustive) in the methodologies used to estimate the costs.

- Suppliers may have included different **aspects of shaping and imbalance costs** in their estimates. For example, one supplier did not include the impact of rehedging day-ahead (from seasonal normal to actual demand).

- Suppliers may have included different **assumptions about future wholesale prices**. For example, one supplier's methodology included the impact of possible changes to wholesale prices by the time of shaping. Another supplier's methodology used the same percentage uplifts that it provided in response to the November 2021 consultation, which were calculated during a period of rising wholesale prices.

1.6. We note that in our calculations we have not made any adjustment to the reported figures in light of these methodological differences. We also note that suppliers provided varying levels of detail to allow us to understand their estimates.

Calculation steps

Calculation of cost per customer at benchmark level of consumption

1.7. As for unexpected SVT demand costs, we used the RFI template to convert suppliers' submissions to benchmark consumption. This is to improve comparability.

1.8. To calculate the cost per customer at the benchmark consumption level we divided each cost estimate by total (SVT and FTC) expected customer numbers for a given supplier and fuel. See Appendix 1 for how we calculated customer numbers.

Calculation of weights

1.9. We calculated the cost per customer based on a supplier's total (FTC and SVT) customers. However, when weighting to calculate a weighted average, we used data on SVT customers only. This is because the cap applies to default (roughly equivalent to SVT) customers only.

1.10. Our calculated weights vary by fuel type and payment type (ie with separate weights for PPM and non-PPM). We calculate these based on a supplier's share of SVT customers (among the suppliers included in our analysis). Therefore, even though the cost per customer (for a given supplier) only varies with fuel type, the weighted average costs vary by both payment type and fuel type, due to the weighting approach.

1.11. An alternative approach would be to calculate a single weight for PPM and non-PPM for each fuel based on the number of SVT customers. This would result in a common weighted average cost for PPM and non-PPM for each fuel.

1.12. We currently consider our approach better reflects the costs faced by suppliers serving customers in a particular segment. For example, a supplier with a high proportion of PPM customers would have a higher weight when calculating PPM weighted average.

Calculation of weighted average costs

1.13. To calculate the weighted average costs, we multiped the cost per customer by each included supplier's relevant weight.

Calculation of lower quartile costs

1.14. There were no additional steps before taking the lower quartile.

1.15. We have calculated the lower quartile dual fuel costs for both PPM and non-PPM. We derived estimates of £6 per dual fuel SVT customer for both PPM and non-PPM in cap period eight. The equivalent figure was £11 for both payment types in cap period nine.

Appendix 4 – Implementing changes in cap models

Annex 8 – Adjustment allowance methodology

1.1. This section sets out the changes that we intend to make to Annex 8, in the event that we consider an adjustment is required.

Inputs: sheet '3d Electricity losses'

1.2. Update with latest values from the Annex 2 model.

Inputs: new sheet 3g

1.3. Include latest copy of sheet '3a allowances' from the Annex 2 model (see below). We would include a new sheet to avoid affecting previous calculations. We would use this sheet as the source for the relevant unidentified gas values.

1.4. Given we intend to apply the uplifts for electricity losses and unidentified gas within the Annex 8 model, suppliers should not include these within their cost submissions.

Inputs: new sheet 3h

1.5. Include calculated cost to recover. This would be the output calculated based on the approach taken in our decision. We would not include the underlying calculations using supplier-specific data in the public Annex 8 model. The values included in this sheet could vary between different customer groups – eg by fuel and payment type.

Calculations: new sheet 2c

1.6. Add sheet to calculate the adjustment for specific wholesale costs. Under our proposal to recover costs over 12 months, the cap level adjustment (in annualised terms) would be the same as the calculated cost to recover. We would only need to apply regional electricity losses and unidentified gas.

Outputs: sheet '1a Adjustment Allowance'

1.7. Pull through the outputs from sheet 2c into the values at typical consumption for cap period nine. Enter zero for the cap period nine values at nil consumption.

Annex 2 – Wholesale cost allowance methodology

1.8. This section sets out the changes that we intend to make to the Annex 2 model.

Inputs: sheet '3a Allowances'

1.9. Create a table for each set of allowances (electricity single rate, electricity multi-register, gas non-PPM, gas PPM) which has a separate column for each cap period. This will allow us to enter different allowance values for each cap period, where necessary.

Outputs: sheet '1a Direct Fuel Cost Component'

1.10. At step 2, we apply the allowances. Change the cell references to reference the relevant allowance values for a given cap period.

Appendix 5 – Privacy notice on consultations

Personal data

The following explains your rights and gives you the information you are entitled to under the General Data Protection Regulation (GDPR).

Note that this section only refers to your personal data (your name address and anything that could be used to identify you personally) not the content of your response to the consultation.

1. The identity of the controller and contact details of our Data Protection Officer

The Gas and Electricity Markets Authority is the controller, (for ease of reference, "Ofgem"). The Data Protection Officer can be contacted at dpo@ofgem.gov.uk

2. Why we are collecting your personal data

Your personal data is being collected as an essential part of the consultation process, so that we can contact you regarding your response and for statistical purposes. We may also use it to contact you about related matters.

3. Our legal basis for processing your personal data

As a public authority, the GDPR makes provision for Ofgem to process personal data as necessary for the effective performance of a task carried out in the public interest. ie a consultation.

4. With whom we will be sharing your personal data

We may share consultation responses with BEIS.

5. For how long we will keep your personal data, or criteria used to determine the retention period.

Your personal data will be held for six months after the project, including subsequent projects or legal proceedings regarding a decision based on this consultation, is closed.

6. Your rights

The data we are collecting is your personal data, and you have considerable say over what happens to it. You have the right to:

- know how we use your personal data
- access your personal data
- have personal data corrected if it is inaccurate or incomplete
- ask us to delete personal data when we no longer need it

- ask us to restrict how we process your data
- get your data from us and re-use it across other services
- object to certain ways we use your data
- be safeguarded against risks where decisions based on your data are taken entirely automatically
- tell us if we can share your information with 3rd parties
- tell us your preferred frequency, content and format of our communications with you
- to lodge a complaint with the independent Information Commissioner (ICO) if you think we are not handling your data fairly or in accordance with the law. You can contact the ICO at https://ico.org.uk/, or telephone 0303 123 1113.

7. Your personal data will not be sent overseas.

8. Your personal data will not be used for any automated decision making.

9. Your personal data will be stored in a secure government IT system.

10. More information For more information on how Ofgem processes your data, click on the link to our "Ofgem privacy promise."