SSC19

Base cost assessment factors including real price effects and topography claim update

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1. Wholesale water cost allowances and real price effects

1.1 Significant power and chemicals cost increases in AMP7

AMP7 has been extremely volatile. First the Covid pandemic from March 2020 for approximately two years, and then following this the war in Ukraine and the resultant effects on the UK economy which are ongoing at the time of this business plan submission.

Circumstances have therefore fundamentally changed from those assumed at PR19. This has led to some significant changes to our expenditure compared to history as we try to accommodate these issues and sustain our service effectively and efficiently.

In the early part of the period the Covid pandemic occurred, which drove material changes to the consumption patterns in our regions, particularly in the South Staffs region where we experienced a material distribution input increase as a result of changes in commuter patterns between our region and our neighbouring Severn Trent region. We have provided more detail on these step changes in appendix SSC18.

In 2022/23 the wider economic impacts of the war in Ukraine meant that market prices for power increased rapidly. We were substantially protected from these increases by our contractual hedging arrangements, which were part of a nearly five year long contract which ends at the close of the 2024/25 year.

Our hedging arrangements for this period initially left the later years partially floating, as we look to fix costs at various stages through a period to spread any risk of volatility. At the onset of the power price crisis our costs were 80% hedged, and we subsequently fixed the remaining 20% early in the power crisis, but at an uplift to the original hedged price. As time went on we also fixed the remaining floating 30% that we had open in 2023/24, and another 20% of the remaining 40% floating that we had open in 2024/25. At this time we remain 20% floating in 2024/25. However as of April 2025 our contract expires and we are fully exposed to the market prices with our hedging arrangements fully due for renegotiation. Our hedging configuration is shown in the table below.

Figure 1: energy hedging as at September 2023

Version of contract	2021/22	2022/23	2023/24	2024/25	2025/26 onwards
Original contract fixed	90%	80%	70%	60%	
Original contract floating	10%	20%	30%	40%	
New arrangement additional fixed amount		20%	30%	20%	
Remaining floating amount				20%	100%

We hedge costs to mitigate risk, not to try and outperform the market, and fortunately this strategy has helped protect our business from the extreme volatility experienced in the energy markets over the past year. However despite this protection, we have still seen increases because of the need to hedge part of our floating usage at higher rates than the original contract set out.

We monitor the power markets regularly, and take advantage of expertise from within our investors, our group, and the wider markets on the state of the energy market. In normal circumstances we would roll forward our hedging arrangements over time to spread the risk. However as prices are currently at historic highs, hedging now and locking in high prices for future certainty risks being poor value if the signs are that prices might fall back. There is also currently not a great deal of liquidity in longer term power contracts, likely because of the uncertainty around world events at the moment. We have to be extremely cautious about locking in high prices now when they may be expected to fall, which would be a bad deal for us and customers.

The table below shows the impact that increased supply volume and the power price increases have had on our power costs, compared to PR19's original business plan assumptions. All costs are shown in 2022/23 price base, and show that over AMP7 we are forecast to spend £9.6m more in real terms than we originally set out in our PR19 plan. Considering that the impact on some other companies has been substantially higher than this, this is a good outcome for us considering the counterfactual of what might have happened had our hedging arrangements not been as strong. Nevertheless the increasing costs meant that we had to look for budget reductions elsewhere in our expenditure plans.

Figure 2: comparison of latest energy costs to PR19 assumptions

POWER COSTS	AMP7 total
Power costs in table WS1, August 2019 DD response, 2017/18 prices, £m	60.769
Power costs in table WS1, August 2019 DD response, adjusted to 2022/23 prices, £m	72.011
Current AMP7 budget (3 years outturn, 2 years forecast), in 2022/23 prices, £m	81.609
AMP7 change from PR19 DD response assumption, £m	9.598

Chemical and materials costs also significantly increased. For chemicals this was largely due to power costs, as chemical manufacturing is power intensive. For materials, this was primarily mirroring the significant inflationary increases being seen across the wider economy.

Chemicals and materials is not a separately reported cost in the annual performance report or in previous business plan submissions, it is contained within the 'other opex' reporting line. The table below shows the original chemical and materials component of the 'other opex' reporting line at PR19, and its actual forecast cost for AMP7, a significant increase of 80%.

Figure 3: comparison of chemicals and materials costs to PR19 assumptions

CHEMICALS AND MATERIALS COSTS	AMP7 total
Chemicals and materials, part of other opex in table WS1, 2017/18 prices, £m	16.641
Chemicals and materials, part of other opex in table WS1, adjusted to 2022/23 prices, £m	19.720
Current AMP7 budget (3 years outturn, 2 years forecast), in 2022/23 prices, £m	35.408
AMP7 change from PR19 DD response assumption, £m	15.688

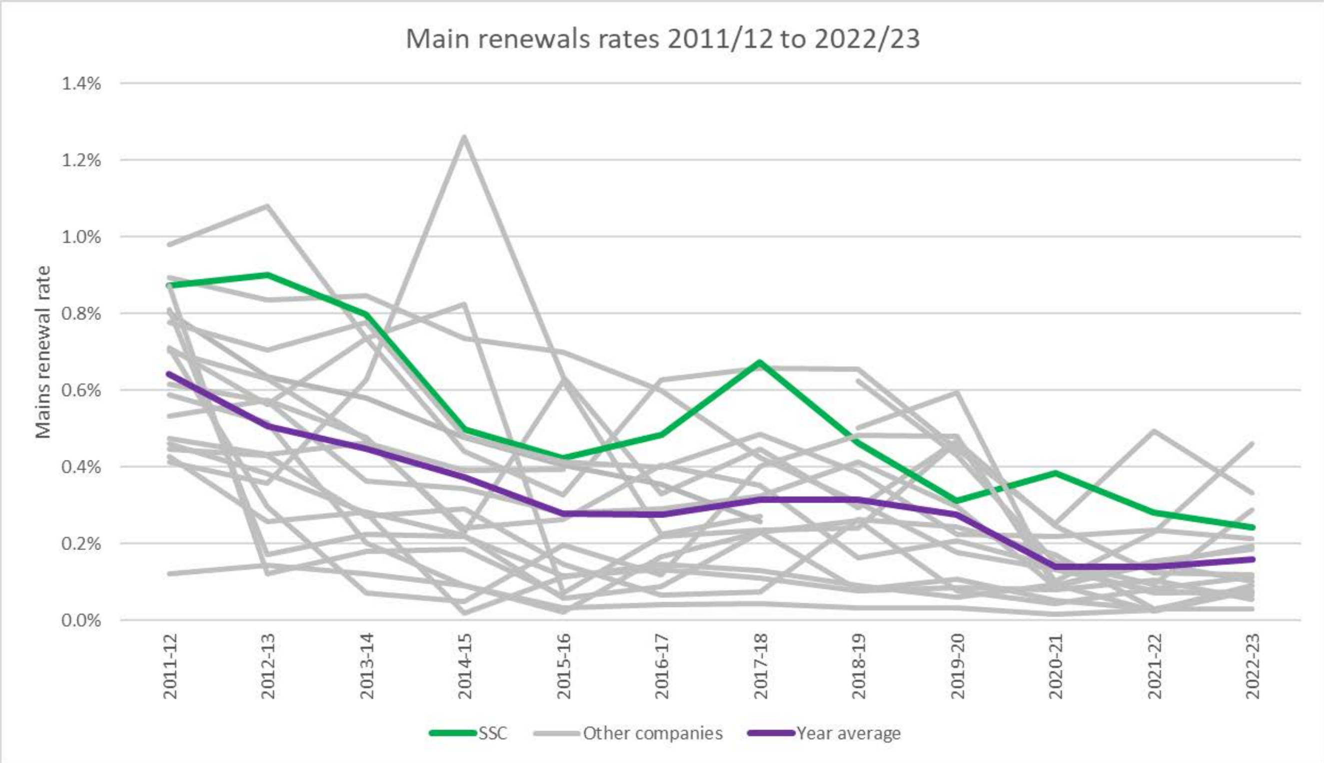
With power, chemicals and materials cost increases combined, this is a net increase of £25.3m in real terms for AMP7, compared to the costs assumed at PR19.

We operate within the cost allowance that we are funded for at each price review. Extending beyond this allowance means we cannot recover the whole amount of overspend due to the cost sharing mechanism, and is considered to be a negative factor in terms of efficiency. We have strived to stay within our PR19 funding envelope.

We are also one of the most efficient companies, being within the upper quartile group of companies in PR19's cost modelling process and continuing to be an upper quartile company in the modelling iterations since PR19 leading up to PR24. There was no headroom in our base cost allowances to be able to absorb this £25.3m real terms increase in our costs, and so we had to decide where we could make some adjustments to our original proposed plan to meet these pressures. These are not easy trade-offs when we are already efficient on base costs.

We primarily elected to reduce spending on infrastructure renewals (IRE) in order to meet these cost pressures. Despite this lower expenditure, the data below shows that we have been one of the leading companies over the data history on rates of mains renewal. The whole sector has been trending to lower renewal rates over the period, and we have continually been one of the front runners in terms of sustaining our renewals rates, as we recognise this activity as a crucial part of the long term asset health of our network. This is increasingly difficult though when, through the modelling process, sector wide reductions in renewals mean continual downwards pressure on the funding within base costs for this activity.

Figure 4: benchmarking of activity level for infrastructure renewals[1]



We are consistently amongst the highest replacement rates in the sector, and always significantly above the industry average, against a trend for the sector of reducing mains renewal rates. The source data for the above chart also shows that over the period since 2011/12, we have been the highest overall company at an average of 0.53%.

Whilst burst rates have been generally improving across the sector over this same period, the 2022/23 winter showed that a period of cold weather can cause a significant burst spike for almost all companies. Our models show that renewal rates will need to increase in the future to ensure the impact of climate change does not adversely affect the service we provide to our customers.

Despite the cost pressures, we have continued to deliver excellent performance on some of the key common performance commitments. We have met our leakage reduction targets and are on track to achieve our c.15% reductions by 2024/25. These leakage reduction costs were deemed to be part of base costs by Ofwat at PR19, adding further pressure to cost allowances which were not lifted to accommodate this historically enhancement activity. We have also continued to be an upper quartile performer on supply interruptions, even through the period of increased burst rates last winter, and we have delivered significant reductions in our water quality contacts for appearance and taste and odour over the period.

We recognise that there are also performance commitments we are not meeting. Per capita consumption has been severely impacted by changes to customer demand factors that have occurred during and since the Covid pandemic. Mains bursts was affected for the whole sector by the cold 2022/23 winter. And in 2023/24 we are expecting a significant penalty for compliance risk index as we have experienced sample failures at our largest works, Hampton Loade, which due to its scale impact CRI significantly when there is a compliance failure. This was a risk we raised at PR19, as we are unique in having two works which supply such a large proportion of supply volume, and for this reason their CRI exposure is higher if there is a failure.

Ofwat’s 2021/22 service delivery report showed that we are a leading company overall, and we have ensured we are still spending within our PR19 cost allowances. The failures we have experienced are not as a result of under delivery of our planned activity – they are the result of external factors that are materially outside of our control. Our AMP8 planning has focussed on areas where we know we need to do more, for example on our metering rollout, on our mains renewals, and on our operational resilience, as well as continuing to meet statutory requirements such as water quality investment.

[1] Data derived from wholesale water master cost assessment data set, being length of mains renewed and relined divided by total length of mains.

1.2 Our views on Ofwat's wholesale cost models

Ofwat's cost models form an important part of PR24 as they are used as the baseline to setting companies' base cost allowances. Ofwat has published a set of proposed cost models in advance of the business plan submission which we use as the basis for this section.

No cost model can perfectly represent a company's costs, they are an assessment which seek to link key cost drivers to industry costs as a whole in order to identify patterns (correlations) that can be used against future forecasts of those same cost drivers, and to which efficiency challenges, either catch up or forward looking, can be applied. Cost models generate a baseline to which our plan can be compared, in order to challenge it with information from the sector as a whole.

There are various statistical approaches to cost modelling, and on the whole we support Ofwat's current approach which is to employ relatively straightforward models with a sensible number of key cost drivers and straightforward statistical approaches that are easier to understand.

However in any set of models it is important to recognise which factors are not represented or inappropriately represented. In previous reviews, we have always challenged the non-inclusion of certain drivers particularly for topography. The modelling process over the last few price reviews has always systemically underfunded us for the topography issue, which we have challenged at various stages of these processes in the past. However when considering the final determinations in the round we have, so far, been able to accept these previous determinations, and have been able to innovate to try and reduce the impacts of power on our costs, for example through optimisation, innovative energy sources and our pump efficiency programme. However, with power prices rising so suddenly and significantly, and with an increased focus on net zero in AMP8, it is no longer possible to absorb these systematic underfunding issues on topography and power, and with the right level of funding for these costs it means we can return to the levels of investment in other areas that our assets need.

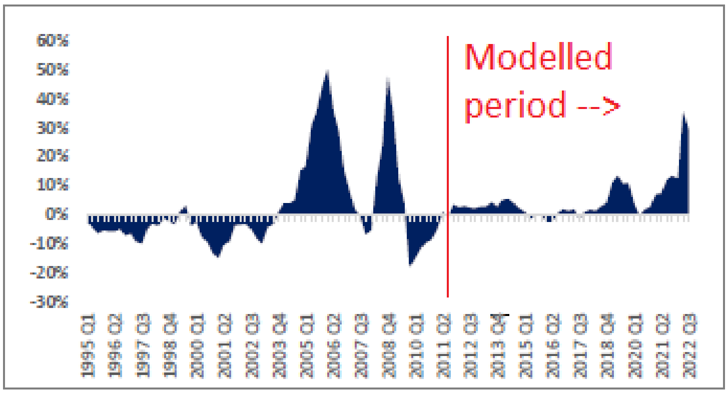
The choice of cost drivers is vital in this process. Ofwat has defined a set of rules which cost drivers should adhere to, and the first of those rules is that cost drivers must have a robust engineering, operational or economic rationale. We have demonstrated in our cost adjustment claim for topography, submitted June 2023 and updated in section 3 of this document, that the models do not fully meet this requirement and we have demonstrated how more appropriate models can materially impact our cost allowances by funding the topography issue correctly.

The current modelling process uses historic data, being built from the actual costs reported by companies over an 11 year period, and therefore reflect an average of this period with each year having equal weight. This approach cannot detect material step changes in future costs where they are different to the past period. This is particularly relevant to this price review, because as demonstrated in section 1, costs have materially changed in AMP7 due to global events and the models are not capable of detecting these impacts without intervention.

1.3 Funding for future power costs

The Ofwat proposed models will currently use data from 2011/12 to 2022/23. There is no time trend cost driver, and so the models will be funding companies at the average of power costs over the full data period. But, the power prices wedge has been consistently above inflation over the modelled period, as shown by KPMG in their report for the sector on real price effects, an extract of which is below, so even the current power prices are not well reflected in the cost models at the moment.

Figure 5: power prices wedge, KPMG[2]

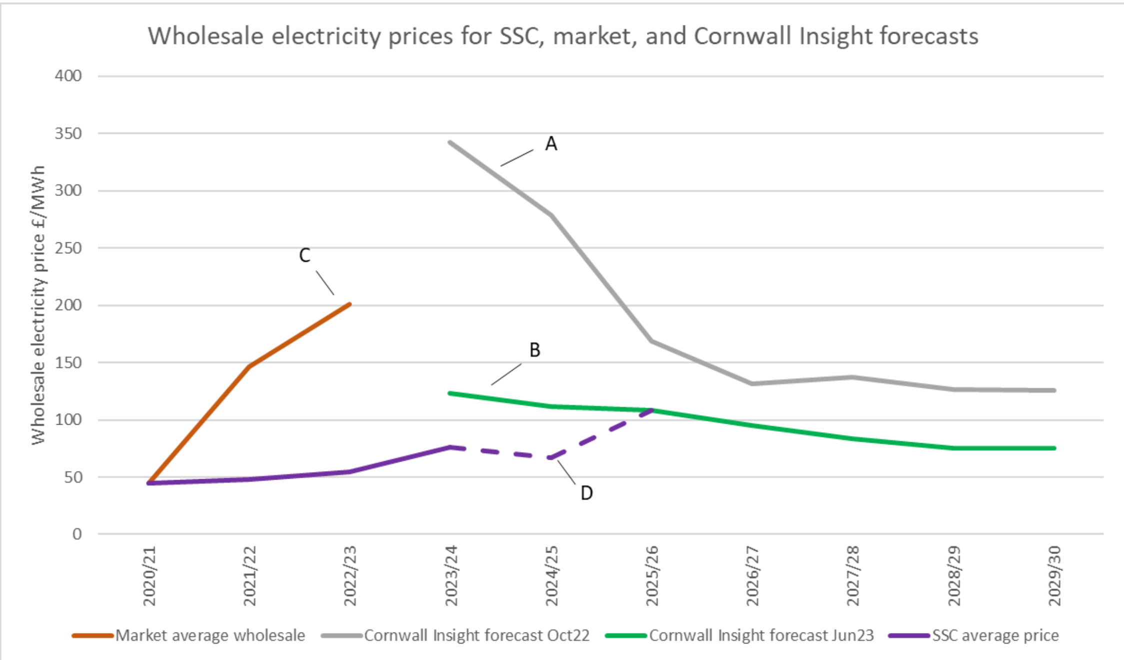


For us, the impact of the market power price increases is mostly still to come. In AMP7 we have been insulated from much of the market increases through our hedging arrangements, but these come to an end completely at the end of this current period, at the end of March 2025. As explained in section 1, as market power prices are currently at historic highs, hedging now and locking in high prices for future certainty risks being poor value. There is also currently not a great deal of liquidity in longer term power contracts, likely because of the uncertainty around world events at the moment. We have to be extremely cautious about locking in high prices now when they may be expected to fall, which would be a bad deal for us and customers.

We have participated in an industry club project with Cornwall Insight to provide a robust power forecast for AMP8. Cornwall Insight are an established independent energy research, analytics and consulting firm that have extensive experience in energy market analysis and forecasting. They have undertaken research work of this nature for the water sector previously and have engaged in similar work for other sectors. The project was initiated in September 2022 with the first version of the forecast provided in October 2022, and a further version of the forecast was provided in June 2023.

We have attached Cornwall Insight's methodology report alongside this appendix (document reference SSC19e). The chart below shows the £/MWh actuals for the market to 2022/23, for our current actuals and expectations until 2024/25, and Cornwall Insight's forecasts to 2029/30.

Figure 6: Cornwall Insight electricity price forecasts



[2] KPMG report on real price effects, June 2023. Supplied along with our submission as document reference SSC19b.

We have annotated the above chart as follows:

A: The October 2022 Cornwall forecast reflected the volatile market conditions at the time, and showed a significant spike in short term prices, reducing thereafter.

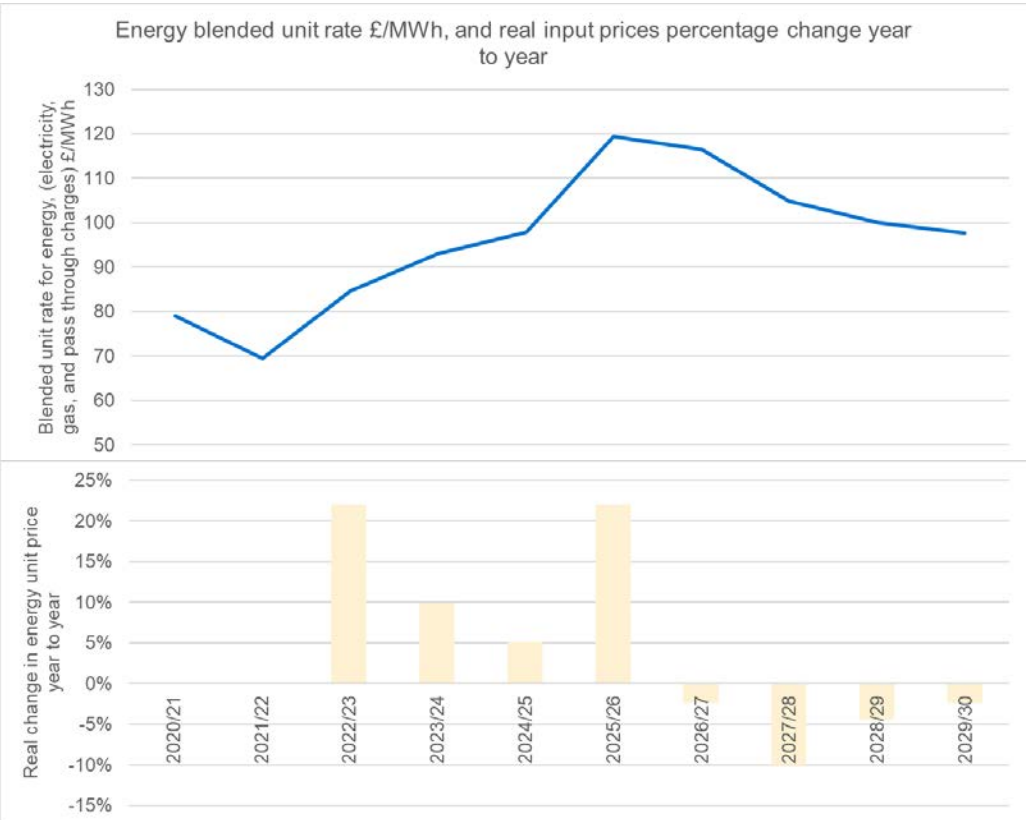
B: The June 2023 revision forecast was undertaken after markets had calmed somewhat, and worries about energy security in Europe had subsided from their peak. The Cornwall forecast is in line with market prices as they currently stand for 2023/24 and 2024/25 forward pricing.

C: The open market actual £/MWh rate shows the significant climb that took place. Our hedging protected us and customers substantially from this exposure. Without our hedging arrangements, our expected power costs in AMP7 would have been in the order of £112m, against our PR19 expectation of £72m and our actual outturn expectation of £82m.

D: The purple line shows our average electricity price over the period and the dotted element shows our current expectations based on the amount we currently have hedged and our residual exposure to current market prices. The key issue is that as at April 2025, all of our historic hedging is fully unwound, and we see a material step change from the circa 50-70 £/MWh that we currently pay to the current market level of circa 110 £/MWh, for all of our required energy consumption. It is this reset, from hedged and protected to not hedged and current market prices, that creates a significant funding gap for us in power. The Cornwall Insight forecast is higher than our historic AMP7 prices all the way out to the end of AMP8 and beyond.

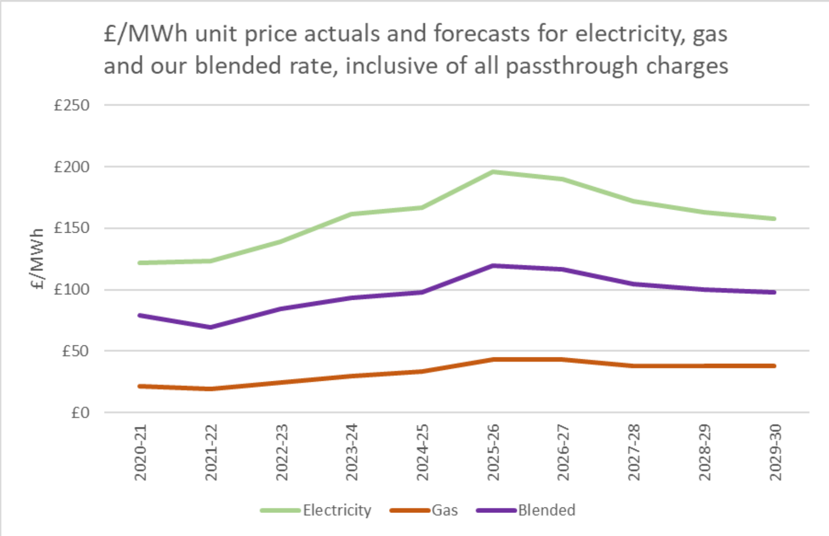
Note that the price forecast chart above is wholesale rates only, and does not include pass through charges (DUoS, TNUoS, CCL). The table below shows the annual power costs we expect for the remainder of AMP7 and into AMP8. This forecast includes a reduction in consumption that results from our planned leakage and demand reductions over the period. These values include pass through charges. Note that this analysis is only for electricity prices, and does not include gas, which we have added later using a separate forecast as shown below. This is because Cornwall Insight's project did not include a gas forecast. The chart below shows our combined electricity and gas forecast (we generate some of our own energy using natural gas, which we understand is a quite unique approach for the sector, but it enables a reduction in cost from 100% grid electricity reliance).

Figure 7: blended £/MWh forecast including electricity and gas, and change in input prices year to year



The chart below shows how our blended rate is split between electricity and gas consumption.

Figure 8: how our electricity and gas unit rates combine into our average blended unit rate for energy



The below table shows how these forecasts convert to a power costs budget for the remaining years of AMP7 and into AMP8. This includes the blended cost of electricity and gas, including all pass through charges, and also includes all additional factors effecting energy use, including leakage and demand reduction (DI reduction), carbon initiatives and the impact of the changing power prices.

Figure 9: AMP7 and AMP8 power cost forecast, in 2022/23 prices

	2020/21	2021/22	2022/23	2023/24	2024/25	AMP7 total
Current AMP7 budget (3 years outturn, 2 years forecast), in 2022/23 prices, £m	14.557	14.500	15.519	18.513	18.520	81.609
	2025/26	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**AMP8 total**
AMP8 forecast, in 2022/23 prices, £m	22.115	21.379	19.304	18.244	17.591	98.633
AMP8 change from AMP7 actuals, £m						17.024

To determine the funding gap however, we cannot just look at the increase between AMP7 and AMP8. We need to examine the amount that Ofwat's models are funding us for power and compare this to our AMP8 forecast. This can be elicited from the models by removing power costs from the models in order to determine the implicit allowance for power.

We have looked at Ofwat's proposed models as published in May 2023, and the modified version of these models we used in our topography cost adjustment claim, which use average pumping head as the topography cost driver. These second set of models give a higher implicit allowance for power costs, similar but not quite at the level of our actual costs, but still not at the required level of funding to meet our AMP8 power costs of £98.3m. These modelled implicit allowances are shown in the table below alongside our AMP8 forecast. Note that for the purposes of operating these models we have used the following assumptions:

- Data to 2022/23
- 4th place catch up efficiency applied to all models
- Frontier shift assumption at the same level as PR19
- Cost drivers aligned to our submitted data tables (please see separate table commentary for explanations of these cost driver movements).

Figure 10: implicit allowances for power from cost models shown alongside our AMP8 power forecast, 2022/23 prices

	2025/26	2026/27	2027/28	2028/29	2029/30	AMP8 total
Ofwat proposed cost models, total allowance, £m, 2022/23 prices	103.129	103.047	102.983	102.966	102.987	515.112
Ofwat proposed cost models, power costs excluded, £m, 2022/23 prices	90.899	90.827	90.771	90.757	90.777	454.031
Implicit allowance for power, £m, Ofwat proposed models	**12.230**	**12.220**	**12.212**	**12.209**	**12.211**	**61.081**
APH_TWD models, total allowance, £m, 2022/23 prices	107.875	107.873	107.888	107.953	108.057	539.647
APH_TWD models, power costs excluded, £m, 2022/23 prices	94.472	94.476	94.495	94.558	94.654	472.655
Implicit allowance for power, £m, APH_TWD models	**13.404**	**13.397**	**13.393**	**13.395**	**13.403**	**66.992**
Our AMP8 forecast for power costs, £m, 2022/23 prices	22.115	21.379	19.304	18.244	17.591	98.633
Funding gap from APH_TWD models	**8.711**	**7.982**	**5.911**	**4.849**	**4.188**	**31.641**

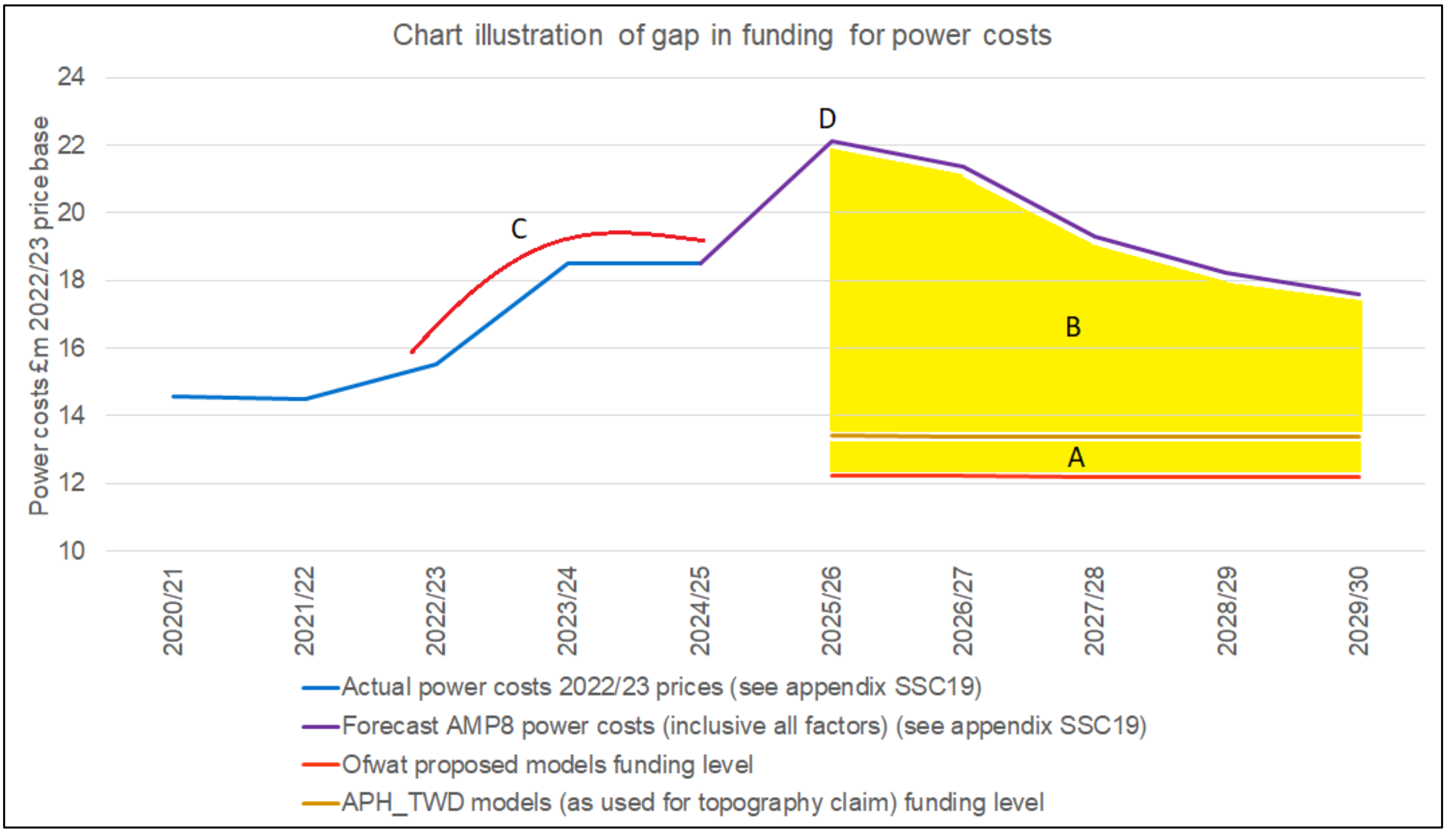
This analysis shows the following:

- Both Ofwat's proposed models, and the modified APH_TWD models that we used for our topography claim, insufficiently fund the true costs of power that we are currently incurring in AMP7, even from the years prior to the power price impacts. Our AMP7 total power is around £76.6m as shown in table 6, but cost models are only providing for a total of £61.1m (Ofwat's proposed models) or just under £67m (APH_TWD models), as shown above in table 7. The reason for this may be due to the point we made at the very start of this section, where we said that as there is no time trend in the models, the models are only providing for the power price average over the data period against a backdrop of inflating prices in real terms.

- Measured from the APH_TWD models, which we have used for our cost adjustment claim, the funding gap for power is £31.265m over the period, in 2022/23 prices. We need to measure from the APH_TWD models to avoid double counting with our topography claim. But if Ofwat rejects or modifies the topography claim, the gap would then need to be measured from the implicit funding level for power that result from Ofwat's modelling decisions.

We have shown this data graphically in the chart below to ensure we are clear on the approach and interpretation.

Figure 11: graphical view of power costs funding gap



The chart shows our actual costs from 2020/21 to 2022/23, our forecast for 2023/24 and 2024/25, and our forecast from 2025/26 to 2026/30, all in 2022/23 price base. This forecast is inclusive of all the factors that are effecting power costs including leakage and demand reduction, carbon activity where it reduces costs, and the impact of future power price forecasts. The annotations are as follows:

Area A: this is the gap between the proposed Ofwat models as of April 2023, and the models we have used in our topography claim. These values are shown with 4th place catch up efficiency and with a 1.1% per annum frontier shift assumption. The gap represents the difference between the two sets of models, and is the component of power costs that is included in our topography claim.

Area B: this is the residual gap between the modelled allowance as used in our topography claim, and our actual AMP8 forecast which includes the impact of demand reduction, carbon activity where it reduces costs, and the impact of future power price forecasts. The gap here is the funding gap we expect to remain if Ofwat accepts the topography claim. The total AMP8 forecast (purple line) sums to £98.6m as shown in figure 9.

C: Position C is the increase we have seen/forecast in AMP7, where we are materially hedged.

D: Position D is the step change jump we are forecasting to have in 2025/26 when all of our current hedging arrangements expire. From here, power prices are expected to decline (see the Cornwall Insight forecast in figure 6) and we will also be delivering consumption savings from DI reduction at the same time, which is built into the forecast for AMP8.

For Ofwat to fund our power costs correctly, three things need to occur. First, the models themselves need to be adjusted so that they fund the existing levels of power correctly. Secondly the future increase in AMP7 and into AMP8 needs to be then included in the cost allowances as an input price increase. Thirdly the genuine impact of our topography needs to be included, either via a cost adjustment claim or by using more appropriate models.

We have completed table Sup11 by calculating the year to year percentage change for power input costs, as shown in figure 7. This means that the percentage change shown on Sup11 includes only the changing blended unit rate, whereas our AMP8 budget values (in £ millions) are inclusive of all of the factors (DI reduction etc) that impact the AMP8 power cost forecast.

For the avoidance of doubt the final summary position is shown below, which shows the final AMP8 power budget of £98.633m is a funding gap of £31.641m from the expected modelled allowance. We also show the blended unit rate for energy and the input price change as a percentage.

Figure 12: final summary position for power costs

	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	AMP8 total
Power costs implicit allowance derived from APH_TWD models			13.404	13.397	13.393	13.395	13.403	66.992
Our forecast for power costs, £m, 2022/23 prices	18.513	18.520	22.115	21.379	19.304	18.244	17.591	98.633
Funding gap, measured from APH_TWD models			**8.711**	**7.982**	**5.911**	**4.849**	**4.188**	**31.641**
Blended energy rate (electricity, gas and pass through), £/MWh, 2022/23 prices	93.14	97.88	119.40	116.57	104.81	100.15	97.74	
Real change in year to year input prices for the blended energy rate, % for table	9.93%	5.09%	21.99%	-2.37%	-10.09%	-4.45%	-2.41%	
Energy hedged (wholesale electricity only), as at September 2023	100%	80%	0%	0%	0%	0%	0%	

1.4 Energy costs additional data request table commentary

We have completed the additional energy costs data request and this file is attached to this document as appendix SSC19h.

Much of the information about the process we have used to calculate our forecasts is included in the above section, supported by the Cornwall Insight methodology, however we have also attached a supporting spreadsheet showing the detail of the Cornwall Insight calculations and how we have applied them to our costs, as document reference SSC19i.

Note that this additional data request asks for electricity prices only. We also utilise gas for our energy requirements, and we have provided the combined rate in figure 12 above with the detail shown in the appendix sheet SSC19i.

In the data request, we have not completed the lines for electricity export. Electricity export is a very small component of our total energy usage at an average of 0.2% of our total purchased consumption over the past five years (around 450 MWh per annum out of 210,000 MWh), from only three sites which are contracted to export power. We forecast that the level of export will progressively reduce to zero in the short term. This means there is no material offset of our purchased energy from the proceeds of exported energy. As it is such a small component, we did not commission any future forecasts of electricity export prices.

We have shown the same unit rates for retail as wholesale.

1.5 Note on data tables CW1, CW1a, CW2

Our understanding is that table CW1 is the final high level totex plan, i.e the one we are proposing to deliver.

Table CW1a is a version of table CW1 that represents the pre-RPE and pre-frontier shift position of the expenditure. Table CW1a is fed by table CW2, which is a pre-RPE and pre-frontier shift breakdown of the base expenditure. We understand that the difference between tables CW1 and CW1a should essentially be the RPE and frontier shift factors in table Sup11.

However there is no version of table CW2 which aligns directly to table CW1, i.e no table showing the post RPE and frontier shift breakdown of the expenditure in CW1. We think that it would be very useful for us to provide this to avoid any doubt, and to avoid reliance on Ofwat's own calculation, which is complex to try and convert the pre-RPE and frontier shift CW2 to the post RPE and frontier shift CW1. Therefore we have provided a post RPE and frontier shift version of table CW2, as appendix SSC19g.

1.6 Power costs true up mechanisms

In conjunction with the above real price effects adjustment, we propose an end-of-period true up mechanism and an in-period reopener mechanism for power costs to support the real price effects adjustment.

These are necessary because whilst the above forecast is a robust estimate of costs from recognised independent forecasters at this point in time, the global issues currently in play are creating high risk of volatility. A true up mechanism is required to ensure two things:

- That customers are protected if power prices fall below the funding provided for in cost allowances, to ensure customers do not fund power costs that we do not actually incur; and
- That we are protected if power prices rise further due to global events, ensuring that we do not have to trade-off other key areas of investment to meet power cost increases that are outside of company control.

We propose that a standard true up mechanism applies at the end of the period in the same way as the existing labour cost true up mechanism does in AMP7. For this true up, we propose that the BEIS energy price index should be used. This ensures that the index used is independent of our actual costs, so as not to create any conflicts of interest with any contractual hedging arrangements that we may implement. This means that we retain the incentive to hedge prices within energy contracts to increase in-period stability and to mitigate against volatility, as we deem appropriate for our business, but customers still recover any benefit if we hedge inefficiently and prices have fallen. To use the BEIS index for this purpose, we propose that the April 2025 index value is set as a baseline and percentage swings measured from that baseline, this will ensure the mechanism reflects power price movements from the point at which AMP8 funding begins.

We are also proposing an additional in-period reopener mechanism for power, due to the risk that global factors create a step-change scenario where costs may suddenly increase or decrease materially. This was not necessary for the labour costs true up at PR19 as we did not consider the range of volatility to be as large or as outside of company control. Power has the potential to be significantly more volatile and of a significant greater scale of risk than labour cost pressures, and we need to ensure that we can continue to fund our operations in-period if we experience a significant increase in power costs, without risking detriment to any other areas of expenditure or service. The reopener mechanism would also apply if costs materially fall in-period, and would return money to customers sooner than end-of-period if this were to occur. We propose that the in-period reopener would apply if power costs change by greater than 1% of annual regulated equity, equivalent to approximately a 12% swing on power prices in the BEIS index, which can be monitored in-period. We propose that the mechanism can be triggered by either us or Ofwat as part of the in-period determination process if the threshold is met, ensuring customers are protected further.

We believe this combination of solutions on power are the most appropriate way of ensuring we are funded properly for our power cost obligations and that both ourselves and customers are protected from cost volatility and detrimental impacts of power cost volatility on other aspects of investment and service. The cost adjustment claim, real price effect adjustment, true up and reopener form a package of adjustments that should be taken together, as only the complete package of adjustments and mechanisms can collectively provide the appropriate solutions to the issues currently experienced.

In summary, the full package of adjustments is as follows:

- Correcting models appropriately to reflect the genuine impact of topography on our power and other costs (our updated cost adjustment claim for topography);
- Implementing a real price effects adjustment to account for the material uplift in power prices in AMP8 compared to modelling allowance; and
- Implementing both an end of period true up and an in-period reopener mechanism.

1.7 Participation in industry research for power and real price effects

We and the industry have recognised the significance of increasing power costs, and other input prices, in the lead up to this business plan submission. We have raised the issue with Ofwat at several opportunities, including within working group meetings, in our topography cost adjustment claim, in our responses to cost modelling consultations, and in our one to one meetings.

We have participated in the following sector club projects over the past year, which have helped build our knowledge, identify appropriate solutions to the issues we face and, being club projects, facilitate collaboration and consistency across those companies that participated. We believe these projects have been very valuable in helping us build a robust plan on these issues.

<u>Cornwall Insight power price forecasting</u>

We have used the Cornwall Insight outputs to help us derive our power cost forecast for AMP8. The output of this project was a tailored spreadsheet tool for each company, which we have used to derive our power forecasts. The project was iterated twice, to account for moving market prices since the project start date, and we have used the latest version (June 2023) of the insight. We have included the Cornwall Insight methodology report alongside this appendix (document reference SSC19e).

<u>KPMG analysis of real price effects</u>

KPMG were asked by a group of companies to examine real price effects for PR24 across a range of cost categories. We have found the output to be very helpful in setting out where we are most impacted going forward, which is on power costs. We also think that KPMGs proposals for how Ofwat could deal with the issue in its cost models have merit and could be examined further by Ofwat. We have included both of KPMGs reports from this project alongside this appendix (document references SSC19a and SSC19b).

<u>First Economics analysis of real price effects</u>

First Economics were also tasked with examining input price pressure. A different approach was taken by First Economics, who considered some ideas for constructing a new composite inflation index to take account of input price pressure across different categories of cost. We are supportive of the principles and ideas outlines and think Ofwat should consider them further, but we do not make any direct proposals of this nature at this stage in our plan. We have included the First Economics report alongside this appendix (document reference SSC19c).

2. Topography cost adjustment claim update

2.1 Introduction

In June 2023 we submitted a cost adjustment claim for additional costs which result from network topography. The original submission is included alongside this appendix (document reference SSC19d). Please note this is for reference only and has not been updated for the latest claim value, as this update is included here.

The claim evidence was presented in two main themes.

Firstly we demonstrated why we have the highest average pumping head in the sector. To recap, this is fundamentally due to the locations of customers. Our SST region is densely populated, and we have areas of very high customer density in areas of physical elevation. We supply these customers from large source pumping stations through a network of strategic storage which tends to be located at high areas within the network so that the majority of customers can be supplied from storage reservoirs by gravity feeds, which is a more resilient approach than relying on a far greater number of pumped supplies.

Secondly we looked at the cost drivers being used to measure topography and whether these have a robust engineering, operational or economic rationale as per Ofwat's modelling framework rules. Ofwat has selected two possible cost drivers for topography and assigns each equal weight in its proposed models. However we provided significant evidence that boosters per length of main is fundamentally flawed as a topography cost driver.

We assessed the claim value by looking at Ofwat's models, models with no topography driver included, and models using only distribution average pumping head (APH_TWD), in order to demonstrate the material differences in cost allowance that each approach provides. At the time, these models were built on data to 2021/22, which we now update to 2022/23. We also made some assumptions on catch up and frontier shift efficiency challenge which we recognised would change when latest data is available.

This section of our cost assessment appendix updates the claim value for the APR23 dataset. Note that we have updated the claim value only, the remaining evidence in the original June 2023 claim document is unchanged. We note that the APR23 dataset as reported by companies may have been subject to queries by Ofwat since the original submission and therefore there may be changes in the data that we are not aware of that could impact the modelling results we have obtained. We therefore recognise that the claim value presented here is still subject to change, as the data set and modelling choices are finalised.

2.2 Update to claim evidence

In our original claim we provided rationale and evidence to show why boosters per length of mains was not an appropriate topography cost driver. We evidenced that:

- That it is an asset count and therefore does not reflect the capacity of pumping assets;
- That it assumes companies control for topography issues by using an increased number of sites rather than increased capacity at a smaller number of sites, and so does not reflect our actual asset configuration;
- That it appears to be correlated to density, which is already included in Ofwat's models;
- That it is not correlated to average pumping head or power costs, which it should be if it is measuring topography;
- That CEPA, in its review for Ofwat, also questioned the rationale of the cost driver and suggested it needed further examination;
- That models using the driver alone produce a lower cost allowance than models with no topography driver at all, in our case, which clearly as we are the company with the highest average pumping head in the sector, is materially flawed.

We note that Severn Trent submitted a cost adjustment claim proposing that Ofwat uses both average pumping head and boosters per length of main together in models. Their claim states that boosters per length of main is an indicator of network complexity, which is similar rationale to CEPAs comment about asset intensity. It is clear that different parties assume boosters per length of main is measuring different things, which strongly shows how unclear the rationale is for the variable, as there is not agreement on what it is measuring and therefore what the relationships to cost actually are. We have provided further views on Severn Trent's arguments in section 4 of this document.

We are extremely concerned about this lack of clarity on boosters per length of main. It is not appropriate for Ofwat to use a cost driver in its models when the engineering rationale and relationships to cost are not understood. We want to support Ofwat and the sector in resolving this issue, and so in July 2023 we asked Water Research Centre[3] (WRC) to independently evaluate the average pumping head and boosters per length of main metrics from a network topography and complexity perspective, with a real world network engineering focus. We asked WRC to construct a set of network models of common water network configurations and assess how each of the two variables (APH and boosters per length) react to those different network configurations and how they move in relation to each other. WRC completed this study in September 2023, and we attach their report alongside this appendix (document reference SSC19f).

WRC found that the two drivers are not measuring the same thing. They move in different, often opposite, directions when presented with a range of network scenarios. They are not correlated to each other, and boosters per length of main, as an asset count only which does not include any measure of capacity, is not capable of correlating to energy use or significant capital maintenance costs, which is the purpose it is meant to fulfil in Ofwat's modelling process. WRC's study supports our evidence case fully – boosters per length of main is demonstrably not an equivalent variable or proxy for pumping topography or average pumping head, and given the lack of clarity on what it is actually measuring, clearly not a suitable variable for use in Ofwat's modelling process. Whilst we recognise that Ofwat was concerned about average pumping head data quality at PR19, we remain unclear on how the boosters variable was selected as a suitable replacement, as it appears to not have been given any robust engineering thought at all in its selection.

2.3 Update to claim value

On pages 16 and 17 of our original claim we showed how the claim value was derived, being the difference between Ofwat's preferred models, which use a combination of average pumping head and boosters per length of main, and models using average pumping head only. This approach ensured we were taking account of the implicit allowance that Ofwat's proposed models provided for the topography issue. We showed two other model configurations (boosters per length of main only, and models with no topography driver) to demonstrate how the output of the models varies depending on the choice of topography cost driver. The below table shows three of these model groups updated for APR23 data (we have not updated the models using only boosters per length of main, as these are not robust models, giving lower cost allowances than models with no topography driver included at all). Other than the data update, the assumptions and model configurations remain unchanged.

We have however also provided the output for a more realistic set of efficiency assumptions, using the catch up efficiency that the models actually derive for the 4th place company, rather than a nominal 5%, and also applying a 1.1% per annum frontier shift efficiency. We needed to do this because we wanted to use a more realistic set of efficiency assumptions in the derivation of the funding gap for power costs, due to power price increases. We provide more information on this below.

[3] https://www.wrcgroup.com/about/

Figure 13: updated modelling outputs for APR23 data

Model group	A. Modelled base allowance (£m over 5 years) with no catch up efficiency challenge or frontier shift challenge, APR23 data	B. Modelled base allowance (£m over 5 years) with fixed 5% catch up efficiency challenge and no frontier shift challenge, APR23 data	C. Modelled base allowance (£m over 5 years) with modelled 4th place catch up efficiency challenge and frontier shift challenge, APR23 data
Models with boosters per length of main only	Not updated for APR23 data		
Models with no topography driver	£510m	£484m	£484m
Ofwat's 50/50 suite of models using both boosters and APH_TWD	£542m	£515m	£515m
Models with APH_TWD only	£587m	£558m	£540m
Resultant claim value for each efficiency assumption, being the gap from Ofwat's 50/50 suite to the APH_TWD only models	£45m	£43m	£25m

In our June 2023 cost adjustment claim, we used the value derived from the models with a fixed 5% catch up efficiency and no frontier shift efficiency, which was £45m. The equivalent value derived from the APR23 update (column B above) is £43m. To be consistent with the previous submission and the submission guidance we have input this value into the cost adjustment claim table.

However, we recognise that once more realistic catch up and frontier shift challenges are applied, the claim value does fall, as shown in column C. This is occurring because the catch up efficiency from the APH_TWD models is more stretching than the one generated from the Ofwat proposed models when using APR23 data. For both the no topography models and Ofwat's proposed models, the 4th place catch up is smaller than the fixed 5% we assumed, such that the addition of the frontier shift results in almost equal values between columns B and C for these models, whereas the APH_TWD only model becomes more stretching.

Both potential claim values, £43m and £25m, are still material (5.9% and 3.4% respectively) against the network plus price control totex of approximately £725m (from table CW1).

2.4 Interaction with power costs adjustments

In sections 1 and 2 of this document we showed how power costs have risen significantly in AMP7 and are forecast to rise further in AMP8 due to the combination of the power price increases and unwinding of our existing hedging arrangements.

It is important that we did not duplicate the impact of power cost funding gaps across the power costs uplift claim and the topography cost adjustment claim.

To achieve this, we have again utilised the modelling suite to derive the gap, taking account of the topography claim that we have already put forward. This is where the estimate of the modelled allowance with realistic catch up and frontier shift assumptions becomes important, because to include the values without these adjustments would result in values which are too high.

As we evidenced in our topography claim submission, topography impacts more than just power costs. It also impacts capital and operational maintenance because to meet a higher pumping pressure we need to have larger pumping plant and ancillary assets.

For the power claim however, we are only looking at the funding for power costs. This can be inferred from the models by looking at the implicit allowance for power. We can then derive the element of this which is impacted by the topography drivers, and from this determine the residual funding gap to our actual AMP8 power cost forecast. This ensures we are not double counting across the separate claims.

The table below shows the implicit allowance for power in the three model groups we are looking at. It can be seen that of the £25m topography claim (with realistic efficiency assumptions included), £5.9m of this is power. We can then show the difference to the actual power costs we have forecast in our business plan, as per section 1 of this document, and this gap is the residual gap that needs to be funded via an additional power costs uplift.

Figure 14: power cost funding and gap to AMP8 forecast

	Implicit allowance for power from model, including 4th place catch up efficiency and 1.1% per annum frontier shift assumption.
Models with no topography driver, implicit allowance for power £m	£49.9m
Ofwat's 50/50 suite of models using both boosters and APH_TWD, implicit allowance for power £m (A)	£61.1m
Models with APH_TWD only, implicit allowance for power £m (B)	£67.0m
Topography claim, power element (historic), £m - (B-A)	£5.9m
Our AMP8 power forecast, as per section 2 (C)	£98.6m
Power cost claim value (future), being the gap from APH_TWD models to our AMP8 forecast, £m – (C-B)	£31.6m

As this topography claim is based on the models, it is based only on the historic power costs implicit within that dataset. Whereas the increase in power prices overall to our AMP8 forecast is a forecast of the future costs, and our AMP8 total includes all elements of our power use including topography. We considered it would get confusing if we attempted to split out the component of the power cost increase that is topography related from the future costs, so for this reason we have elected to keep the topography claim historic only (i.e it is more of a modelling claim aimed at improving the robustness of the model suite for topography and ensuring robust treatment of this issue for us and the sector) and the future power costs uplift claim as standalone reflecting the residual gap to our specific AMP8 forecast for power costs.

However if required, we can estimate the proportion of the AMP8 costs that are topography related. As shown in the table above, the APH_TWD models provide an implicit allowance of £67.0m for power, compared to the £49.9m in the models with no topography driver in. That increase (£49.9m-£67.0m) is £17.1m, which is an uplift of 34% for topography. This means that of the AMP8 forecast of £98.6m, approximately £25.1m is for the increased topography of our supply areas compared to industry average.

If Ofwat uses alternative models, then these claim values may have to be recalculated. Ultimately, we have a power cost forecast of £98.6m in our AMP8 plan, robustly derived and inclusive of all operational factors. And so across the modelling suite, topography claim, and power cost claim, this should be the amount that is funded for power as an end result. Depending on how Ofwat achieves this, the intermediate steps may change, and we will review the approach taken and the allowances provided at future stages of the PR24 process. The power costs issue is complex, and so we would welcome and encourage further collaboration between Ofwat and ourselves in advance of the draft determination on the issue.

3. Retail cost allowances and real price effects

3.1 Our views on Ofwat's retail cost models

Ofwat's cost models form an important part of PR24 as they are used as the baseline to setting companies' base cost allowances. Ofwat has published a set of proposed cost models in advance of the business plan submission which we use as the basis for this section.

In our response to Ofwat's modelling consultation in May 2023, we expressed our concerns about the retail models. To recap, these were:

- A concern that the average bill size cost driver is not appropriately representing industry structure, particularly for WOCs, and that there is very weak to no correlation between average bill size and normalised bad debt.
- That individual correlations between bad debt and deprivation cost drivers are poor.
- That the approach taken at PR19 on retail inflation has resulted in a far more impactful efficiency challenge than originally envisaged, due to the current inflationary pressures in the economy.
- That Ofwat's retail cost models are likely not detecting the true underlying reason for different bad debt performance – that is the effectiveness of individual companies' policies and procedures in collecting debt. We showed a quadrant analysis where it is clear that companies have different levels of performance on bad debt collection that are not correlating only with the drivers chosen.

We have updated Ofwat's proposed model set to incorporate 2022/23 data, and uplifted to 2022/23 price base using the CPI-H index.

We still find that the modelling approach is not taking full account of deprivation and debt collection policy variability across companies, which we believe is the factor really driving cost variation. Whilst the cost drivers for deprivation are included in the models, our evidence showed that they are poorly correlated with actual costs. We also demonstrated that average bill size was also poorly correlated to bad debt, and also this cost driver shows some behaviour opposite to that expected when looking at water only companies, indicating that there is a structural difference between retail businesses of water only companies compared to water and sewerage companies. This may simply be due to scale opportunities for the much larger water and sewerage companies. We note that the retail scale issue has been put forward as a cost adjustment claim by one company.

3.2 Retail real price effects

3.2.1 Power

The power contracts we negotiate with our suppliers cover our wholesale operations but include our main office sites in Walsall and Cambridge, which are shared with the majority of the retail function. Therefore the same power prices apply to both wholesale and retail functions.

However the power costs of the retail function are very small in comparison to wholesale, and a small proportion of the retail costs. This data is also not reported, so we have no wider sector data on retail power costs from which to calculate a modelled implicit allowance as we have done for wholesale water.

On balance we recognise that the impact of power price increases in retail is relatively small, and so we have elected not to propose either an up-front adjustment or true up mechanism for retail power. If Ofwat does implement an appropriate mechanism at the sector level for retail power, we would support it, but we do not need to suggest one in our plan given the small impact.

3.2.2 Labour

A significant proportion of the costs in the retail function are labour.

In PR19, Ofwat did not allow indexation of retail costs. At the time, this approach was considered to be in lieu of, or by extension, broadly equivalent to, a forward looking efficiency challenge. At the time, inflation forecasts were under 2% per annum.

However in practice, world events have meant that we are currently in a high inflation environment, which far exceeds the originally envisaged inflation forecast. As a result of the inflationary environment, we are rightly having to fund pay increases for our workforce in retail. With no automatic indexation of the price control to account for this, this is equivalent to an efficiency challenge far in excess of that envisaged at PR19, and far in excess of an efficiency challenge that we could have accepted at PR19. The events that have materialised, namely the Covid pandemic and the war in Ukraine, could not reasonably have been foreseen at PR19.

We still think that the most appropriate approach for retail is to index the price control but set a separate efficiency challenge, mirroring the approach in wholesale. However, as Ofwat has indicated against this change in its methodology, we have included a 2% per year uplift to our retail costs in our AMP8 retail cost forecast, as this is the current forward inflation forecast.

There is real risk however, that actual inflation may remain higher than 2% in practice, at least in the shorter term. If this occurs, we consider that a true up mechanism should be in place to correct for this, mirroring the labour cost true up in wholesale that was implemented at PR19. As a company and sector we must retain and attract experienced and competent employees to meet the high service standards demanded by customers and that we all want to see for the sector. Input cost pressures risk damaging this if they are materially above assumptions and presenting an undeliverable efficiency challenge or cost allowance in practice.

4. Comments on other companies' cost adjustment claims

This short section gives our comments on a small selection of cost adjustment claims put forward by other companies in June 2023. We have not made comments on the majority of claims as an initial review indicated to us that they are unlikely to be material at the sector level. We recognise Ofwat will evaluate all of these claims and we may comment further on any outcomes that impact us at the draft determination stage.

4.1 Network complexity (Severn Trent)

Several companies have included some form of topography/average pumping head cost adjustment claim.

Of these, Severn Trent has proposed that the solution to the representation of topography issue within the models is to utilise both average pumping head and boosters per length of main together in the same models. Rather than being only topography that this combination measures, Severn Trent argues this represents a wider suite of network complexity assessment.

We demonstrated extensively in our cost adjustment claim that the boosters per length of main cost driver is not appropriate measure of network topography. CEPA, in its review for Ofwat also concluded that this driver was likely measuring asset intensity, not topography. We also showed evidence that the driver is correlated with density drivers, which are already included in all of the models. We also have commissioned an independent study from Water Research Centre to evaluate the behaviour of average pumping head and boosters per length of main in several common network scenarios, which is included alongside this appendix (document reference SSC19f).

Severn Trent argues that under some circumstances, small discrete hilly areas will be supplied with small boosters, and some companies may legitimately have more of these areas than others. We agree with this operationally, and we have some of these configurations within our own network. But what is the impact on cost and why is it not measured by the overall average pumping head metric? Average pumping head is the combined average of all pumping across the network, and so if there is more pumping, whether it comes from a small number of larger sites or a larger number of smaller sites, every site is still reflected at the appropriate weighting within the average pumping head metric. The metric was designed to do this and to have those relationships to cost.

We can agree with Severn Trent that there may be some additional costs from having a greater number of sites to manage over the supply area. But, there are also proportionally higher costs from having larger sites, which require larger associated assets such as electrical equipment and power supplies. Are these costs broadly equivalent, or does one approach have systematically larger costs than the other? This leads on to the density variable, which we have showed is correlated to boosters per length of main. It appears that the density variables may already be implicitly incorporating a degree of network complexity, given that they are partially correlated to the boosters per length of main variable which Severn Trent argues is fulfilling this purpose. It is reasonable to assert from an engineering rationale perspective that more dense networks are also more complex. Therefore the combination of average pumping head and density could be sufficient to reflect network complexity and total region topography.

If network complexity is considered a valid driver, then boosters per length of main is also not the whole story by far. The degree of interconnectivity within a network, the number of valve schemes (automated or manual), the number of service reservoirs, the locations of mains (i.e rural mains compared to mains under major roads) – all these factors might indicate a network of increased or reduced complexity to manage, and could impact costs. And in all these factors, there would need to be considerations of size, not just number of, to create reliable relationships to cost.

We would support a wider research study into network complexity and how it could be robustly assessed, including whether the boosters per length of mains cost driver is representing any genuine exogenous factor, as a future industry-wide research project. But, as our cost adjustment claim showed, at the moment we consider the rationale for boosters per length of main to be poor and the correlations to the relevant costs to be unevidenced and inappropriate.

4.2 Meter renewals (South East Water)

South East Water argues that its higher meter penetration requires higher costs for meter replacement, given that meters have an asset life of approximately 15 years.

We agree with the premise, increased meter replacement costs are an inevitable consequence of rolling out full metering coverage. This is a necessary step change for the sector in order to meet our goals for fairer charging, finding leakage, and giving customers the information they need to help them reduce their consumption. Over time, modelled allowances for all companies would need to increase to meet this need.

As metering rollout has accelerated quite quickly, it is only very recently that the meter replacement costs have started to materially increase, it is not over the full period of the data set used in cost modelling and not for all companies.

Whilst we understand South East Water's point – that the current models do not allow for their increased renewal rate - we do not consider this a symmetrical claim. It is reasonable for South East Water to have their costs adjusted upwards because of their increased replacement costs, as it is not included in the models going forward, but as a recent activity that is only now starting to increase, any cost allowances that are embedded within the existing historic data set since 2011/12 are relatively small.

4.3 Retail scale (SES Water)

We agree with the premise of SES Water's claim, as we also believe that the current retail models are not correctly accounting for scale or the structural difference between water only companies (WoCs) and water and sewerage companies (WaSCs), issues which are clearly correlated as most of the WaSCs are significantly larger than the WoCs. We have raised these issues before in the context of bad debt, but we agree with SES Water that there are also scale impacts present in the models through the way in which they are constructed.

Whilst the retail models include different variables to account for factors other than scale, there is a significant discrepancy between the ultimate funding level across the companies, as our table below shows for 2022/23 data and PR19's retail cost allowances.

Company	Connected HH props, k	Rank	Retail totex, £m	Rank	Totex per property, £	Rank
HDD	99	1	14.441	1	£147	12
SES	288	2	27.777	3	£96	5
PRT	309	3	21.330	2	£69	1
BRL	524	4	50.816	4	£97	6
WSX	591	5	143.108	9	£242	17
SSC	713	6	62.312	5	£87	2
SEW	1004	7	88.195	6	£88	3
SWB	1010	8	141.011	7	£140	9
SRN	1090	9	261.689	12	£240	16
WSH	1358	10	204.625	10	£151	13
AFW	1497	11	142.206	8	£95	4
NES	1977	12	250.110	11	£127	7
ANH	2167	13	402.988	14	£186	14
YKY	2240	14	321.874	13	£144	10
NWT	3257	15	474.841	15	£146	11
SVE	3552	16	492.246	16	£139	8
TMS	3827	17	754.009	17	£197	15

By connected properties (water), we are the 6th smallest company, and 5th smallest in terms of total retail allowance at PR19. But, we are funded for a totex per property which was the 2nd smallest in the sector. This is despite having overall levels of deprivation in the top four in the sector, clearly this demonstrates that the retail models are not working as intended.

Whilst the data above does not account for dual service, we question what the true costs of dual service are, given that the meter readings are the same (wastewater consumption is measured from the same meter as the water consumption for the property), bills are combined for dual service customers of WASCs, and billing systems and various other back-end systems and processes will be combined for water and waste in those larger companies. We would expect call volume to be higher for dual service for operational issues (as there are two services), but not necessarily for billing issues given the bill production, billing systems and cash collection methods would likely operate on a combined basis.

We therefore agree with SES Water that larger companies will be able to elicit material economies of scale compared to smaller retail operations particularly for the back end operation. We still need to invest in billing systems, in social media monitoring, in customer contact channels and numerous other services that underpin our retail function and sit behind the customer facing operation, and it is reasonable to assume that these costs do not scale linearly with size. We consider that this means that a significantly larger company, gaining substantially more funding per property, will likely have significantly more freedom and headroom for back-end and customer facing services investment.

Since PR19, Hafren Dyfrdwy and Bristol Water have both merged with larger companies (Severn Trent and South West Water respectively) and will now be able to be benefit from access to those same back-end systems, customer facing systems and the resultant economies of scale, even though they still report as separate water companies. This leaves Portsmouth, SES Water and ourselves as the smallest three companies in the sector for the retail operation (by overall totex allowance).

Underfunding on retail cost allowances risks exposing smaller companies, such as SES and ourselves, to very difficult efficiencies and choices when it comes to back-end and customer facing services investment. There is a risk that this affects service levels, or at least prevents innovation and progress at the pace desired, for those companies receiving the smallest allowances. We think Ofwat should look again at how the models are accounting for these differences between companies of different sizes, including the issue we have separately raised on bad debt, so that the appropriate adjustments are made to all cost allowances in a symmetrical way and all companies, whatever their size, have the same opportunity to invest in leading back-end and front end systems and services to drive retail services forward.