Decision Appendix

Default Tariff Cap: Decision	
Appendix 4 – Wholesale costs	

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In accordance with the Domestic Gas and Electricity (Tariff Cap) Act 2018, we are implementing the default tariff cap to come into effect from 1st January 2019. This supplementary appendix sets out our decision and the detailed methodology in relation to wholesale costs.

Please see the default tariff cap – decision overview document for an accessible summary of the complete methodology.

Document map

Figure 1 below provides a map of the documents published as part of the decision on the implementation of the default tariff cap.

Figure 1: Default tariff cap – decision document map

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Default tariff cap – decision overview document

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1. Introduction

1.1. We set the default tariff cap using a bottom-up assessment of efficient costs. Under this approach, we set and update separate allowances for each component of the cap.

1.2. In this appendix, we explain our decision on the methodology we are using to set and update the wholesale allowance. We also discuss how we considered responses to our statutory consultation.[1]

Decisions and methodology

1.3. In Chapter 2, we explain our methodology for calculating the wholesale allowance. We set this allowance in three parts (as shown in Tables A4.1 and A4.2):

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 Competition and Markets Authority's (CMA) prepayment meter (PPM) cap wholesale market model

2. **additional direct fuel allowances:** we uplift the core direct fuel allowance by a set percentage to reflect the expected costs of converting less granular forward contracts to more granular demand before delivery, transaction costs, losses and additional uncertainty

3. **Capacity Market payments:** We provide an allowance for the costs of the Capacity Market (CM) scheme, designed to ensure electricity security of supply. We calculate these costs using information on auction clearing prices with forecasts of gross peak demand.

1.4. We update the allowance every six months by:

1. updating the core direct fuel allowance

2. applying the set additional direct fuel allowances to the updated core direct fuel allowance values

3. adding the CM payments based on relevant data.

[1] Statutory consultation: Default tariff cap, https://www.ofgem.gov.uk/publications-and-updates/default-tariff-cap-overview-document

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
2. Additional direct fuel allowances	24.78	33.39	14.32]	39.10
3. CM payments	3.41	3.63	n/a	3.41
Total	**169.70**	**229.54**	**199.48**	**369.18**

Table A4.2: Estimates of wholesale costs in Q1 2019, £ per customer (GB average)

Cost component	Electricity (single rate)	Electricity (multi-register)	Gas	Dual fuel (implied)
1. Core direct fuel allowance	164.77	225.00	225.89	390.65
2. Additional direct fuel allowances	27.91	37.74	17.47	45.38
3. CM payments	11.08	11.82	n/a	11.08
Total	**203.75**	**274.55**	**243.36**	**447.11**

Source: Ofgem, SLC28AD Annex 2 – Methodology for determining the Wholesale Cost Allowance

Notes:
The figures reflect a weighted average of our estimates of wholesale costs as they would have been calculated according to our proposed methodology. Table A4.1 is for the periods starting April 2017 and October 2017, and table A4.2 is for the period starting January 2019. 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.

These figures are for Typical Domestic Consumption Values (TDCV), which are 3.1 megawatt hours (MWh) per year for electricity (single register), 4.2MWh per year for electricity (multi-register) and 12.0MWh per year for gas.

Considering consultation responses

1.5. In Chapter 3, we explain how we considered stakeholders' responses to our statutory consultation (and our previous May consultation).[2] We received 24 responses relating to various aspects of our approach to setting the wholesale allowance.

1.6. Key issues raised by stakeholders in relation to the core direct fuel allowance were:

- how the length of the forward view affects prices (seasonality)
- the length of the cap period and the frequency of the updates (smoothing)
- impacts of the 6-2-12 approach (eg volume and basis risk).

1.7. Several stakeholders raised concerns about our approach to setting the allowance for the first cap period. Broadly speaking, they were not in favour of the change in proposal between our May and statutory consultations. Stakeholders broadly thought that the May consultation had provided a signal that they had based their wholesale market activities for the first cap period around. Further, assessing costs based on a February to July 2018 observation window would under estimate supplier costs. Stakeholders also thought we failed to provide evidence and justification for our statutory consultation proposal.

[2] Default tariff cap: policy consultation, https://www.ofgem.gov.uk/publications-and-updates/default-tariff-cap-policy-consultation-overview.

1.8. We discuss this feedback and explain why we consider the statutory consultation proposal to be appropriate in pages 41 to 51 of Chapter 3.

1.9. Stakeholders also provided feedback on several issues relating to our proposed additional direct fuel allowances. The main issues relating to these allowances were in relation to:

- the level of unidentified gas (UIG)
- our approach to addressing remaining risk and uncertainty (eg weather and basis risk)
- how we allow for CM costs.

1.10. Finally, suppliers also provided feedback on specific elements of allowance models. We used these models to calculate shaping, forecast error, imbalance costs and transaction costs.

2. Decisions and methodology

An overview of our decisions and methodology for each component of the wholesale cost allowance.

Overview

2.1. We set the wholesale allowance in the default tariff cap using a bottom-up cost assessment. This means we calculate the appropriate level of wholesale costs by estimating efficient allowances for each element of wholesale cost.

2.2. 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 PPM cap wholesale market model

2. **additional direct fuel allowances:** we uplift the core direct fuel allowance by an additional set percentage to reflect the expected costs of converting less granular forward contracts to more granular demand before delivery, transaction costs, losses, and additional uncertainty

3. **Capacity Market payments:** We provide an allowance for the CM scheme, designed to ensure electricity security of supply. We calculate the cost of payments by information on auction clearing prices with forecasts of gross peak demand.

2.3. Tables A4.3 and A4.4 below set out the wholesale allowance for 2017-18 and Q1 2019, with core components of the wholesale allowance displayed separately.

Table A4.3: 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	9.03	12.29	8.56	17.59
2b) Additional uncertainty	1.42	1.93	1.85	3.27
2c) Electricity losses/UIG	14.33	19.17	3.91	18.24
3. CM payments	3.41	3.63	n/a	3.41
Total	**169.70**	**229.54**	**199.48**	**369.18**

Table A4.4: Estimates of wholesale costs in Q1 2019, £ per customer (GB average)

Cost component	Electricity (single rate)	Electricity (multi-register)	Gas	Dual fuel (implied)
1. Core direct fuel allowance	164.77	225.00	225.89	390.65
2a) Reshaping; forecast error and imbalance; transaction costs	10.52	14.36	10.44	20.96
2b) Additional uncertainty	1.65	2.25	2.26	3.91
2c) Electricity losses/UIG	15.74	21.13	4.77	20.51
3. CM payments	11.08	11.82	n/a	11.08
Total	**203.75**	**274.55**	**243.36**	**447.11**

Source: Ofgem, SLC28AD Annex 2 – Methodology for determining the Wholesale Cost Allowance

Notes:
The figures reflect a weighted average of our estimates of wholesale costs as they would have been calculated according to our proposed methodology. Table A4.3 is for the periods starting April 2017 and October 2017, and table A4.4 is for the period starting January 2019. 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.

These figures are for Typical Domestic Consumption Values (TDCV), which are 3.1 (MWh) per year for electricity (single register), 4.2MWh per year for electricity (multi-register) and 12.0MWh per year for gas.

2.4. In this chapter, we explain our method for setting each allowance and updating the cap over time in line with the decisions we have made on the wholesale costs.

Core direct fuel allowance

2.5. We set the majority of the wholesale cost allowance using a model that assesses the value of forward gas quarter and electricity season contracts. Our approach is primarily based on the CMA's wholesale market model, which is used for the PPM cap. We describe that model in more detail in Chapter 2 of Appendix 6 – Wholesale costs of our May consultation. We have made some amendments between May and our statutory consultation. For example, we have updated the demand weightings to a level we believe better reflects the energy usage patterns of default tariff customers. Please see SLC28AD Annex 2 for more details on the adjustments that we have made.[3]

2.6. Annex 2 provides full details of our calculations, including a number of examples to illustrate how the methodology works in practice.

The model – smoothing and seasonality

2.7. We set the core direct fuel allowance by valuing a selection of forward gas and electricity contracts. We 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 and statutory consultations, and the approach used in the wholesale indexation model for the PPM cap.

[3] Ofgem (2018), Default Tariff Cap – Decision: Annex 2 Methodology for determining the Wholesale Cost Allowance www.ofgem.gov.uk/publications-and-updates/default-tariff-cap-decision-overview

2.8. An illustrative 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:

- **an observation period ("6" months):** The allowance would be the average of daily wholesale prices 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)

- **a lag period ("2" months):** There is a two-month lag between the end of the observation period and start of the cap period (e.g. 1 February to 31 March 2018). This allows time for the cap level to be announced, and suppliers to inform customers

- **a forward view period ("12" months):** The model observes contracts for delivery in the 12-month period from 1 April 2018 (the start of the cap period) up to the end of March 2019

- **a cap period ("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.

2.9. For a winter cap period, which would normally start on the 1 October:

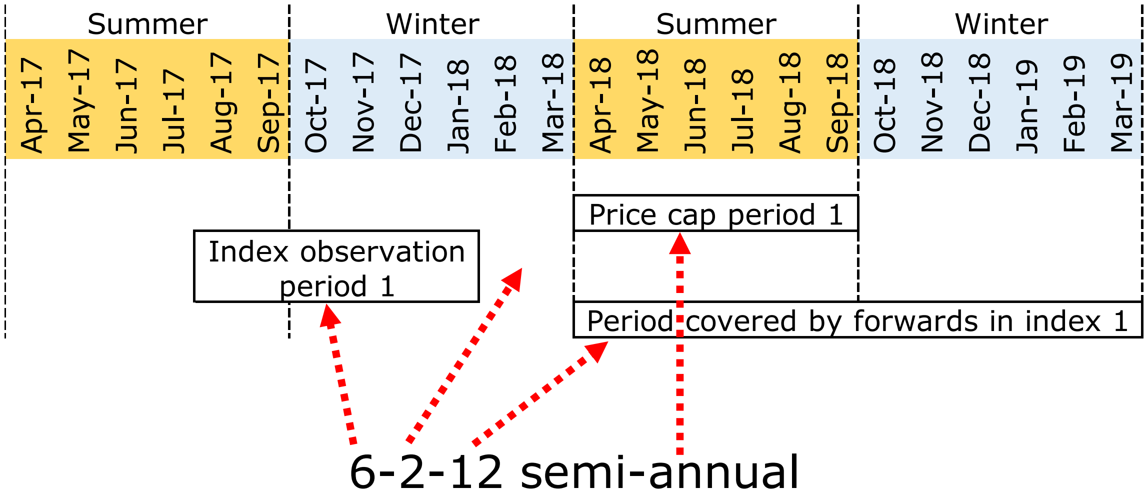
- **the observation period**: would run from 1 February to 31 July

- **the lag period**: would run from 1 August to 30 September

- **the forward view period**: would run from 1 October to 30 September (of the subsequent year)

- **the cap period**: would run from 1 October to 31 March (of the subsequent year).

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



Source: CMA, Ofgem

Initial electricity shaping – baseload and peakload split

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

Price data

2.11. We 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 PPM cap methodology) are robust and the market already has good access to these.

2.12. We use the midpoint of the assessed bid (buy) and offer (sell) prices. We consider the midpoint of the bid and offer prices is an appropriate option given the range of market participants and market conditions it will cover.

Additional direct fuel allowances

2.13. Our valuation of wholesale costs based on forward contracts does not capture all of the wholesale costs that suppliers face.

2.14. To address this, we include additional allowances to cover the costs of:

- shaping, forecast error and imbalance costs
- transaction costs
- additional risk and uncertainty
- losses and UIG.

2.15. We calculate the additional allowances for shaping, forecast, imbalance, and additional risk and uncertainty by applying a fixed percentage to the direct fuel costs we calculate based on forward contracts. The proposed allowances are set out in Table A4.5.

Table A4.5: Summary of additional direct fuel cost allowances for gas and electricity

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

Source: Ofgem

2.16. We then uplift our total estimate of the 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 UIG (equal to an uplift of 2.0%). These uplifts are applied to both the core direct fuel cost allowance and the additional direct fuel cost allowances in Table A4.5.

2.17. In the rest of this chapter, we describe how we have calculated the additional direct fuel cost allowances for gas and electricity shown in Table A4.5.

Shaping, forecast error and imbalance costs

2.18. We calculate the additional direct fuel cost allowances by first assuming a starting positon of forward energy contracts described above (in the core direct fuel allowance methodology). We then estimate the associated costs of shaping, forecast error and imbalance that could follow from this initial position. We treat these elements together because they are different parts of the same broad objective, and because different suppliers place different emphasis on each component depending on their circumstances and market conditions. For example, a supplier may incur higher shaping costs, but reduce its imbalance costs as a result.

2.19. At a high level, we consider that our estimates reflect the expected costs of an efficient supplier managing shaping and imbalance, from a starting position that takes into account our method for buying forward wholesale energy contracts (eg 6-2-12 semi-annual with a 70/30 baseload/peakload split for electricity).

2.20. We modelled the cost of shaping, forecast error and imbalance separately for each fuel, using the same broad approach.

- We start with a valuation of forward contracts using the 6-2-12 model described above (see core direct fuel allowance methodology).
- Throughout the analysis, demand is assumed to be a fixed annual amount for both electricity and gas (ie the TDCV).
- We estimate the costs of shaping the forward contracts to more granular products, assuming seasonal normal demand. For electricity, this broadly re-hedges seasonal contracts into monthly contracts, and quarterly into monthly contracts for gas. This also accounts for intraday shaping in the case of electricity. The equivalent stage is not applied to gas due to our assessment of the cost of this stage.[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.

[4] When we assessed the gas equivalent for this calculation stage during the model development before statutory consultation, we found this to be a small gain to suppliers (ie reducing the allowance). We removed this step from our further modelling, affectively setting the allowance level for this stage to zero.

- We calculate imbalance costs, based on historical imbalance volumes and the average absolute price difference between system buy and day-ahead prices.

2.21. This approach includes some key assumptions, as outlined below.

- We analyse volumes at a national level (we do not reflect regional fluctuations).

- We initially model shaping costs using seasonal normal demand throughout. For electricity, this is based on the data for 2017-18 provided by Elexon.[5] For gas, it is based on annual load profiles for 2017-18 provided by Xoserve.

- We do not shape between monthly and day-ahead (eg weekly). As we use seasonal normal demand, the absolute impact of these steps is minor, mainly increasing transaction costs. In reality, suppliers would manage their forecast error in stages.

- For electricity, we base our analysis of the shape of demand on profile class one only (single rate customer, not multi-register customers). As most domestic consumers fall into this category, we consider this is appropriate.

- Shaping to granular electricity demand, we convert monthly contracts into hourly contracts. This is an additional step for electricity compared to gas. When developing our statutory consultation, we assessed this as a small gain to suppliers. We have removed this step from the model and affectively set it at zero.

- We analyse forecast error directly from monthly to daily, and this is done differently for gas and electricity. For gas, we calculate the re-hedging cost on a day-by-day basis, opposed to taking errors and price across the year, as changes in demand and prices have a stronger. Averaging could understate the relationship between demand and cost and the impact on costs in this case.

- 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. We assume it has a perfect view one day-ahead but that only weather affects demand.

- We account for losses separately.

[5] As set out in the demand and losses workbook published alongside this decision. www.ofgem.gov.uk/publications-and-updates/default-tariff-cap-decision-overview

2.22. Table A4.6 sets out our approach for gas and electricity at each step of our modelling.

Table A4.6: Summary of methodologies for setting additional direct fuel allowances for gas and electricity

Allowance	Electricity	Gas
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. • Based on 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 and historical day-ahead price ratios.	• Not applied to gas (effectively set at zero).[6]
Forecast error • Establish volumetric error between seasonal normal and out-turn	• The demand error is calculated comparing out-turn demand and seasonal normal demand. • For the year of analysis (2017-18). • A single demand error is calculated by taking the weighted average percentage absolute daily difference between out-turn and seasonal normal.	• The demand error is calculated comparing out-turn demand and seasonal normal demand. • For each specific day (in the analysis year, 2017-18). • Demand error is kept at a daily level and cost of error is calculated on a daily level.
Forecast error • Establish cost of forecast error, assuming unknown demand at month ahead, and fully known at day ahead	• Average volumetric error multiplied by the average absolute price change between day-ahead and month-ahead prices over a two-year delivery period. • We 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.[7] • We 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 daily cost per unit of gas estimated as the larger of system buy price minus day ahead price, and day ahead price minus system sell price[8]

Source: Ofgem

2.23. We recognise that wholesale costs are a material and variable element of suppliers' costs. Suppliers have raised concerns about additional risks that are not explicitly taken into account in our modelling for additional allowances. We discuss these below

[6] When we assessed the gas equivalent for this calculation stage during the model development before statutory consultation, we found this to be a small gain to suppliers (ie reducing the allowance). We removed this step from our further modelling, affectively setting the allowance level for this stage to zero.
[7] The nine largest electricity suppliers in the domestic retail market.
[8] Seven of the nine largest gas suppliers in the domestic market. Two suppliers were removed as they use a third party for shipping.

(paragraphs 3.78 to 3.119) in our consideration of uncertainty, headroom, and updating the default tariff cap.

Transaction costs

2.24. We provide an additional allowance for transaction costs: 0.32% of direct gas costs, and 0.39% of direct electricity costs.

2.25. We account for collateral costs in the cost of capital component of the EBIT allowance included in the cap (i.e. using 1.9% earnings before interest and tax, or EBIT, rather than 1.25%), rather than in the wholesale allowance.[9] Please see Appendix 9 – EBIT for more details.

Losses and unidentified gas

2.26. We uplift the wholesale allowance to reflect electricity distribution and transmission losses and UIG.

2.27. Forecast electricity losses are calculated according to the methodology set out in Appendix 5 – Policy and network costs. 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 the sum of the core direct fuel allowances and the additional direct fuel allowances.

2.28. We also provide an allowance for UIG, which is not captured in our analysis of forward contracts. We have set this allowance at 2.0% 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.

2.29. This value represents a change from our statutory consultation proposal. It takes into account stakeholder feedback on our proposed methodology,[10] broader feedback on the overall level of UIG, and information we have received from Xoserve around the developments in this area. Please see paragraphs 3.54 to 3.77 of Chapter 3 for more information on stakeholder feedback and how we considered this.

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[9] Suppliers conducting their own wholesale arrangement require more collateral, than suppliers that use a third party intermediary for their wholesale purchasing. Suppliers with more collateral, need to use more capital, meaning they need a higher return (EBIT) to finance their capital. A supplier with a third party conducting their wholesale purchasing will need less EBIT to pay for their invested capital, but have higher expenses. Both factors reduce the EBIT margin required for a normal return. Competition and Markets Authority, *Energy market investigation.* https://www.gov.uk/cma-cases/energy-market-investigation#final-report

[10] In our statutory consultation, we proposed valuing UIG at 0.96%. We calculated that estimate based on the annual UIG uplift value for EUC1 Product 4 using publicly available from the Final Allocation of Unidentified Gas Statement for 2018/19. Please see our statutory consultation for more information on our proposal.

Additional risk and uncertainty

2.30. We increase our additional direct fuel cost allowances by a further 1.0% of the core direct fuel cost allowance, for both gas and electricity.

2.31. In setting this allowance, we have considered that there are additional risks and uncertainties in suppliers' wholesale costs, the net costs of which might not be explicitly covered in our other allowances. Many of these risks come from the inherent volatility and uncertainty of future wholesale prices and customer's energy demand. We would not expect the wholesale allowance to be sufficiently high that it would cover any possible combination of these risks that may or may not occur in a particular period. In any given period, a supplier may have higher or lower costs than they can recover in retail prices; this is a challenge suppliers already face. However, we do give serious thought to whether the wholesale allowances, taken together, are likely to cover average costs (including realised risks) when considering a longer period of time.

2.32. In setting the allowance, we have given regard to:

1. specific risks identified by suppliers in their representations and valuations based on predictions, or the impact of past events (such as warmer summer than expected, or colder winter)

2. the potential for unforeseen shocks that increase, that supplier may not, or could not, provide representations on. These risks are, by their very nature, difficult to assess. The likelihood, frequency, and impact of any particular is largely unknowable. Its impact may reduce costs rather than increase them. However, in the long run, it is reasonable to consider that there will be some unforeseen cost increases, even if the individual circumstances cannot be foreseen

3. the potential for errors and unrealistic assumptions in our approach that have a net impact that would understate costs. This risk may, to some extent, have reduced since our statutory consultation, as supplier's economic advisors have reviewed our modelling and approach. While it is possible that net errors and assumptions have a net impact that increases the allowance, we have not taken this into account. We also consider the risk of optimism bias in our assumptions.

2.33. The allowance we have set represents a significant increase in the allowances we provide. For electricity, it represents a c.16% increase in additional direct fuel allowances for shaping, imbalance and transaction costs. For gas, it represents a c.22% increase in the allowances for shaping, imbalance and transaction costs.

2.34. We note that this allowance is not the only way we address wholesale risk. We take prudent assumptions in areas with significant uncertainty. We mitigate the need to systematically increase the allowances (reducing protection for customers) by updating the cap every 6 months (compared to annually), to pass through changes in wholesale prices. We also provide headroom. The headroom allowance is not specifically allocated to wholesale costs, but it applies to it. See Appendix 2 – Cap level analysis and headroom for further details on headroom and how it is applied to the default tariff cap.

Capacity Market (CM) payments

2.35. Suppliers must also make payments to fund the CM scheme, which is designed to ensure electricity security of supply. In our view, these costs are best categorised as wholesale energy costs, as the CM and wholesale prices are complementary ways of remunerating generators for providing capacity.[11]

2.36. We set the CM element of the wholesale allowance with reference to costs for a given fiscal year (running April to March). To do this, we estimate costs for the two CM delivery years overlapping the fiscal year, and then take a weighted average. This is consistent with the periods used in the existing safeguard tariffs.

2.37. Specifically, we:

- 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 listed in the CM register, as well as inflating auction clearing prices by the consumer prices index (CPI), where necessary
- 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 EMR Settlement[12]
- add to this the settlement cost levy for the given fiscal year, as published by the Department for Business, Energy and Industrial Strategy (BEIS)
- divide by forecast total winter peak demand to derive an implied cost per peak winter MWh on the transmission system
- 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
- uplift for forecast regional transmission and distribution losses, estimated according to the methodology set out in Appendix 5 – Policy and network costs.

2.38. Full details of our methodology – including historic examples - are provided in Annex 2 - Methodology for determining the Wholesale Cost Allowance to the licence condition 28AD published alongside this decision.

2.39. Tables A4.7 and A4.8 set 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.

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[11] See Appendix 1 to our statutory consultation: https://www.ofgem.gov.uk/system/files/docs/2018/09/appendix_1_-_benchmark_methodology.pdf
[12] See key payment figures: https://www.emrsettlement.co.uk/settlement-data/settlement-data-roles/

Table A4.7: Estimates of CM 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

Table A4.8: Estimates of CM costs in Q1 2019 (£ per customer per year based on typical annual consumption, GB average)

Electricity (single rate) (£)	Electricity (multi-register)(£)
11.08	11.82

Source: Ofgem calculations based on data from Low Carbon Contracts Company and Elexon.

Notes:
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 (Table A4.7), and January 2019 (Table A4.8). For electricity, we assume that 57% of consumption takes place in winter for single rate and 61% for multi-register.
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.

Updating the cap

First cap period

2.40. The first default tariff cap period will be shorter than the normal six-month period (starting on 1 January 2019 and ending 31 March 2019). We have set the wholesale allowance using the same approach we will use for a normal winter cap period (estimating the core direct fuel allowance in the manner described in paragraphs 2.5 to 2.12, and applying additional allowances, as described in paragraphs 2.13 to 2.34.

2.41. This decision and approach means we will set the core direct fuel allowances for the first cap period by observing wholesale prices starting in February 2018, and ending in July 2018. We consider stakeholders' responses to our statutory consultation proposal for approach in Chapter 3.

The update process

2.42. As part of the six-monthly cap update we will calculate a new wholesale allowance for the upcoming cap period. This involves:

- calculating the core direct fuel allowance using the approach described earlier in this chapter
- applying the additional direct fuel allowance multipliers for shaping, forecast error, imbalance, transaction costs, and uncertainty, at the values set out in Table A4.5
- applying the uplift multiplier for electricity losses and UIG to the combined total of core direct fuel allowance and additional direct fuel allowances
- adding CM costs to the allowance.

3. Considering statutory consultation responses

An outline of the responses we have received to our statutory consultation proposals relating to wholesale allowances, and our consideration of this feedback.

Overview

3.1. We received responses from 24 respondents relating to various aspects of our approach to setting the wholesale allowance.

How we set the core direct fuel allowance

3.2. Stakeholders addressed several aspects of our statutory consultation proposals relating to the core direct fuel allowance. We discuss this feedback and our considerations in paragraphs 3.7 to 3.36 of this chapter. Key issues raised by stakeholders were:

- how the length of the forward view affects prices (seasonality)
- the length of the cap period and the frequency of the updates (smoothing)
- impacts of the 6-2-12 approach (eg volume and basis risk).

How we set the additional allowances

3.3. Stakeholders also provided direct feedback on several issues relating to our proposed additional direct fuel allowances. The main issues relating to these allowances were:

- the level of UIG
- our approach to addressing remaining risk and uncertainty (eg weather and basis risk)
- how we allow for CM costs.

3.4. Finally, suppliers also provided feedback on specific elements of wholesale allowance models. We used these models to calculate shaping, forecast error, imbalance costs and transaction costs (see paragraphs 3.37 to 3.53).

How we set the wholesale allowance for the first cap period

3.5. Stakeholders raised concerns about our approach to setting the allowance for the first cap period. Broadly speaking, they were not in favour of the change in proposal between our May and statutory consultation.

3.6. We discuss this feedback and our considerations paragraphs 3.126 to 3.177 of this chapter.

Core direct fuel allowance

3.7. In our statutory consultation, we proposed to set the core direct fuel allowance using a 6-2-12 (semi-annual) model for analysing forward contracts. We highlighted different aspects for stakeholders to consider.

How the length of the forward view affects prices (seasonality)

3.8. In our statutory consultation, we proposed setting the core direct fuel allowance on a 12-month weighted average of forward contracts. We noted that using a shorter forward view was likely to result in the price cap being higher in winter and lower in summer. Our proposal aimed to avoid these seasonal prices.

3.9. Only two stakeholders directly addressed this issue with both agreeing that removing seasonal variability in the price cap was desirable. This feedback is in line with previous feedback provided by stakeholders to our May consultation.

Our consideration

3.10. On this basis, we consider setting the core direct fuel allowance based on a 12-month weighted average of forward contracts to be a reasonable approach. As we noted in our statutory consultation 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 protect existing and future domestic customers who pay standard variable and default rates, which we have taken into account in reaching our decision. For previous considerations on this topic please see paragraphs 2.8 through 2.49 of Appendix 4 of the Statutory Consultation.[13]

The length of the cap period affects volume and basis risk (smoothing)

3.11. In our statutory consultation, we proposed to update the core direct fuel allowance every six months (semi-annual), rather than every 12 months (annual). This would smooth changes in prices for customers as more frequent updates to the cap would likely result in smaller price changes from period to period. This approach would also allow suppliers to pass through cost changes quicker, reducing the risk that the allowance in the cap differed materially from the prevailing wholesale market price over long periods of time. We consider that this approach reduces several risks for suppliers. We acknowledged, however, that the approach exposed suppliers to changes in the winter-summer spread (referred to as basis risk), but considered the risk to be manageable.

3.12. As noted in our statutory consultation, this basis risk occurs due to a range of factors in the approach; the wholesale allowance is a weighted average price of (relatively) high winter contracts and (relatively) low summer contracts. We assume therefore, that suppliers under recover the cost of winter contracts (when the weighted average allowance priced into the cap is below the cost of winter contracts), and 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 for the next six-month period the summer-winter spread (the difference between winter and summer prices)

[13] https://www.ofgem.gov.uk/system/files/docs/2018/09/appendix_4_-_wholesale_costs.pdf

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.

3.13. Four stakeholders provided feedback on the frequency for updating the direct wholesale allowance. Two suppliers agreed with our approach while two stakeholders disagreed. Of the two that disagreed, one called for more frequent updates to the allowance to further smooth price changes and the other preferred annual updates to remove basis risk exposure. This stakeholder noted they preferred to manage volume risk rather than basis risk as they see the management of volume risk as part of the business as usual activities of suppliers operating in the energy market.

3.14. Two stakeholders also raised concerns that our 6-2-12 (semi-annual) approach would influence supplier hedging strategies, with one suggesting this influence may result in reduced liquidity in the wholesale market as some suppliers will begin hedging based on a shorter time horizon than previously.

3.15. No alternative models for valuing forward contracts were provided by stakeholders.

Our consideration

3.16. As noted in Appendix 4 – Wholesale, of our statutory consultation, 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 this frequency increased.

3.17. We also consider the risk of passing through wholesale changes less frequently, or on an annual basis, to be significant for the reasons listed below:

- for customers, less frequent updates of the wholesale allowance could create large step changes in the default tariff cap level when we update it. 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 consider six monthly updates to a customer's bill strikes the right balance between smoothing bill increases and minimising the number of price changes in a year

- for suppliers, annual updates of the cap would increase 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 default tariff customers. This is a risk suppliers are already exposed to, but currently they can adjust standard variable tariff (SVT) prices if necessary,[14] and have relatively predictable customer numbers.

3.18. In considering volume risk, it is important to consider the interaction between fixed tariffs (FTs) and default tariffs. The default tariff cap is likely to mean that some suppliers reduce the price gap between their FTs and default tariffs. This increases suppliers' exposure to volume risk, compared to the risk they already face. When

[14] Although not frequent, there have been a number of occasions when suppliers have changed their SVT tariffs more than once a year.

wholesale prices are rising, suppliers tend to increase FT prices before they increase SVTs, as suppliers tend to purchase the energy for the fixed period when the acquire the customer. If wholesale costs are rising, and we do not update default tariff 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 revert to default tariffs, increasing the volume risk faced by suppliers at a time when wholesale prices are higher than the allowance.

3.19. The semi-annual model still faces this risk, but six monthly updates to the wholesale allowance reduces the risk compared to annual updates. 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.

3.20. 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.

3.21. While we note that six-monthly updates expose suppliers to basis risk, we consider there to be a number of options available to manage this risk. Stakeholder feedback to our May consultation supported this assertion, with several suppliers identifying ways they could manage basis risk. Further detail on these options is provided in paragraphs 2.39 and 2.40 of Appendix 4 – Wholesale of our statutory consultation.

3.22. We also consider that this is not a recurring cost over the long-term. We discuss our consideration of basis risk further in the risk and uncertainty section of this chapter (paragraphs 3.78 to 3.119), as well as how we have given regard to this.

3.23. Finally, we recognise that our 6-2-12 (semi-annual) approach to setting the core direct fuel allowance may have an impact on the liquidity of the wholesale market and we intend to monitor developments in the market on this basis. We do, however, note that default tariff demand does not account for the majority of traded volumes and therefore expect only a small proportion of the market will be affected.

3.24. With this in mind, on balance we consider a 6-2-12 (semi-annual) approach to be a suitable approach for balancing desired outcomes and managing supplier and consumer risk.

Initial electricity shaping – base and peakload split

3.25. In our statutory consultation, we proposed to use a 70/30 split between baseload and peakload forward electricity contracts in the model used to calculate the core direct fuel allowance.[15] This approach replicates the assumptions used for calculating wholesale costs under the PPM cap.

[15] Baseload contracts relate to electricity delivered continuously every day of the week, and peakload contracts deliver electricity Monday to Friday from 7am to 7pm.

Consultation responses

3.26. Two suppliers responded to our statutory consultation proposal on this issue. Both suggested alternative approaches to the one we proposed. However, these alternative approaches were not the same.

3.27. One supplier explained that the baseload/peakload split is influenced by season and the type of meter a customer has. They also noted that they believe the split should evolve over time. Based on this, they proposed a range of baseload/peakload split values for the April 2018 to March 2019 period varying between 71/29 and 81/19. This supplier also noted that while their modelling results appear to be close to our proposed split (confirming the ratio is broadly reasonable), even very small inaccuracies in the split would impact the commercial positions of suppliers materially.

3.28. The other supplier said their modelling suggested a more accurate baseload/peakload split would be 87/13 for profile class one customers, and 100/0 for profile class 2 customers.

Our consideration

3.29. Assessing responses to our statutory consultation, as well as previous information we have received on this issue, we note that there are large variations between individual supplier estimates. As noted in our statutory consultation, it is therefore not clear what an appropriate alternative to a 70/30 split would be, given that any particular option would deviate from some of the approaches adopted by different suppliers. Further, we have no reason to consider an alternative ratio would be more or less suitable for the market as a whole.

3.30. Based on previous feedback, we also consider that it is more important that this level is used as the starting assumption to allow for other costs that suppliers may face (ie shaping, forecast error and imbalance costs). For example, using a higher ratio of peakload contracts increases the core direct fuel allowance, but would decrease the cost of further shaping.

3.31. In our statutory consultation, and in line with the issues discussed above, we also have concerns around identifying an appropriate alternative ratio if we were to vary this for different profile classes and/or seasons. Again, we are aware these factors may change the value, however, there is still like to be variability between suppliers. We therefore consider that a single ratio is suitable in this context. Further, as most domestic consumers have single rate meters, we consider this should represent the market as a whole.

3.32. Accordingly, we have decided to proceed with a 70/30 split between baseload and peakload forward electricity contracts in the models used to calculate the core direct wholesale allowance.

Price data

3.33. In our statutory consultation, we proposed to use ICIS price data and the midpoint between reported bids and offers as the main input to our model to calculate the core direct fuel allowance for wholesale.

Consultation responses

3.34. We did not receive direct feedback from stakeholders on this proposal.

Our consideration

3.35. As noted in our statutory consultation, we believe this approach is reasonable on a number of grounds, including:

- the data source is robust and trusted, with most relevant parties already having access to it
- we consider that the midpoint is an accurate indicator of the underlying cost for various situations or circumstances given that the price paid by suppliers may depend on market conditions, a particular supplier's market access, the volume of energy traded or agreements with other parties.

3.36. Given we did not receive direct feedback from stakeholders on this issue, combined with our previous assessments of this issue, we consider that this is an appropriate approach. Further detail on our previous consideration of this issue is provided in paragraphs 2.62 to 2.73 of Appendix 4 – Wholesale, of our statutory consultation.

Additional direct fuel allowances

Shaping, forecast error and imbalance costs

3.37. In our statutory consultation, our proposal included an allowance for the expected costs of converting forward energy contracts into more granular contracts in order to meet customers' out-turn demand. We explained that these are legitimate costs that an efficient supplier would incur, but they are not captured in the costs of forward contracts for the seasons or quarters ahead.

3.38. We published our proposed methodology for calculating these costs and outlined the assumptions behind the approach, and provided access to our wholesale allowance models through the disclosure room.

Consultation responses

3.39. We received a range of feedback related to these allowances and the models. Suppliers' comments were generally focused on specific elements of the allowance models and were unique in most cases.

3.40. Eight comments related to our gas and electricity allowance models which we have summarised below:

- **electricity transaction cost calculation**: one supplier noted an error in the calculation of our transaction cost value
- **use of averaging in calculations**: two suppliers questioned our use of averages, opposed to volume-weighted averages, in some our calculations

- **number of steps in models**: one supplier noted that there was a difference in the number of calculation steps between our gas and electricity models, and they thought these should be the same.[16]

3.41. One supplier responded on our proposal for the overall level of the shaping, forecast error and imbalance costs allowance (as opposed to the models that calculate it). They told us our proposal was lower than both their forecasts and experienced costs over the last few years. In their forecasts, they allow for more extreme weather events (ie 1 in 20 year events).

Our consideration

3.42. We have evaluated the comments relating to our allowance models, considered how we should respond to these points, and have made adjustments to our calculations where appropriate. This process included undertaking additional modelling in a number of cases.

3.43. The adjustments we had to make to the models were minor. In total, they resulted in £0.14 per dual fuel customer increase in the combined wholesale allowance level for the base period (ie 2017-18).[17] This is broken down into a £0.13 per dual fuel customer increase in the electricity allowance for shaping, forecast error imbalance and transaction costs. For the equivalent gas value, there was a ~£0.01 per dual fuel customer increase.

3.44. With regards to the comment that the overall level is below a supplier's forecast and expectations, we consider that our allowance for shaping, forecast error and imbalance costs are suitable. We have considered and given regard to the costs of extreme weather events (1-in-20 winters, warm summers, or other events) in our assessment of wholesale risk and uncertainty and in headroom, as described in Chapter 2 and in Appendix 2 – Cap level analysis and headroom.

Transaction costs

3.45. In our statutory consultation, we explained that the cap would include an additional allowance for transaction costs of 0.32% of direct gas costs and 0.38% of direct electricity costs.[18]

3.46. We also noted that we intended to account for collateral costs in the cost of capital allowance included elsewhere in the cap (by using 1.9% earnings before interest and tax, or EBIT, not 1.25%), rather than in the wholesale allowances.[19]

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[16] See Table A4.6 on page 14.
[17] The change in the electricity allowance also includes the updated transaction allowance.
[18] Please note, in our statutory consultation we published 0.40% for our electricity transaction cost. This was an incorrect rounding of 0.38%.
[19] Suppliers conducting their own wholesale arrangement require more collateral, than suppliers that use a third party intermediary for their wholesale purchasing. Suppliers with more collateral, need to use more capital, meaning they need a higher return (EBIT) to finance their capital. A supplier with a third party conducting their wholesale purchasing will need less EBIT to pay for their invested capital, but have higher expenses. Both factors reduce the EBIT margin required for a normal return. Competition and Markets Authority, *Energy market investigation.* https://www.gov.uk/cma-cases/energy-market-investigation#final-report

Consultation responses

3.47. Two suppliers responded directly to this issue.

3.48. One supported the additional allowance for transaction costs but argued it should be set at an alternative minimum level to better reflect their experience and understanding of these costs.

3.49. The other supplier raised a number of concerns, and questioned our approach to setting the transaction cost allowance. They thought our proposal should allow for the cost of operating a trading function, and the sample size used to assess and set the transaction allowance was limited. However, this supplier did not provide an alternative figure for transaction costs in their response.

Our consideration

3.50. As noted in our statutory consultation, transaction costs vary considerably between suppliers depending on their circumstances and activity in the wholesale market.

3.51. We have taken into consideration additional information on transaction costs provided to us as part of the statutory consultation process. Our allowance is based on a supplier that does not use an intermediary for wholesale costs, and therefore we assume has lower fees (that would otherwise require an allowance). We therefore consider our proposed level suitable.

3.52. 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 - EBIT) where we use 1.9% rather than 1.25% (which we would use if we modelled a supplier with an intermediary wholesale arrangement).

3.53. Based on the considerations noted above, and the limited amount of additional or alternative evidence that we received to our statutory consultation, we have decided to have an allowance for transaction costs of 0.32% of direct gas costs and 0.39% of direct electricity costs.[20]

Losses and unidentified gas

3.54. In our statutory consultation we explained that we proposed to:

- account for electricity transmission and distribution losses
- provide an allowance for UIG, based on our estimate of physical underlying losses.

[20] This is ~0.01 percentage points higher than our statutory consultation proposal. Please see *Adjustments to the allowance model* in this chapter for more details.

Consultation responses

3.55. We received little feedback relating to how we have accounted for electricity transmission and distribution losses.[21] One supplier thought that losses in the price cap should take account of reshaping costs and that we should apply the losses uplift to the total wholesale cost figure.

3.56. 12 stakeholders commented on UIG. Their comments broadly relate to the following three issues:

- a greater allowance is required to cover the cost of recent increases and variability in UIG costs (since the implementation of Project Nexus)[22] and the risk associated with these movements
- the UIG level should not be fixed, and Ofgem should have a mechanism for updating the level through time
- the allowance should be priced at a level different to our reference price.

3.57. The most frequent issue raised on UIG was around the proposed allowance not being large enough. The majority of stakeholders that addressed this issue thought the UIG allowance level should reflect observed levels of UIG in the market seen since the implementation of Project Nexus, and should therefore be higher.

3.58. Ten suppliers also provided assessments of what they thought the level of UIG is. These assessments ranged from 2.1-8%, compared with the 0.96% level proposed in our statutory consultation.

3.59. Many of these suppliers said the observed level of UIG has been higher since the implementation of Project Nexus in June 2017, therefore our allowance should be higher to reflect this. One supplier addressed specific concerns with the Allocation of Unidentified Gas Expert (AUGE) methodology that we had based our proposal on. Specifically, they did not believe the AUGE methodology accurately corrected for temperature and pressure, and there was an error in the assessment relating to the treatment of shrinkage. Using external assessments, they thought the level of UIG would increase to ~2.1-2.4% once these issues were addressed.

3.60. Another supplier thought the UIG level and the risk/uncertainty around it should be addressed separately. They suggested a 4% allowance specifically for UIG with a further 2% risk allowance to address its variability.

3.61. Several stakeholders also raised concerns around how much they can influence the level of UIG. Some of these suppliers indicated there were actions individual suppliers could take to reduce the level of UIG. However, they thought the majority of these costs were outside of their control. One disagreed that an efficient supplier acting individually could affect UIG, while another thought there was no evidence that more meter readings would reduce the average level of UIG. Finally, one supplier described

[21] Please see Appendix 5 – Policy and network costs for more information on how we calculated losses.
[22] 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.

UIG as a public bad that equally affects efficient and inefficient suppliers in the same way.

3.62. Several stakeholders thought that the level of UIG should be an updateable variable in the price cap, or we at least have the ability to change this level in the future. Within this group of responses, one supplier wanted a provision included in the standard licence condition committing Ofgem to undertake and implement an urgent review of the UIG allowance in time for the second default tariff cap period starting on 1 April 2019.

3.63. One supplier thought it would be more appropriate to value UIG using spot prices compared to our reference price, which is calculated by assessing forward gas contracts. They argued it is difficult for them to forecast and purchase the correct volume of gas in advance due to the volatility in the value. The supplier thought it is more likely that most of the UIG volume is purchased on the settlement day (intraday price), or at the System Average Price (SAP) at imbalance cash-out.[23] They assessed a 15-month period and found that the spot price was on average 5% higher than the cost a quarter ahead.

Our consideration

3.64. On electricity losses, we have reviewed stakeholder feedback and consider that our methodology already accounts for this issue. Losses are applied to the total wholesale allowance figure (see Chapter 2 and Annex 2[24]), which is the sum of the core direct fuel allowance and the additional direct fuel allowances. This means losses are applied to a wholesale cost figure, which includes an uplift for the cost of shaping, forecast error and imbalance. We therefore consider that our losses calculation takes into account the reshaping costs.

3.65. On UIG, below we summarise our key considerations and rationale.

- Following our consideration of the information presented through the consultation and discussions with Xoserve, we are of the view that there remains uncertainty as to the level of UIG, a question that is the subject of further work by industry through the UIG taskforce.

- Ultimately, the physical level of losses from the system has not changed since the implementation of Project Nexus (ie the system is not losing more gas) and the introduction of a new methodology for UIG. As such, it is difficult to explain if UIG were at the upper end of the range suggested by suppliers how such large losses had gone unnoticed for decades.

- Notwithstanding that there is not enough evidence to confirm the level of UIG, however, having considered what information is available, we consider that the 0.96% level in our statutory consultation is likely to be an underestimate of UIG. We also have good reason to consider that the allowance value should be set

[23] This is calculated using the aggregate price traded for a specific delivery day. This SAP is then used to calculate charges for shippers who do not balance their portfolio.
[24] Ofgem (2018), Default Tariff Cap – Decision: Annex 2 Wholesale cost allowance methodology
www.ofgem.gov.uk/publications-and-updates/default-tariff-cap-decision-overview

below 4% given the Xoserve-led UIG Task Force is aiming to identify recommendations by the end of 2018 that will reduce UIG below this level.

- We also consider that elements of UIG can be influenced and controlled by suppliers, and there are actions they can take to reduce UIG below currently observed levels. Therefore, an allowance set at current UIG levels would undermine any incentive to improve.

- We acknowledge suppliers are currently exposed to UIG volatility, and have given regard to this alongside our consideration of incentives to reduce UIG.

- Taking all this into account, we have increased the UIG allowance level to 2%. We consider that this is a better estimate of UIG as this takes into account missing costs. It will also still maintain incentives to reduce UIG.

3.66. Below we go through our considerations on UIG in more detail, as well as address the specific concerns raised by stakeholders to our statutory consultation.

3.67. We have assessed the information provided to us by suppliers, to understand what a suitable allowance level for UIG may be. We consider that there is a lack of consensus and significant uncertainty regarding the true level of permanent UIG. This level in responses to our statutory consultation ranged from around 2.1-8%. We note that even within individual supplier assessments, there was still a range in some cases.

3.68. We have also sought Xoserve's view around the uncertainty surrounding UIG, given their expertise and role in leading the UIG taskforce. They have acknowledged, that since the implementation of Project Nexus, gas shippers have experienced higher than expected absolute levels and volatility of UIG. They have also acknowledged the challenges surrounding this trend, and that there was not enough evidence available to make an accurate estimate of long-term UIG. However, they thought that it was highly likely that it would be higher than the previous AUGE estimate of 0.96% (which was the basis for our statutory consultation position). Xoserve also told us that the Task Force is working on a number of actions that suppliers could take to reduce UIG, as discussed below.

3.69. Taking all this together, we now have good reason to consider that the 0.96% level in our statutory consultation may not be appropriate, as it may be an underestimate. For example, it may not fully take into account certain factors that may alter the level of UIG (eg temperature). We are aware that the AUGE is investigating existing and new issues relating to permanent UIG, and we anticipate that an update will be included in the Final Allocation of Unidentified Gas Statement for 2019-20.

3.70. We equally have good reason to consider that the allowance value should be set below 4%. Xoserve is leading a UIG Task Force working towards a more centralised and focused approach to the resolution of UIG on behalf of the industry. Specifically, one of their targets is to identify recommendations by 31 December 2018 that will reduce the levels of UIG to less than 4% of local distribution zones (LDZ) by 31 December 2018.[25] Given the level and timing of the target, and that the task force is being led on behalf

[25] It is likely that the required changes will take longer and could be subject to industry change governance. This target is in line with UNC Modification 658. The other quoted target is to report on an absolute level, and propose measures aiming to reduce UIG variance to ±0.5% of absolute levels by 31 October 2019.

of the industry, we consider it would be inappropriate to provide a UIG allowance greater than 4%.

3.71. We are not persuaded that gas losses are uncontrollable. Suppliers can influence these costs, and there are individual and collective actions a supplier could take to influence the level of UIG costs to which they are exposed. For example, 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.

3.72. In late October 2018, Xoserve communicated the latest findings of the UIG taskforce.[26] This showed that the Non-Daily Metered (NDM) algorithm correctly accounts for wind speed, day of week and holiday factors. Xoserve found that it was not possible to deliver materially better results based on the current inputs. This finding indicates the next step for them is to focus on the inputs to the model (as opposed to the mechanics). Xoserve plan to carry out further tests and assessments in Sprint 4.

3.73. The significant finding from Sprint 3 is that within the NDM demand sample dataset, there are a small number of sites that have a measured consumption far greater than the Annual Quantity (AQ) recorded within Xoserve's systems. This can be a result of sites having a usage change and the shipper needs to increase the AQ to reflect the real consumption. There could also be erroneous historic meter readings or incorrect site set up data, which would need to be resolved. These outliers alone have been shown to have a marked impact on UIG levels,[27] and can affect either UIG base, volatility or both. In addition to this, the UIG Task Force has identified shipper performance issues that could be contributing to current UIG base levels and volatility:

- **meter read performance:** the UIG position between allocation and reconciliation could be corrected more quickly if meter reading performance was brought up to the required Uniform Network Code (UNC) standards. It would also enable more up to date AQs. The UIG Task Force will collaborate with the Xoserve Customer Account Managers to work with customers to create specific action plans, where necessary, to improve read performance.

- **accuracy of AQs:** the difference between the live AQ, and a more accurate figure, may contribute to UIG each day. The Xoserve Customer Account Managers have commenced engagement with customers to understand some of the more unusual trends surrounding AQ corrections.

- **low take-up of Winter Annual Ratio (WAR) Band End User Categories (EUCs):** if NDM sites (in EUCs 3 to 8) are not assigned correctly, the difference between actual and allocated usage each day contributes to UIG. A dedicated UIG Task Force Customer Engagement Manager has started work with each shipper to create specific action plans to move such sites into an appropriate EUC Band.

3.74. Our view is that the latest findings from the UIG taskforce indicate both that suppliers do have levers to control levels of UIG, and that current levels may not be indicative of what the level of UIG should ultimately be. Given that we consider suppliers can influence UIG, either through their individual behaviour or being an active part of a

[26] These findings are available here: *UIG Task Force Sprint Three Update* - https://www.xoserve.com/index.php/uig-task-force-sprint-three-update/
[27] Exact impact depends on the End User Category (EUC) profile allocated on our systems.

centralised task force, we consider that providing an allowance of 4% would reduce the incentives on them to reduce UIG levels any further. We wish to support incentives to improve information on UIG and its management, improving incentives to manage the network and settlement systems efficiently, which will ultimately bear down on the costs (which are paid for by customers). We are therefore 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.

3.75. We acknowledge suppliers are currently exposed to UIG volatility, and have given regard to this alongside our consideration of incentives to reduce UIG. This volatility is the result of new charging arrangements, but we expect UIG costs to become stable through time. Xoserve and the broader industry are taking steps to further understand the causes of these trends, and reduce the volatility. We therefore do not anticipate the need to provide for a permanent increase in the level of the cap. Should there be a material and long-term departure from our allowance, we consider we have the means to address this. Please see Appendix 2 - Cap level analysis and headroom for more details on how this may work.

3.76. We have therefore set the UIG allowance level at 2%. We consider that this takes into account missing costs from our statutory consultation proposal, whilst maintaining incentives on industry to reduce UIG.

3.77. In summary, 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 with 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 over the course of the Task Force 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 the explicit wholesale allowance. To the extent that there are uncertainties which suppliers cannot reduce or otherwise manage, we do consider it when discussing uncertainty, headroom, and updating the default tariff cap (see Appendix 2 – Cap level analysis and headroom).

Additional risk and uncertainty

3.78. In our statutory consultation, we proposed to increase our additional direct fuel allowances by a further 1% of the core direct fuel allowance, for both gas and electricity.

3.79. We explained that in setting this additional allowance we give regard to the fact that wholesale costs are a volatile and uncertain element of suppliers' costs. That uncertainty could result, on average, in net cost that exceeds our other wholesale allowances.

3.80. We also explained that the allowance is not the only way we address uncertainty and should not be considered in isolation. We give regard to the net cost of risk and uncertainty in our overall headroom allowance. Risk and uncertainty is also addressed in how we monitor and update the cap. Further details on the headroom allowance and updating the cap can be found in Appendix 2 – Cap level analysis and headroom and Appendix 3 – Updating the cap methodology.

Consultation responses – Overview

3.81. In response to our statutory consultation, two suppliers told us that they thought the current additional risk allowance is too low. One supplier thought this risk allowance should be larger. They said an additional allowance of at least £5 should be provided in the cap to appropriately account for wholesale and operating cost uncertainty. In addition, the stakeholder explained that an additional variable allowance should be included for the costs of backwardation (which, based on recent data, would be £10).They thought these should be in addition to the combined £13 allowances that Ofgem has proposed to accommodate.

3.82. Several stakeholders also raised a number of risks associated with the wholesale component of the default tariff cap that they felt were inadequately captured in the cap. Particular risks raised by stakeholders were:

- Market Making Obligation (MMO)
- customer numbers
- basis risk and backwardation
- unexpected shocks
- extreme weather events
- net risk of error or optimism.

3.83. Stakeholder views on each of these set out in turn below. Our overall consideration of these risks is then provided.

Consultation responses – Market Making Obligation (MMO)

3.84. In August 2018, Ofgem announced it was considering whether there was a case for suspending the MMO.[28] The MMO was designed to support the availability of hedging products and improve price robustness in the wholesale market. Under this at the outset, six market makers were obligated to post bids and offers for specific wholesale products (eg electricity for delivery in the next season) at specific times every day. However, if planned changes in the ownership of generation assets take place, we consider it likely that the resulting structure of the market would not support the continued operation of the MMO.

3.85. In light of the August announcement, five stakeholders highlighted the impact that a decision to suspend the MMO could have. Of these stakeholders, three told us that suspension of the MMO could result in a wholesale reference price that is less reliable as an indicator of supplier costs. One specifically explains that should the MMO be suspended, bid-offer spreads are likely to widen and it may no longer be appropriate to

[28] The MMO is part of the Secure & Promote (S&P) licence condition. It obliges the relevant parties to post bid (buy) and offer (sell) orders for specific electricity contracts, at certain times of the day and within a mandated spread. Please see *Open letter: Secure and Promote Update* for more details: https://www.ofgem.gov.uk/system/files/docs/2018/08/ofgem_open_letter_-_secure_and_promote_update.pdf

use the midpoint price as the main input to our model for the core direct fuel allowance.

3.86. On this basis, three of the five stakeholders are calling for a way to update the transaction cost allowance level in the event of an MMO suspension.

Consultation responses - Customer numbers

3.87. Six suppliers addressed risk associated with customer number volatility. Five told us that challenges around accurately forecasting customer numbers presents an additional risk for them that could increase their costs.

3.88. One supplier explained that more customers may be drawn to default tariffs following the implementation of the cap depending on the price difference between default tariffs and FTs. This change in default tariff customer numbers may be difficult to anticipate as it relates to customer behaviour when they come to the end of a FT.

3.89. Another supplier noted holding risk due to customer churn of this type may be more significant for suppliers with large numbers of default tariff customers. This supplier estimated that for every 1% increase or decrease in customer numbers, there was a cost to them of £0.50 per customer.

3.90. An additional supplier explained to us customer number volatility is likely to be a larger risk for smaller suppliers. They said it was more difficult for small suppliers that are growing to predict customer acquisition than larger businesses will find forecasting customer losses.

3.91. Finally, one supplier told us (in the context of our 6-2-12 (semi-annual) proposal) that volume risk always applies to suppliers, and is a fundamental part of operating in the energy market. Relative to other risks, they preferred to manage volume risk compared to basis risk.

Consultation responses - Basis risk and backwardation

3.92. Four suppliers noted concerns in relation to basis risk. Three of these suppliers thought our statutory consultation proposal did not adequately allow for the risks and costs associated with this issue.

3.93. One supplier noted that the market is structurally in backwardation,[29] so it is incorrect to assume that basis risk exposure nets out over time. They thought an additional variable allowance should be included for the costs of backwardation (which would be £10 based on recent data). They also told us that it is not reasonable to expect suppliers to absorb under recovery for potential future over recovery. They note that the costs associated with basis risk are known at the time of setting the cap and should therefore be allowed for.

3.94. Another supplier noted it is possible to hedge basis risk but this comes at a cost and should be accounted for in the cap. They thought the proposed allowance for basis risk is too low and wanted a mechanism to recover unexpected basis risk costs not allowed

[29] This is when the price of a commodities' forward or futures contract is trading below the expected spot price at the point of delivery.

for in the cap. They quantified what they thought the impact would be on them over the April 2019 (second) and October 2019 (third) default tariff caps. They expected that this would provide a risk level greater than our proposed 1%, and it would create significant earnings volatility for them.

3.95. The fourth supplier explained that they do not believe it is possible to manage basis risk under the 6-2-12 (semi-annual) approach by hedging their exposure to losses and gains.

Consultation responses - Unexpected shocks

3.96. One supplier noted that unexpected shocks, such as a no deal Brexit event, are likely to leave suppliers exposed to unrecoverable costs not currently accounted for under the cap. In this example, the supplier thought a no deal Brexit event is likely to devalue the pound, increasing their wholesale costs.

3.97. Two other suppliers wanted to see a retrospective cost recovery mechanism to address unexpected costs. One of these suppliers also acknowledged that another option would be to review the level of the additional uncertainty allowance when resetting the cap.

Consultation responses - Extreme weather events

3.98. Three suppliers told us that they did not think there was an adequate allowance for extreme weather events, or deviations from seasonal norms. Two of these suppliers said the price cap does not currently account for short term extreme weather events, explaining that these can have significant impacts on supplier costs

3.99. The other supplier told us that while these extreme weather events are not predicted to happen frequently, the UK has experienced a series of events which have been worse than 1 in 20 year events in the past few years. For example, the Beast from the East.

3.100. The third supplier told us about the interactions between warm weather and gas margins, and thought the impact of this had not been included in the headroom allowance. They told us gas demand is very sensitive to weather, and therefore impacts supplier profitability. They acknowledged that these variations should balance out over the longer-term. However, they told us there was a cost to managing this risk.

Our consideration

3.101. As we have set out in Chapter 2 (paragraphs 2.30 to 2.34), in setting the additional allowance for uncertainty, we have given regard to all the risks presented by suppliers in their consultation responses. We also considered the likelihood, frequency, and potential impact of unknown risks and the possibility that our estimates contain net error or optimism.

3.102. Based on the evidence provided by stakeholders around the costs that these risks pose, as well as our understanding of the additional risks suppliers face, we consider an additional uncertainty allowance of 1% is appropriate.

3.103. Below we address the specific areas that were highlighted to us by stakeholders.

Market Making Obligation (MMO)

3.104. On the future of the MMO, we consider that the impact of suspending this policy on supplier costs is uncertain and therefore hard to predict. If bid-offer spreads increase to the levels seen before the introduction of the MMO, this would increase supplier costs. We cannot forecast what the exact market impact would be, but we consider it unlikely that spreads for the contracts we are assessing would return exactly to pre-MMO levels because the market context is now very different. For example, there has been a noted reduction in vertical integration, as well as increases in the number of new generators and suppliers in the market. There remains uncertainty around the future level of the bid-offer spread. We give regard to this unknown through the uncertainty allowance and headroom.

Customer numbers

3.105. Several suppliers told us volatility in customer numbers created risk for them under the default tariff cap. We acknowledge this is a risk supplier's face. The amount or forecast error (ie the variance from the expected number of customers) varies between suppliers, depending on their circumstances and because some are better at forecasting their customer number than others; no supplier could be perfect at forecasting.

3.106. We consider that the impact of error (ie the cost of buying additional energy, or selling excess contracts) is relatively low. Suppliers will not be able to perfectly forecast their default tariff customer numbers, though we consider that forecasting customer numbers accurately is a core activity of being an energy supplier, meaning suppliers should have some control over this risk. To the extent that they make errors, they may have to buy/sell the wholesale energy purchased to meet this unforeseen change in demand and so are exposed to wholesale price risk. We consider that the impact of error (ie the cost of buying additional energy, or selling excess contracts) is relatively low. That is because there is not the same relationship between prices and demand. We have given regard to this issue in our decision to set the wholesale uncertainty allowance and headroom.

Basis risk and backwardation

3.107. In paragraphs 3.11 to 3.24, we discuss the basis risk that the 6-2-12 semi-annual model can create if suppliers are exposed to the summer-winter spread. Some suppliers have told us they can manage that exposure.

3.108. Suppliers have also told us that they face costs managing basis risk when the market is in backwardation – ie the price of forward contracts is less than the market expects the spot price to be when the contract is delivered. We agree that when the market is in backwardation, suppliers face an exposure. We have calculated the current exposure at very similar level to those presented in suppliers' representation.

3.109. The market is not always in backwardation. The opposite – when the market expects spot prices at the time of delivery to be lower than the current forward price – is contango. Contango can be a benefit to suppliers, or reverse previous exposure. We also do not consider that this is a recurring cost in the allowance as wholesale gas and electricity markets may switch between contango and backwardation during the lifetime of the default tariff cap. In this context, we have assessed a five-year historical period and found that the associated cost would broadly net out over the longer-term.

3.110. We have assessed the viability of correcting for this exposure through an allowance that is updated every six months with the rest of the wholesale costs. However, we consider that this would introduce seasonal wholesale pricing which we are intending to avoid by using the 6-2-12 semi-annual model to assess forward wholesale contracts. Please see the core direct fuel allowance section of this chapter for our considerations on seasonality.

3.111. Although this exposure nets out in the long-run, we acknowledge suppliers currently face costs, which they need to manage until their exposure reduces. The net impact of that management in the long-term is an increased cost to working capital. We consider that this will give a lower cost (than the values provided to us), but a material and recurring management cost. We have given this impact regard when setting the wholesale risk and uncertainty allowance (ie 1% per fuel) and headroom.

Unexpected events

3.112. We acknowledge that unexpected events can materially affect suppliers' wholesale costs. However, it is inherently difficult to assess the frequency, magnitude and direction of these events on supplier costs. We also note that unexpected events can also apply downward pressure on supplier costs.

3.113. The likelihood, frequency, and impact of any particular is largely unknowable. However, in the long-run, it is reasonable to consider that there will some unforeseen cost increases, even if the individual circumstances cannot be foreseen.

Extreme weather changes

3.114. Extreme weather creates risk and uncertainty for suppliers, and can increase supplier wholesale costs. However, we consider that it is unlikely that extreme weather events (eg a 1 in 20 year demand) will occur every year.[30] Therefore, it would be inappropriate to allow for the full cost of an extreme weather event within the default tariff cap. We have considered the values of weather risk provided to us in this context, and have given regard to it when setting the wholesale risk and uncertainty allowance.

3.115. We recognise deviations from seasonal normal demand more broadly can also impact supplier costs. We have considered the impact of this year-on-year variation away from average temperatures on supplier revenues and costs, to the extent that such fluctuations requires additional working capital to manage the risk. For instance, we have seen evidence that weather-driven reduction demand in the past few years has meant some suppliers were less profitable than expected due to the way variable costs and variable revenue interact. In other years, higher than average demand increases profitability. In the long run this, more or less nets out, but there is net cost to managing that volatility. We have given regard to this in our uncertainty allowance and headroom.

[30] Broadly, 1 in 20 year demand is the level of demand that would be exceeded in one out of 20 winters, with each winter counted only once.

Net risk of error or optimism

3.116. There are inherent risks in modelling future costs, and 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 assumptions that limit the impact on uncertainty. We also consider this risk to be lower now than at the statutory consultation stage given stakeholders have had the opportunity to assess our proposals and models. See paragraphs 3.37 to 3.44 of how we considered these. We have also given regard to the risk of residual uncertainty when setting the headroom allowance (see Appendix 2 – Cap level analysis and headroom).

3.117. We have also taken prudent assumptions where there is particular uncertainty or risk (such as with our shaping, imbalance, and transactions allowances). For instance, we assume electricity imbalance is always a cost to suppliers. Smaller suppliers tend to have higher imbalance and transaction costs, so we are overstating costs slightly for typical, larger, suppliers serving the majority of default tariff customers. This safeguards against the risk we are too optimistic in our approach.

Setting the allowance

3.118. In setting this allowance, we have considered the magnitude, frequency, and likelihood of the issues raised by suppliers carefully. In deciding on an appropriate level, we would not expect that the wholesale allowance be so high that it would cover any possible combination of these risks that may or may not occur in a particular period. In any given period, a supplier may have higher or lower costs than they can recover in retail prices; this is a challenge suppliers already face. However, we do give serious thought to whether the wholesale allowances, taken together, are likely to cover average costs (including realised risks) when considering a longer period.

3.119. Finally, in setting the allowance we did not consider it in isolation. We have considered unforeseen changes in the market in two ways. Firstly, we have given regard to this in our assessment of headroom (Appendix 2 – Cap level analysis and headroom). Secondly, in the event that changes are significant and unanticipated, we update the cap to pass thorough changes in costs, and can use modifications to adjust for material changes in circumstances. We have kept these considerations in mind when setting the allowance.

Capacity Market costs

3.120. Suppliers must also make payments to fund the CM scheme, designed to ensure electricity security of supply. We categorise these charges as part of a supplier's wholesale electricity costs.

3.121. In our statutory consultation, we proposed to set the allowance included in the default tariff cap for CM with reference to capacity payments for a given fiscal year (running April to March). To do this, we would 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.

Consultation responses

3.122. In response to the consultation, three suppliers raised concerns regarding the proposal to align our methodology with the fiscal year rather than with the CM mechanism recovery period (October to September). They cited that using fiscal years would:

- add more pricing risk for suppliers
- mean that part of the costs for the 2021-22 delivery year will be recovered in 2022-23 fiscal year (a year not currently covered by the CM)
- risk distorting competition in the wider market by causing the level of the cap to depart from supplier's actual costs
- create unnecessary uncertainty for the summer periods – for instance due to the timing of auctions, which might not be concluded by the date of the February update to the cap, and because of the greater reliance on inflation forecasts.

3.123. In addition, it was argued that the lag between when the obligations are determined and the cap comes into effect can mean that suppliers with decreasing market share will not be able to recover costs.

Our consideration

3.124. We acknowledge that using fiscal rather than charging years could create some additional risk and uncertainty for suppliers. We have considered this in setting the overall level of the cap, given the various uncertainties that it is subject to (as discussed in Appendix 2 – Cap level analysis and headroom). We nevertheless propose to continue to calculate CM costs for fiscal years, consistent with the horizon used in the existing safeguard tariffs.

3.125. As set out in Appendix 5 – Policy and network costs in the context of ECO, where a supplier's obligation under a government scheme depends on their size, we consider it appropriate to set the allowance included in the cap based on a supplier at steady state (ie neither growing or shrinking). This will ensure that the cap reflects the costs of a company operating at efficient scale.

Setting wholesale allowance for the first cap period

3.126. In our statutory consultation we proposed:

- the first default tariff cap period would be shorter than the normal six-month period (ending on 31 March 2019)
- in setting the wholesale allowance for the first period, we would use the same approach as for a normal winter cap period (ie use a weighted average of forward prices for contracts between October 2018 and September 2019 as observed between February and July 2018).

3.127. This approach differed from our May consultation proposal, which proposed using an observation period between April and September 2018.

3.128. In a flat wholesale market, there would be no difference between the two approaches. However, wholesale prices have increased significantly during 2018. The proposal outlined in statutory consultation sets the wholesale allowance around £35 (on an annualised basis) lower than it would be if we had maintained our May proposal.

3.129. We have decided to set the wholesale allowance for the first cap period using the approach proposed in our statutory consultation – an average price of forward contracts observed between February and July 2018. A number of suppliers made representations that we should revert to the proposal in our May policy consultation (which would set the allowance in line with the average price for a later period, when wholesale prices were higher).

3.130. Below we outline our rationale, and consider in detail stakeholders' responses to our proposal.

Our rationale

3.131. In accordance with the Act, our primary concern is whether our position appropriately protects default tariff customers. We consider our statutory consultation proposal more appropriate, as it better protects the majority of SVT customers. Given the sharp and sustained increases in wholesale prices, had we decided to proceed on the basis of the May proposal, suppliers with a typical approach to forward purchasing of energy could have charged the majority of SVT customers substantially more than their actual costs would justify.

3.132. Typically, the six largest suppliers start purchasing energy for SVT customers around 18 months before the start date of the forward contract. Due to large and sustained increases in wholesale prices, the gap between average wholesale *prices* (between April and September 2018) and average wholesale costs (for suppliers purchasing energy over a longer and earlier period) increased greatly. The six largest suppliers serve around 90% of SVT customers.

An overview of consultation responses

3.133. In response to our statutory consultation, we received feedback on our proposal for the first cap period from 11 suppliers. None of these respondents supported our statutory consultation proposal that reduced the allowance. They were broadly in favour of us reverting back to our May proposal.

3.134. We categorise stakeholders concerns into several themes:

- **May consultation 'signal':** we had engendered a legitimate expectation and therefore should not have changed our proposal in the statutory consultation.

- **our evidence and understanding of how suppliers purchase energy:** stakeholders queried whether our evidence was sufficient for us to make a reasonable decision about suppliers' hedging strategies, their actual costs, and the impact on SVT customers.

- **financial impact on typical suppliers:** some suppliers stated they had changed their wholesale approach to one with higher prices (than their previous approach), and our September proposal would mean they under-recover those higher costs.

- **financial impact on small suppliers:** small to medium sized suppliers raised concerns that our statutory consultation approach is more reflective of a larger supplier's wholesale buying strategy than the approach they use.

- **replication:** some suppliers were concerned that they are unable to replicate our September proposal, as its observation period (February to July) had passed at the point of its publication.

3.135. Below we detail the feedback we have received on these key themes and how we considered them in coming to our decision.

May policy consultation 'signal'

Stakeholders' views

3.136. Several suppliers thought that we should not have altered our proposal after our May consultation. They believed this proposal provided a clear signal to the market. Some suppliers have indicated that they adjusted their wholesale approach for the first cap period in line with our initial proposal, and this was the rational and efficient action for them to take. They stated that, they will now not fully recover their wholesale costs relative to our May consultation proposal. One supplier told us that we anticipated that they would follow our May consultation proposal.

3.137. Two suppliers thought that we had failed to make it clear that we were considering multiple options for this approach as there was only one proposal in our May consultation. Another supplier, although also opposing our statutory consultation proposal, did recognise the iterative nature of policy design.

Our consideration

3.138. In May, we asked stakeholders about different aspects of our proposal and which they suggested we should change. For each aspect of our May consultation proposal, we presented the advantages and disadvantages and sought views on adjustments we might make. Nearly all suppliers suggested an alternative approach to some or all elements of our May proposal.

3.139. Some suppliers suggested completely different approaches of their own design. For instance, one of the largest suppliers suggested we use average of wholesale prices over an 18-month observation period (the same approach we refer to as 'typical' for the six largest suppliers). They made this suggestion responding to our first working paper in March 2018, and again responding to our May consultation in June 2018.

3.140. It is of course an inherent feature of the consultation process that proposals may change as the process takes its course, and all stakeholders knew that the May policy consultation was only one part of the process, and that the statutory consultation process would follow subsequently. In our statutory consultation, we proposed an allowance based on the average prices of an earlier period (than the one we proposed in our May consultation). We consider that we were entitled to do so.

Evidence and understanding of how suppliers purchase energy

Suppliers' views

3.141. Several suppliers told us that we lacked or did not show the evidence and justification for our statutory consultation proposal. They told us that we do not have up to date and detailed enough information to say how suppliers had purchased energy.

3.142. Two suppliers told us that the information we hold on their hedging strategies does not reflect their hedging strategy for 2019. This was partly due to the impact of our May consultation on their hedging strategies. Suppliers said they used this information to inform their approach for the first cap period, meaning their hedging strategy for the first three months of 2019 effectively resembles our May proposal. Another supplier told us that we did not conduct basic inquires to understand and get evidence on supplier hedging strategies for the beginning of 2019.

Our consideration

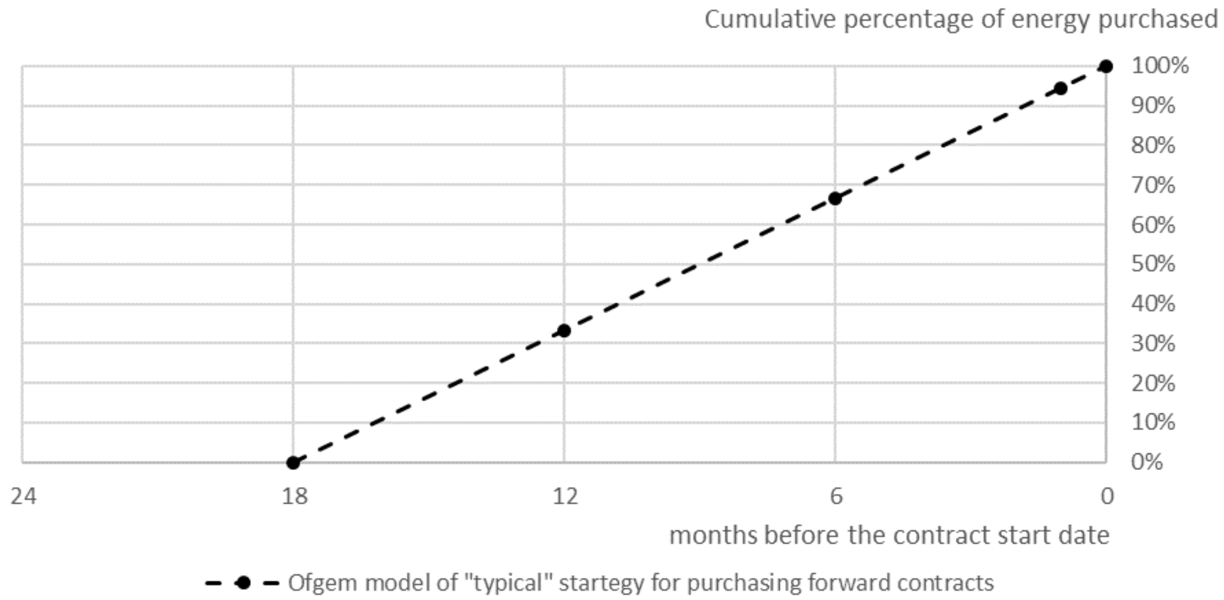
3.143. We consider that we have sufficient evidence and understanding of how suppliers typically purchase energy for SVT customers to assess the impact of our proposals on SVT customers and suppliers. We do not agree with the suggestion that we ought to have sought further evidence or information before proposing to set the allowance using an observation period between February and July 2018.

3.144. Our analysis of a typical supplier's approach to purchasing energy for SVT customers has been informed by information provided to us by the six largest suppliers as recently as 2017. In 2017, we inspected detailed data on how each of the six largest energy suppliers had purchased energy for their SVT customers. Over the course of the year, we discussed with each supplier the rationale for their approach.[31] Historically,

[31] After its investigation into the energy market, the Competition and Markets Authority (CMA) recommended that Ofgem explore whether we should require the six large energy suppliers to change the way they report their wholesale costs. Normally, these suppliers report their historic cost: the weighted average price they paid for energy *delivered* in a specific period (but not necessarily *purchased* in that period).[31] The CMA recommended comparing this historic cost against a benchmark to show the potential inefficiency in a supplier's purchasing strategy. To test its feasibility, we had to inspect detailed data on how suppliers purchase contracts, and understand suppliers' rationale

the six largest energy suppliers started purchasing energy for their SVT customers over 18 months in advance. The exact approaches differ, but the suppliers had the same broad approach. On average, they started buying energy over 18 months before the start of the contract period, and gradually purchased the total volume they needed from that point. The data shows that those suppliers' average approach is very similar to our typical representation (shown in Figure A4.2).

Figure A4.2: How suppliers purchase energy contracts over time for SVT customers



Source: Ofgem data from a 2017 request for information on the six largest suppliers' approach to purchasing energy.

Note: For the avoidance of doubt, this chart shows our simplified model of an 18-month long purchasing strategy. We do not show the raw data provided by suppliers. The average approach was slightly 'longer' than our model, and the 'shortest' approaches were broadly equivalent.

3.145. Given their stated rationale for their approach to purchasing energy as provided to us in 2017, it is unlikely the six largest suppliers would have deviated materially from that approach in the succeeding months (before our May consultation).

3.146. Suppliers' rationale for purchasing energy over a long period was that it makes their wholesale *costs* less exposed to changes in wholesale *prices*. When suppliers buy the contracts they need gradually over a defined period, they smooth any spikes in wholesale prices into a weighted average cost over that period. The longer the period that suppliers smooth their purchasing over, the more stable their costs are (because each day – and potential spike – is a lower proportion of their average cost). A stable and predictable average cost means they can set predictable prices for customers. Retail price changes, more specifically retail price increases, tend to encourage more SVT customers to switch to cheaper FT deals, potentially with rival companies. By purchasing energy over a long period, their average wholesale costs are more stable. When wholesale prices are increasing their wholesale costs stay comparatively low, and retail price increases can be delayed. For example, when announcing its retail

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for their approach. We undertook this work over the course of last year (2017) We developed a substantial request for information and conducted a number of discussions with each supplier to understand their approach.

price increases in 2018, one of the large suppliers included an explanation that the increase had been delayed and mitigated by the way it purchased energy in advance.

3.147. Given market conditions, suppliers may have adjusted their strategy, but not in a way that changed the overall rationale. Historically, suppliers continually adjust their strategy, but only in relatively small ways; the broad approach would remain to spread cost out over a long period of time. For instance, suppliers commented that they frequently adapted to changing circumstances, but these changing circumstances are not material enough to change the broad approach. When wholesale prices are rising suppliers 'speed up' the rate at which they purchase energy (ie to acquire more energy before the price increases further), or 'slow down' the rate of purchasing if they expect the market price to fall. However, these are relatively marginal changes. The overriding objective is to avoid risk by spreading the cost of purchasing energy over a long period.

3.148. Although we recognise that suppliers may regularly adjust their strategy in small ways, no development in the market since 2017 suggests a substantial change in approach before May 2018. In our 2017 discussions, some of the suppliers did discuss when and why they had made more substantial changes in the past. For instance, one supplier discussed that it had changed from a 36- and 24-month purchasing strategy to an 18-month one. This change, in part, responded to a period when wholesale prices were *decreasing* for a long period of time, meaning suppliers with long strategies had high costs relative to suppliers that purchased more energy closer to the contract date. At this time competition increased from smaller suppliers. These suppliers accessed cheaper wholesale prices by purchasing most of their energy near to delivery. On that basis, it would be surprising in a *rising* wholesale market (which we have had since 2017) if the large suppliers then went against their own rationale and experience by changing to a substantially *shorter* purchasing strategy. We have seen more small suppliers get into financial difficulty this year than has historically been the case. This is in part because they are on average more exposed to high and increasing wholesale prices, as they purchase more energy closer to the contract date.

3.149. During the consultation process one of the largest suppliers twice recommended that we use a typical (ie. an 18-month average of wholesale prices) approach to set the allowance. In March 2018 (in response to our first working paper) and again in June 2018 (in response to our May consultation) it reiterated the benefits of this typical approach, providing the same rationale it had given in 2017. The rationale it provided for this approach was the same as the rationale provided by suppliers in 2017: that suppliers' costs, and by extension the allowance in the cap, would be less sensitive to changes in wholesale prices.

3.150. We consider our evidence in the context of a three-month period within a two to five year cap. We expect suppliers will adapt their previous approach to fit within the cap. For the six largest suppliers that means changing to a shorter strategy that passes through costs into retail prices more quickly than they previously did. In that context, we do not need to request data on their actual costs (whereas we needed detailed information on operating costs). However, for the first cap period, we do need to consider actual costs because suppliers have already purchased a significant proportion of their energy.

3.151. Since we had recently obtained information direct from the large suppliers, we did not consider it was necessary or proportionate to repeat the long, detailed process we had undertaken in 2017.

3.152. The statutory consultation process afforded suppliers an opportunity to respond to our proposal and make representations as to the impact of our proposal on themselves and their customers.

Financial impact on large suppliers

Suppliers' views

3.153. Multiple suppliers have provided estimates of what they thought the financial impact would be on them from the change in our proposal (between our May consultation and our statutory consultation). All of these suppliers calculated a reduction in the wholesale allowance level for the first cap period. This ranged between £37-52 per dual fuel customer on an annualised basis. Suppliers then assessed this as a cost for the first quarter of 2019 of between £15-19 per dual fuel customer.

3.154. One supplier provided detail on how the change in proposals specifically affected them. They told us they incurred a loss, broadly split into two components: the impact of moving the observation period forward by two months (ie the reduction in the allowance); and the impact of announcing a lower price increase than they otherwise would have announced.

Our consideration

3.155. We have given careful consideration to the financial impact of this aspect of our decision on suppliers, as part of our duty to have regard to the need for an efficient supplier to finance its licenced activities.

3.156. The first cap period will be short – only three months long. Our consideration of an efficient supplier's ability to finance its activities includes, but is not limited to this three month period. We consider the financial impact of our approach in the first cap period, in the context of a two to five year cap period.

3.157. Nonetheless, to inform our decision, we sought to analyse and understand the financial impact of our decision during the first cap period. This includes the impact on suppliers that may have adjusted their purchasing strategy in the wake of our May proposal (even though that proposal was not part of the statutory consultation process, which as all suppliers knew in May, would come later).

3.158. We analysed the impact of setting our allowances using three different approaches, and importantly, we considered combinations of them. To ensure consistent comparisons we analysed the weighted average cost of contracts for October 2018 to September 2019 in each case. We considered (see Figure A4.3):

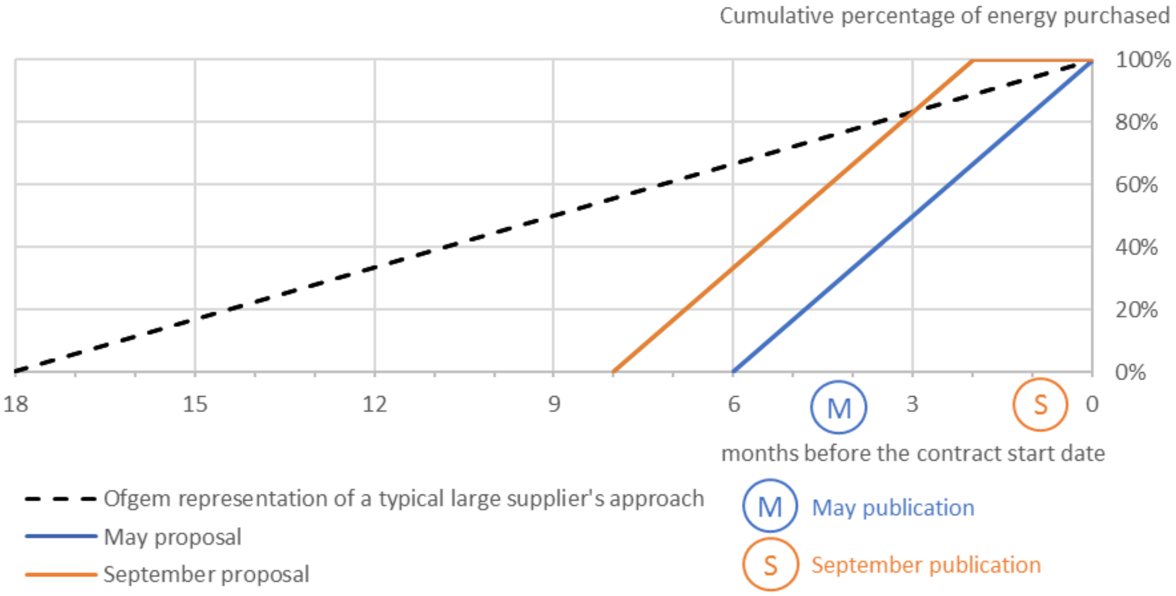
1. **the 'typical' approach**: an 18-month observation period between April 2017 and September 2018

2. **our May consultation proposal**: a six-month observation period between April 2018 and September 2018

3. **our statutory consultation proposal**: a six-month observation period between February 2018 and July 2018, with a two-month lag before the contract start date

4. **a 'medley' approach**: the contracts a supplier would have purchased if it adjusted its strategy as we published our proposals in our May consultation and statutory consultation.

Figure A4.3: The typical approach, May consultation proposal, and statutory consultation proposal



Source: Ofgem.

3.159. First, we considered suppliers that, after May 2018, continued to use a typical strategy when purchasing energy for SVT customers. Had we maintained the observation window that we proposed in our May consultation, we would have set the allowance 18% higher than a supplier using a typical 18-month purchasing strategy.

3.160. Second, we considered suppliers that used a typical strategy up to May 2018, but then adjusted their purchasing strategy following the May proposals. Given the rationale provided by the six largest suppliers, we do not consider it likely that these suppliers had no purchasing strategy before we published our May consultation. Given that wholesale prices were increasing, not having a purchasing strategy would have increased the risk they would have higher costs than competitors that maintained a typical strategy.

3.161. However, even if a supplier had originally started purchasing energy using a typical approach for a large supplier, then it could have changed its approach following our proposals in May and September. Some stakeholders have told us that this is what they did, even though our May consultation proposal preceded the statutory consultation process. A supplier that adjusted its strategy in response to our May consultation would not have adopted the May proposal or statutory consultation proposal exactly. This is because we published the consultations, some of the observation period had already passed. Instead, we compare the allowance to the costs of a supplier taking the following actions, which we refer to as the "medley approach".

1. **April 2017 to May 2018**: the supplier purchased energy using its typical approach, acquiring most of the energy it requires at a low average price.

2. **End of May 2018:** the supplier responds to our May proposal. It sells its contracts at the prevailing market price for a profit. It purchases just under 30% of the volume it needs at the prevailing price, which is the energy that would have been bought between April 2018 and the end of May 2018.

3. **End of May to beginning of September 2018:** the supplier purchases contracts in line with our May consultation proposal. By early September, it has over 85% of the contracts it needs.

4. **Beginning of September 2018:** the supplier would purchase the remaining energy it needs at the new prevailing price, as the observation window has been moved to an earlier period.

3.162. We calculate that our allowance would slightly *overcompensate* a supplier that adjusted its strategy in response to our consultations. The allowance we have set is just over 1% higher than the total net costs of the approach stated in the paragraph above (the medley approach). When considering if the allowance is sufficient for a supplier that changed its approach, we cannot simply compare the allowance to the cost of the contracts they would have bought between May 2018 and September 2019; we acknowledge that this comparison, *in isolation*, results in a loss. We must also consider the profit that the supplier would have made when it sold the contracts it bought before May 2018. It bought these contracts between April 2017 and May 2018 at lower average cost than the price it would have sold them at in May 2018. In their responses, some suppliers acknowledged this profit.

3.163. We are not persuaded that we should exclude from our consideration the profits suppliers made when moving from their typical approach to their May consultation proposal. For instance, some suppliers stated that they do not consider this a profit because they passed the benefit onto customers by not increasing their prices (either SVTs or FTs). That decision is an independent consideration. The supplier has made a gain when selling the contracts; that it may have decided to invest that gain in a separate business decision, which may have provided other benefits (for instance, growing or maintaining market share), is not a relevant factor.

3.164. To allow comparison with the allowance in the first default tariff cap period, we have analysed approaches for purchasing contracts covering the entire forward view period (October 2018 to September 2019). We take this approach to ensure a reasonable like-for-like comparison when looking at the impact of proposals on customers and suppliers. We would not make direct comparisons with suppliers' costs for contracts for January to March 2019 for two reasons:

1. **how we treat seasonal contracts in the wholesale allowance:** we set the wholesale allowance for each cap period using the weighted average cost of contracts covering a 12-month period. Winter contracts are more expensive than summer contracts, which means that the allowance undercompensates suppliers in winter and overcompensates them in summer. We set the wholesale allowance this way to avoid seasonal price changes for customers (high retail prices in the winter and low retail prices in the summer) – see paragraphs 3.8 to 3.10 above for a full discussion of this design feature. This feature of the cap means that we cannot, in isolation, compare the first cap period allowance against suppliers' actual wholesale costs for winter. By design, we expect the second cap period to provide some of the compensation for winter contracts.

2. **how we treat the purchase of granular contracts**: when suppliers purchase energy a long time in advance, they tend not to purchase granular contracts (eg

for energy in a given month, week, or day). For the purpose of setting the allowance we analyse seasonal contracts, and then we add an additional allowance to cover the costs of shaping these contracts into more granular ones. In practice, suppliers' shaping costs are not a lump sum, added on at the end. They may build up shaping during the observation period depending on their approach. This complexity means we cannot make direct comparisons with the different approaches suppliers may have taken in May or September.

3.165. On average, our analysis suggests that the wholesale allowance in the first cap period is sufficient for a supplier using a typical purchasing strategy, or one that used a typical purchasing strategy and then adjusted it in response to our consultations. We recognise that some suppliers may have more favourable or less favourable positions than average. This variance is an inherent outcome of the cap, as the Act requires one allowance for all suppliers.

3.166. We also take the view that any residual impact on particular suppliers has to be considered in context. First, the first cap period is short – only three months long. We consider it in the context of a two to five year cap period. Second, if a supplier had less favourable costs *in the first cap period* than one using a typical approach, then we should consider how the *second* cap period might mitigate this. The second default tariff cap period will start in April 2019. Our May and statutory consultations proposed that we would set the allowance for the second cap period using an observation period between August 2018 and January 2019. That allowance will be higher than the costs of any supplier that used a typical 18-month observation period before we published our consultation in May 2018, as they would have already purchased some the energy in advance.

Financial impact on small suppliers

Stakeholders' views

3.167. Some small to medium sized suppliers raised specific concerns around the impact the change in approach between consultations would have on smaller suppliers. These suppliers were broadly concerned that our statutory consultation proposal would have a direct negative impact on small suppliers. One supplier quantified the negative impact on. Another supplier highlighted that it does not have a predictable SVT portfolio, which makes it harder for it to hedge. As a result, it may use a shorter hedging strategy, and as such wholesale prices which are closer to the current period would reflect its cost base more accurately.

Our consideration

3.168. We have set the wholesale allowance such that, *taking this allowance in isolation*, we recognise smaller suppliers that purchase energy much closer to the date of delivery are likely to not be fully compensated for wholesale costs. We consider this reasonable for the following reasons.

- First, most SVT customers are served by large suppliers, so we weigh their outcomes more heavily when considering the objective in the Act to protect SVT customers.
- A low proportion of small suppliers' customers are on SVTs, so these suppliers are less exposed in absolute terms, to the extent the cap undercompensates them for each SVT customer.

- Within the cap itself, small suppliers tend to be overcompensated by the other allowances in the cap (due to policy cost exemptions, lower operating cost bases and fewer standard credit customers). This offsets the loss they would incur when considering just their wholesale costs and the wholesale allowance in isolation.

3.169. Having considered this impact on small suppliers, and mitigations of it, we concluded that our proposal was appropriate.

Replicating our approach

Stakeholders' views

3.170. One supplier told us that as most of the six-month observation period proposed in our May consultation lay in the future, it provided a choice for suppliers to follow the hedge. They said the main justification for this option was to allow suppliers to follow the hedge for the first quarter of 2019, and we have now removed that with our statutory consultation proposal.

Our consideration

3.171. Our primary concern is whether our approach to setting the wholesale allowance protected SVT customers. In our consultations, we considered 'fully replicable' options, and ruled them out (ie setting an observation period that did not contain historic prices). Had we used a much shorter, later, observation period suppliers would have been better able to match it, but that was not our objective. That approach would have set an allowance that was very sensitive to wholesale prices, but not reflected the underlying wholesale costs for the majority of SVT customers. By taking this approach the allowance would have exceeded underlying costs by more than our May consultation proposal, and so the fully replicable option would not have protected default tariff customers.

Other issues raised by stakeholders

Stakeholders' views

3.172. In response to our statutory consultation, the main alternative proposal suggested by suppliers was to revert back to our May consultation proposal. Two suppliers suggested providing a bespoke allowance or uplift for the first cap period to cover the difference in allowances between proposals if we did not revert back to our May consultation approach. However, suppliers did suggest alternative proposals in response to our May consultation. These included using a shorter, forward-looking period for the transition observation period, as well as delaying the cap to fit in a 'normal' observation period before the cap is introduced.

3.173. Several suppliers have also highlighted concerns that the observation period in our statutory consultation will lead to a larger increase in the wholesale allowance, and therefore the overall level of the default tariff cap, between first and second cap periods. Two suppliers thought the change in observation period would lead to an increase of £125-150 per dual fuel customer between the first and second cap periods. One supplier calculated the jump to be around £50 greater than it would have otherwise been.

3.174. One supplier was concerned that this proposal would artificially narrow the gap between FT and SVTs in the market. This in turn could hamper suppliers' efforts to increase customer engagement as the default tariff cap is introduced. Another supplier thought the proposal for the first cap period could stall competition until April 2019, as suppliers would be unable to hedge new sales.

Our consideration

3.175. Given the objective in the Act, our primary concern is whether the wholesale allowance protects default tariff customers. As discussed above, we consider that using our May consultation proposal would set the allowance higher than suppliers' costs for the majority of SVT customers. This approach would not protect those customers. Therefore, we do not consider it appropriate to revert to that approach.

3.176. We recognise that the wholesale costs in the second cap period will be higher than for the first cap period. This would be the case if average wholesale prices between February and July 2018 were significantly lower than the average between August 2018 and January 2019. We do not consider it would protect SVT customers to set the allowance in the first cap period higher than underlying costs would justify, simply to reduce the size of a potential increase whenwe set the second cap level.

3.177. We are not persuaded that the gap between FT prices and SVT prices is artificial. Due to differences in the way that suppliers purchase energy for SVT customers and FT customers, wholesale price changes are reflected in a suppliers' FT costs sooner than they are for SVTs. This is a temporary effect when wholesale prices are changing. It would not protect SVT customers to increase the allowance above the level of costs associated with them, simply to maintain a wider gap between SVT prices and FT prices.