UUW114

Approach to energy cost forecasts - UUW response

October 2023

UUW's response to Ofwat's request for information on our approach to forecasting energy costs.

United Utilities

Water for the North West

1. Introduction

1.1.1 Recent global events have led to a dramatic and sustained increase in the price of energy. Water companies are price takers in a national (and arguably, global) market for energy and as such, have limited control over this element of their cost base.

1.1.2 Companies use hedging to mitigate against the risk of price spikes, and (in 'normal' times) hedged prices are generally slightly higher than the prevailing market rate. In recent years, hedging has helped mitigate exposure to the recent peak in prices. However, hedges are only in place for a short term (see Table 1), so any new hedges going forward will naturally reflect the current market prices – at times of high market prices, hedged energy will be more expensive. Therefore, the benefits from historing hedging cannot be used to assume that forward looking (above historic average) prices can be avoided.

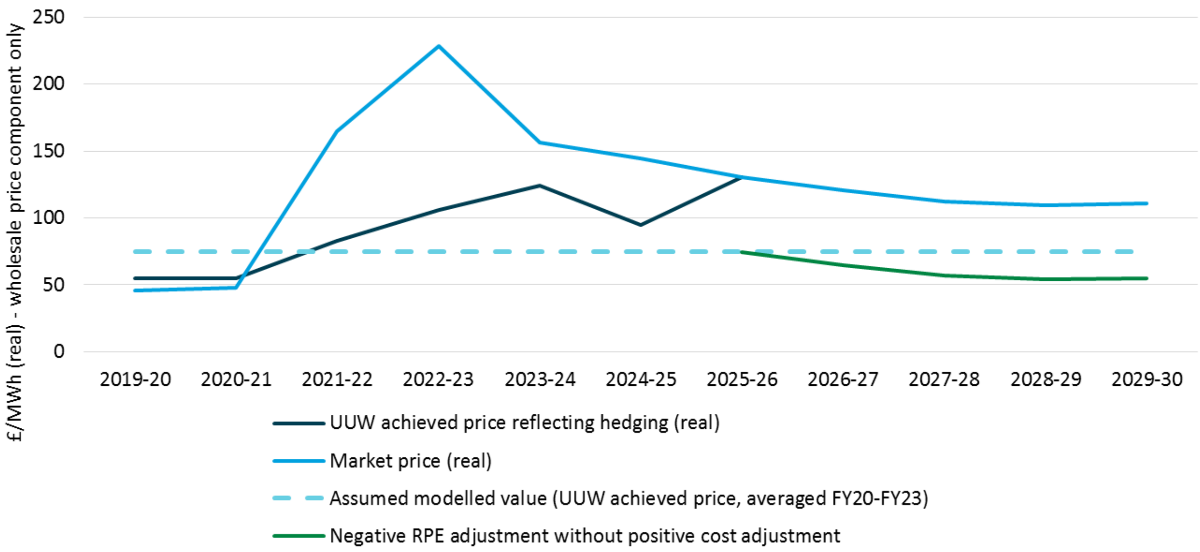
1.1.3 Additionally, (higher) forward looking prices will not be entirely reflected in the historical cost record. AMP8 base expenditure targets are set by reference to an econometric model suite, which relies upon historical data covering the period 2011-12 to present. The recent energy cost spike is only present in the most recent year of data (2022-23). As such, this high cost year will only have a muted effect on modelled base expenditure targets. As we demonstrate in '*UUW46 – Cost assessment proposal*', this muted effect is generally proportional to the number of high cost years in the overall dataset e.g. if there is one high cost year in a panel dataset with 13 years, cost allowances will reflect 1/13th of the increase seen in the high cost year. Reckon's simulation analysis[1] provides more substantiation for this effect. As such, cost models can't reasonably be thought to provide adequate implicit allowances for energy given current market conditions.

1.1.4 This means that while energy prices are expected to fall (in real terms) over AMP8, applying a negative RPE reduction directly to modelled cost would be entirely inappropriate. This is because the models are not fully reflecting higher starting point energy price from which future energy prices are falling, and as such Ofwat would (in effect) be applying the negative adjustment to an inappropriately low starting point (i.e. the value implied within the botex models). This is illustrated in Figure 1, which has the following components:

- **UUW achieved price reflecting hedging**. The represents the effective price UUW paid for energy reflecting hedging (in real terms).
- **Market price (real).** This reflects the market price (in real terms).
- **Assumed modelled value.** For the purposes of this example, this is assumed to be the implicit allowance for energy i.e. the average over the assumed period of the historical dataset. Note that the period in the historical cost record is greater than FY20 to FY23 – this is a stylised example.
- **Negative RPE adjustment without a positive cost adjustment.** This demonstrates that a negative RPE adjustment (seeking to mimic the fall in prices in AMP8) without a corresponding positive cost adjustment will result in an inappropriately low allowance because it is starting from too low of a base.

[1]https://static1.squarespace.com/static/5ff89bfefe0aa250928022e3/t/6316025899029e0cf3b76e69/1662386784854/2022+09+01+Base-enhancements+report.pdf

Figure 1: How UUW's achieved/hedged price responded to higher market prices and how this is reflected in modelled costs



1.1.5 It's clear from this example that hedged prices protected UUW from the worse of the price increases. However, it's also clear that the achieved/hedged price has slowly increased, reflecting the higher market prices since 2021-22. Importantly, this graph is in real terms so the effect shown in Figure 1 are after inflation. This clearly shows that (a) despite hedging, companies have still incurred above inflation increases in energy costs, and (b) models based upon the historical cost record will not recognise the energy prices that UUW is currently subject to.

1.1.6 Crucially, the fact that UUW (and the wider industry) has historically hedged energy prices will act to make the issue of under-remuneration worse. This is because hedging has muted the impact of the recent energy costs increase within the historical cost record and as such the cost models won't reflect the prices that companies are actually now subject to (because these prices are primarily influenced by the prevailing market price).

1.1.7 We note that there are two potential approaches to address this issue within the regulatory framework:

- Apply a cost adjustment claim to ensure base cost allowances appropriately reflect expected higher AMP8 energy costs, and then apply a negative RPE adjustment to reflect falling energy prices; and
- Assume that the gap between modelled and actual AMP8 energy prices will be broadly offset by falling energy prices i.e. that the combination of the positive cost adjustment claim and negative RPE adjustment will be immaterial.

1.1.8 We have adopted the second approach in our business plan, recognising this will likely subject us to an efficiency stretch. However, we note that whichever approach is ultimately adopted by Ofwat should be applied as a common adjustment across the industry as a whole. We note that Figure 1 makes clear that applying a negative RPE adjustment without a corresponding cost adjustment would result in entirely inappropriate cost targets.

1.2 Other comments on our response

1.2.1 In our data return we have summarised our energy (electricity) costs in the Nominal Import Input Price – Energy line. Our average price for AMP7 is £185.6 per MWh. In terms of the price over AMP7, our forward purchasing (hedging) helped to softened the unprecedented price rises caused by the energy crisis but even with this our average price in the last three years AMP7 is £214.5 per MWh compared to £142.3 per MWh for years one and two. The increase in energy costs in AMP7 has been absorbed in our base expenditure. Our forecast for AMP8 presented in the Nominal Import Input Price – Energy line shows an average price for AMP8 of £245.3 per MWh, which highlights prices are far higher than historic prices and higher than AMP7. Our forecast through AMP8 is a small year on year reduction in the price in nominal terms.

1.2.2 We note that Ofwat asked for net consumption cost within its information request. While we have aligned our submission to Ofwat's request, we caution that 'net' consumption cost is not representative of our actual costs for the following reasons:

- Transfer pricing rules mean that the Wastewater Network Plus price control purchases energy generated by Bioresources at market rates. The 'net' consumption cost line assumes this energy is free;
- The market costs for electricity which we are exposed to do not change as a result of self generation;
- Self generation through the bioresources business is as a result of the bioresources treatment process. The calculation effectively assumes this is a zero cost for power; and
- Renewable energy generation by water companies can take a number of forms (e.g. hydro, CHP, solar PV, wind or green gas production) and is typically supported by incentive payments in addition to the value of the energy which is offset. The calculation therefore only includes some of the value and does not include alternative value creation such as green gas.

1.2.3 As such, we would advise caution over the use 'net' consumption cost as it could give a misleading picture over the costs that companies are actually subject to.

2. Our approach to completing the data request

2.1.1 We have used two alternative data sources to complete this request:

- For years to 2024-25, we have used information from internal company budgets; and
- For years 2025-26 onwards, we have used forecast information sourced from a third party, Cornwall Insight

2.1.2 For the purpose of the data request, we focus our commentary upon AMP8 forecasts. We align our commentary to the questions asked by Ofwat in its letter.

2.2 Energy prices – actual and forecasts: Please provide actual and forecast nominal input and export energy prices between 2018-19 and 2029-30. Also explain how your energy price forecasts have been derived in accompanying commentary. Any difference between wholesale and retail energy price forecasts should also be explained.

2.2.1 The sector, through Water UK, jointly commissioned Cornwall Insight to provide delivered electricity cost forecasts (i.e. “import prices”) for the period to 2031-32 in order to support our business plan submissions to Ofwat. Cornwall Insight is a third party consultancy considered expert in its field, which provides price forecasting services to a variety of businesses.

2.2.2 Due to the nature of the electricity grid; the economic regulation of the network operators; and the diverse nature of each company’s portfolio of assets, WaterUK requested a separate forecast for each company. This ensured that each forecast reflected each company’s circumstances. While underlying macro-economic assumptions remain consistent across each of the forecasts, company-specific variations are accounted for as far as possible.

2.2.3 For example, UUW’s portfolio is located primarily in the Electricity North West and Scottish Power/Manweb distribution networks. The forecast for UUW therefore uses the forecast costs associated with these network operators as a volumetrically weighted average based on forecasted electricity demand. In addition, the location of a site on the distribution network (e.g. at high voltage or at low voltage) affects electrical losses and network costs. This is also accounted for in the forecast on a company specific basis. Finally, the ‘shape’ or when energy is consumed can affect prices and this is accounted for through the provision of data relating to electricity usage in red (peak), amber (daytime) and green (night time) periods, which is particular to UUW.

What is driving the forecast trend?

2.2.4 Cornwall Insight has provided a detailed summary of market drivers, technology and regulatory change which drives the forecast trend. The key drivers of the wholesale price over the term of the forecast and beyond are summarised below:

- The generation mix changes due to a drive to low carbon technology and reduction in the use of gas-fired generators;
- Electrification of the economy (increased use of electric vehicles and electric heat pumps for space heating) increases (roughly doubling) the requirement for electricity by 2040 – this is the outcome of the transition away from fossil fuels such as natural gas and petroleum products and replacement with electricity;
- New generation is predominantly wind and solar which are ‘zero marginal cost’ technologies i.e. there is no fuel input cost to run compared to traditional generators such as gas or coal. When zero marginal cost generators run, it has the effect of reducing the wholesale price as the marginal cost

generator which sets the wholesale price is more efficient and hence at a lower cost in the generation stack;

- During the AMP8 period, wholesale electricity prices reduce in real terms from today's elevated highs due primarily to the connection of new offshore wind to meet the Government's target of 50GW by 2030;
- Electricity prices are however still higher in AMP8 in all scenarios than before the energy crisis;
- Gas prices (which are a significant driver of electricity prices by virtue of the volume of gas generation in the GB generation mix) have reduced since the winter 2022/23 period although future contracts remain elevated compared to prices before the Russian invasion of Ukraine. This is reflective of the transition of European gas supply from Russian pipeline supplies to more expensive LNG;
- The UK Emissions Trading Scheme (UK ETS) impacts wholesale power markets as carbon emitting generators incur costs associated with their generation which are reflected in the price of energy. Carbon prices are expected to increase under both the EU ETS and UK ETS as a result of policy requirements for carbon reductions. This increased cost is passed onto energy consumers;
- Third party charges (sometimes known as 'non-commodity' charges) are the elements of the retail price which are not the cost of the energy. They relate primarily to the costs recovered by energy networks (transmission and distribution) and levies associated with various renewables support policies;
- Network charges reflect current regulatory settlements for network operators and any known regulatory changes; and
- Renewables support schemes, taken together, are increasing over the AMP8 period as new low carbon generation comes on line to progress towards carbon targets.

2.2.5 The forecasts provided by Cornwall Insight are based on current known legislation, regulatory and commercial boundaries.

2.2.6 There are no differences in the underlying energy mix taken by our wholesale and retail business and as such, each is subject to the same costs.

2.3 We expect companies to explain how much of its energy consumption it hedges in advance, and if/how it operates a 'hedging ladder'

2.3.1 UUW's hedging objective is to implement energy trades in order to balance cost efficiency and price stability over the timescale of the hedging policy. A summary of our current policy is set out below.

2.3.2 Our hedging principles for the business as a whole seek to cover uncontrollable, volatile and material costs, for example, interest, inflation, currency and also energy. We hedge without speculation and within a clear and transparent policy. There is some discretion in terms of the timing and volume of purchases, however this is within limits as set out in the policy, shown below.

Table 1: Purchase limits within our hedging policy

By the start of:	Year 1	Year 2	Year 3	Year 4	Beyond Year 4
Fixing percentage	≥80% - ≤100%	≥60% - ≤100%	≥40% - ≤100%	≥20% - ≤100%	≤50%
	With a permitted tolerance of +/-5% for each target				

2.3.3 The policy intends to allow for flexibility on the type of power purchase we can undertake, whether that be through the wholesale market, through swaps with banks, or for long term corporate power purchase agreements direct with generators. The intention of a fixing target up to 50% beyond year 4 is to allow scope for self-generation and power purchase agreements which are typically longer term agreements.

2.3.4 The intention of our hedging policy is to increase financial certainty and to avoid short term cost shocks. Hedging is not intended to outperform the market – over time we have both outperformed and underperformed against the market. As we increase our hedged position, we gain cost certainty, however we also reduce the potential for achieving lower costs if market prices fall after we secure a hedge.

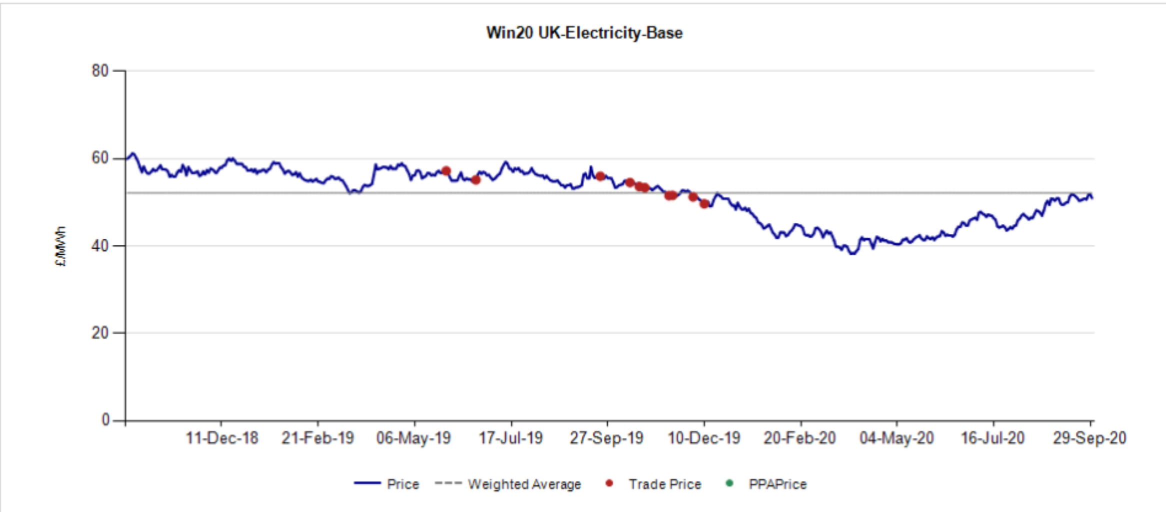
2.3.5 Hedging cannot provide indefinite protection against rising or higher prices. Although the market in general saw its highest prices in winter 22 (i.e. between October 2022 and March 2023), our hedged position for that year, and the subsequent increased price relative to the long term average, means that we are expecting to see higher prices in FY24 and FY25 than we achieved in FY23.

2.3.6 We can demonstrate the above points practically by highlighting how we have hedged/traded over recent years. It is clear to see how the price at which we hedge has increased substantially since winter 2020, which is fairly representative of the period covered by the cost models.

2.3.7 Starting in winter 2020, as this was pre-pandemic and pre-energy crisis, Figure 2 shows a 'typical' seasonal set of trades:

- Note the winter 2020 price ranges between £40 to £60/MWh;
- The red dots indicate the trades which we placed (a total of 11) at prices ranging between £49 and £57/MWh;
- This delivered a weighted average price (WAP) of £52/MWh, which was at that time, neither high nor low relative to the market taken as a whole;
- To comply with our hedging policy, the bulk of the trading was completed prior to the start of the year in which the energy was to be used. Top up trades at month ahead purchased the remaining volume for the season; and
- This reflects a 'baseline' in terms of electricity prices when prices had been stable for a number of years.

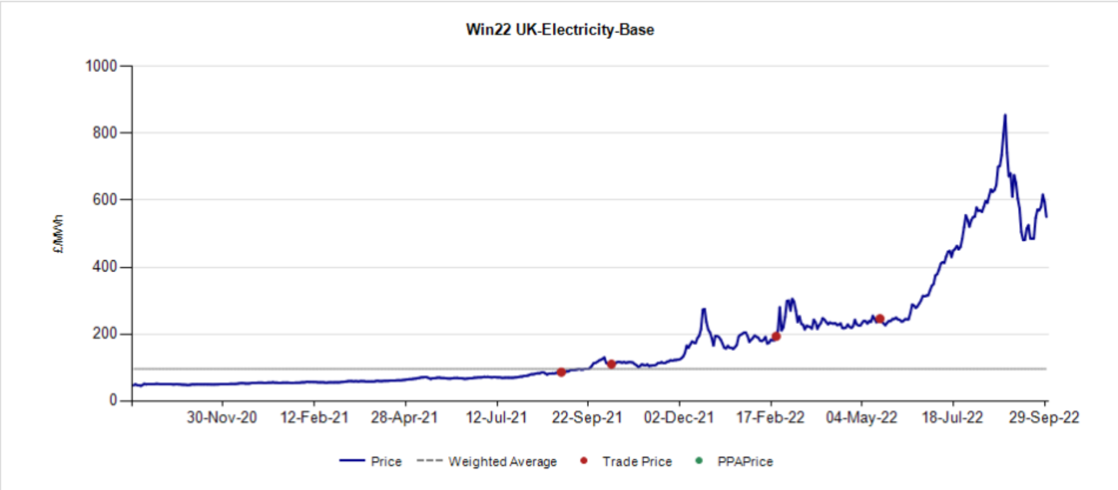
Figure 2: Energy prices over winter 2020



2.3.8 The winter 22 contract is the height of the energy crisis, shown in Figure 3 below:

- Note the winter 2022 prices range from £55/MWh peaking over **£800/MWh;**
- We undertook trading activity prior to the October 2020 period (i.e. the start of liquidity in the wholesale market for winter '22) through bank swaps with eight trades taken by May 2020, with the prices ranging between £47 and £52/MWh;
- We completed four trades in the physical wholesale market at prices between £86 and £246/MWh (shown as red dots); and
- We achieved a weighted average price for winter 2022 at £96/MWh (so approximately two times the winter 2020 price). However, this did insulate us from the energy price peak.

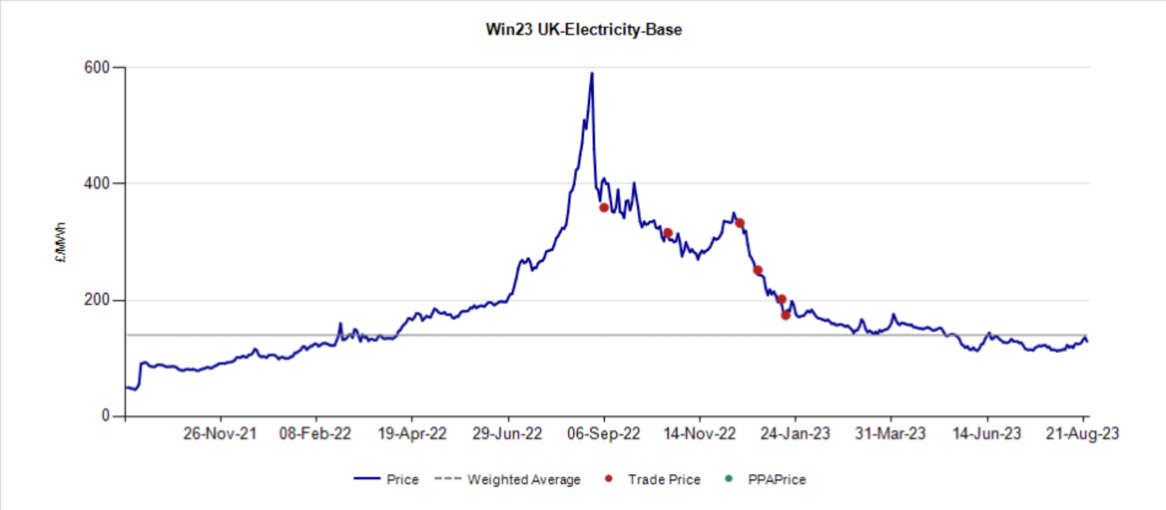
Figure 3: Energy prices over winter 2022



2.3.9 The winter '23 contract covers the peak of the energy crisis but also shows the subsequent fall in prices since January 2023:

- Note the price range between £90/MWh and £590/MWh;
- Also note the 'levelling off' from January 2023 of prices in the range £100 to £150/MWh;
- We undertook trading activity prior to November 2021 in the form of bank swaps, with eight trades placed by Jan 2020 for prices ranging between £47/MWh and £52/MWh;
- We made five trades in the physical wholesale market range between £174 and £315/MWh; and
- We currently have a weighted average price of £140/MWh (roughly three times the winter 2020 price).

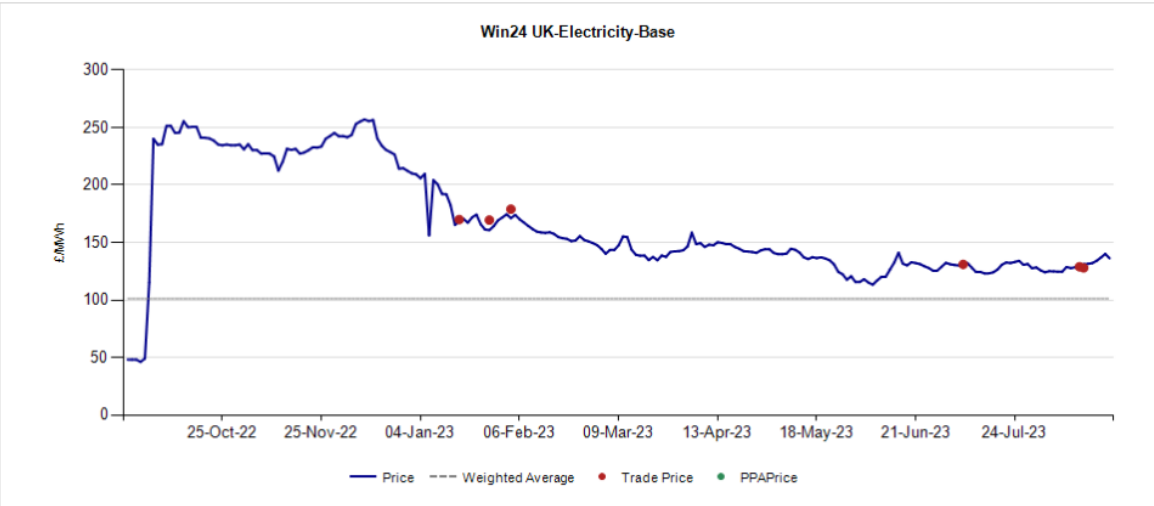
Figure 4: Energy prices over winter 2023



2.3.10 Finally, the winter 24 contract shows how the market has changed from before the energy crisis with prices settling at a point well above £100/MWh@:

- Note the price range between £120/MWh and £250/MWh;
- Again, we have traded financial swaps at pre-energy crisis prices which has insulated us and allowed us to outperform the wholesale market rate with nine trades between £46 and £50/MWh;
- We made five trades in the physical wholesale market range between £170 and £128/MWh; and
- Our weighted average price is at £100/MWh (roughly twice the winter 2020 price).

Figure 5: Energy prices over winter 2024

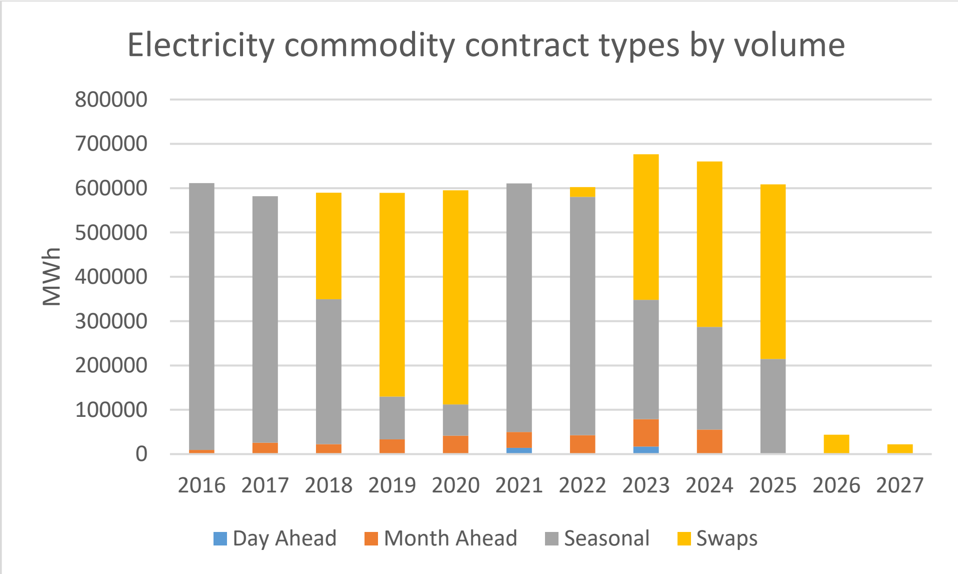


2.3.11 In summary, the trades we undertook in line with our hedging policy pre-pandemic and pre-energy crisis at around the £50/MWh price point have allowed us to avoid the worst of the price increases we have seen at the end of 2022 and continued through 2023. It is important to recognise that the prices available pre-energy crisis are no longer available, with current future prices beng offered showing wholesale price consistently well over the £100/MWh mark. The factors which have caused high prices (primarily the impact on gas prices form the Russian invasion of Ukraine) are still evident today, so whilst wholesale prices have been falling from the market high of c. £800 per MWh the forecast out to 2030 shows elevated wholesale prices compared to pre-energy crisis levels. This position is supported by the analysis from Cornwall Insight and enquiries we have made with banks for AMP8 hedging.

2.4 We expect companies to explain how much (if any) of its consumption is effectively purchased at spot market prices.

2.4.1 Our typical approach is to purchase seasonal baseload (e.g. winter or summer seasons) to meet our policy targets. The remaining volumes are purchased on a month ahead basis. The vast majority of volume is purchased in advance and is therefore not subject to 'spot' market prices. See Figure 6 below showing AMP6, AMP7 and AMP8 trading activity by volume consumed as at end of July 2023.

Figure 6: Trading activity by volume



2.4.2 Seasonal contracts and swaps are long term agreements purchased in the years leading up to the delivery of power. We tend to use seasonal contracts in the wholesale market for the first two years of an AMP period as the market is liquid to c. two years. For years three to five of an AMP period, we tend to use bank swaps for a proportion of the total volume. The month and day ahead purchase decisions are taken in the month prior to the delivery of power and account overall for 6.5% of the energy consumed from 2016 to end of July 2023.

2.4.3 As such, we expect all AMP8 energy purchases to be subject to current market rates, which are significantly higher than historic rates, as evidenced in section 2.2.

2.5 We expect companies to explain how much (if any) of its consumption is set under long-term offtake contracts.

2.5.1 The portfolio of assets which we developed under the United Utilities Renewable Energy business, now owned and operated by SDCL, accounts for around 6% of our demand each year, depending on generation volumes and outturn demand. This portfolio is under a long term power purchase agreement running until 2047. Note that this volume is not shown in the above charts which focus only on grid imported electricity as per the definition in the data request (i.e. electricity imported from the grid).

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