

# Consultation Appendix

## Default Tariff Cap: Statutory Consultation

### Appendix 4 – Wholesale costs

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We are consulting on our proposals for setting and updating a default tariff cap in accordance with the Domestic Gas and Electricity (Tariff Cap) Act 2018. This supplementary appendix provides details of the proposals and methodology in relation to wholesale costs. This document is aimed at those who want an in-depth understanding of our proposals. Stakeholders wanting a more accessible overview should refer to the Default tariff cap – Overview document.

We welcome views from stakeholders on all of our proposals set out within this document. Please see the Default tariff cap – Overview document for instructions on how to respond to the consultation.

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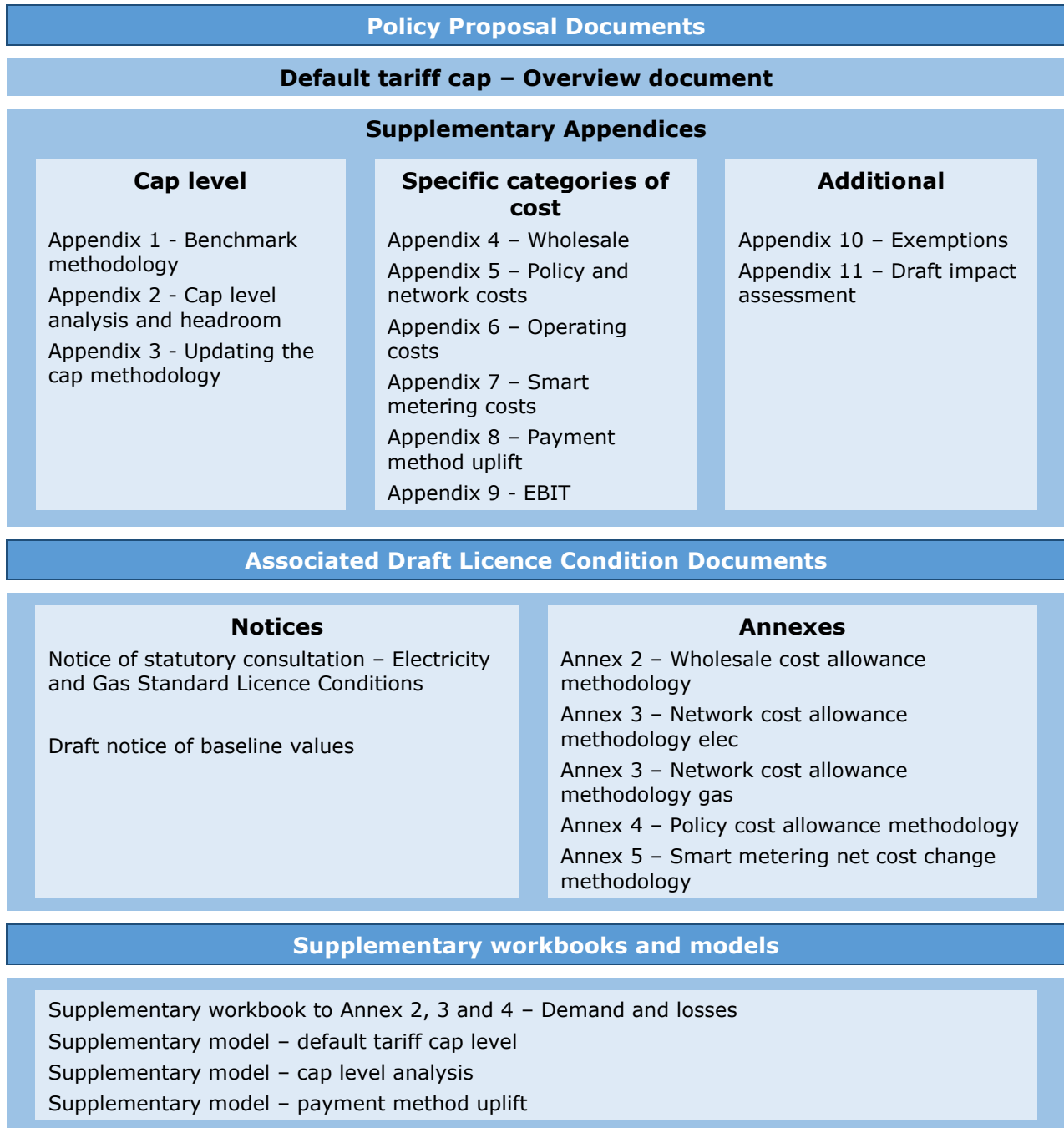
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## Document map

Figure 1 below provides a map of the default tariff cap documents published as part of this statutory consultation.

**Figure 1: Default tariff cap – statutory consultation document map**



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## 1. Overview

- 1.1. This chapter provides an overview of the contents and structure of the wholesale costs appendix, and our approach to setting the wholesale allowance in the default tariff cap.

### **The challenge of setting an allowance**

- 1.2. Estimating an efficient wholesale cost allowance is challenging regardless of the method we use.
- 1.3. Reported wholesale costs vary significantly between suppliers depending on the approach they have taken to purchasing their energy (eg their hedging strategy). Variation between suppliers is unlikely to primarily be a result of differences in their efficiency, but rather driven by the timing of their purchases that could turn out to be advantageous or disadvantageous in retrospect. This makes it difficult to estimate what an efficient level of wholesale costs in a given baseline period. We cannot benchmark costs based on suppliers with low historic costs (in a manner similar to our approach with Appendix 6). This challenge is heightened because wholesale costs are likely to represent the largest proportion of a supplier's costs.
- 1.4. Although we can estimate the significant majority of wholesale costs by assessing the price of forward wholesale contracts (which is the case independently of any given approach to purchasing wholesale energy), suppliers face additional costs that are not captured in the price of forward contracts alone (eg shaping, imbalance and transaction costs). These costs need to be considered as part of estimating wholesale costs, in a way that appropriately reflects their materiality to overall wholesale costs. This is a challenging exercise in its own right, and some of the costs may vary between small and large suppliers. We do not believe there is one correct way carrying out this assessment and we need to exercise some judgement.
- 1.5. Suppliers have strong incentives to follow a buying strategy that matches the valuation given by the way we assess wholesale costs. This is to reduce the risk that they incur costs that exceed the allowance included in the level of the default tariff cap. However, suppliers would still face risks that their costs differ from the allowance in the default tariff cap. First, suppliers will be exposed to wholesale price movements that occur during the cap period that have not been assessed via the value of forward contracts. This happens as suppliers buy different, more 'granular' contracts to better match their customers' demand as they approach a delivery period (shaping cost). There will also be changes in expected demand, requiring a supplier to adjust volumes at the prevailing market price, which may not reflect the cap's allowance (forecast risk). Secondly, supplier risks can also occur from the fact we propose to update the allowance every six months based on a 12-month weighted average wholesale price. Changes in market prices can mean that the second default tariff cap period may under- or over- recover costs compared to the assumptions that set the previous allowance (basis risk).
- 1.6. These risks make wholesale cost a primary issue when we consider the design of how we set and update the default tariff cap, and how to take account of the volatility of these costs in the default tariff cap methodology.

## Our proposal

- 1.7. We propose to set the wholesale allowance in the default tariff price cap using a bottom-up cost assessment. This means we will calculate the appropriate level of wholesale costs in by estimating efficient allowances for each element of wholesale cost.
- 1.8. In our May consultation we suggested we may use a bottom up methodology or a price-reference approach. For reasons discussed in Appendix 1, we have decided to use a bottom-up approach. Our proposal was influenced by, but not determined by, our consideration of wholesale costs. The primary benefit of the bottom-up approach is that we can specify and assess exactly what we have provided allowances for in the cap, and how much we have provided. We consider that this enables us to better take account of uncertainties. For example, it is much more difficult to consider whether a price reference approach includes sufficient allowance for efficient costs of energy, shaping, and other wholesale costs.
- 1.9. Our bottom-up assessment of wholesale costs consists of three parts:
1. **Core direct fuel allowance:** we estimate the significant majority of wholesale costs based on forward contracts for electricity and gas, using an updated version of the CMA’s prepayment meter cap wholesale market model.
  2. **Additional direct fuel allowances:** we uplift the core direct fuel allowance by an additional amount to reflect the expected costs of converting less granular forward contracts to more granular demand, transaction costs, losses, and additional uncertainty.
  3. **Capacity Market payments:** We also provide an additional allowance, passing through the cost of Capacity Market (CM) auctions.
- 1.10. Table A4.1 sets out the wholesale allowance for 2017/18. The draft Annex 2 to the draft licence condition 28AD (published on our website<sup>1</sup>) provides full details of our calculations, including a number of other historic examples to illustrate how the proposed methodology works in practice.

**Table A4.1: Estimates of wholesale costs in 2017-18, £ per customer (GB average)**

Cost component	Electricity (single rate)	Electricity (multi-register)	Gas	Dual fuel (implied)
1. Core direct fuel allowance	141.52	192.53	185.15	326.67
2a) Reshaping; forecast error and imbalance; transaction costs	8.90	12.11	8.55	17.46
2b) Additional uncertainty	1.42	1.93	1.85	3.27
2c) Electricity losses/unidentified gas	14.31	19.15	1.88	16.19
3. Capacity market payments	3.41	3.63	n/a	3.41
<b>Total</b>	<b>169.56</b>	<b>229.35</b>	<b>197.43</b>	<b>367.00</b>

<sup>1</sup> Ofgem (2018), Default Tariff Cap – Statutory Consultation: Annex 2 Wholesale cost allowance methodology <https://www.ofgem.gov.uk/publications-and-updates/default-tariff-cap-overview-document>

Source: Ofgem, Annex 2 - Wholesale cost allowance methodology  
Notes:

1. The figures reflect a weighted average of our estimates of wholesale costs as would have been calculated according to our proposed methodology for the periods starting April 2017 and October 2017. For electricity, we assume that 57% of consumption takes place in winter for single rate and 61% for multi-register. For gas, we assume that 75% of consumption takes place in winter.
2. Typical Domestic Consumption Values (TDCV) are 3.1MWh per year for electricity (single register), 4.2MWh per year for electricity (multi-register) and 12.0MWh per year for gas. See [this](#) page for further details.

1.11. We explain our approach to wholesale costs in the following three chapters:

1. **Chapter 2:** Setting the core direct fuel allowances.
2. **Chapter 3:** Setting the additional direct fuel allowances. Capacity Market costs are also included in this chapter.
3. **Chapter 4:** Updating the default tariff cap.

### Setting the core direct fuel allowances

1.12. In Chapter 2, we outline how we propose to set the allowance for direct fuel costs, based on forward contracts. We highlight stakeholder feedback and our own assessments that have informed our proposed decisions. We discuss the merits of the options that we considered, and the rationale for our proposals.

1.13. We propose to use the CMA's wholesale model, which is used to update the prepayment safeguard tariff, as the basis of calculating the allowance. In our May consultation, we consulted on three potential adjustments.

1. **Valuation – smoothing and seasonality:** We propose to set our direct fuel cost allowance based on forward prices, using a 6-2-12 semi-annual approach.
2. **Initial electricity shaping:** We propose to split base and peakload contracts on a 70/30 basis.
3. **Price data:** We propose to use ICIS data, using the mid-point price for contracts in our calculations.

1.14. As well as making assessments and proposals on these key policy areas, we have also adjusted other important areas of the CMA's model. For example, we have updated the demand weightings in it which we believe better reflects the energy usage patterns of default tariff customers. Please see Appendix 1 and Annex 2 of the draft licence condition for more details on the adjustments that we have made.

### Setting the additional direct fuel allowances

1.15. In Chapter 3, we outline the additional allowances we propose to include, and discuss our approach for estimating the costs. These allowances cover the costs of activities suppliers undertake to deliver energy, but would not be otherwise valued in our assessment of core direct fuel allowances. These will be set as a multiplier of the forward contract index.

1.16. We discuss the following key issues in Chapter 3:

1. shaping, forecast error and imbalance costs
2. transactions costs
3. losses and unidentified gas, and
4. additional risk and uncertainty.

1.17. In addition, we provide an allowance for CM costs. We propose to add these costs as a lump sum, not a multiplier of direct costs.

### **Updating the cap – transition**

1.18. In Chapter 4, we discuss how we propose to update the default tariff cap over time.

1.19. In our May consultation, we suggested using an index to update the initial baseline. As we are now proposing to use a bottom-up approach, mostly based on external cost data, we propose to simply recalculate the wholesale allowance for each default tariff cap period. We propose to use the approach set out in Chapter 2 to establish the core direct fuel cost allowance for an upcoming cap period, and then apply the additional allowances described in Chapter 3.

1.20. We propose to update the wholesale allowance every six months, although the first default tariff cap period will be shorter (ending 31 March 2019).

1.21. For the first default tariff cap period, in our May consultation we proposed to set the wholesale cost allowance with reference to an observation period (April to September) nearer to the period of delivery, as opposed to using a normal winter observation period, which would be between February and July. This was in response to comments on our early working papers that suppliers were worried they would have already started hedging for the first default tariff cap period, potentially on a different hedging strategy and wanted as much notice as possible. However, to some extent, it is unavoidable that, as we transition into the default tariff cap, the wholesale allowance will differ from the actual costs that suppliers incur in the first default tariff cap period.

1.22. On balance, and taking in a range of considerations, we judge that for the first default tariff cap period using the usual winter observation window (February to July) gives a sufficient approximation of the cost suppliers actually incur and it is the most reasonable position to adopt. Given increases in wholesale costs since April, and that suppliers will have purchased a proportion of the energy for delivery in the first default tariff cap period, this proposal ensures that the allowance more closely reflects underlying costs.

1.23. In making this proposal, we have also taken into consideration the objective for the default tariff cap as set out in the Domestic Gas and Electricity (Tariff Cap) Act (the Act), protecting Standard Variable Tariff (SVT) customers from being overcharged compared to the actual likely cost incurred by most suppliers. For larger suppliers, we consider our allowance is likely to be an overestimate, although by a lesser amount than the proposed approach in our earlier consultation (using an observation window between April and September would set the allowance over £30 higher for a dual fuel



SVT customer in annualised terms, and around £7 for the duration of the cap period). We do not consider the risks to those smaller suppliers, who may have shorter hedging strategies, are likely to be significant given their limited exposure to SVT customers, and the different approach to hedging for fixed term customers (which they have more of). See Chapter 4 of this appendix for more details.

## **Context and related publications**

- 1.24. Ofgem (2018), Default Tariff Cap: Policy Consultation. Appendix 6 – Wholesale costs. [https://www.ofgem.gov.uk/system/files/docs/2018/05/appendix\\_6\\_-\\_wholesale\\_costs.pdf](https://www.ofgem.gov.uk/system/files/docs/2018/05/appendix_6_-_wholesale_costs.pdf)

## 2. Calculating the core direct fuel cost allowance

In this chapter, we outline how we propose to set the allowance for direct fuel costs, based on forward contracts. We highlight stakeholder feedback and our own assessments that have informed our proposed decisions. We discuss the merits of the options that we considered, and the rationale for our proposals.

### Overview

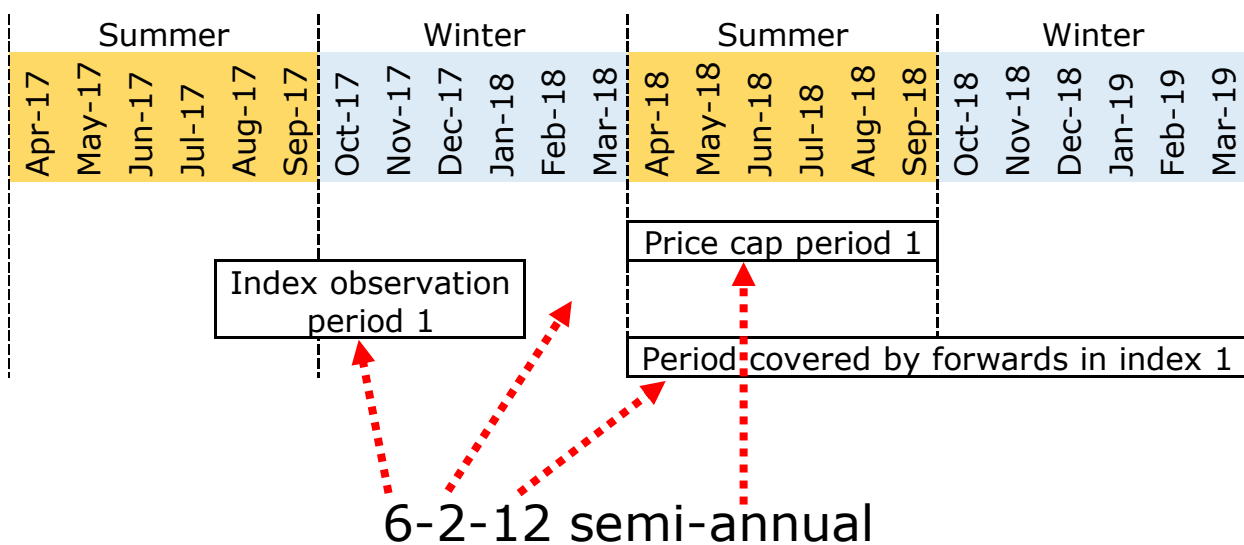
- 2.1. We propose to set the majority of the wholesale cost allowance using a model that values a direct wholesale cost allowance, based on forward gas and electricity contracts. Our approach is based primarily on the CMA's wholesale market model, which is used for the prepayment meter cap. We describe that model in Chapter 2 of Appendix 6 of our May consultation.
- 2.2. In this chapter, we describe our proposed approach, and rationale. We discuss what, if any, specific adjustments we intend to make to the CMA's wholesale model. These adjustments affect both the model used to calculate the majority of the direct energy costs through forward gas and electricity contracts in the initial wholesale allowance, and the updates to wholesale costs over time.
- 2.3. In particular, we describe how we use forward contract prices to set the direct cost allowance depends on three issues (below).
  1. **Valuation – smoothing and seasonality:** We propose to set our direct fuel cost allowance based on forward prices, using a 6-2-12 semi-annual approach.
  2. **Initial electricity shaping:** We propose to split base and peakload contracts on a 70-30 basis; and
  3. **Price data:** We propose to use ICIS data, using the mid-point price for contracts in our calculations.
- 2.4. As well as making assessments and proposals on these key policy areas, we have also adjusted other important areas of the CMA's model. For example, we have updated the demand weightings in it which we believe better reflects the energy usage patterns of default tariff customers. Please see Appendix 1 and Annex 2 of the draft licence condition for more details on the adjustments that we have made.
- 2.5. Setting an allowance for direct costs based on forward contracts alone would not reflect the value of all of the wholesale costs suppliers incur. In Chapter 3, we describe how we propose to set additional allowances for the wholesale costs not captured in forward contract prices. The total wholesale allowance included in the cap combines the core direct fuel cost allowance described in this chapter with the additional direct fuel cost allowances.

## Valuation – smoothing and seasonality

### Proposal

- 2.6. We propose to value forward contracts using a 6-2-12 semi-annual approach to calculate the weighted average cost of energy over a 12-month period. This is in line with the proposal in our May consultation, and the approach used in the wholesale indexation model for the prepayment meter cap.
- 2.7. An example of the 6-2-12 semi-annual approach is described below and in Figure A4.1, based on an assumption the cap started on 1 April 2018:
- A six-month observation period:** The wholesale index will be the average of daily index values observed in the six months between 1 August 2017 (eight months before the first day of delivery in the cap period) and 31 January 2018 (two months and one day before delivery). For a cap starting in October, the observation period would run from 1 February to 31 July.
  - A two-month lag:** There is a two-month lag between the observation period and delivery (e.g. 1 February to 31 March 2018). This allows time for the cap level to be announced, and suppliers to inform customers.
  - A 12-month forward view:** The model observes contracts for delivery in the 12-month period from 1 April 2018 up to the end of March 2019. For a cap starting in October, the forward view would cover the 12-month period from 1 October up to 31 September.
  - Semi-annual:** The cap is updated twice a year, running from April to September and October to March. A new value of the index, based on a different observation period and a different forward view, is therefore calculated semi-annually.

**Figure A4.1: 6-2-12 pricing-in period with semi-annual wholesale cost pass through**



Source: CMA, Ofgem

## What we consulted on

- 2.8. In our May consultation, we explained the value of forward contracts is the most significant component of the wholesale cost allowance. It controls how quickly the direct cost of forward gas and electricity contracts is passed through to suppliers under the default tariff cap.
- 2.9. We also explained that it influences both the 'smoothing' and 'seasonality' of how wholesale costs are passed through to customers.
1. **Smoothing:** This relates to how frequent, and how sizeable, changes in the cost allowance could be. The more often we update the allowance, the smaller and more frequent (i.e. smoother) each price change should be for customers. We also reduce the risk for suppliers that the allowance in the cap and the prevailing market price of wholesale energy differ substantially, or for long periods.
  2. **Seasonality:** This relates to whether the allowance reflects seasonal prices – higher costs in the winter and lower costs in the summer. It is controlled by the length of our forward view period. The current 12-month forward view takes in one summer and winter season at any point and should not be subject to seasonal variability. A six-month forward view would create a seasonal allowance, and therefore a cap level that was higher in winter than summer.
- 2.10. We considered the 6-2-12 semi-annual approach to have the following benefits:
1. eliminating seasonal pricing for consumers and
  2. allowing wholesale cost changes to pass through more frequently (in general, suppliers buy energy for SVT customers over a much longer period, reducing how quickly cost increases or decreases are passed on to customers).
- 2.11. We also highlighted concerns with suppliers' ability to hedge an allowance set by this approach. The wholesale allowance is a weighted average price of (relatively) high winter contracts and (relatively) low summer contracts. This approach assumes that suppliers under recover the cost of winter contracts (against the weighted average allowance priced into the cap), but make up that deficit in the summer – when the weighted average exceeds the cost of summer contracts. However, when we update the default tariff cap, the summer-winter spread (the difference between winter and summer prices) may have changed, meaning suppliers may over recover the deficit they have brought forward from the winter (if the wholesale market has moved in that direction), or under recover it. Suppliers refer to this exposure to the winter-summer spread as 'basis risk'.
- 2.12. On that basis, we sought stakeholders' views on two alternative approaches:
1. shortening the forward view to align with the allowance: a 6-2-6 semi-annual approach (observing prices for delivery in a six-month period that matches the delivery period of the default tariff cap), as opposed to a 6-2-12 semi-annual approach and
  2. lengthening the allowance period, to align with the forward view: a 6-2-12 annual model (observing prices in a 12-month delivery period, and reflecting that annual

delivery period in the default tariff cap), as opposed to a 6-2-12 semi-annual model.

- 2.13. Although both of these options remove the apparent basis risk highlighted above, we acknowledged they bring their own challenges. For a shorter option, this introduces seasonality to the wholesale cost pass through – high winter prices, and low summer prices. For the longer option, there is greater time between updates, meaning it will take longer to pass through changes in wholesale costs, which increases the volume risk that suppliers face (exposure to changes in demand due to weather or changes in the number of SVT customers).

### **Stakeholder feedback and evidence**

- 2.14. Amongst the responses to our May consultation, support was broadly split between the 6-2-12 semi-annual and the 6-2-12 annual method.

#### *Seasonal prices*

- 2.15. Most stakeholders were in favour of a 6-2-12 approach that avoided seasonal prices for customers. Most suppliers try to avoid seasonal prices, and reported that customers do not appreciate winter and summer pricing.
- 2.16. One supplier explicitly favoured the 6-2-6 semi-annual approach, arguing that the seasonal pricing effect was relatively small. They argued that there was a £35 difference (per typical dual fuel customer in annualised terms) between winter and summer bills (all else being equal).

#### *Smoothing*

- 2.17. The majority of suppliers (small and large) preferred the semi-annual model to the annual model, as it passes through changes in wholesale cost more quickly.
- 2.18. Disadvantages with the annual approach suggested by suppliers included:
1. **Increasing the risk from volume forecasting:** Suppliers will need to forecast default customers over a longer period, increasing the likelihood and magnitude of error. This could be compounded if new fixed tariffs were priced above SVTs (if SVTs have not yet passed through price increases), meaning fixed customers opt to default on loss making tariffs at the end of their term.
  2. **More susceptible to shocks:** Longer periods without an update could make suppliers more susceptible to price shocks in the wholesale market, as the cap and market prices could be further apart for longer.
  3. **Distorting the wholesale market:** A consequence of the annual method is that six months of the year are consistently outside the observation window, significantly reducing trading in that period, which reduces liquidity and could distort the behaviour of sellers and buyers in the wholesale market.
  4. **Greater transaction costs:** Some suppliers expressed concerns around the length of the assumed hedge, suggesting that buying energy further into the future than they are currently doing, would increase their transaction costs (through working capital and collateral).

- 2.19. A significant minority of suppliers favoured the annual approach, largely because they had reservations about the apparent basis risk introduced by the 6-2-12 semi-annual approach. Even suppliers that favoured the semi-annual approach were concerned about the risk, and suggested that allowances need to be provided to help suppliers managed the risk.

#### *Other approaches*

- 2.20. One supplier suggested using a 'rateable purchasing strategy' to evaluate forward wholesale costs. They believed this approach would better protect customers from volatility compared to the prepayment meter cap methodology, while addressing the market liquidity and seasonality issues.
- 2.21. At a high level, this approach would build the index for a given default tariff cap period rateably over an 18-month period, buying each delivery month in the default tariff cap as time to delivery shortens. For each delivery month in the default tariff cap period, energy is purchased in monthly tranches of 1/18 over 18 months. To allow the default tariff cap to be set for a summer period (for example) at the end of January, the open volumes will be purchased during the January, closing out the summer demand.
- 2.22. As highlighted above, an 18-month rateable mechanism was suggested by this supplier. However, they believed that a 12-month rateable mechanism would also be a more suitable mechanism for evaluating forward wholesale contracts than the existing prepayment meter cap methodology. This supplier noted that if this method was not used, they would favour a 6-2-12 semi-annual approach.
- 2.23. Another supplier did not want contracts in the forward contract cost assessment to deliver beyond the next 12 months at a given point in time, and wanted the value of these updated on a monthly basis. This would also mean the lag period would be removed. They believed this approach would better reflect the 'true cost' of energy, would be easier to explain to customers and would reduce the risk of wholesale costs for suppliers going up (eg increased collateral). One other supplier supported monthly updates to wholesale costs.

#### **Our rationale**

- 2.24. We recognise that all of the approaches we presented in our May consultation have advantages and disadvantages, and may not match the way all suppliers currently manage their wholesale costs. It should be noted that our approach to setting the direct wholesale cost allowance is not to provide suppliers with a specific hedging strategy. Rather we estimate an allowance that is set at a realistic level to cover suppliers' costs.
- 2.25. Based on the evidence we have received and our own assessments, we consider the 6-2-12 semi-annual approach to be the most suitable approach for balancing desired outcomes and managing supplier and consumer risk.

#### *Seasonal prices*

- 2.26. Our proposal avoids seasonal pricing. Most customers' incomes are not seasonal, so seasonal prices could make budgeting their expenditure more difficult, in particular for those who are more financially vulnerable. The objective in the Act is to provide protection to consumers, which we have taken into account in reaching our proposal.

We note that most stakeholders suggested we avoid seasonal prices. Suppliers already have the option to charge their customers seasonal prices but almost all opt to pass on costs evenly throughout the year, despite the benefits they might otherwise receive.

- 2.27. Although it was suggested seasonal price difference might be (relatively) small, we consider that default tariffs should minimise these differences in order to protect SVT customers.

*Smoothing: considering volume risk*

- 2.28. We consider the risk of passing through wholesale changes less frequently to be significant for the reasons listed below.
1. For customers, this difference creates bigger step changes in the default tariff cap level, when we do update the wholesale allowance. For those customers who may be financially vulnerable, the bigger bill increases may be more difficult to manage, an effect that could be considered similar to receiving an unexpected back bill. Therefore, we see benefits from this approach to the overall objective of the Act.
  2. For suppliers, this difference increases their volume risk. This is the risk that market prices are significantly higher or lower than the allowance when suppliers correct for changes in demand, due to weather or changes in the number of SVT customers. This is a risk suppliers are already exposed to, but currently they can adjust SVT prices if necessary,<sup>2</sup> and have relatively predictable customer numbers. The lower risk to suppliers is something we have considered in line with the requirement in the Act to consider the financeability of an efficient operator.
- 2.29. In considering volume risk for suppliers, it is important to consider the interaction between fixed tariffs (FTs) and SVTs. The default tariff cap is likely to reduce the price gap between FTs and SVTs for many suppliers with high operating costs. This changes suppliers' exposure to volume risk, compared to the risk they already face. Suppliers price FTs based on the current forward view of forward contracts. If wholesale costs are rising, and we do not update SVT allowances frequently, FTs may be priced close to or above the level of the default tariff cap. This would make it more likely that customers default on to SVTs, increasing the volume risk faced by suppliers.
- 2.30. The semi-annual model still faces this risk, but more frequent updates to the default tariff cap wholesale allowances reduces this. We also consider that updating the allowance every six months is, in principle, less likely to distort competition in the wider retail market, as it means that the default tariff cap will better reflect the prevailing opportunity cost of supplying energy at any given point in time.
- 2.31. We consider waiting an additional six months between updating wholesale costs would pass too much risk and uncertainty onto suppliers and their customers in the event of large and sustained wholesale market movements in those 12 months.

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<sup>2</sup> Although not frequent, there have been a number of occasions when suppliers have changed their SVT tariffs more than once a year.

- 2.32. In relation to the Act, reducing the risk that the wholesale costs used to price FTs and set the default tariff cap deviate, enables suppliers to compete effectively for domestic customers. It also helps maintain stability in the incentives for domestic customers to switch to different domestic supply contracts.

*Considering apparent 'basis risk'*

- 2.33. We recognise that, although the 6-2-12 semi-annual reduces volume risk by passing through wholesale changes more quickly, it appears to introduce basis risk.
- 2.34. In a flat wholesale market, suppliers would not make any gains or losses against an allowance set by the 6-2-12 semi-annual model. In a flat market, the summer-winter spread is the same in both cap periods, so the same weighted average allowance that applies in the summer, allows a supplier to recover their winter deficit and break even.
- 2.35. However, when the wholesale market moves, suppliers can under- or over-recover their winter deficit because the model exposes them to changes in the winter-summer spread. Some suppliers provided us with worked examples of the exposure to these changes in the summer-winter spread. These ranged from around £6.50-8.00 per customer depending on the timing of the assessment. One supplier provided a 'worst case' value of £15 per dual fuel customer. We believe the use of different periods and assumptions in the calculations of these values limits the comparability.
- 2.36. We consider the risk introduced by the 6-2-12 semi-annual approach is smaller than that suggested by some of the examples suppliers' presented. The examples provided show the resulting exposure from one or two iterations of the default tariff cap. In fact, the exposures net out, with an over-recovery in one period (if the summer-winter spread moves in advantageous direction) being offset when the spread moves back again in a subsequent period. We consider it implausible that the summer-winter spread would consistently shift in a single direction. We have tested this empirically, continuing the examples provided, and algebraically. Our calculations are that every period, except the first and the last, are offset.
- 2.37. We also consider that the risk introduced by the approach is manageable. In line with feedback received to our May consultation, suppliers have a number of options. We consider that suppliers will adopt different approaches depending on their circumstances, or whichever offers the lowest long run costs.
- 2.38. Firstly, if a supplier were to take no action, other than to buy energy for delivery in the six-month default tariff cap period, they would face a cost. Although the exposure would net out over the long run, at any given point in time, the supplier may have a positive or negative impact. Managing this cash flow would incur some cost. This would increase a supplier's cost of capital, reflecting the greater working capital requirement, and a potentially greater risk. It is difficult to assess in advance, but we do think the long-run cost of additional working capital would be large if a supplier took no actions to manage this risk.
- 2.39. However, a supplier could choose to manage their risk. Two suppliers indicated they could actively manage the basis risk by adopting a hedging strategy that limited their exposure to losses or gains. At the time the default tariff cap is announced, the 6-2-12 semi-annual model creates an expected profit or loss impact. A supplier can hedge in a way that locks in that profit or loss from that point, exposing themselves to no additional basis risk. However, this hedging strategy is not cost neutral. We anticipate



that traded volumes may increase, which would have a relatively small impact on the necessary allowance through higher transactions costs.

- 2.40. One supplier suggested a third way to manage the risk (alongside managing the working capital, or locking in the spread): entering a structured deal with a third party to pass on some of the risk exposure at cost. The exact costs would vary as they are negotiated bilaterally.
- 2.41. It should be noted that the 6-2-12 semi-annual model is not, in itself, a hedging strategy. It sets a realistic allowance within which suppliers can manage their wholesale costs. We consider whether to include additional allowances to cover the costs of managing the 6-2-12 semi-annual in the Chapter 3.
- 2.42. Comparing the semi-annual and annual approaches to the 6-2-12 model, we consider the semi-annual approach to have greater benefits because it passes through prices changes through to customers more quickly than the annual method. We also consider the apparent basis risk easier for suppliers to manage than the potential impact of a large mismatch between prevailing market prices and the wholesale allowance.

#### *Liquidity*

- 2.43. The annual approach would mean that suppliers mainly buy energy for SVT customers during six months of the year. We are concerned what impact this might have on liquidity, although note that SVT demand does not account for the majority of traded volumes.

#### *Other models suggested*

- 2.44. Some suppliers suggested approaches other than the 6-2-12 semi-annual and the 6-2-12 annual method to how we set the allowance based on forward contracts.
- 2.45. One supplier suggested using an 18-month rateable mechanism. We recognise that this may provide a greater level of cost smoothing for both suppliers and consumers. However, as the CMA noted with their assessment of a 12-month rateable mechanism,<sup>3</sup> it introduces the risk of producing price cap levels that are materially out of step with current market prices. This risk may increase with an 18-month rateable mechanism. When comparing the 12-month rateable mechanism that was also suggested, the CMA found that the 6-2-12 semi-annual model was the least volatile.
- 2.46. We therefore believe that our proposed 6-2-12 semi-annual approach provides a better balance of keeping the default tariff level in line with current market trends, whilst adequately shielding consumers from price volatility via the update frequency and the length of the forward view.
- 2.47. Another supplier suggested only using forward contracts that do not to deliver beyond the next 12 months at any given point in time, and updating the cost of these every month. We believe there are numerous challenges to this approach. Firstly, only

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<sup>3</sup> Energy market investigation: Final report.  
<https://assets.publishing.service.gov.uk/media/5773de34e5274a0da3000113/final-report-energy-market-investigation.pdf>

assessing wholesale contracts 12 months ahead at any point in time may reduce the liquidity of forward contracts. It may also introduce more price volatility to these customers. Secondly, we have doubts around how workable this approach would be, as it could lead to the default tariff cap level changing on a monthly basis. This presents potential challenges and costs for suppliers communicating these changes to customers. Given these challenges, we therefore do not think this would be in the best interest of consumers.

- 2.48. We consider that our proposed 6-2-12 semi-annual model provides a balance between these longer- and shorter-term approaches. We note that the two suggestions offered by suppliers prioritise opposing considerations. The longer strategy reduces the relationship between the allowance in the default tariff cap and prevailing wholesale price, which risks distortion. The other approach passes through costs much more quickly, more closely matching the prevailing wholesale opportunity costs, but increasing customers' exposure to volatility.

#### *More frequent updates*

- 2.49. We consider updating the wholesale allowance more frequently than every six months, not to be in customers' best interest. We note that it is not common for default tariffs in the market to be updated more than twice a year, and consumers may not want to increase this frequency.

## **Initial electricity shaping – base and peakload split**

### **Proposal**

- 2.50. We propose to use a 70/30 split between baseload and peakload forward electricity contracts in the models used to calculate the energy costs through forward contracts and update wholesale costs.

### **What we consulted on**

- 2.51. For electricity, the CMA's prepayment meter cap wholesale model has an assumption on the ratio of forward baseload and peakload contracts it buys. Baseload contracts relate to electricity delivered continuously every day of the week, and peakload contracts deliver electricity Monday – Friday, 07:00 to 19:00).
- 2.52. This ratio is set as a 70/30 split between baseload and peakload in the indexation model used for the prepayment meter cap. In our May consultation we presented three options that we were considering:
1. a 70/30 split between baseload and peakload, as currently used in the model to update the existing safeguard tariff
  2. a baseload and peakload split, using different proportions and
  3. shaping based on products relating to other delivery periods, potentially more 'granular'.

- 2.53. We asked suppliers whether they agreed that the initial shaping should be based on a 70/30 split between baseload and peakload, and for evidence to support alternative approaches. We did not propose altering the products in the assessment, in particular, including more granular block products due to their low forward liquidity and challenges selecting the correct product.
- 2.54. At the time, we noted that changes to energy system might affect the price differential between base and peakload products, and the overall usefulness of the peakload contract to build shape. However, it was not self-evident what an alternative ratio should be. We also acknowledged that simply using baseload and peakload contracts does not reflect all of the contracts suppliers buy as part of their wholesale activities.

### **Stakeholder feedback and evidence**

- 2.55. We received a range of responses on this issue. However, the proposal in our May consultation (ie 70/30 baseload/peakload split) was the most supported approach identified through stakeholder responses. Suppliers that supported this approach generally thought that it represented a reasonable approximation.
- 2.56. Other suppliers identified different ratios that they thought would be more appropriate. Some of these varied by meter profile class and season, and there was a relatively large range of values amongst those submitted to us. At the most extreme, these values ranged from a baseload/peakload ratio of 100/0, to 50/50. Outside of these ranges, values provided by suppliers tended to cluster around our 70/30 baseload/peakload proposal depending on the specific meter type or season.
- 2.57. However, some suppliers broadly thought the key consideration with this assumption was not the whether the initial split was 70-30, but how that split was accounted for in the wholesale allowance when estimating the cost of shaping to final demand.

### **Our rationale**

- 2.58. That stakeholders' feedback supports, or clusters around, our intended approach suggests that 70/30 is a reasonable approximation of suppliers' activities. This gives us confidence that this represents a suitable assumption that we can apply across a range of supplier types.
- 2.59. From the range of submissions that we received, it was not clear what an appropriate alternative ratio would be, given that any particular option would deviate from some of the approaches adopted by different suppliers. We have no reason to think an alternative ratio would be more or less suitable for the market as a whole.
- 2.60. Secondly, feedback suggests that whatever level we use, it was more critical that this was used as the starting assumption to allow for other costs that suppliers may face. For example, a suitable allowance for shaping should be made based on this starting position. We tested this in a shaping modelling (discussed in Chapter 3). Using a higher ratio of peakload contracts broadly increased the core direct fuel cost allowance, but decreased the cost of shaping.
- 2.61. When considering different values by profile class and season, we have similar concerns as noted above. We are aware that the numbers may differ, but it is not clear that there is a different, single value that is more appropriate for a range of suppliers. Therefore, we have opted to continue with the proposed 70/30 split for both profile

classes and throughout the year. This approach has an additional benefit of keeping the approach simple in its design.

## Price data

### Proposal

- 2.62. We intend to use ICIS Energy price data in the model used to calculate our estimates of core direct fuel costs based on forward contracts. We consider the prices (already used in the prepayment meter (PPM) cap methodology) are robust and the market already has good access to these.
- 2.63. We propose to use midpoint prices. We consider the midpoint of the bid and offer prices the most appropriate given the range of market participants and market conditions it will cover.

### What we consulted on

- 2.64. We need pricing data to assess the direct cost of energy (ie the value of forward contracts). These prices will be used in the models used to calculate the energy costs through forward contracts and update wholesale costs.<sup>4</sup> The model used to update the existing safeguard tariffs uses the midpoint of assessed bid and offer prices from ICIS Energy. There is a competitive market for this information and it is available to the market (at a fee).
- 2.65. In our May consultation, we proposed using the same approach used for the PPM cap methodology. That is using ICIS Energy as the price data provider, and using the midpoint of bid and offer prices as the contract value. At the time we noted that this approach creates consistency with the existing PPM cap methodology, meaning most suppliers will already have access to it. We also recognised that it continues to be a trusted and widely used throughout the industry.
- 2.66. We also noted some concerns that non-vertically integrated suppliers bought energy closer to the offer (sell) price than the midpoint. Whilst we recognised the factors that may result in this behaviour, we said we required more evidence of the size of this trend, as well as our view that the price suppliers pay depends on a number of factors, including market conditions at the time.

### Stakeholder feedback and evidence

- 2.67. We received little stakeholder feedback to our May consultation around this issue. On the data provider, stakeholders did not raise any concerns around our proposals.
- 2.68. We received relatively little feedback around which element of the price we use (ie the midpoint or offer price). We were aware of previous concerns that non-vertically integrated suppliers had to buy energy closer to the offer (sell) price. In response to

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<sup>4</sup> This issue is separate to how we calculate specific wholesale cost allowances, where we may use other prices to calculate costs (eg half-hourly prices). Please see the *Bottom-up allowances* section of Chapter 4 for more details.

our May consultation, some stakeholders raised concerns around the differentials between the offer/midpoints, and the bid/offer prices. This was in the context of transaction costs. They highlighted the difference between these prices as a transactional cost for them.

### **Our rationale**

- 2.69. We consider that the price data source used in the PPM cap methodology is robust and trusted, and that most relevant parties will have access to it. We have not received any stakeholder comments that raise any concerns around these points.
- 2.70. Keeping the same data source also creates consistency with the PPM cap methodology, and means market participants can gain access to this data. This access will allow suppliers to understand our approach and manage the cost of these activities.
- 2.71. For the price level, non-vertically integrated suppliers may buy energy closer to the offer (sell) price. However, the price participants pay varies on several factors. The market conditions (eg rising or falling market) at a given point in time influence the price paid. The level of market access, the volume of energy traded or agreements with other parties (eg credit agreements) also influence the price suppliers pay.
- 2.72. Furthermore, for initially assessing forward prices, we believe the midpoint is a closer indicator of the underlying cost of the energy – that is independent of a particular supplier. We view the difference between the bid-offer prices more as a transaction cost issue, which may differ depending on a supplier and its circumstances. We address transaction costs in Chapter 3.
- 2.73. We also note that using the midpoint is used in the industry, including other price assessments produced by the data supplier, such as volume-weighted trade-based indices for different contracts and spark spreads.<sup>5</sup>

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<sup>5</sup> Please see ICIS Energy's European Daily Electricity Markets Methodology for more details: <https://s3-eu-west-1.amazonaws.com/cjp-rbi-icis-compliance/wp-content/uploads/2017/06/EDEM-Methodology-24-May-2017.pdf>

### 3. Calculating additional direct fuel cost allowances

In this chapter, we outline the additional allowances we propose to include, and discuss our approach for estimating the costs. These allowances cover the costs of activities suppliers undertake to deliver energy, but would not be otherwise valued in our assessment of core direct fuel allowances. These will be set as a multiplier of the forward contract index.

#### Overview

- 3.1. Our valuation of wholesale costs based on forward contracts does not capture all of the wholesale costs that suppliers face. We propose to include additional direct fuel cost allowances to cover the costs of:
1. shaping, forecast error and imbalance costs
  2. transactions cost
  3. losses and unidentified gas
  4. additional risk and uncertainty, and
  5. CM costs.
- 3.2. We propose to calculate the additional allowances for shaping, forecast, imbalance, and additional uncertainty by applying a fixed percentage to the direct costs we calculate based on forward contracts described in Chapter 2. The proposed allowances are set out in Table A4.2.

**Table A4.2: Summary of additional direct fuel cost allowances for gas and electricity**

Allowance	Electricity (single rate and multi- register)	Gas
Shaping, forecast and imbalance	5.9%	4.3%
Transaction costs	0.4%	0.3%
Additional allowance for uncertainty	1.0%	1.0%
<b>Total</b>	<b>7.3%</b>	<b>5.6%</b>

- 3.3. In addition, we propose to uplift our estimated wholesale allowance using multipliers to reflect the expected level of distribution and transmission electricity losses (equal to an uplift of around 9.5% in 2017/18, for a single rate customer), and unidentified gas (equal to an uplift of around 1.0%). These uplifts are applied to both the core direct fuel cost allowances, and the additional allowances in Table A4.2.
- 3.4. Finally, we add an allowance to reflect the costs of the capacity market scheme in a given fiscal year, estimated using information on the clearing prices of capacity auctions and forecasts of winter peak demand.

## Shaping, forecast error and imbalance costs

### Proposal

- 3.5. We propose to include an allowance for the expected costs of converting forward energy contracts into more granular contracts in order to meet customers' outturn demand. These are legitimate costs that an efficient supplier would incur, but they are not captured in the costs of forward contracts for the seasons ahead. For this reason, we separately assess these costs and provide an additional allowance for them.
- 3.6. We calculate this allowance by estimating the costs of shaping and imbalance, given typical forecast error. We treat these elements together because, firstly they are different parts of the same broad objective, and secondly, different suppliers place different emphasis on each component depending on their circumstances and market conditions. One supplier might incur higher shaping costs, but reduce its imbalance costs compared to another supplier.
- 3.7. We set out our approach below. At a high level, we believe that our estimates reflect the expected costs from a prudent approach to managing shaping and imbalance, from a starting position that takes into account our method for buying forward wholesale energy contracts (eg 6-2-12 with a 70/30 baseload/peakload split).

### What we consulted on

- 3.8. In our May consultation, we asked stakeholders for their views on whether it was necessary to include additional allowances for shaping, forecast error, imbalance, and transaction costs.
- 3.9. If they thought it was necessary, we asked them for views on the size of these and evidence to support this position.
- 3.10. In the same publication, we highlighted that the changing energy system may lead to a greater reliance on shaping contracts, and increase their relative value (eg solar generation depressing demand in the middle of the day and peakload prices).

### Stakeholder feedback and evidence

- 3.11. All suppliers that commented on wholesale costs suggested additional allowances were necessary. They argued that they incur costs (on average) converting forward contracts into ones that meet more granular demand. Basing the allowance purely on forward contracts would mean the cap under recovered costs.
- 3.12. Suppliers provided confidential valuations of these costs, which varied significantly between them. In part, this variation is because the costs of shaping and imbalance depend on suppliers' different approaches to purchasing less granular forward contracts and to shaping these contracts to meet demand.
- 3.13. Valuations varied depending on whether they included allowances for extreme demand and price shocks, apparent basis risk, and unidentified gas losses. We aim estimate typical forecast error, and discuss these other examples later in the chapter (under losses and unidentified gas).

## Our approach

- 3.14. We modelled the cost of shaping energy contracts for gas and electricity separately, using the same broad approach.
1. We start with a valuation of forward contracts using the 6-2-12 model described in Chapter 2.
  2. Throughout the analysis, demand is assumed to be a fixed annual amount for both electricity and gas.
  3. We estimate the costs of shaping these to more granular products, assuming seasonal normal demand. This broadly re-hedges seasonal contracts into monthly contracts. For electricity, this also accounts for intraday shaping.
  4. We calculate the additional cost of adjustments required to account for revised forecasts at the day-ahead stage, by comparing weather-corrected to out-turn demand.
  5. We calculate imbalance costs, based on historical imbalance volumes and the price difference between system buy and day-ahead prices.
- 3.15. This approach includes some key assumptions. In total, we have taken a conservative approach.
1. We analyse volumes at a national level. We do not reflect regional fluctuations.
  2. We do not include losses. We account for losses separately.
  3. We initially model shaping costs using seasonal normal demand throughout. For electricity, this is based on the data for 2017-18 provided by Elexon.<sup>6</sup> For gas, it is based on annual load profiles for 2017-18 provided by Xoserve.
  4. We do not shape between monthly and day-ahead (eg weekly). As we use seasonal normal demand, the impact of these steps is minor, pushing up transaction costs. In reality, suppliers would use these contracts to manage their forecast error in stages. We analyse forecast error directly from monthly to daily.
  5. We model forecast error differently for gas and electricity. This is because changes in demand and prices are more correlated for gas, meaning we do not wish to average out the impact of surges in demand and price that coincide.
  6. For electricity, we base our analysis on profile class one only. As most domestic consumers fall into this category, we believe this should represent the market as a whole.

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<sup>6</sup> As set out in the demand and losses workbook published alongside this consultation.



7. In calculating forecast error costs, we assume a supplier has no accurate view of weather one month ahead and bases their hedging on seasonal normal demand, but has a perfect view one day ahead (an overstated assumption), but also that only weather affects demand (an understatement).

3.16. Table A4.3 sets out our approach for the gas and electricity.

**Table A4.3: Summary of methodologies for setting additional direct fuel cost allowances for gas and electricity**

Allowance	Electricity	Gas
Starting reference contracts	Seasonal products for winter and summer, purchasing these at a 70/30 split between baseload and peakload, as per 6-2-12 model.	Quarterly contracts, as per 6-2-12 model.
Shaping to monthly demand, assuming seasonal normal demand	Convert seasonal contracts into quarterly contracts, and in turn, monthly contracts. Based on seasonal normal demand profiles and historical price shape of the forward contracts.	Convert quarterly contracts into monthly contracts, assuming seasonal normal demand profiles and historical price shape of the forward contracts.
Shaping to granular demand	Then convert monthly contracts into hourly contracts, based on seasonal normal demand profiles.	Not applied to gas.
Establish volumetric forecast error between seasonal normal and outturn	The average absolute percentage difference between out-turn demand and seasonal normal demand for the year of analysis (2017-18).	The demand error is calculated for each specific day (in the analysis year, 2017-18), comparing out-turn and seasonal normal.
Establish cost of forecast error, assuming unknown at month ahead, and fully known at day ahead	Volumetric error multiplied by the equivalent metric for the change between day-ahead and month-ahead prices over a two year deliver period. We conservatively assume that the change in price is always in the wrong direction, increasing the allowance.	The cost is calculated for each day, taking the volume error multiplied by day ahead price for that day. Some days have profit, some days incur losses. There is a net loss.
Imbalance	We multiply the average volumetric imbalance of a group of nine suppliers using two years of data, by the average absolute price difference between system buy prices and day-ahead prices. We conservatively assume that the change in price is always in the wrong direction, increasing the allowance.	We multiply the average volumetric imbalance of a group of seven suppliers using two years of data, by the average absolute price difference between system buy prices and day-ahead prices. We conservatively assume that the change in price is always in the wrong direction, increasing the allowance.

Source: Ofgem

- 3.17. We recognise that wholesale costs are a material and unpredictable element of suppliers' costs. Suppliers raised concerns about additional risks not explicitly taken into account in our modelling for additional allowances. We discuss these below (paragraphs 3.48 to 3.53) in our consideration of uncertainty, headroom, and updating the default tariff cap.

## Transaction costs

### Our proposal

- 3.18. We propose to provide an additional allowance for transaction costs: 0.32% of direct gas costs, and 0.40% of direct electricity costs.
- 3.19. We propose to account for collateral costs in the cost of capital allowance included in the cap (i.e. using 1.9% earnings before interest and tax, or EBIT, rather than 1.25%), not in the wholesale allowances.<sup>7</sup> Please see Appendix 9 for more details.

### What we consulted on

- 3.20. In our May consultation, we said we would consider costs such as broker and exchange fees, the cost of operating a trading desk, and the cost of credit and collateral. However, we also said that these might also be better covered in other areas of the price cap.

### Stakeholders views

- 3.21. Most stakeholders that addressed transaction costs thought that this was a cost not captured by only assessing the value of forward wholesale contracts, and should be included as a separate allowance. However, there were different views where these costs may be included within the different elements of the default tariff cap. There was also an acknowledgement that these may vary between suppliers of the different sizes. For example, the route to market or credit rating of a supplier could lead to vastly different transaction costs.
- 3.22. Some stakeholders initially pointed out that wholesale transaction costs can materialise from market factors such as the bid-offer spread.<sup>8</sup> They said that as they operate as a supplier, they have to buy wholesale energy products on the offer (sell) price, and sell them on the bid (buy) price. These means they incur a cost every time they buy and sell in the market.
- 3.23. Some suppliers thought we should make an allowance for the cost of collateral, however, there was some acknowledgement that this cost may vary a lot between suppliers depending on their credit rating. One supplier believed their collateral costs would increase as a result of our 6-2-12 proposal. Another supplier believed that collateral should be considered a capital employed, not a hedging cost, and included in the appropriate section (eg Appendix 9). Whilst another supplier thought these transaction costs as a whole would be better captured in operating costs (Appendix 6).
- 3.24. Suppliers also addressed market access costs they believed should be covered as part of wholesale transaction costs. Several suppliers raised broker and exchange fees as items that they believed should be considered as part of a transaction cost allowance. However, one supplier suggested that broker costs were negligible. In a similar vein,

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<sup>7</sup> Competition and Markets Authority, *Energy market investigation*. <https://www.gov.uk/cma-cases/energy-market-investigation#final-report>

<sup>8</sup> The difference between the level a buyer is willing to pay for wholesale energy, and a seller is willing to accept for it.

two suppliers also thought that the cost of operating their own trading desk should be included.

### **Our rationale**

- 3.25. Transaction costs vary considerably between suppliers depending on their circumstances and activity in the wholesale market. In part, this variation reflects the different trading arrangements that different suppliers have.
- 3.26. Our benchmark is based on a supplier that does not use an intermediary for wholesale costs, and therefore we assume lower fees (that would otherwise require an allowance). We also assume higher collateral requirements (which increases capital employed). The cost of that capital employed is not recognised as an allowance here. It is recognised in the normal rate of return (see Appendix 9), where we use 1.9%, rather than 1.25% (which we would use if we modelled a supplier with an intermediary wholesale arrangement).
- 3.27. Stakeholders viewed other costs as relatively minor. We have set the transaction costs based on supplier submissions. They are applied as a percentage of direct costs (the allowance based on forward contracts).

## **Losses and unidentified gas**

### **Proposal**

- 3.28. We propose to uplift the wholesale allowance to reflect electricity distribution and transmission losses, and unidentified gas.
- 3.29. Forecast electricity losses are calculated according to the methodology set out in Appendix 5. In particular, we take forecasts of losses for different periods and regions as published by the electricity distribution network operators and Elexon for a given year, and then take a weighted average of these values to derive our overall multiplier. The resulting uplift is then applied to both the core direct fuel cost allowances, and the additional allowances discussed in the previous sections of this chapter.
- 3.30. We also propose to provide an allowance for unidentified gas (UIG), which is not captured in our analysis of forward contracts. We set the allowance of 0.96% based on our estimate of underlying gas losses. We apply this percentage to the wholesale allowance for direct gas costs based on forward contracts including the other allowances discussed in the previous sections of this chapter.
- 3.31. We recognise that recent reforms have not changed the physical amount of gas lost in the network, but they have exposed suppliers to UIG costs that are volatile in the short-term. However, the new gas settlement arrangements introduced through Project Nexus provide suppliers with domestic customers the ability to avoid other uncertain and volatile costs that resulted from the former Reconciliation by Difference (RbD) arrangements. Suppliers also have the ability to control their exposure to UIG costs both in the short and long term. For example, through the submission of more regular meter reads. We note that Xoserve is also leading a cross-industry project to reduce the volatility of UIG charges in the short term and help establish a more certain view on long-term costs. As such, we do not consider that these uncertainties need further additional increases in this in the explicit allowance. To the extent that there

are uncertainties which suppliers cannot reduce or other manage, we do consider it when discussing uncertainty, headroom, and updating the default tariff cap (paragraphs 3.48 to 3.53).

### **What we consulted on**

- 3.32. We did not specifically consult on an allowance for this cost area in our May consultation. However, we did mention it in the context of forecast error and imbalance. We highlighted it as an area there may be specific challenges with in terms of using historical trends to assess future levels.

### **Stakeholder feedback and evidence**

- 3.33. Despite not asking any specific questions on this issue, we received feedback on UIG as part of the responses to our May consultation. Suppliers that raised this issue were all in favour of providing an allowance for UIG. The estimates of the cost and potential allowance provided by suppliers broadly came out within a similar range.
- 3.34. Feedback from suppliers broadly characterised this cost in two ways. Firstly, some suppliers discussed the cost in terms of its long-run nature. In this context, they argued it was an unavoidable supplier cost as it related to the amount of gas that could not be attributed directly to any system user. Secondly, and of larger concern to suppliers, they discussed this cost in terms of recent variability in UIG costs and the risk associated with these movements.
- 3.35. On the volatility, suppliers have reported marked changes in the volatility of UIG since the implementation of Project Nexus<sup>9</sup> in 2017. Imbalances were previously passed through using the RbD mechanism (which also resulted in volatility for suppliers). This has been replaced with individual meter reconciliation, making any demand estimation error more transparent. The allocation remains heavily weighted towards the non-daily metered sector, so the impact of any changes may be more noticeable to domestic suppliers.
- 3.36. Suppliers reported the levels of UIG volatility in the last year or so. At one extreme, a supplier had reported seeing industry wide swings of between -7 to 18%. Another supplier observed increases of up to 10%, whilst other suppliers reported that the volatility was affecting profitability and out-turning at double their expectations.
- 3.37. One supplier thought this level of volatility was not a matter of efficiency and was out of their control, with the implication that there should be an allowance to cover the full cost of this variability.
- 3.38. Suppliers also provided us with estimates of what they believe the level of an UIG allowance should be. Several suppliers reported UIG costs in the 5-7% range reported costs. One of these suppliers also drew out the risk element of UIG. They split the

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<sup>9</sup> This is the replacement of legacy UK Link systems. This aims to replace the systems to meet the current and anticipated requirements of market participants, and ensure market participants update their own IT systems to work with the new Xoserve systems.

allowance they would like to see between costs (4%) and risks (2%), recognising the difference between some of the recent uncertainty observed and the underlying cost.

- 3.39. Another supplier noted that while they were seeing large and variable costs on UIG, they were also seeing some initial large reconciliations. However, at this stage reconciliation values were still outweighed by the initial cost. They noted that even if this was not a new cost and the outgoings would eventually be reconciled, this could potentially present a cash flow problem whilst waiting for reconciliation.

### **Our rationale**

- 3.40. We agree with suppliers that there are two separate issues: the underlying gas losses and variability in the costs associated with those losses. However, we do not agree that these costs are uncontrollable for an efficient supplier.

#### *Electricity losses*

- 3.41. We have included losses in this section as the prices we use to estimate direct fuel costs are based on energy delivered on transmission system. These are subject to physical losses and therefore need to be uplifted to reflect the costs a supplier incurs per MWh as some of the electricity they put onto the transmission system is lost before it reaches the customers meter point.

#### *Physical gas losses*

- 3.42. We agree that the default tariff cap should provide an allowance for the underlying losses. Gas losses are a physical feature of the network and not something an efficient supplier can avoid, therefore there is a need for some kind of allowance. However, we do not agree with those suppliers claiming that gas losses are uncontrollable. There are actions suppliers could take – for example to tackle theft (one of the largest causes of UIG) which would reduce the level of these costs. Moreover, at an individual level, an efficient supplier could (through their shipper) utilise the new gas settlement arrangements to control their exposure to UIG costs through the submission of more regular meter reads into the central gas systems. We have calculated our estimate of UIG at 0.96%, and we propose to use this figure as the basis for an allowance. We have used publically sources (Allocation of Unidentified Gas Expert, or AUGES) to derive this factor.
- 3.43. We have calculated the allowance for physical gas losses by following the steps below, using information from the Final Allocation of Unidentified Gas Statement for 2018/19.<sup>10</sup>
1. We calculate a daily permanent UIG figure in GWh by dividing the forecast of total permanent UIG for 2018-19 by 365 (ie  $3,826 / 365 = 10.48$  GWh).<sup>11</sup>

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<sup>10</sup> Final Allocation of Unidentified Gas Statement for 2018/19.  
[https://www.gasgovernance.co.uk/sites/default/files/ggf/book/2018-06/Final%20AUGES%20for%202018\\_19\\_V3.0.pdf](https://www.gasgovernance.co.uk/sites/default/files/ggf/book/2018-06/Final%20AUGES%20for%202018_19_V3.0.pdf)

<sup>11</sup> Expected total permanent Unidentified Gas for 2018-19 is 3826 GWh (pg 71). Final Allocation of

2. We then calculate how much of the 10.48 GWh should be allocated to domestic gas consumers, ie End User Category (EUC) 1 Product 4. This is 8.27 GWh<sup>12</sup> of 10.48 GWh. We then create an annual value by calculating  $8.27 \times 365 = 3018.55$  GWh.
3. Finally, we calculate the annual UIG uplift value for EUC1 Product 4 by dividing annual gas losses of 3018.55 GWh for this category by the projected Annual Quantity (AQ)<sup>13</sup> for EUC1 Product 4 (ie  $3018.55 / 313,663 = 0.96\%$ ).

#### *Volatility in charges for gas losses*

- 3.44. We acknowledge there is uncertainty and volatility around the current cost of UIG. That volatility is the result of new charging arrangements, and is not expected to continue in the long term. Suppliers have highlighted concerns related to variability in the level of UIG to Ofgem.<sup>14</sup> Xoserve has been tasked with developing and publishing a model assessing forecast UIG that all shippers will have access to.
- 3.45. Despite volatility in the current charges, we note that suppliers can, and are expected to, influence the costs they are exposed to. Suppliers can assess and limit the extent to their exposure (for instance, by submitting more regular meter readings) and procure the extra energy volumes required. Collective action by suppliers to submit more regular meter reads would have an impact in both reducing short-term volatility. We do not consider suppliers' ability to assess future levels of UIG to be limited. We regard this as a potential transitional issue that may partly be related to suppliers submitting poor quality data (eg infrequent meter reads).
- 3.46. We wish to support incentives to improve information on UIG and its management, improving incentives to manage the network efficiently. We are aware that industry is taking steps to resolve this. We therefore anticipate that any issues will be resolved and do not believe it would be appropriate to base the level of the UIG allowance on recent volatility. Therefore, we are wary of building in a permanent increase to the default tariff cap, which could dampen incentives, curtail progress, and overstate costs given the paucity and variation in current information.
- 3.47. We consider this remaining volatility and uncertainty in the next section, where we consider additional allowances, headroom, and updating the default tariff cap.

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Unidentified Gas Statement for 2018/19.

[https://www.gasgovernance.co.uk/sites/default/files/ggf/book/2018-06/Final%20AUGS%20for%202018\\_19\\_V3.0.pdf](https://www.gasgovernance.co.uk/sites/default/files/ggf/book/2018-06/Final%20AUGS%20for%202018_19_V3.0.pdf)

<sup>12</sup> This is based on the annual Aggregate AQ for April 2019 of 313,663 GWh for EUC 1 Product 4 (pg 26). This is divided by 365 to create a daily figure. The daily figure (859.4 GWh) is then multiplied by the AUG factor for EUC 1 Product 4 of 94.64 (pg 70). The product of this (81,329) is then divided by the sum of the calculation for all product types (103,050), and multiplied by daily permanent UIG figure (10.48 GWh). Final Allocation of Unidentified Gas Statement for 2018/19.

[https://www.gasgovernance.co.uk/sites/default/files/ggf/book/2018-06/Final%20AUGS%20for%202018\\_19\\_V3.0.pdf](https://www.gasgovernance.co.uk/sites/default/files/ggf/book/2018-06/Final%20AUGS%20for%202018_19_V3.0.pdf)

<sup>13</sup> An estimate of annual consumption under seasonal normal conditions.

<sup>14</sup> Open letter: unidentified gas allocation. <https://www.ofgem.gov.uk/publications-and-updates/open-letter-unidentified-gas-allocation>

## Additional risk and uncertainty

### Our proposal

- 3.48. We propose to increase our additional allowances by a further 1% of the core direct fuel cost allowance, for both gas and electricity.
- 3.49. This additional allowance recognises that wholesale costs are a material and unpredictable element of suppliers' costs, and that there are additional risks not explicitly taken into account in our modelling.
- 3.50. We also propose to include a headroom allowance of 1.45% of all costs excluding networks, which is equivalent to £10 in 2017-18 for a dual fuel customer paying by direct debit, with a single rate electricity meter. See Appendix 2 for further details on headroom, and how it is applied to the default tariff cap. We note that this allowance relates to other areas of uncertainty as well as wholesale costs.

### Our rationale

- 3.51. Stakeholders have raised several risks that are only partially accounted for, or not accounted for in the wholesale allowance.
1. **Volatile demand due to weather.** Suppliers could face higher costs than the cap may allow for, for instance if there is a long severe winter period (such as 'the Beast from the East').
  2. **Apparent basis risk.** As discussed in Chapter 2 (paragraphs 2.33 to 2.42) the 6-2-12 model bases the allowance on a 12-month average cost, but applies it for 6 months. This can expose them to shifts in the summer-winter spread, potentially incurring additional transaction costs, additional working capital, or fees.
  3. **Volatility around gas losses:** as discussed above, suppliers incur cash flow costs from the current volatility in charges for gas losses, and there is some uncertainty around the underlying level of losses. Some suppliers suggest they have limited control to monitor and manage losses.
  4. **Modelling uncertainty.** There are inherent risk in modelling future costs. Suppliers can manage this by including a risk premium in their prices, or by adjusting them after the fact. The cap prevent suppliers from doing the second of these responses.
- 3.52. We have considered four ways to mitigate the impact of these concerns, and others.
1. Adjusting our methodology, by making prudent assumptions.
  2. Including a specific additional wholesale allowance
  3. Including non-specific headroom allowance
  4. Adjusting the way the default tariff cap is updated.

- 3.53. We use a combination of these four levers to balance protection for customers (for instance by not permanently increasing the default tariff cap for uncertain, atypical or temporary costs), and ensuring we have had due regard to the need to ensure the financeability of an efficient supplier:
1. **Volatile demand due to weather.** We have chosen to update wholesale costs every six months, in order to pass through wholesale price changes more quickly, and limit large deviations between the cap and prevailing prices. We also assessed forecast error using outturn data from 2017-18 (which included severe weather in the first quarter of 2018, increasing the allowance compared to a milder year (2016-17). There may be shocks in the future, but we do not think it is in customers' interest (in line with the Act's objective on protection) to permanently increase the wholesale allowance to provide for such temporary shocks, over and above the allowances we have already made. We provide headroom so that suppliers to manage their temporary volatility across a range of sources.
  2. **Apparent basis risk.** In Chapter 2, we acknowledge that suppliers are exposed to change in the summer-winter spread for the first default tariff cap. After that, there is a range of options to manage exposure from locking in the profit and loss impact, to managing the cash flow. These incur some cost. We have considered this in providing the additional specific wholesale cost allowance and headroom.
  3. **Gas losses.** We recognise the current volatility and uncertainty around gas charges, but do not think it is necessary to increase costs to consumers based on poor information about their costs, or dampen incentives for suppliers to take steps to improve their data and management of gas losses; steps we consider it reasonable for an efficient supplier to take. We will continue to monitor the developments and could adjust the allowance using our modification powers if data shows that to be necessary.
  4. **Modelling uncertainty.** We recognise that the modelling we have carried out introduces uncertainty and that wholesale costs are a significant element of overall costs. We consider that we have used prudent assumptions for wholesale, to limit the impact on uncertainty. However, we have factored the risk of residual uncertainty into in when setting the headroom allowance.

## Capacity Market costs

### Our proposal

- 3.54. Suppliers must also make payments to fund the CM scheme, designed to ensure security of supply. As discussed in Appendix 1, we consider that these are best categorised as wholesale energy costs.
- 3.55. For CM we propose to set the allowance included in the default tariff cap with reference to costs for a given fiscal year (running April to March). To do this, we will estimate costs for the two CM delivery years overlapping the fiscal year, and then take a weighted average. This is consistent with the horizon used in the existing safeguard tariffs.



3.56. Specifically, we propose to:

- a) calculate expected aggregate payments for each CM delivery year based on the outcome of previous capacity auctions as published by National Grid – after taking into account any contract terminations, as well as inflating auction clearing prices by consumer price index (CPI), where necessary
- b) weight these to reflect the proportion of the costs of each CM delivery year that overlap with the given fiscal year, based on weighting factors published by the Low Carbon Contracts Company (LCCC)
- c) add to this the settlement cost levy for the given fiscal year, as published by the Department for Business, Energy and Industrial Strategy (BEIS)
- d) divide by forecast total winter peak demand to derive an implied cost per peak winter MWh on the transmission system
- e) combine this with an estimate of the proportion of domestic customers’ demand that takes place during the winter peak period for a single rate and multi-register electricity customer, to get a cost per MWh for a domestic customer
- f) uplift for forecast regional transmission and distribution losses, estimated according to the methodology set out in Appendix 5.

3.57. Full details of our proposed methodology – including historic examples - are set out in Annex 2 to the licence condition.

3.58. Table A4.4 sets out our estimates of the costs of the CM scheme in 2017-18 calculated using this methodology. The estimates provided reflect the charges to suppliers. However, it is important to note that they will not reflect the full impact of the scheme on customer bills – or the overall cost of the scheme to customers. This is because this will depend on the wider impacts of CM on wholesale prices.

**Table A4.4: Estimates of Capacity Market costs in 2017-18 (£ per customer per year based on typical annual consumption, GB average)**

Electricity (single rate) (£)	Electricity (multi-register)(£)
3.41	3.63

Source: Ofgem calculations based on data from LCCC and Elexon.

Notes:

1. The figures reflect a weighted average of our estimates of scheme costs as would have been forecast for periods starting April 2017 and October 2017. For electricity, we assume that 57% of consumption takes place in winter for single rate and 61% for multi-register.
2. Typical Domestic Consumption Values (TDCV) are 3.1MWh per year for electricity (single register), 4.2MWh per year for electricity (multi-register) and 12.0MWh per year for gas. See [this](#) page for further details.

### Key changes compared to our May consultation

3.59. In our May consultation, we proposed to estimate CM costs based on aggregate capacity payments, including administration costs, which would be combined with estimates of forecast winter peak domestic demand and total electricity demand from National Grid’s Future Energy Scenarios (FES).

- 3.60. In response to our consultation, a number of stakeholders suggested that our capacity market estimates should be based on domestic customers' share of consumption that falls in the specific winter peak period used for the purposes of calculating CM charges. It was argued that using forecasts from the FES for winter peak demand was not appropriate as a different definition of winter peak demand was used.
- 3.61. Following this feedback, we have revised our proposed approach to estimating domestic demand in the specific winter peak periods that are used to calculate suppliers' CM payments. In particular, rather than using the FES data, we now estimate for single rate and multi-register customers the expected share of weather-corrected demand taking place in the specific 4pm to 7pm, November to February, weekday winter peak period based on Elexon data. Full details of our calculations are provided in the supplementary Demand and losses workbook.
- 3.62. One respondent suggested that our peak demand forecasts could be uplifted to reflect BEIS estimates of the trend in overall forecast demand from year to year. However, we noted that these forecasts do not relate to the specific winter peak period. Our preferred approach to estimating chargeable demand for the purposes of forecasting the costs of the CM scheme is therefore to use forecasts specifically of gross demand during the winter peak, as calculated by the LCCC.
- 3.63. Another stakeholder commented that T-4 auction prices that Ofgem proposed to use for calculating CM costs were in 2012 prices, and should be updated to current prices using CPI. We agree, and have adjusted our methodology to reflect this.
- 3.64. We also propose to increase the accuracy of our estimates of the total value of capacity payments used to calculate the costs of the scheme by basing these on the latest Capacity Market Registers for the relevant scheme year, as published by National Grid as of 1 August and 1 February for the August and February updates respectively.

## 4. Updating the default tariff cap

In this chapter, we outline how we propose to value the forward wholesale contract costs in the core direct fuel allowance for the first default tariff cap period.

### Overview

- 4.1. In this chapter, we explain how we propose to value the forward wholesale contract costs in the core direct fuel allowance for the first default tariff cap period. This will be shorter than the enduring periods for the default tariff cap.

### Our proposal

- 4.2. The first default tariff cap period will be shorter than the normal six-month period (ending 31 March 2019). We propose to set the wholesale allowance using the same approach we would use for a normal winter cap period (estimating the core direct fuel allowance in the manner described in Chapter 2, and applying additional allowances, as described in Chapter 3).

### What we consulted on

- 4.3. In our May consultation, we acknowledged that transition to the default tariff cap posed potential risks for wholesale cost, whatever approach we take.
- 4.4. In our May consultation we presented a 6-3-12 three-month model, which used a later observation period (between 1 April 2018 and 30 September 2018) but was otherwise the same as the approach we set out above. We asked stakeholders whether they agreed that our approach setting the first allowance was appropriate, or whether we should consider alternatives.
- 4.5. We also discussed adjusting the CMA's model to have shorter observation and/or lag times to allow the initial indexation to use only prices in the future (eg from the point of publishing a minded to decision). At the time, we did not propose to pursue this option. We concluded that this would result in a very short observation period that would be susceptible to short-term market movements. We also had concerns about a large proportion of the market attempting to follow this approach at the same time, increasing demand for products.
- 4.6. We acknowledged that suppliers were likely to have already purchased a proportion of the energy for delivery in the first cap period, which posed a risk or benefit to suppliers depending on the way wholesale market prices evolved.

### Stakeholder feedback and evidence

- 4.7. The majority of suppliers that addressed this issue broadly agreed that our proposal was appropriate. Not all of the responses explained the reasons for their support. However, two suppliers supported our position broadly on the basis that our May consultation provided a signal to suppliers. In their view, any deviation from these proposals represented more uncertainty and potentially increased costs to suppliers.

- 4.8. One supplier raised concerns that the transition period in our May consultation included an observation period that began before the publication of our May consultation.<sup>15</sup> They believed suppliers should be able to replicate the approach, but our proposal was not replicable. Further, they believed this approach creates an unjustified commodity risk as we may impose a wholesale allowance level lower than the costs suppliers have already incurred, for reasons outside of the supplier's control. They considered this approach "retrospective", and thought that it exposed the market to regulatory risk.
- 4.9. This supplier instead suggested using a shorter, forward-looking period that suppliers could follow. They thought a three-month observation period would be sufficient, and believed they could purchase the volumes they needed for the upcoming default tariff cap in this period.
- 4.10. One other supplier highlighted the use of historical prices in the first default tariff cap period as a concern.
- 4.11. Other suppliers suggested various different approaches to set the direct fuel allowances for the first default tariff cap period, implicitly requiring a change to the transition period on which we consulted.
- 4.12. One supplier broadly agreed with this approach, but expressed a preference to delay the start of the default tariff cap to align with the update dates of the existing safeguard tariff (ie April 2019). They raised concerns that suppliers will now be exposed to risk related to whether they pre-emptively adjusted their hedge. However, they also acknowledged this had to be balanced with the lack of certainty with the design of the default tariff cap. Another supplier expressed a preference for a delayed start date of the default tariff cap.

### **Our rationale**

- 4.13. In our May consultation, we recognised that there was no perfect solution to manage the transition into the new arrangements under the default tariff cap. We set out a proposal as part of a consultation process with the intention of seeking feedback from stakeholders. In light of further assessment, we have reconsidered the issues and are proposing to adjust our approach from the proposal to improve outcomes for customers and ensure the wholesale allowance reflects underlying costs more closely.

#### *Considering historic prices*

- 4.14. We recognise suppliers' concerns about using historic prices to set the allowance for the first default tariff period. Doing so, means that suppliers can no longer access the prices that we have used to set the allowance.
- 4.15. However, as we state in Chapter 2 the allowance is not, in itself, a 'hedging strategy' that supplier must follow. Its primary function is to set an allowance that gives a realistic allowance to cover the costs that suppliers might incur delivering energy. In later periods, we consider that suppliers will adjust their behaviour to manage their costs within the default tariff cap. There is nothing in principle wrong or retrospective

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<sup>15</sup> The observation period started at the beginning of April 2018. Our Policy Consultation was published on 25 May.

about using our model in the early periods to approximate the costs of contracts that suppliers have already incurred (similarly, our approach on operational costs benchmarks to historic costs).

- 4.16. Some suppliers, particularly those with many SVTs, are likely to have purchased a proportion of the energy to be delivered during the first default tariff cap period already, given historic purchasing strategies. Submissions in response to our consultation, and data we have on suppliers' strategies in 2016, suggest that large proportions of energy for delivery in early 2019 would have been bought in early 2018 or even earlier, and as such predating any detailed discussion or consultation on the default tariff cap. Suppliers have historically tended to buy energy contracts for SVT customers significantly further in advance than for fixed-term customers.
- 4.17. Suppliers existing purchasing strategies create a risk that their wholesale costs may be different from those assessed in the default tariff cap. However, we do not consider it likely that suppliers would seek to undo previous actions to align to the model for setting the initial periods of the default tariff cap. Suppliers are unlikely to sell all of their contracts, and then buy them back again at newly available prices. Even if they did so, this would incur costs (reducing potential profits) or realise potential losses. If market prices had increased since that supplier purchased the contracts initially, they would make a gain (adjusting for transaction costs). As such, the default tariff cap would provide a higher allowance than their actual cost required. If the market had fallen since the supplier had first bought contracts, they would incur a loss. Our default tariff cap would set a lower allowance than the supplier's actual costs required. In the latter case, we may have needed to consider a temporary adjustment to allow suppliers to recover their actual cost.
- 4.18. In practice, wholesale costs have increased significantly since the beginning of April 2018, and are now broadly 30% higher.<sup>16</sup> The effect would be that suppliers that have purchased energy for SVT customers in advance would incur significantly lower costs than the transition arrangement we proposed. This risks significant overcharging for SVT customers. An approach that uses more prices from earlier in 2018 is more likely to better reflect their actual costs, and better protect customers.
- 4.19. We considered using an interim observation window that we judged to better reflect the costs incurred by large suppliers that have the most SVT customers (ie by setting an observation window earlier and/or longer than our normal winter window between February and July). However, we recognise that different suppliers take different approaches. If we were to move the observation window back far enough to reflect the likely costs incurred by suppliers that hedge a long time in advance, then we know other suppliers with historically shorter hedging periods would have actual costs significantly above the allowance in the cap. Whatever period we choose, some suppliers are likely to over recover their costs, and some may under-recover.
- 4.20. We considered, but do not think it justified, delaying the cap, as suggested by some suppliers. Some suppliers hedge a very long time in advance, so even a cap introduced in April 2019 would risk suppliers under- or over-recovering due to contracts they had

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<sup>16</sup> This comparison takes into account the assessed price changes of Day Ahead and Winter '18 contracts for gas and electricity (base and peak) from the beginning of April '18 to the first week of September '18.

already purchased. Although it might mitigate the effect, it would substantially delay protection to customers, the objective of the Act.

- 4.21. On balance, we judge that using the usual winter observation window (February to July) gives a sufficient approximation of the cost suppliers actually incur and is the most reasonable position to adopt. In making this proposal we have also taken into consideration the objective for the default tariff cap as set out in the Act. For larger suppliers, we consider it is likely to be an overestimate, although by a lesser amount than the proposed approach in our earlier consultation (eg using an observation window between April and September would increase the wholesale allowance by more than £30 for a dual fuel SVT customer in annualised terms, and around £7 for the duration of the first cap period). We do not consider the risks to those smaller suppliers, who may have shorter hedging strategies, are likely to be significant given their limited exposure to SVT customers, and the different approach to hedging for fixed term customers (of which they have more).

## 5. Next steps

In this chapter, we outline our next steps in relation to the disclosure of models and underlying data used to determine the wholesale allowance

- 5.1. As part of our policy development process, Ofgem has received information and/or data from a number of parties to inform the development of the wholesale allowance model for gas and electricity.
- 5.2. In light of the particularly sensitive and confidential nature of the underlying data, we consider it necessary to disclose the models and underlying data through the establishment of a disclosure room. This will be accessible to a limited number of approved external legal and/or economic advisers of the relevant parties.
- 5.3. The disclosure room will include two wholesale allowance models (one electricity and one gas) and the underlying data used in the models. Both of these models calculate estimates of additional direct fuel cost allowances that the core direct fuel allowance does not capture. The allowance models assume the approach that we use to value the direct wholesale cost allowance (eg same forward contracts) as starting position, and then calculate an allowance for shaping, forecast and imbalance that derive from this. Our assessment of transaction costs will also be included.
- 5.4. Further information on the arrangements for the disclosure room will be set out in the legal undertakings that all parties intending to take part in the disclosure room are required to sign.
- 5.5. As part of the default tariff cap draft licence consultation, we have published Annex 2 (wholesale cost allowance methodology), the model which is used to calculate the value of wholesale cost allowance using the prices of forward wholesale gas and electricity contracts.
- 5.6. The above approach recognises the detail and complexity related to deriving wholesale costs through a bottom-up methodology. We believe access to these wholesale models and input data increases the level of transparency around our approach, and makes it easier for stakeholders to engage with our proposals.