TEC ENERGY & EDUCATION CONNECTED

Electricity & Gas Non-commodity Charges Update Q1 23

Jan 2023

Produced in partnership with Mitie Energy mitie.com/energy

Executive Summary:

Wholesale energy prices have risen to record levels over the past year given the war in Ukraine, meaning the share of non-commodity costs remains low compared to previous years. But at 20 – 30%, non-commodity costs still account for a sizeable portion of the electricity bill. These costs are projected to continue to rise in the near future. The number and complexity of third-party charges has increased over time in response to moves to decarbonise the energy sector and guarantee energy supply. They include green support schemes which support the deployment of low-carbon generation as well as network tariffs. Non-commodity charges can be split into three primary categories: delivery charges; taxes and levies; and system/administration charges. Costs vary depending on the customer and various factors such as the nature of business, location and size.

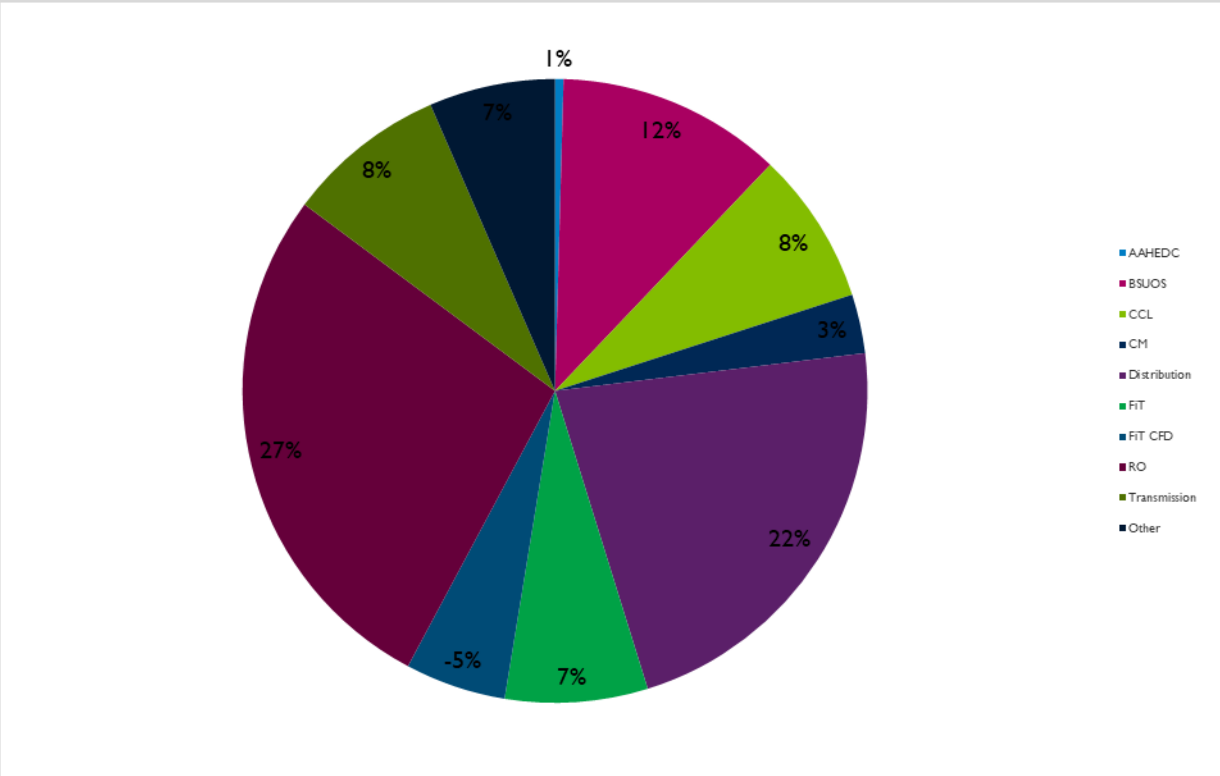

Figure 1: 2022/23 Non-Commodity breakdown (illustrative only)

Electricity Non-commodity Charges Update

The high cost of energy continues to impact non-commodity charges like BSUoS, which reflect the cost of balancing the transmission system. Half-hourly BSUoS charges are capped at £40/MWh this winter to protect consumers from excess costs. Costs priced above this level will be deferred to the 2023/24 charging year.

Ofgem has decided the first fixed BSUoS tariff for the 2023/24 charging year beginning in April will apply for six-months from 1 April to 30 September with a second tariff applying from 1 October to 31 March. National Grid plans to release the tariffs for the first two 6 month periods (April 23 to September 23 and October 23 to March 24) by the end of January.

Ofgem confirmed the final determinations for the RIIO-ED2 (April 2023 – March 2028) distribution price control at the end of November. Total allowed expenditure at £22.2 billion is nearly 12% lower than the amount the networks had originally submitted. Networks will have to deliver less expensive, cleaner and more reliable networks at no extra cost to consumers.

Renewables Obligation mutualisation was triggered for a fifth consecutive year in December. Mutualisation costs amounted to £119.7 million for the 2021/22 obligation period after 54 suppliers failed to meet their obligation by the late payment deadline of 31 October, according to Ofgem.

Meanwhile, the 2023/24 Renewables Obligation will not now be amended in July under plans to shield Energy Intensive Industries (EIIs) from the indirect costs of the Renewables Obligation announced last summer. Under the proposal Beis aims to extend relief to 100% from 85% to protect EIIs' international competitiveness by subsidizing their electricity costs. But this would likely increase costs for other energy consumers at the same time.

The government has confirmed that the Electricity Generator Levy (EGL) announced in the Autumn Statement excludes electricity generated under the Contracts for Difference (CfD) scheme—the government's preferred scheme to support the deployment of large-scale, low-carbon generation.

The EGL applies a 45% levy on the profits from wholesale power sold for more than £75/MWh from 1 January 2023 as a way of helping offset the cost of energy bill support schemes like the Energy Bill Relief Scheme for businesses.

1) Retail Price Index (RPI)

The Retail Prices Index (RPI) measures the rate at which prices increase over time. The RPI records the movement in the prices of a basket of goods and services. Consequently, a number of non-commodity tariffs like FiT and the RO are adjusted by it.

What is driving it?

While RPI eased to 14.0% in the 12 months to November 2022 compared to 14.2% in October 2022, prices still rose at their fastest annual rate since December 1980. The Consumer Price Index (the other main inflation indicator) rose to 10.7% in November from 11.1% in October. The largest increases came from housing and household services (including electricity and gas costs) and transport (motor fuels).

	2022	2023
Low	7.4	2.1
Central	10.5	5.1
High	13.7	8.7

Table 1: Y-O-Y RPI movements

2) Electricity Delivery charges

2.1) Transmission Network Use of System (TNUoS) Charges

TNUoS charges take effect each April and are levied by the National Grid ESO to recover the cost of installing, operating and maintaining the electricity transmission system. Generators are charged based on their Transmission Entry Capacity (TEC), whereas suppliers are charged on their actual demand. Charges vary by location based on the geographical zone users are connected to and reflect the costs they add to the transmission network to transport electricity for their needs.

Final tariffs are published in January before the start of the charging year in April. In addition, National Grid publishes quarterly forecasts including a draft tariff schedule in November which show projections for the year's final tariffs. A five-year forecast is published during the summer.

Until April 2023 end-users with half-hourly meters will be charged based on their average demand during the three half-hourly periods of highest national demand between 4-7 pm during November and February (known as Triads), multiplied by the locational tariff for the zone they are in. Triads are separated by 10 clear days to avoid the possibility that all three could fall within consecutive hours on the same day. For non-half-hourly portfolios, a user's TNUoS charge will be based on their profiled electricity use between 4-7pm each day throughout the year, multiplied by the locational tariff.

Latest update:

Draft tariffs for the 2023/24 charging year were released by National Grid in November. The schedule incorporates major reforms under Ofgem's Targeted Charging Review (TCR) designed to remove distortions caused by Triad avoidance by replacing the residual element of the demand charge with a fixed capacity charge.

Demand residual banded charges will make up the majority of the demand charge based on a single set of fixed capacity charges. These apply to HH and NHH demand based on segmented charging bands defined by voltage level, making the allocation of network costs fairer across the charging base.

The average non-locational banded demand tariff decreases to £92.75/site/annum compared to the August update of £97.69/site/annum. The average HH locational tariff increases to £5.32/kW up from £5.28/kW while the average NHH locational tariff rises to 0.26 p/kWh from 0.25 p/kWh.

National Grid attributes the decrease in demand tariffs to a fall in the total amount of revenue recovered through TNUoS as well as an increase in the amount of revenue to be collected through generation tariffs, which reduces the proportion to be collected through demand tariffs.

The amount of revenue to be collected from the demand residual decreases to £3,053 million from £3,074 million compared to August. Revenue recovered through the demand residual (total demand revenue less locational demand revenue, plus revenue paid to embedded exports) is the main driver behind changes in banded charges. The residual recovers total allowed revenue after forward-looking charges are levied.

Meanwhile, consumption-based charging will continue this winter, enabling those consumers who can still benefit from Triad avoidance to continue to do so.

Demand tariffs for the 2022/23 charging year rose compared to the previous charging year.

The average HH demand tariff increased to £55.06/kW compared to £51.36/kW. Meanwhile, the HH demand residual, which can account for most of the HH demand tariff in some zones, rose to £56.86/kW from £53.23/kW. The average NHH tariff rose to 6.81 p/kWh from 6.50 p/kWh.

The key driver was the increase in total allowed revenue and the subsequent increase in revenue recovered through demand.

The locational element of the tariff structure, which is charged on Triad demand on a forward-looking basis (reflecting the need for likely investment at different points on the network in the future) will remain, meaning Triads will continue albeit at a much reduced rate after April.

Currently the locational charge can be positive in zones where demand leads to increased generation. But it can be negative in some zones, particularly those in Scotland and northern England, where the level of demand signals a reduced need for investment in generation.

Ofgem has decided to apply a floor of £0/kW and 0p/kWh to locational charges in zones where consumers face a negative forward-looking signal. This will have the effect of reducing the residual for all consumers meaning fixed capacity charges will be lower as a result. This is because the forward-looking 'credits' to areas with a negative forward-looking charge will no longer be recovered from the residual pot.

The forward-looking element of the demand charge is being considered as part of Ofgem's further work on the reform of transmission charges following last year's call for evidence.

Ofgem has established a taskforce to consider those elements of TNUoS charges which should be paid by distributed generators as part of its work to reform electricity transmission charging arrangements. The work will also look at existing data inputs to models such as charging bases which help determine tariffs.

The earliest implementation date of any proposed changes is likely to be April 2024.

Furthermore, the core purpose of TNUoS in the long term is being considered in the context of potential wholesale market reform options under the Review of Electricity Market Arrangements (REMA) as part of efforts to realise the importance of ensuring consistent rather than competing signals between markets and network charges.

Work is expected to progress this winter to ensure packages of complimentary measures are developed alongside the REMA programme.

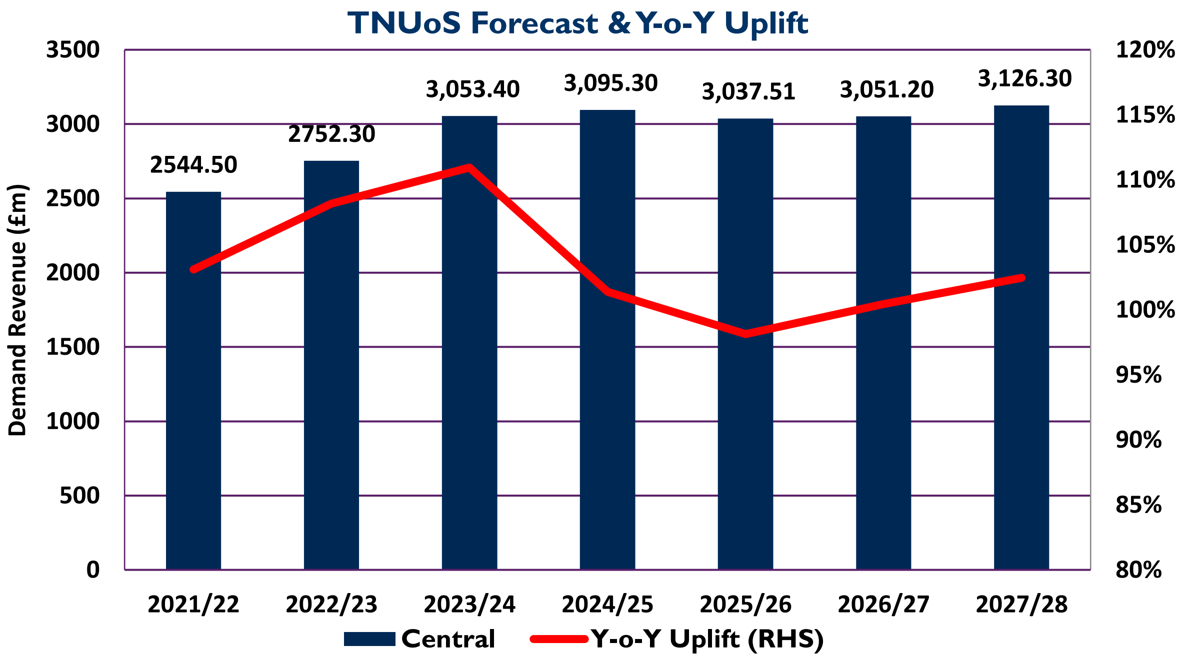

Figure 2: TNUoS allowed revenue forecast

2.2) Distribution Use of System (DUoS) Charges

DUoS charges are set by Distribution Network Operators (DNOs) in order to recover the cost of installing and maintaining the local distribution networks. They are regulated by Ofgem and usually passed through to the customer by the supplier.

The tariff structure changed from April 2022 to include a fixed charge based on voltage connection as part of Ofgem's TCR reforms. The rest of the structure includes capacity and exceeded capacity charges based on contracted connection capacity as well as a reactive power charge. Tariffs also include variable Time-of-Use charges, based on the volume consumed. Rates vary depending on meter type, location, as well as the time of day represented by 'Red', 'Amber' and 'Green' bands.

Latest update:

Ofgem confirmed the final determinations for the RIIO-ED2 (April 2023 – March 2028) price control at the end of November. Total allowed expenditure at £22.2 billion is nearly 12% lower than the amount the networks had originally submitted.

Networks will have to deliver less expensive, cleaner and more reliable distribution networks at no extra cost to consumers. This will be achieved by cutting network company profits and increasing the efficiency of their running costs, requiring them to do more for less.

Networks will need to focus investment on supporting the transition away from a high dependence on fossil fuel imports towards domestically-produced low-cost, low-carbon generation.

Major changes to the energy system are expected during the price control including an increase in renewable generation like wind and solar which require grid connection. Electricity demand is also expected to increase because of an expected rise in electric heat pumps and electric vehicles. But there is also the potential for consumers to sell electricity back to the grid from sources such as EV (Electric Vehicles) batteries.

Work has been paused on the DUoS SCR, the review of distribution charging arrangements, as Ofgem considers on more immediate priorities for network regulation this winter. The DUoS SCR investigates might respond to wider policy developments like system flexibility and decarbonisation of transport and heat.

The review considers charging methodologies for connections at differing voltages. It will also look at the balance between usage-based and capacity-based charges as well as Time-of-Use (ToU) charges. Other considerations include increased predictability of charges for EHV users.

	Apr-23	Apr-24	Apr-25	Apr-26
Central	Published	+3.3%	+2.1%	+1.7%

Table 2: current annual movement in DUoS based on published DNO forecasts

3) Taxes and Levies

3.1) Climate Change Levy (CCL)

The CCL was introduced as a tax on energy usage solely for businesses in the industrial, commercial, agricultural and public services. Energy intensive users who participate in a Climate Change Agreement (CCA) with the Environment Agency can pay a discounted rate in return for making energy and carbon savings. From 1 April 2022 eligible participants can reduce the rate they pay on electricity by 92% and 86% on natural gas. While the discount for electricity will remain at 92%, it will increase to 88% for gas from April 2023 and further to 89% from April 2024.

Latest update:

The Treasury confirmed in November's Autumn Statement that the government will legislate in the Spring Finance Bill 2023 to raise the CCL main rate on gas to £7.75/MWh while freezing the CCL main rate on electricity at £7.75/kWh in 2024-25.

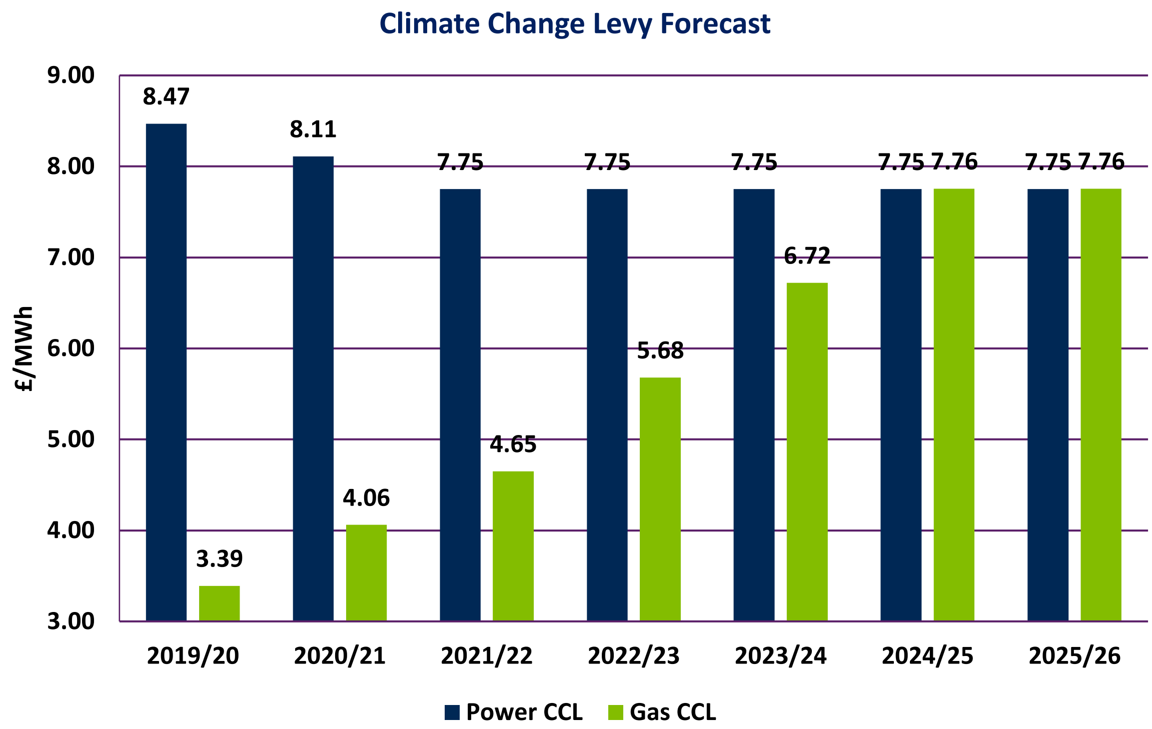

Figure 3: CCL Y-O-Y rate movement

3.2) Renewables Obligation (RO)

The RO is one of the main support frameworks which incentivises the deployment of renewable generation. The degree of support provided by the RO is set by the government annually. Revenue raised is ultimately distributed to large-scale renewable electricity projects. The RO is now closed to new applicants.

The RO charge is calculated annually, from April to March, based on the following elements:

- **Obligation level:** the amount of expected renewable generation as a proportion of overall electricity generation within the compliance period.
- **Buy-out price:** the buy-out price is set by Ofgem, and is index-linked to RPI. The buy-out price is the amount suppliers must pay for each ROC not presented towards compliance with their obligation.

The RO charge (£/MWh) is calculated by multiplying the obligation level by the buy-out price.

In 2015, the government implemented measures to reduce the impact of renewable policy on the cost of electricity paid from Energy Intensive Industries (EIIs) which led to the exemption of these industries from certain renewable charges (RO, FiT, and FiT CfD). The EII exemption from the RO charge was implemented in April 2018. This resulted in a 7% increase in the charge for non-EIIs customers. This extra levy has been included in the forecasts below.

Latest update:

Renewables Obligation mutualisation costs amounted to £119.7 million for the 2021/22 obligation period after 54 suppliers failed to meet their obligation by the late payment deadline of 31 October, according to Ofgem. Of these suppliers, 27 are either now in administration or have had their licence revoked. The shortfall triggered the mutualisation process for the fifth year in a row after the mutualisation threshold of £63.7 million was breached, requiring suppliers to make additional payments to make up the shortfall in funds.

The 2023/24 Renewables Obligation will not now be amended in July under plans to shield Energy Intensive Industries (EIIs) from the indirect costs of the Renewables Obligation announced last summer. Under the proposal Beis aims to extend relief to 100% from 85% to protect EIIs' international competitiveness by subsidizing their electricity costs.

Had there been time to consider consultation responses and complete the subsidy control processes as well as secure Parliamentary approval by March 2023, then the obligation level announced in September would only have applied between 1 April and 30 June 2023.

But Beis has determined that the current EII exemption will remain unchanged at 85% for the 2023/24 obligation period meaning there is no need to amend the obligation, determined at 0.469 ROCs/MWh in Britain and 0.184 ROCs/MWh in Northern Ireland last September.

The Cost Plus Revenue Limit (a measure included in October's Energy Prices Act) has been replaced by the Electricity Generator Levy (EGL) announced in the Autumn Statement.

The EGL applies a 45% levy on the profits from wholesale power sold for more than £75/MWh from 1 January 2023 as a way of helping offset the cost of energy bill support schemes like the Energy Bill Relief Scheme for businesses.

The EGL is being introduced as a relatively swift way of breaking the link between gas and power prices. Market reforms aimed at delivering the framework for a decarbonised, low-cost marketplace as well as reduced reliance on gas-fired generation over the longer term are being considered under REMA.

The government and Ofgem have responded to last year's consultation seeking to address the issue of supplier payment default under the RO.

A move to more frequent settlement on a quarterly basis to reduce default amounts was considered but the government believes this is not the right approach. Instead, it aims to gather more evidence to further develop policy thing around the RO in a way that supports industry and consumers as well as supports delivery of Net Zero.

While current settlement arrangements limit volatility in the ROC market caused by the seasonal and intermittent generation, they also enable suppliers to default on up to 19 months of payments.

What is driving it?

While the RO closed to new generating capacity in April 2017, it continues to support existing schemes for their allowed period, which is normally 20 years (first started in 2001). Thus, capacity supported under RO is forecasted to peak at around 35.1GW by the end of 2023/24. The RO buy-out price is set to increase in line with inflation. For the following years, we assume that capacity will gradually drop hence netting off the RO buy-out price uplift.

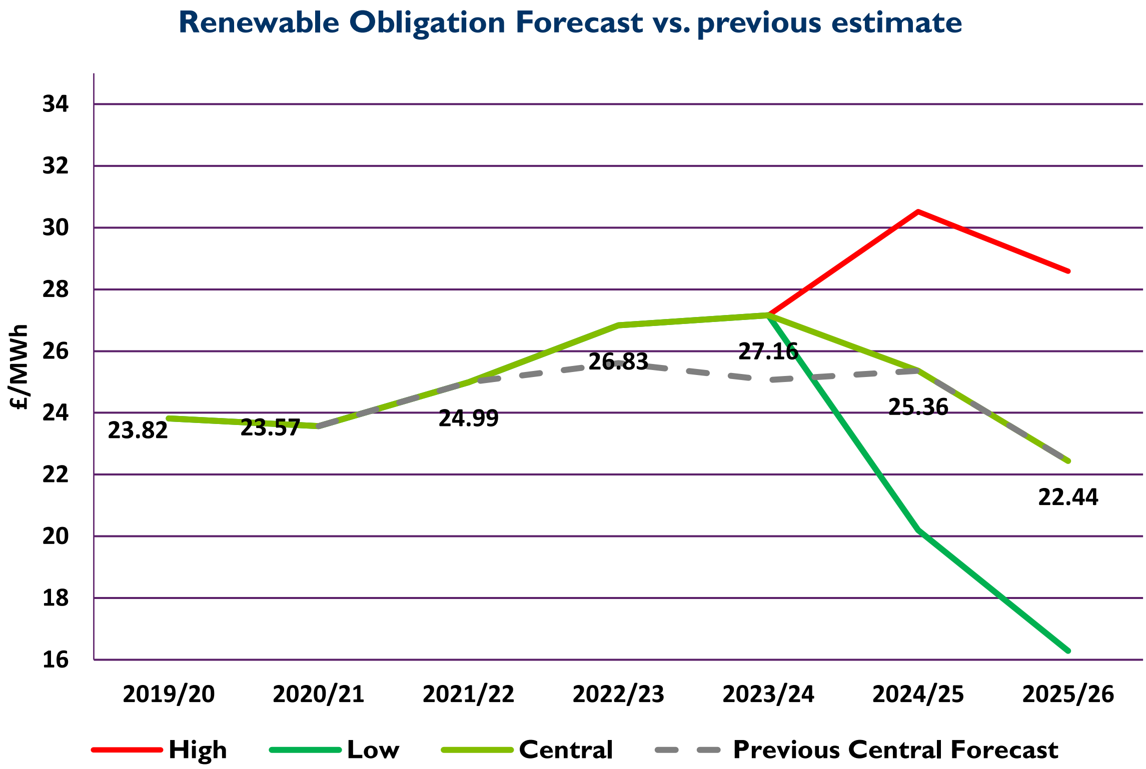

Figure 4: RO Forecast vs. previous estimate

3.3) Contracts for Difference (CfD)

The CfD scheme is one of the main mechanisms supporting the deployment of low-carbon generation. The scheme aims to reduce the cost of capital for developers in projects with high up-front costs and long payback times, while minimising costs to consumers. Generators apply for a CfD allocation, during a competitive Allocation Round (AR). In these ARs renewable technology projects compete against each other in auctions. The developer then sells energy to the wholesale market and receives a top-up payment or pays back of the difference between the market outturn and the pre-agreed strike price.

Now that the RO and the FiT schemes are closed to new projects, the CfD is the only subsidy scheme available to developers of new, large-scale renewable generation. Although CfD costs are predicted to rise over the medium term, costs have fallen to minimal levels because generators are paying money back given wholesale prices are higher than the strike price they are paid. This makes the deployment of renewables under the scheme effectively 'subsidy-free' at the moment.

From 2015, the Government implemented measures to reduce the impact of renewables policy on the costs of electricity for Energy Intensive Industries (EIIs) by exempting them from certain renewable charges (the RO, FiT, and the FiT CfD). The EII exemption for CfD was implemented from November 2017. This additional cost has been included in the forecasts below.

Latest update:

CfD Interim Levy Rates (ILRs) are forecast at £0.000/MWh during the 2022/23 charging year according to the Low Carbon Contracts Company (LCCC), the scheme's administrator.

The government has confirmed that the Electricity Generator Levy (EGL) announced in the Autumn Statement excludes electricity generated under the Contracts for Difference (CfD) scheme—the government's preferred scheme to support the deployment of large-scale, low-carbon generation.

The EGL applies a 45% levy on the profits from wholesale power sold for more than £75/MWh from

1 January 2023 as a way of helping offset the cost of energy bill support schemes like the Energy Bill Relief Scheme for businesses.

The EGL is being introduced as a relatively swift way of breaking the link between gas and power prices. Market reforms aimed at delivering the framework for a decarbonised, low-cost marketplace as well as reduced reliance on gas-fired generation over the longer term are being considered under the Review of Electricity Market Arrangements (REMA), launched in the summer. The reforms should ensure that all generators can make a fair profit in line with the investment and risks they make.

Deployment of large-scale, low-carbon generation will accelerate from 2023 when the government begins to hold annual auctions, starting with the fifth allocation round (AR5) in March.

Details of AR5 including the pots which group technologies, as well as strike prices and delivery years were announced in December. The auction will feature two pots; the first made up of mature technologies like on and offshore wind as well as solar and the second including nascent technologies like marine tidal power. Administrative strike prices for on and offshore wind have been set at £53/MWh and £44/MWh. Projects competing for funding are scheduled for delivery in the three years from 2025.

The government published a consultation on policy considerations for future rounds of the CfD scheme from AR6 onwards in December. This ensures it remains fit-for-purpose as the electricity system transitions as part of efforts to achieve the UK's net-zero ambitions. The consultation closes in February.

The government is reviewing the energy intensive industries exemption scheme, which exempts energy-intensive users from 85% of the costs of green support schemes including the CfD scheme. Under the measure Beis would extend relief to 100% to protect EIIs' international competitiveness by subsidizing their electricity costs.

What is driving it?

As the CfD costs are dependent upon wholesale prices, predicting costs is difficult. Should wholesale prices increase, scheme costs will fall, as lower top-up payments will be required. The opposite holds true if wholesale prices fall. Wind generation may also affect scheme costs, higher wind production pushes wholesale prices lower and eligible generators will require top-ups.

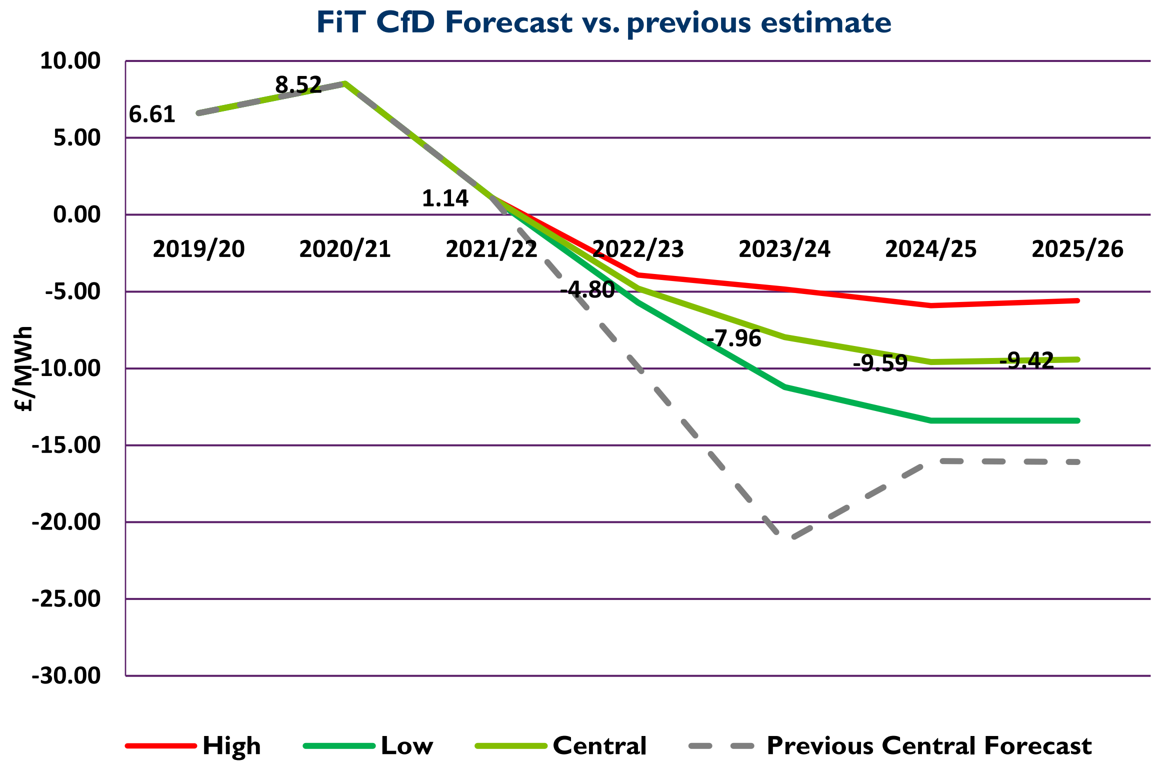

Figure 5: CfD movement per year based on central scenario

3.) Small Scale Feed-in Tariff (FiT)

The FiT is a scheme that incentivises the installation of small-scale, low-carbon electricity generation. Electricity suppliers pay for the electricity generated by small-scale installations with costs passed onto consumers through the FiT charge. The charge is calculated by dividing the total cost of the scheme by total supply volume in Britain. The FiT scheme closed to new installations in April 2019.

In 2015, the Government implemented measures to reduce the impact of renewables policy on the costs of electricity for Energy Intensive Industries (EIIs) by exempting them from certain renewable charges (RO, FiT, and FiT CfD). The EII exemption for FiT was implemented from April 2019, meaning a consequent additional increase of 3% in the FiT charge for non-EIIs customers. This extra levy has been included in the forecasts below.

Latest update:

The government is reviewing the energy intensive industries exemption scheme, which exempts energy-intensive users from 85% of the costs of green support schemes including the CfD scheme. Under the measure Beis would extend relief to 100% to protect EIIs' international competitiveness by subsidizing their electricity costs.

What is driving it?

The main driver in the scheme is the rate of support that the government makes available to each of the eligible technologies. The addition of new generators in the scheme increases the scheme's cost for electricity business users. Another contributing factor is national demand, as the cost is distributed amongst total electricity consumed. If demand rises, the cost is spread more thinly and the cost per unit of electricity consumed is lower.

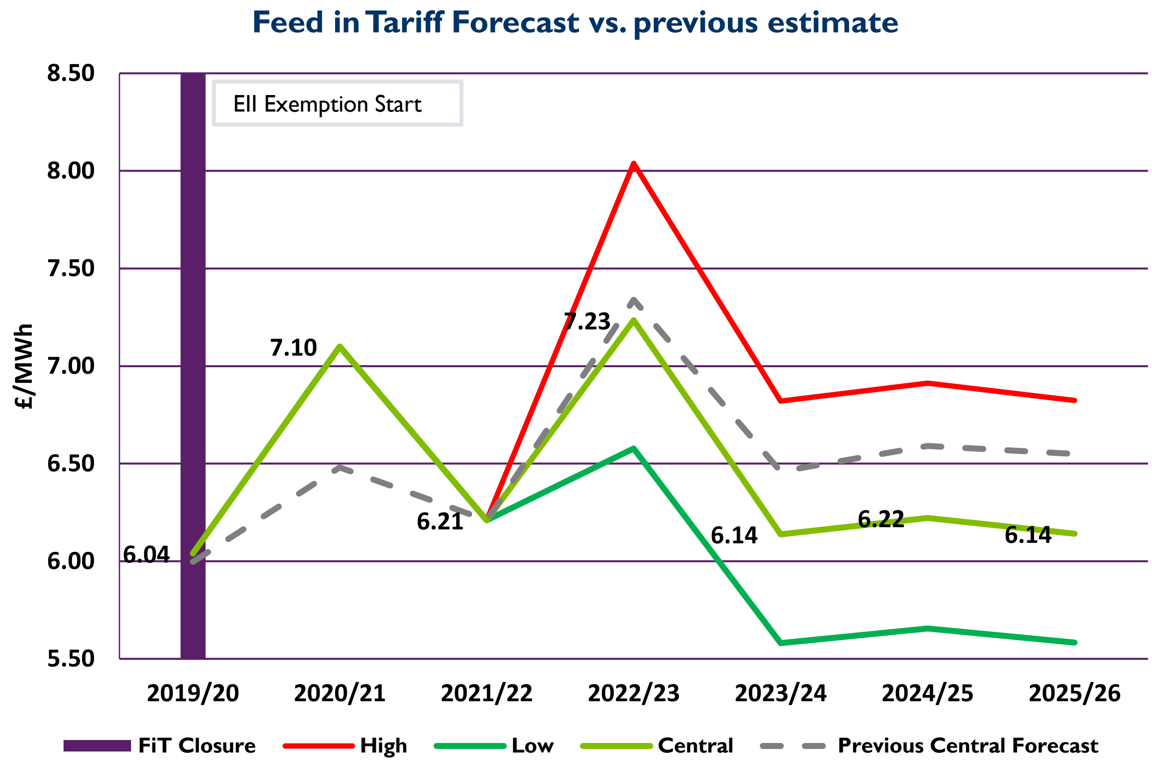

Figure 6: FiT Forecast vs. previous estimate

3.5) AAHEDC (Assistance for Areas with High Electricity Distribution Costs)

The AAHEDC was introduced in the Energy Act 2004. It replaces an earlier arrangement, commonly referred to as 'Hydro Benefit', which ended in January 2004. The intention is to reduce the costs to consumers for the distribution of electricity in northern Scotland. Under the scheme, National Grid as the Electricity System Operator, recovers an Assistance Amount from all authorised suppliers, which is passed to Scottish Hydro Electric Power Distribution Ltd to reduce the distribution costs for consumers in its area.

Tariffs are calculated for each financial year from 1 April, but are published in mid-July. The later publication date allows the previous year's final quarter payment to be reflected in the tariff thereby including any under or over recovery.

Latest update:

The government is analysing feedback to its recent consultation on the reform of the scheme. Some minor technical improvements to funding arrangements are expected. As such, the government proposes to switch the inflator for the Hydro Levy to CPIH from RPI to maintain consistency with Ofgem's price control process.

Furthermore, calculating each supplier's market share based on gross rather than net demand was proposed to address potential distortions arising from embedded benefits. This would bring the Hydro levy into line with supplier charging arrangements for the Capacity Market and the CfD schemes.

However, the government does not intent to make any changes to support for the Shetland islands which is valued at £27 million a year.

What is driving it?

RPI drives both the Assistance Amount and Administration Allowance components of the AAHEDC. In addition, variances in out-turn demand compared to the forecast demand for a given period play a vital role in determining the final tariffs. Lastly, any under- or over-recovery or any expected changes in the demand-charging base can have an impact on the final tariff.

Following a 3-year Hydro Benefit Review, BEIS confirmed its intention to integrate the Shetland Cross Subsidy cost into AAHEDC commencing from April 21 onwards. Our forecast reflects this change.

£/MWh at GSP	Apr-21	Apr-22	Apr-23	Apr-24	Apr-25
AAHEDC	0.40	0.41	0.44	0.44	0.46
Y-O-Y change	+32.8%	+2.5%	+7.3%	-0.3%	3.9%

Table 3: AAHEDC Y-O-Y rate movement

3.6) Capacity Market (CM)

The CM scheme aims to ensure security of electricity supply by offering payments to reliable generators, which commit to provide energy in times of system tightness. Generators take part in auctions and bid for additional revenue required to have available capacity. The scheme also encourages investment in new capacity or for existing capacity to remain open at least cost to consumers.

Suppliers are charged based on their market share during the peak winter season (November to February) and then pass on the charge onto their customers. The CM rate is calculated by multiplying the volume of the contracted delivery for the year in question by the auction clearing prices and then dividing by the amount of electricity supplied.

Latest update:

Beis has summarised responses to its request for information about which emerging generation technologies could contribute to security of supply and should be eligible to participate in future Capacity Market auctions.

Emerging technologies include Vehicle-to-X (V2X, where X could represent the home, a building or the grid) technology with one CM unit already participating in Demand Side Response.

In particular, respondents highlighted a number of factors across the electricity system that will need careful consideration to facilitate the participation of vehicle to grid technologies, such as half-hourly market settlements and coordination between balancing services and Capacity Market participation.

Target capacity of 5.8 GW for the 2023/24 T-1 top-auction due to be held in February has been set by the government. Meanwhile, a target of 43.9 GW has been announced for the 2026/27 delivery year in the T-4 auction. Beis has also decided to set aside 1.5 GW of this for the associated T-1 auction. The price cap for both auctions remains unchanged at £75/kW/year.

The REMA consultation looked at how the electricity market could change to bring down costs for consumers in the future. It focused on ensuring market design works effectively for consumers, including consideration of the reform of the Capacity Market to better support firm low-carbon technologies.

What is driving it?

The rate is determined by auction results and the total UK energy supply. The costs will spread widely depending on how well the system is supplied. This makes forecasting more challenging.

A drop in electricity supply to the UK's physical system has provided support to an increased CM rate. However, competition between generators and decreasing auction volumes are set to result in lower clearing prices and hence lower costs for consumers.

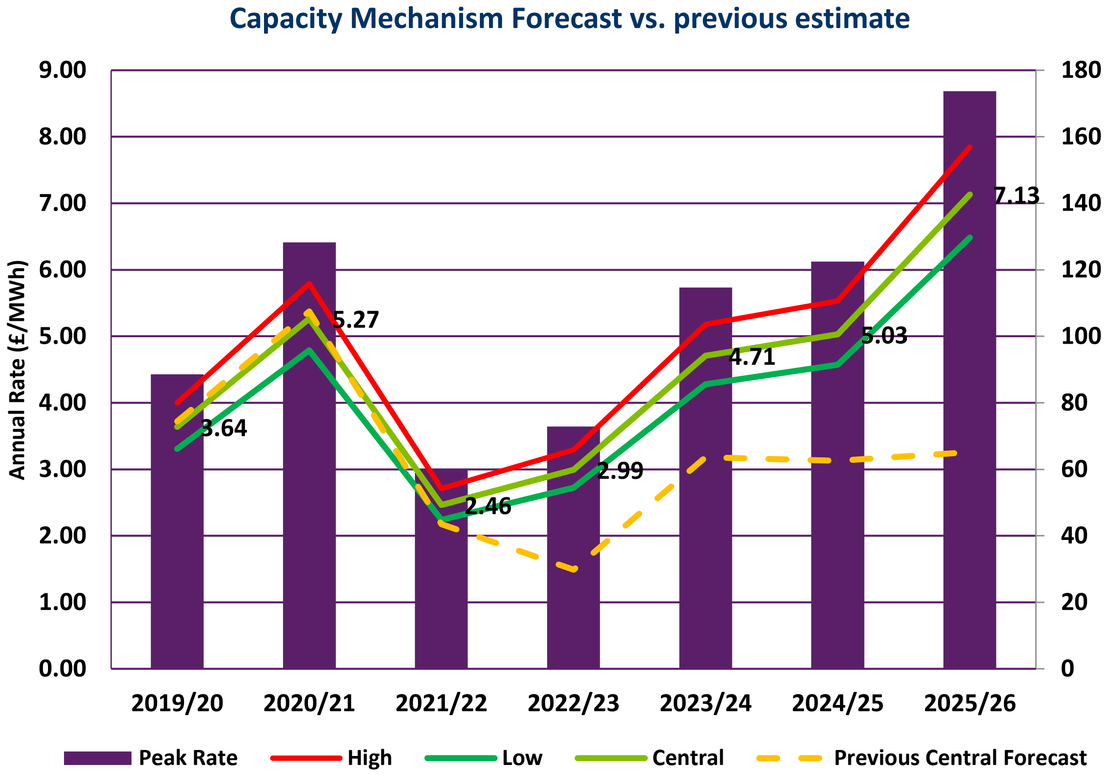

Figure 7: CM Y-O-Y rate movement based on central scenario

4) System and Administration Charges

4.1) Balancing Services Use of System (BSUoS) Charges

BSUoS charges recover the cost of the day-to-day operation of the transmission system and are payable to National Grid ESO. These costs primarily relate to the balancing of Britain's electricity system and include the costs of constraining generation. Generators and suppliers are liable for these charges, which are calculated daily as a flat tariff for all users.

Latest update:

Half-hourly BSUoS charges are capped at £40/MWh this winter in a bid to protect consumers from excess costs. Costs priced above this level are deferred to the 2023/24 charging year following approval of the scheme by Ofgem. The move is a temporary measure between 1 October 2022 and 31 March 2023.

Ofgem has decided the first fixed BSUoS tariff for the 2023/24 charging year beginning in April will be fixed for six months from 1 April to 30 September with a second tariff applying from 1 October to 31 March. While a notice period of nine months will apply in subsequent years, the proximity to the start of the new charging year means only a two-month notice period will be given for the first six-month period and then an eight-month notice period will apply to the tariff for the second half of the year.

National Grid plans to release the tariffs for the first two 6 month periods (April 23 to September 23 and October 23 to March 24) by the end of January 2023.

Earlier this year Ofgem announced consumers would be solely responsible for balancing costs by removing the liability for large generators to pay from April 2023, effectively doubling the cost of balancing the electricity transmission system is set to double for consumers from that point onwards.

What is driving it?

Intermittent wind generation has significantly affected balancing costs in recent years, as short-term instability in the generation profile requires additional balancing actions. Short-term power prices are important given that it can be expensive to undertake balancing actions. Lastly, higher national demand can result in a decrease of cost, as the same costs are spread over a larger consumption volume.

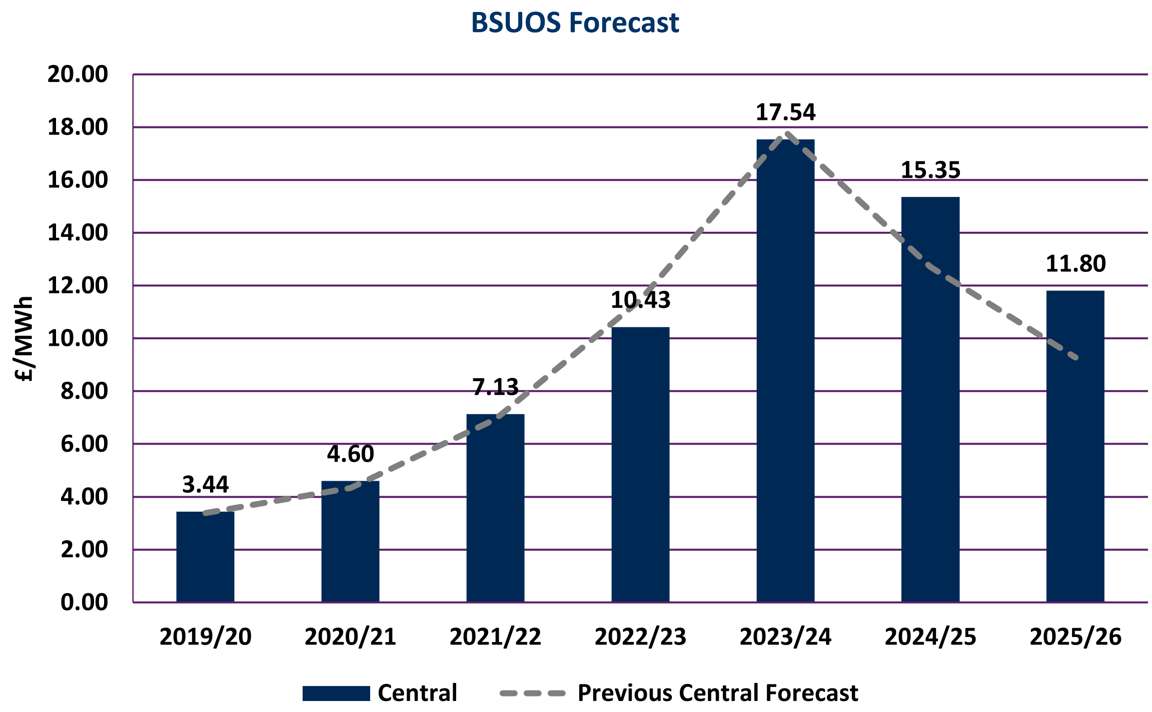

Figure 8: BSUoS Y-O-Y rate movement based on central scenario

4.2) Elexon

Responses to the consultation on the change in the ownership of Elexon, the administrator which operates the electricity market, are being analysed by the government. The consultation was launched following the publication of the response to the consultation on the Future System Operator (FSO) in April.

The creation of the FSO as a public corporation and the associated transfer into the public sector requires the future ownership of Elexon Limited, which is a subsidiary of National Grid ESO (NGESO), to be considered.

While Elexon is wholly owned by NGESO, the organisations have different roles and considerations around their future ownership may differ, necessitating consideration of Elexon's ownership.

Options include either public ownership as a subsidiary of the FSO, or industry ownership, owned by a representative group of industry stakeholders.

Consumers pay a supplier charge covering Elexon's operational costs.

What is driving it?

Usually fixed by the supplier at contract tender or at annual renewal.

4.3) Imbalance

Imbalance is a supplier fixed charge to reflect the cost of managing the difference between a customer's forecasted and actual consumption on a half-hourly basis.

What is driving it?

Costs are based on customer consumption and intraday spot price volatility.

4.4) Margin

Margin is a charge levied by the supplier to cover its administration costs and profit.

What is driving it?

The charge depends on individual contract circumstances.

4.5) Shape

The shape fee represents the residual element of forward purchasing i.e. the non-tradeable volume (outside of baseload and peakload blocks) that a customer needs to buy.

The supplier will evaluate past (or forecast) consumption patterns (generally through HH data) and will establish a 'best fit' trading profile.

This 'cost' is converted into a £/MWh which is charged to the customer.

What is driving it?

The charge depends on individual contract circumstances.

5) Gas Delivery Charges

5.1) Transmission Charges

Transmission charges take effect each April and October and are levied by National Grid NTS to recover the cost of installing, operating and maintaining the National Transmission System (NTS), the high pressure network.

Price controls set by Ofgem determine the maximum revenue National Grid NTS can earn from the transportation of gas. Allowed revenues are collected via Transportation Services and General Non-Transportation Services charges.

Shippers pay entry and exit capacity charges to flow gas to and from the system. Shippers are required to buy one unit of capacity to flow one unit of energy across the network. They are charged in units of kWh/day.

Indicative notices of charges are published before the notices of final charges which are published each March and September which take effect the following month.

Latest Update

National Grid has published the notice of its October 2022 schedule of gas transmission charges.

The General Non-Transmission Services (GNTS) charge increases to 0.0343 p/kWh from 0.0092 p/kWh in October 2021. The increase is attributed to the rise in wholesale gas prices as well as the cost of shrinkage. Shrinkage gas is gas lost to the network either through theft, own use or leakage.

The GNTS previously covered the exit commodity (NCO) element of the transmission charge. The GNTS is payable on gas allocated to shippers at exit and entry points.

Exit capacity charges for gas distribution zone exit points have been set at 0.0218 p/kWh/day from October 2022 compared to 0.0211 p/kWh/day in October 2021.

The Revenue Recovery Charge (RRC) operates as a mechanism to manage any under or over recovery of revenues at entry and exit during the gas year.

The exit RCC has been set at 0.000 p/kWh/day from October 2022.

What is driving it?

Reforms to the gas transmission charging regime came into effect from October 2020 as part of Ofgem's Gas Transmission Charging Review. Previously, charges were split between capacity and commodity charges.

The new methodology for setting capacity prices for entry/exit points (the points where gas enters and is taken from the system) is called a 'postage stamp' model and applies a single, uniform price on all entry and exit flows regardless of geographic location. This is intended to significantly reduce the locational variations for capacity charging.

5.2) Gas Distribution Charges

Distribution charges are levied by the eight distribution networks (the low pressure networks) to recover their regulated allowed revenues as determined through the price control.

Charges are set annually on 1 April. While indicative charges are published five months in advance (1 November), actual charges are published two months in advance (1 February).

Latest Update

Gas distribution operators published indicative notices of transportation charges, which will apply during the 2023/24 charging year from 1 April 2023 in November.

Charges have been calculated based on the latest available forecasts of Allowed Revenue for 2023/24, which are subject to change. Other influencing factors include the rate of inflation as well as forecast demand. Definitive notices of transportation charges will be published by 1 February 2023.

What is driving it?

Maximum Allowed Revenue is determined by the amount of base revenue determined through the price control. Allowed revenue is also adjusted each year to allow for inflation. Any under or over-recovery is applied through a correction factor which is lagged by a year.

6) Other Charges

6.1) Unidentified Gas Charge

Unidentified Gas (UIG) is gas which is lost to the system which cannot be attributable to any particular user. Sources include consumption through unregistered supply points as well as shrinkage, leakage and theft.

Meterpoints are apportioned an amount of UIG on a daily basis based on information provided by Xoserve, the gas market's data services provider. The amount is subsequently revised as more data from meter reads becomes available.

Typically, UIG is less than 5% and is spread across the consumer base with meters categorized by end user category and meter class. The cost is determined by the Allocation of Unidentified Gas Expert (AUGE).

Latest Update

A code modification was raised in November to change the method by which UIG is allocated to shippers from the current AUGE table of weighting factors to a throughput or universal allocation model. The AUGE allocates UIG to different types of shipper users.

UIG allocations change annually, creating uncertainty for shippers and suppliers in the pricing of contracts to customers and potentially results in increased risk premiums versus the proposed solution benefits.

Accordingly, the UIG allocation table will be updated with a set of permanent and common allocation factors so that UIG is allocated to all LDZ customers equally on a throughput basis. The role of the AUGE will removed.

A working group is expected to report in June to the Uniform Network Code panel, the body which sets the rules for the operation of the gas market.

What is driving it?

The way UIG is charged to consumers changed following implementation of a revision of the charging methodology. The new charging methodology quantifies the amount of UIG rather instead of providing an estimation. This has led the total volume to increase by over 40%.

Meanwhile, the table of weighting factors assigning UIG to different classes of meter has been revised with the number of categories in the first two end user categories expanded into four new categories to include: non-prepayment domestic, prepayment domestic, non-prepayment industrial and commercial and prepayment industrial and commercial.

UIG is priced based on that day's forward prices in the wholesale market, meaning that the exceptional strength of wholesale prices has led to a proportionally large increase in the expected cost of UIG.

7) Taxes and Levies

7.1) Green Gas Levy

The Green Gas Levy for the 2023/24 charging year beginning in April has been set at 0.122 pence per meter per day (equivalent to 45p per meter over the period) by Beis. This compares to a rate of 0.576 pence per meter per day (equivalent to £2.10 per meter a year) for the current year. Beis is required to publish the rate for each scheme year by 31 December of the preceding year.

The levy applies to all licensed fossil fuel gas suppliers. But those suppliers whose total gas supply for the duration of a scheme year is sourced from at least 95% certified biomethane qualify for an exemption.

Suppliers seeking an exemption must prove their biomethane supply using retired green gas certificates from a scheme on the approved biomethane certification scheme list including:

- the Green Gas Certification Scheme, run by Renewable Energy Assurance Ltd
- the Biomethane Certification Scheme, run by Green Gas Trading Ltd

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