Consultation Appendix

Default Tariff Cap: Statutory Consultation			
Appendix 5 – Policy and network costs			
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We are consulting on our proposals for setting and updating a default tariff cap in accordance with the Domestic Gas and Electricity (Tariff Cap) Act 2018. This supplementary appendix provides details of the proposals and methodology in relation to policy and network costs. This document is aimed at those who want an in-depth understanding of our proposals. Stakeholders wanting a more accessible overview should refer to the Default tariff cap – Overview document.

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

Document map

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

Figure 1: Default tariff cap – statutory consultation document map

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Default tariff cap – Overview document

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1. Introduction

Overview

1.1. In this appendix, we discuss our approach to estimating the costs that suppliers incur in relation to:

a) their obligations under different environmental and social programmes ('policy costs')

b) charges from the gas and electricity network companies ('network charges').

Policy costs

1.2. Energy suppliers are subject to a number of environmental and social obligations, designed to achieve a variety of different policy goals. In most cases, these obligations result in additional costs to suppliers, which are then passed on to gas and electricity customers via their energy bills.

1.3. There are currently six schemes in operation which directly result in additional expenditure by domestic suppliers:

- policies supporting low carbon and renewable energy, including the Renewable Obligation (RO), Contracts for Difference (CfD), and Feed-in Tariffs (FiT)
- delivering energy efficiency measures under the Energy Company Obligation (ECO) scheme
- Warm Home Discount (WHD) rebates paid to fuel poor customers
- Assistance for Areas with High Electricity Distribution Costs (AAHEDC, previously known as the 'Hydro Benefit Scheme') which aims to reduce electricity prices in areas of high distribution costs (currently Northern Scotland).

1.4. In addition, suppliers must also make payments to fund the Capacity Market scheme, designed to ensure security of supply. As discussed in Appendix 1, we consider that these are best categorised as wholesale energy costs, and so discuss these costs in Appendix 4.

1.5. In Chapter 2, we set out how we propose to estimate the costs of each of these schemes when setting the level of the default tariff cap. Our broad proposed approach remains the same as set out in our May consultation[1], although we have made some changes to our detailed methodology, most notably in relation to how the expected cost of CfDs would be calculated.

[1] Default tariff cap: policy consultation May 2018 https://www.ofgem.gov.uk/publications-and-updates/default-tariff-cap-policy-consultation-overview

1.6. Based on our proposed methodology, we estimate that the total costs of these schemes was equal to approximately £117 for a dual fuel customer with typical consumption in 2017/18 (for a customer with a single rate electricity meter).

Network charges

1.7. Suppliers are charged for the costs of building, maintaining and operating the energy network and system infrastructure used to deliver energy to their customers. Because the networks are largely monopoly businesses, we regulate the prices that the network companies are able to charge by controlling the companies' allowed revenues. The network charges paid by suppliers vary depending on where their customers live, what type of electricity meter they have and how much energy they use.

1.8. Different charges apply for the high voltage/high pressure transmission networks (which take electricity and gas around Great Britain) and the lower voltage/lower pressure distribution networks (which connect customers to the national transmission networks).

1.9. In Chapter 3 of this appendix, we describe how we propose to estimate these costs when setting the level of the default tariff cap. As with policy costs, our broad proposed approach to estimating network charges remains the same as set out in our May consultation, although we have made some changes, including in relation to how we estimate losses and the share of demand that takes place in peak periods.

1.10. Based on our proposed approach, we estimate that network charges amounted to a total of approximately £258 for a dual fuel customer with typical consumption in 2017/18 (for a customer with a single-rate electricity meter). This is based on a simple average across GB regions – our estimate varies from £234 in the region with the lowest network charges up to £297 in the region with the highest.

Context and related publications

1.11. Ofgem (2018), Default tariff cap working paper – setting the level of the cap. https://www.ofgem.gov.uk/publications-and-updates/default-tariff-cap-working-paper-setting-level-cap

1.12. Ofgem (2018), Default Tariff Cap: Policy Consultation. Appendix 7 – Policy and network costs. https://www.ofgem.gov.uk/system/files/docs/2018/05/appendix_7_-_policy_and_network_costs.pdf

2. Policy costs

In this chapter, we set out how we propose to estimate the costs of suppliers' environmental and social obligations ('policy costs') when setting the level of the default tariff cap. Using our proposed approach, we estimate that the total costs of these schemes was equal to approximately £117 for a dual fuel customer with typical consumption in 2017/18 (for a customer with a single rate electricity meter).

Summary of our approach

2.1. Our proposed approach to estimating policy costs for the purposes of setting the default tariff cap, which is similar to that set out in our May consultation, is as follows:

- We propose to estimate policy costs using administration data (ie data from scheme administrators, rather than the suppliers themselves), and wherever possible rely on publically available information to do so. This will increase transparency around how the level of the cap is being set.

- In general, we propose to set the cap to reflect forecast policy costs in the given six month price cap period, to ensure the cap is cost reflective and reduce the risk of distorting competition in the wider market. However, in the case of CfDs, we will base our cost estimates on an annualised view of the costs of the scheme, to avoid the risk of the cap systematically varying between winter and summer as a result of seasonal trends in wholesale prices. This is a change to our approach compared to the proposal in our May consultation.

- We intend to set the allowance based on the costs that we would expect to be incurred by a fully-obligated supplier in steady state (ie where their obligation reflects their market share in the relevant period). This means that suppliers that are not obligated under ECO and WHD schemes will incur costs beneath the level allowed under the cap.

- The costs to a supplier of all of the schemes vary in proportion to the amount of electricity a customer uses (for ECO, electricity or gas), with the exception of the WHD, where a supplier's obligation depends on the number of customer accounts. We propose to reflect this in how we set and update the level of the cap at nil and typical consumption.

- Where necessary, charges to suppliers will be uplifted by forecasts of losses on the electricity networks to ensure the true cost to a supplier associated with a given obligation is reflected in our estimates. Losses were not captured in the method set out in our May consultation.

2.2. Table A5.1 summarises the specific approach we propose to take to estimate the costs of each scheme for the purpose of setting the level of the cap. Full details – including links to sources and details of the calculations - are set out in Annex 4 to the draft licence condition 28AD, which we have published alongside this document.[2]

[2] https://www.ofgem.gov.uk/publications-and-updates/default-tariff-cap-overview-document

Table A5.1: **Summary of our proposed approach to estimating policy costs**

Scheme	Approach
RO	For RO, the allowance is calculated by combining the buy-out price and the obligation level for the given scheme year. At the start of February, when the final buy out price is not available, it is estimated using the Office of Budget Responsibility's (OBR) inflation forecast.
CfD	For CfDs, the allowance is based on a weighted average of quarterly interim levy rates as published by the Low Carbon Contract Company (LCCC) for the year running April to March, uplifted to reflect the our estimate of maximum allowable green exempt electricity. To this, we add the operational cost levy as published by the LCCC. We then uplift to reflect costs per MWh of electricity *supplied* using our estimate of regional transmission and distribution losses for single rate and multi-register electricity customers (meaning that our estimate of CfD costs will vary between regions by a small amount).
FIT	For FiTs, the allowance is based on the latest OBR estimates of total scheme costs, divided by a forecast of total supply volumes for the given scheme year from BEIS.
ECO	For ECO, the allowance is based on BEIS' forecast of the annualised cost of the scheme, taken from the most recent impact assessment, divided by our latest estimates of the supply volumes used to calculate suppliers' obligations (or the final values, where available).
WHD	For WHD, the allowance is based on target spending for the scheme year, divided by our latest estimates of the customer numbers of compulsory suppliers (or the final values, where available).
AAHEDC	For AAHEDC, the allowance is based on the final charges as published by National Grid (in August) and the previous year's charge increased using RPI when the final charge is not available (in February). This is uplifted using our estimate of distribution losses.

2.3. Table A5.2 sets out our estimates of the costs in relation to each scheme in 2017/18, calculated using our proposed methodology.

Table A5.2: **Estimates of scheme costs in 2017/18 (GB average)**

Scheme	Electricity (single rate) (£)		Electricity (multi-register)(£)		Gas (£)	
	Nil	TDCV	Nil	TDCV	Nil	TDCV
RO	n/a	57.79	n/a	78.29	n/a	n/a
CfD	n/a	8.33	n/a	11.49	n/a	n/a
FiT	n/a	14.39	n/a	19.51	n/a	n/a
ECO	n/a	9.43	n/a	12.77	n/a	12.41
WHD	6.70	6.70	6.70	6.70	6.70	6.70
AAHEDC	n/a	0.78	n/a	1.06	n/a	n/a
Total	**6.70**	**97.42**	**6.70**	**129.83**	**6.70**	**19.11**

Source: Ofgem calculations based on data from BEIS and scheme administrators.
Notes:
1. The figures reflect a weighted average of our estimates of scheme costs as would have been forecast for periods starting April 2017 and October 2017. For electricity, we assume that 57% of consumption takes place in winter for single rate and 61% for multi-register. For gas, we assume that 75% of consumption takes place in winter.
2. Typical Domestic Consumption Values (TDCV) are 3.1MWh per year for electricity (single register), 4.2MWh per year for electricity (multi-register) and 12.0MWh per year for gas.[3]

2.4. These estimates reflect the charges to suppliers under each of the schemes. However, it is important to note that they will not reflect the full impact of the schemes on customer bills – or the overall cost of each scheme to customers. This is because this

[3] See the TDCV page on our website for further details: https://www.ofgem.gov.uk/gas/retail-market/monitoring-data-and-statistics/typical-domestic-consumption-values

will depend on the wider impacts of the schemes on, for example, wholesale prices (in the case of RO and CfDs), energy efficiency (in the case of ECO), and network charges (in the case of AAHEDC).

2.5. Because they rely on forecasts, these estimates differ to suppliers' actual *outturn* costs in 2017/18 (and those included as our "baseline values" in our May consultation). We compare our forecasts to our best estimates of outturn costs for those schemes which are subject to greatest forecast uncertainty in the final section of this chapter.

Issues

2.6. Most respondents to our May consultation broadly agreed with our proposed approach to estimating policy costs. Some respondents raised detailed issues in relation to the methodology, which we discuss below.

Uncertainty

2.7. A number of respondents highlighted the uncertainty affecting our estimates of policy costs - for example because the costs of some of the schemes were not known in advance, and because of the impact of short term fluctuations in consumption on suppliers' costs under some of the schemes. One respondent argued this could lead to a risk of under recovery from the cap in periods of low consumption. Some respondents argued that headroom should be included within the cap to reflect this uncertainty, while others argued that a review mechanism should be used to correct for any inaccuracy in forecasts.

2.8. We agree that our policy cost estimates are subject to some uncertainty. In paragraphs 2.51 to 2.55 in this appendix we compare forecasts with outturns for the three years between 2015-16 and 2017-18. We find that using forecasts overstated the cap by £5 to £13 per customer, depending on the year. There are some reasons to think this uncertainty – which would have led to customers being over charged – will be reduced in the years to the cap's actual operation. To address uncertainty, we discuss our view on whether a review mechanism should be included in the cap in Appendix 3, while the case for including headroom in the cap to reflect uncertainty in policy costs is discussed in Appendix 2.

Time periods

2.9. One respondent highlighted the inconsistency between the periods used when estimating different elements of costs – with policy and network costs estimated for the six months of the price cap, while wholesale costs and BSUoS were based on an annualised view. They argued that most fixed tariffs would be priced to reflect costs over a 12 month period. This difference in horizons could create a difference between the costs priced into the cap and those priced into other tariffs in the market, particularly in the second half of the year (ie following the October update). This might disproportionately affect switching, given that switching is generally higher in winter.

2.10. As a general principle we consider the risk of creating unintended distortions to the wider market will be minimised by ensuring that, so far as possible, policy costs are recovered under the cap in the period in which they are incurred – ie setting the cap to reflect costs within the six month price cap period. While moving to an annual horizon would likely increase alignment with the costs priced into fixed term tariffs, we note that a significant mismatch would continue to exist (eg because not all fixed tariffs will start or end in line with the price cap periods and there are many fixed tariffs for periods longer than 12 months).

2.11. The exception to our general position that the cap should reflect policy costs in the six month price cap period is where costs exhibit strong seasonal patterns within the year. At present, domestic tariffs generally do not reflect seasonal trends in costs, and we consider it appropriate to maintain this feature of the market in the design of the default tariff cap (a position that most respondents to our consultation supported). Most significantly, this affects wholesale costs, which - as discussed in Appendix 4 we intend to set with reference to an annualised view of wholesale prices. However, as discussed below, we also propose to set the cap with reference to an annual view of the costs of CfDs and BSUoS, which are also expected to have a seasonal element.

2.12. One respondent highlighted that because lagged supply volumes were used in assessing obligations under the ECO, FiT and CfD schemes, this would create a risk that suppliers with reducing market shares would not be able to recover their costs. We note that the converse effect exists for a growing supplier, for which our methodology may overstate the cost of the scheme. In our view, basing the allowance on a supplier in steady state (neither growing nor shrinking) best balances these risks.

Losses

2.13. In response to our consultation, a number of respondents highlighted that losses should be taken into account where estimating the cost to a supplier of schemes where charges were based on demand at the transmission system or at the grid supply point.

2.14. We agree with these stakeholders. We therefore propose to uplift our estimates of the costs of CfDs, and AAHEDC to reflect forecasts of distribution and (in the case of CfD) transmission losses:

- for distribution line losses, these are based on the distribution network operators' forecasts as published in their final charging statements, for each region and period

- for transmission losses, these are based on the expected transmission loss multipliers as published by Elexon for each region.

2.15. We weight the loss multipliers by domestic demand in different periods to derive appropriate loss multipliers for the different schemes. We propose to update our estimates of losses annually in February with the latest forecasts published by the distribution network companies and Elexon for the coming year.

2.16. Full details of our calculations are provided in the supplementary 'Demand and losses' workbook that we have published alongside this consultation.[4]

[4] https://www.ofgem.gov.uk/publications-and-updates/default-tariff-cap-overview-document

CfDs

2.17. In our May consultation, we proposed to base the allowance for CfDs on the quarterly interim levy rates (ILR), as published by the Low Carbon Contract Company (LCCC), to which we would add the operational cost levy.

2.18. In response to our consultation, it was highlighted that our proposal to use forecasts of the ILR for two rather than four quarters when setting the allowance for CfD risked introducing seasonality into the cap. To avoid this, as set out in Table A5.1, we now propose to use ILR forecasts covering four quarters.

2.19. Specifically, we propose to base the CfD allowance on costs over the year running from April to March both when we publish the level of the cap prior to the start of that year in February, and when we update it in August. In August updates, we will take into account any in-period revisions made to the ILRs in the period between 1 April and 1 August.

2.20. A number of stakeholders argued that the level of the ILR should be uplifted to reflect the impact of green exempt electricity. One supplier recommended a correction equal to the maximum allowable under the scheme.

2.21. We agree that the true expected cost to suppliers of CfDs will exceed that captured by the methodology we proposed in our May consultation due to the impact of the exemption of green supply, which - unlike the exemption for Energy Intensive Industries – is not taken into account in the ILR forecasts published by the LCCC.

2.22. We therefore propose to adjust the ILRs upwards by a percentage reflecting the assumption that green exempt electricity (GEE) is equal to the maximum allowed under the scheme. This percentage is calculated by dividing the cap on green exempt electricity - as per the regulations - with the previous year's total reconciled supply volumes (excluding exempt volumes).

2.23. LCCC data shows that total reconciled green excluded demand was below the maximum allowed level in 2017/18 (about 2.4% of total reconciled demand excluding EII and GEE in the quarter from July to September 2017 – the most recent for which information was available - compared to a maximum allowable of about 3.1%). To the extent that this is the case going forwards, our methodology will overstate the true expected costs of the CfD scheme (although we note that GEE volumes have shown an increasing trend over time, and so we expect any overstatement to be small).

2.24. Some respondents to our consultation highlighted that single rate and multi-register customers would have a different consumption profile, and this should be captured in the weights we applied to the quarterly ILRs. It was suggested that these weights should be based on seasonally normal demand, to avoid our estimates being affected by weather in a given year.

2.25. We agree, and have calculated different demand weights for single rate and multi-register electricity customers, to reflect their different consumption patterns, using Elexon profile data evaluated at ten-year average temperatures. Full details of our calculations are provided in the supplementary 'Demand and losses' workbook that we have published alongside this consultation.[5]

2.26. One respondent suggested that a mechanism should be included to allow reconciliation of costs from season to season – whereby departures from forecast in previous quarters would be passed through in the subsequent price cap period. However, as set out in Appendix 3, we do not propose to include a mechanism designed to retrospectively correct for forecast error, given the risk this would distort competition in the competitive market segment, and the fact that it would not be possible to ensure that the correction reflected the level of over or under recovery in the previous period.[6]

2.27. Finally, one respondent recommended that Ofgem used the *actual* interim levy rate for the purposes of estimating costs in 2017/18, rather than forecasts. This is the data source we have used when comparing our forecasts with realised costs in Table A5.3 below. When setting the level of the cap in future price cap periods, it will not be possible to use the actual interim levy rate, as this is only known subsequent to the level of the cap being published.

2.28. The full details of our revised approach, including historic examples, are provided in Annex 4 to the licence condition.

FiTs

2.29. In our May consultation we proposed that the baseline allowance for FiTs would be estimated by dividing the total realised cost of the scheme (based on a provisional estimate of the levelisation fund) by total relevant electricity supplied. For the purposes of updating the allowance, we proposed to use the OBR forecasts of total costs of the scheme, divided by BEIS forecasts of total supply in the scheme year.

2.30. A number of stakeholders commented on our estimates of the realised costs of the FiTs scheme:

- One respondent said that it was important to use the latest data from the annual levelisation process, as there could be changes between the annual process compared to the quarterly process.
- Another party said that due to levelisation process not being completed by Ofgem until September 2018, there was a risk that the true cost of the scheme would not be available in time for Ofgem's modelling of a default tariff cap baseline.
- Some parties argued that in estimating FiT cost for 2017/18 Ofgem should include the value of deemed exports.

2.31. We discuss how suppliers' realised FiT costs compare to our forecasts at the end of this chapter. For the purpose of these comparisons, we have included the value of deemed

[5] https://www.ofgem.gov.uk/publications-and-updates/default-tariff-cap-overview-document
[6] For example, because the number of default tariff customers of each supplier will change between periods.

exports, and use the most recent estimates of the levelisation fund and relevant electricity supplied that are available.

2.32. One stakeholder noted that because of the lag in the publication of the OBR's forecasts, exogenous changes could take place affecting the costs of the scheme in the period between the forecast being published and the level of the cap being set. They argued that in such a situation it would be important to adjust the OBR forecasts to ensure the cap was cost reflective.

2.33. Our proposal is to use the most reliable publically available official forecasts of the costs of the scheme, which we consider to be those published by the OBR. We will review the design of the cap if a preferred source becomes available.

2.34. One respondent said that if the OBR estimates were used, Ofgem should ensure that these estimates were consistent with the levelised amount. We compare our forecasts with our best estimates of the realised cost of each scheme in Table A5.3 below. We find that the forecasts understated the true costs of the scheme in some periods, overstated the true costs in others.

2.35. One respondent argued that because the costs of FiTs are charged on gross demand, our estimates should take into account losses. We note, however, that our forecasts of scheme costs are based on BEIS' forecast of total customer supply, and therefore a further adjustment is not required.

2.36. Finally, in relation to the exemption of Energy Intensive Industries (EII) from the costs of FiTs – if confirmation is provided by BEIS that the exemption will apply for a price cap period, we propose to use BEIS' estimate of total supply volumes *excluding* forecast EII demand, to ensure the impact on costs for a domestic customer are captured.

2.37. The full details of our revised approach, including historic examples, are provided in Annex 4 to the licence condition.

ECO

2.38. In our consultation document we proposed to base the allowance for ECO on the estimate of the annualised forecast cost of the scheme to suppliers, taken from the BEIS impact assessment, combined with estimates of the total supply volumes of fully obligated suppliers and the share of the ECO costs accounted for by these suppliers. We set out our expectation that this would provide a more reliable guide to the likely future costs that suppliers will incur under the scheme than using historic data from the previous obligation period.

2.39. Two stakeholders noted that Ofgem's estimate of annualised ECO costs of £638m was based on an incorrect input – and reflected the net present value of the scheme rather than the annual cost to suppliers. We agree, and have updated to reflect the correct value in our revised estimates.

2.40. One respondent argued that smaller suppliers may have higher ECO costs due to reduced buying power. However, given the objective of the Act, in our view the allowance for the costs of ECO should be set to reflect the costs of a supplier operating at efficient scale. We also noted that smaller suppliers may enjoy other cost advantages compared to larger companies (see Appendix 6).

2.41. One respondent argued that it did not consider the current BEIS impact assessment would prove to be realistic and therefore a headroom allowance should be included above the BEIS forecast to reflect this risk. However, we still consider that the BEIS impact assessment provide the most reliable view of the forecast costs of the scheme available. Were a revised impact assessment published following feedback to the consultation, we would use any updated forecast to set the allowance for ECO. In paragraphs 2.51 to 2.55 in this appendix we compare forecasts with outturns for the three years between 2015-16 and 2017-18. We find that using forecasts overstated the cap by £5 to £13 per customer, depending on the year. There are some reasons to think this uncertainty – which would have led to customers being over charged – will be reduced in the years to the cap's actual operation. We discuss the requirement for a headroom allowance to reflect forecast uncertainty relating to policy costs in Appendix 2.

2.42. One respondent requested that Ofgem clarify what was meant by estimating the costs of a "fully obligated supplier", in light of the obligation arrangements which currently exist, and the proposed new taper mechanism under ECO3.

2.43. For ECO2, we have estimated historic costs based on the share of ECO expenditure falling to suppliers above the higher threshold amount (ie suppliers that do not have a reduced obligation), and then dividing by those suppliers' total demand as used in calculating suppliers' obligations to derive a cost per MWh. This is also the approach we propose to take for phase one of ECO3, using the revised thresholds published by BEIS.

2.44. Our proposed approach for later phases of ECO3 reflects the revised approach to tapering set out in the BEIS decision document.[7] In particular, under the new proposals, the cost of the obligation per typical domestic customer will vary between all suppliers, depending on their total supply volumes (and so there will be no single 'fully obligated' level of costs), due to the deduction of a fixed "supplier allowance".

2.45. We therefore propose to calculate an average allowance for the costs of the scheme by dividing the annualised cost by the total gross supply of *all* obligated suppliers at 31 December of the previous calendar year, irrespective of their size, as used for the purpose of calculating their obligation. We consider this a more appropriate approach than dividing by supply volumes net of the supplier allowance deductions, which would overstate the average cost of the scheme to a supplier. We note that while this may disadvantage larger suppliers, the impact may be offset to the extent these suppliers are able to achieve economies of scale.

2.46. The full details of our revised approach, including historic examples, are provided in Annex 4 to the draft licence condition 28AD.

WHD

2.47. In our May consultation, we proposed to calculate the cost of WHD by multiplying the target spending for the core group by the total market share of compulsory suppliers at 31 December of the previous calendar year. This figure would then be added to the

[7] See https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/727065/Energy_Company_Obligation_ECO3_2018-2022.pdf

non-core obligation (ie broader group and industry initiative expenditure), and the total divided by estimates of the customer numbers of compulsory suppliers as used in calculating suppliers' obligations.

2.48. One supplier asked for clarity about exactly which customer numbers would be used for the purposes of estimating the WHD allowance, asking for a worked example for the April 2019 level of the cap. It noted that different assumptions could have a material impact, when looking across the market as a whole.

2.49. For caps starting in April (published in February), we propose to use our best estimates available on the customer numbers of compulsory suppliers – as used for the purposes of calculating suppliers' obligations under the scheme - to estimate WHD costs.[8] In the August update, we propose to update our estimates to reflect the final number of customers of compulsory suppliers that were used in calculating suppliers' obligations, where there are any differences.

2.50. The full details of our revised approach, including worked examples for historic periods, are provided in Annex 4 to the licence condition.

Forecast vs outturn costs

2.51. As described in Appendix 3, we propose to set the level of the cap in advance based on our expectation of costs in the coming price cap period. This will ensure that – so far as possible – the cap reflects costs in the period covered by the cap, avoiding distorting competition in the wider market. This means that we must rely on forecasts to estimate policy costs for the purposes of setting the cap.

2.52. We have considered the likely extent of uncertainty in our forecasts – and so the risk that the cap is set above or below the actual policy costs incurred by suppliers. Specifically, for the three schemes for which costs are most uncertain at the point at which the cap will be set (FiTs, CfDs, ECO) we compared the values that we would have calculated using the methodology described above for 2015/16, 2016/17 and 2017/18; and our best estimate of suppliers' actual outturn costs in each year.

2.53. Table A5.3 sets out our findings. They suggest that our methodology would have:

- understated FiT costs in 2015/16 and 2017/18, and overstated them in 2016/17. This is primarily a result of differences between the OBR forecasts of total scheme costs and the final levelisation amount, although there are also differences between forecast and final demand.

- overstated CfD costs in both 2016/17 and 2017/18. This is likely to be primarily a result of contracts taking longer to come online than forecast, as well as green exempt electricity below the maximum allowable amount.

[8] Due to the timing of when updates to the cap will be published in February, the customer account and supply volume data available may be different to the audited values used to calculated suppliers' final obligations. If the final values are not available, we will use our best estimates. In August, the final values used to calculate supplier obligations will be used.

- overstated ECO expenditure in all three years. This is to a large extent likely to be a result of suppliers front-loading spending across the obligation period.

Table A5.3: Forecast versus outturn policy costs, 2015/16 to 2017/18 (£ per customer per year)

	2015/16			2016/17			2017/18		
	(a) Forecast	(b) Outturn	a-b	(a) Forecast	(b) Outturn	a-b	(a) Forecast	(b) Outturn	a-b
FiT	9.62	13.80	-4.18	16.04	14.86	1.17	14.39	16.05	-1.66
CfD	n/a	n/a	n/a	2.48	1.19	1.29	8.33	6.40	1.93
ECO (elec)	11.78	7.87	3.91	11.85	7.14	4.71	9.43	4.66	4.77
ECO (gas)	15.37	10.27	5.10	15.92	9.61	6.31	12.41	6.13	6.28
Sum	**36.77**	**31.94**	**4.83**	**46.29**	**32.80**	**13.48**	**44.55**	**33.23**	**11.32**

Notes:
1. Values shown are in £ per customer per year and are expressed at typical consumption. For electricity, they reflect estimated costs for a customer with a single rate meter.
2. Forecast costs are a weighted average of the values of the indices calculated in the February and October updates, according to the methodology set out in Annex 4.
3. Outturn costs are calculated as follows:
   FiTs – estimated using the final levelised scheme cost. This excludes the value of deemed exports.
   Cfd – estimates based on a weighted average of the reconciled daily levy rates as published by LCCC in its transparency tool, to which the operational levy is added. Note that, for 2017/18, the estimates are based on the most recent reconciliation runs as of July 2018.
   ECO – outturn ECO costs are based on total scheme costs as reported by BEIS in its Household Energy Efficiency national statistics, as published July 2018.

2.54. Looking across the three schemes, the comparison suggests that our methodology would have overstated policy costs by a total amount ranging from £5 to £13 per dual fuel customer looking across the period. We discuss what the level of uncertainty affecting policy costs suggests for whether headroom should be included in the cap to reflect uncertainty in Appendix 2.

2.55. We note that the scale of uncertainty affecting each of these forecasts is likely to fall going forward. This is because of the proposed closure of the FiTs scheme (making generation and therefore costs more predictable); as the CfD program becomes more established; and as a new ECO obligation period begins (reducing the effect due to differences in the profile of suppliers' ECO expenditure over time).

3. Network costs

In this chapter, we describe how we propose to update the level of the cap over time to reflect changes in network charges. Our broad approach to estimating these costs remains the same as set out in our May consultation, although we have made some changes, including in relation to how we estimate losses and the share of demand that takes place in peak periods.

Using this proposed approach, we estimate that network charges amounted to a total of approximately £258 for a dual fuel customer with typical consumption in 2017/18 (for a customer with a single-rate electricity meter). This is based on a simple average across GB regions – our estimate varies from £234 in the region with the lowest network charges up to £297 in the region with the highest.

Summary of our approach

3.1. The broad approach we will take to estimating network charges remains the same as described in our May consultation. In particular, we propose to combine information on charges from the network companies' charging statements with assumptions about demand and losses to estimate the costs to a supplier for each customer type.

3.2. Our proposed methodology is set out in full in Annex 3 to draft licence condition 28D. Key changes compared to the previous version include revised estimates of distribution and transmission losses and revised estimates of the share of consumption which takes place in winter, both of which are described in more detail below. We have also made a number of formatting changes to the model in order to improve transparency and reduce the risk of error. Our estimates of network charges in 2017/18 are provided in Table A5.4, below.

Table A5.4: **Estimates of network charges in 2017/18**

Scheme	Electricity (single register)		Electricity (multi register)		Gas	
	Nil	TDCV	Nil	TDCV	Nil	TDCV
Transmission	n/a	37.27	n/a	40.08	n/a	8.81
Distribution	16.43	89.84	16.43	89.99	n/a	113.65
Balancing Services	n/a	8.35	n/a	11.35		
Network costs, total	**16.43**	**135.46**	**16.43**	**141.41**	**n/a**	**122.46**

Source: Ofgem calculations based on data from BEIS and scheme administrators.
Notes:
1. The figures reflect a weighted average of our estimates of scheme costs as would have been forecast for periods starting April 2017 and October 2017. For electricity, we assume that 57% of consumption takes place in winter for single rate and 61% for multi-register. For gas, we assume that 75% of consumption takes place in winter.
2. Typical Domestic Consumption Values (TDCV) are 3.1MWh per year for electricity (single register), 4.2MWh per year for electricity (multi-register) and 12.0MWh per year for gas.

Issues

3.3. Most respondents to our May consultation broadly agreed with the proposed approach to estimating network costs. A small number of detailed points in relation to the methodology were raised– we discuss these below.

Demand profile

3.4. In response to our May consultation, one respondent told us that more granular and accurate consumption profiles could be used to improve the methodology.

3.5. We agree that more accurate demand information could be used. To address the comments received, we have calculated revised estimates of the share of profile class 1 and profile class 2 customers' demand which takes place in peak periods. Our estimates are based on the Estimated Regional Average Demand Per Customer[9] for each settlement period in 2017/18, evaluated using the ten year average noon temperature, as provided by Elexon. Note that we have not proposed to assess demand separately by region, as doing so would not be consistent with our typical domestic consumption values (which are calculated across GB), and would introduce greater complexity.

3.6. Our revised estimate of the share of domestic demand that takes place between 4pm and 7pm has decreased from 17.7% to 17.6% for profile class 1 customers, and reduced from 14.5% to 14.0% for profile class 2 customers.[10] Full details of our calculations are provided in the supplementary 'Demand and losses' workbook that we have published alongside this consultation.

3.7. One respondent argued that we should consider taking into account Grid Supply Point group correction factors when estimating demand for the purposes of setting the cap. While we considered that realised group correction factors would affect suppliers' final settled demand volumes, we do not propose to adjust for these in our methodology, because we expect the overall impact of doing so would be small. It would also introduce additional complexity into the models. We are not aware of any forecasts of group correction factors that could be used.

BSUoS

3.8. In response to our May consultation, one responded highlighted that there could be variance in Balancing Services Use of System (BSUoS) charges between the first settlement run ("SF", used to update the level of the cap) and the final settlement run

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[9] See this document: https://www.elexon.co.uk/wp-content/uploads/2016/02/Calculate-BM-Unit-Allocated-Demand-Volume_v1.0.pdf

[10] We note that the estimated share of demand taking place in the 4pm-7pm period for profile class 2 customer is materially *above* the actual proportion of consumption of customers with the most common Economy 7 settlement configurations that was allocated to the peak period in settlement in 2017/18 (12.5%). We therefore propose to keep this parameter under review, and – if there is any evidence to suggest that the Estimated Regional Average Demand Per Customer values overstate the true share of consumption that would be expected in peak periods based on average temperatures, we will consider alternative sources (eg taking an average over more than one year of the period profile class coefficients used in settlement).

("RF"). It pointed to additional Black Start costs, around half of which it said had been billed in the final settlement run.

3.9. We noted that using RF BSUoS charges to set the cap would introduce a significantly longer lag in the pass through of these costs. We compared total BSUoS charges at SF to total charges at RF for the period 2011/12 to 2015/16. We found that in some years, charges in the final reconciliation run were higher than at the first reconciliation run – in other years they were lower (although in all periods the difference was relatively small – less than 3%).

3.10. Given this, while we agree that using charges based on the SF run would introduce some uncertainty into the cap, we did not expect this to systematically bias our forecasts of BSUoS costs in one direction or another. We discuss whether additional headroom is required within the cap to reflect uncertainty in Appendix 2.

3.11. One stakeholder pointed out that the approach of using prior year, actual costs to determine the allowance for BSUoS charges was different to the method used for all other costs. It argued that National Grid's forecasts could instead be used to estimate costs for the relevant period. Another respondent supported the use of lagged historic data for this element of costs, as per the proposal in our May consultation.

3.12. As described above, in general we intend to set the cap to reflect our forecasts of costs in each period. This will avoid the risk of distorting competition in the wider market. However, one reason why this might not be possible for certain elements of costs is if forecasts are not sufficiently accurate for our purposes. In this case, a preferred alternative may be to base the allowance on historic data.

3.13. We took a simple average of forecast monthly BSUoS charges as published by National Grid in its Monthly Balancing Services Summary, and compared these with the lagged values calculated according to the methodology we proposed in our May consultation for the same period.

3.14. Table A5.4 sets out our findings. It shows that in each of the periods, using the forecasts would have led us to underestimate the charges as billed to suppliers in the first settlement run, by an amount ranging from £0.30/MWh up to £0.80/MWh.

Table A5.4: Comparison of forecast BSUoS charges with outturns for historic periods

Indicative price cap period	BSUoS charge included in cap (£/MWh)	Period this charge relates to	Forecast for the same period, from MBSS (£/MWh)	Difference (£/MWh)
2016-17 Summer	2.14	1 Jan 2015 to 31 Dec 2015	1.57	-0.57
2016-17 Winter	1.98	1 Jul 2015 to 30 Jun 2016	1.69	-0.28
2017-18 Summer	2.31	1 Jan 2016 to 31 Dec 2016	1.66	-0.65
2017-18 Winter	2.57	1 Jul 2016 to 30 Jun 2017	1.77	-0.81
2018-19 Summer	2.42	1 Jan 2017 to 31 Dec 2017	1.80	-0.62
2018-19 Winter	2.30	1 Jul 2017 to 30 Jun 2018	2.00	-0.30

Notes

1. The BSUoS charges in the second column are those that would have been included in the cap in each period based on the methodology in our May consultation, had the cap been in place. These are based on lagged actual BSUoS charges, relating to the periods set out in the third column in the table.
2. The forecasts are taken from National Grid's Monthly Balancing Services Summary (MBSS). They are simple averages across the 12 month periods that match the outturn data. They are taken from the MBSS that would have been available according to the proposed February and August update schedule – ie the November MBSS for the summer price cap periods, and the May or June MBSS for the winter price cap periods.

3.15. Given this systematic departure between forecast and actual charges, we propose to continue to use the lagged approach as described in our May consultation document to estimate the component of the cap relating to BSUoS charges. We may revisit this in the future if forecasts become available which we consider would materially increase the accuracy of our estimates – we discuss our approach to review elements of the design of the cap in Appendix 3.

3.16. One respondent argued that a half-hourly shape should be applied to BSUoS forecasts. However, we note that the proposed methodology set out in our May consultation already weights charges for each settlement period, using total volumes relating to that period. While in principle it would be possible to replace these with weights specific to domestic customers, doing so would introduce further complexity, and would be unlikely to have a material impact on our estimate of this element of costs.

Electricity losses

3.17. In response to our May consultation, one stakeholder proposed using more accurate information on zonal losses. They also asked for greater transparency around how the distribution loss factors currently used in the model had been derived.

3.18. We discuss our proposed approach to calculating forecasts of losses above. We have used this granular information on forecast transmission and distribution losses to revise our estimates of the loss multipliers for both TNUoS and BSUoS charges. Full details of our calculations are provided in the supplementary 'Demand and losses' workbook that we have published alongside this consultation.[11]

Gas regions

3.19. One respondent argued that setting the cap for the 14 DNOs would lead to unnecessary approximations in gas charges, because gas regions would not map clearly to electricity regions. They recommended setting the gas cap separately for gas regions.

3.20. We share the view taken by CMA when they designed the prepayment meter cap. The CMA considered that using gas regions would risk introducing significant complexity while the risk of distortion was low.[12] We noted that in most cases suppliers' gas tariffs are already mapped to the electricity regions – ie this approximation is already a feature of the current pricing strategies observed in the market. Therefore we propose to continue to set the cap by mapping gas network charges to each of the 14 electricity regions.

[11] https://www.ofgem.gov.uk/publications-and-updates/default-tariff-cap-overview-document

[12] See CMA Energy Market Investigation Final Report paragraph 14.69 and 14.442.