HM Government

Northern Ireland Executive

Scottish Government
Riaghaltas na h-Alba
gov.scot

Renewables Obligation

Call for Evidence on introducing Fixed Price Certificates into the UK-wide Renewables Obligation schemes

Closing date: 9 October 2023

July 2023

Any enquiries regarding this publication should be sent to us at: ro@energysecurity.gov.uk

Contents

General information

As part of the UK Government's Net Zero agenda, we have committed to a fully decarbonised electricity system by 2035, subject to security of supply considerations. This includes an ambition to deploy up to 50GW of offshore wind by 2030 – including up to 5GW of floating offshore wind – as well as 70GW of solar PV by 2035. In the draft Energy Strategy and Just Transition Plan (ESJTP), the Scottish Government set out ambitions for 2030 of 8-11 GW capacity of offshore wind and up to an additional 12 GW of installed onshore wind in Scotland. It also sets out a renewable and low-carbon hydrogen production ambition of 5 GW by 2030 and 25 GW by 2045, as well as consulting on a draft Solar vision for Scotland.

The Renewables Obligation (RO) has incentivised UK renewable electricity generation since 2002 through a system of tradable green certificates called "Renewables Obligation Certificates" (ROCs). Three separate but complementary Renewables Obligation schemes cover the UK. The RO and the Renewables Obligation Scotland (ROS) were introduced in 2002. The Northern Ireland Renewables Obligation (NIRO) was introduced in 2005. The three schemes closed to new applications on 31 March 2017,[1] but limited grace periods extended the deadline for certain projects up to 31 March 2019.

The schemes remain an important support mechanism, assisting the UK to achieve its renewable energy deployment targets. With nearly 30 per cent of the UK's electricity generation in receipt of ROCs, ensuring that the scheme provides stable and consistent support to renewable electricity generators, at a fair cost to consumers, is an important priority.

In 2011, the UK Government announced the intention to transition the England and Wales RO from a live-traded scheme to a Fixed Price-Certificate (FPC) based scheme from 2027 onwards. This was intended to address volatility in the market price of certificates, which was expected to emerge when the early generating stations reached the end of their support period and began retiring from the scheme. Due to a steep increase in stations joining the RO ahead of its closure in 2017, price volatility is now expected to be delayed until the early to mid-2030s. In recent years, however, further potential benefits associated with the transition to FPCs have been identified, including offering a permanent solution to the issue of supplier payment default and allowing for the potential reduction or rebalancing of costs.

In 2021, a joint consultation between the then-Department for Business, Energy and Industrial Strategy (BEIS) and Ofgem sought initial views on the introduction of FPCs as a way of addressing supplier payment default.[2] In November 2021, a Scottish Government consultation on the amendment of the ROS mutualisation provisions also sought initial views on the introduction of FPCs.[3]

This Call for Evidence seeks views and evidence on options for a future FPC scheme across the RO, ROS and NIRO. Following this Call for Evidence and further policy development, any proposed changes to the RO, ROS and NIRO schemes would be consulted on by the respective Governments, as appropriate.

---

[1] There were a number of early closures for particular technology types and capacities. A summary is available at: https://www.ofgem.gov.uk/sites/default/files/docs/2016/10/renewables_obligation_-_solar_pv_and_wind_grace_periods_factsheet.pdf

[2] Available at: https://www.ofgem.gov.uk/publications/beisofgem-joint-response-consultation-addressing-supplier-payment-default-under-renewables-obligation-ro

[3] Available at: https://consult.gov.scot/energy-and-climate-change-directorate/changes-to-ros-scheme/

Call for Evidence details

Issued: 31 July 2023

Respond by: 9 October 2023

Enquiries to: ro@energysecurity.gov.uk

Reference: Renewables Obligation: Call for Evidence on introducing Fixed Price Certificates into the UK-wide Renewables Obligation schemes.

Audiences:

The Government welcomes responses from anyone with an interest in the policy area. We envisage that the Call for Evidence will be of particular interest to those currently in receipt of ROCs, electricity traders and suppliers, businesses operating in the energy sector, and consumers and environmental groups with an interest in the electricity sector.

Territorial extent:

The RO operates as three separate but complementary schemes, in England and Wales, Scotland, and Northern Ireland. **This Call for Evidence seeks views on all three schemes**.

How to respond

Your response will be most helpful if it is framed in direct response to the questions we have asked, though further comments and evidence are also welcome. When responding, please state whether you are responding as an individual or representing the views of an organisation.

We encourage respondents to make use of the online e-Consultation platform, Citizen Space, to respond to this Call for Evidence wherever possible. This is the department's preferred method of receiving responses. Alternatively, please use the response form to submit your responses by email. Please do not send responses by post to the department, as we may not be able to access them.

Respond online at: https://beisgovuk.citizenspace.com/clean-growth/renewables-obligation-call-for-evidence

or

Email to: ro@energysecurity.gov.uk

The response form is available on the GOV.UK Call for Evidence page: www.gov.uk/government/consultations/introducing-fixed-price-certificates-into-renewables-obligation-schemes-call-for-evidence

Responses to this Call for Evidence and related inquiries will be shared with the Scottish Government and the Northern Ireland Executive.

Confidentiality and data protection

The information you provide in response to this Call for Evidence, including personal information, may be disclosed in accordance with UK legislation (the Freedom of Information Act 2000, the Data Protection Act 2018 and the Environmental Information Regulations 2004).

If you want the information that you provide to be treated as confidential, please tell us but be aware that we cannot guarantee confidentiality in all circumstances. An automatic confidentiality disclaimer generated by your IT system will not be regarded by us as a confidentiality request.

We will process your personal data in accordance with all applicable data protection laws. See our privacy policy.

Quality assurance

If you have any complaints about the way this Call for Evidence has been conducted, please email: bru@energysecurity.gov.uk.

Call for Evidence

Background

The UK-wide Renewables Obligation has been a flagship support mechanism to encourage and reward the development of large-scale renewable electricity projects in the UK (and small-scale projects in Northern Ireland) from the early 2000s. It operates as three separate but complementary schemes: the RO in England and Wales (since 2002), the ROS in Scotland (since 2002) and the NIRO in Northern Ireland (since 2005). For the rest of this call for evidence, references to the RO mean all three schemes, unless otherwise specified.

Ofgem is the scheme administrator for the RO and ROS. The Northern Ireland Authority for Utility Regulation (UR) retains statutory responsibility for the NIRO. By virtue of an Agency Services Agreement between Ofgem and UR, Ofgem carries out the necessary administrative functions for the NIRO on behalf of UR. For simplicity, ‘scheme administrator’ will refer to Ofgem throughout this document.

The RO remains the UK’s largest renewable electricity support scheme, with nearly 30 per cent of UK electricity generation in receipt of ROCs. During Scheme Year 20 (from 1 April 2021 to 31 March 2022), there were over 26,600 generating stations across the UK accredited under the scheme, with a total generating capacity of c. 35GW. This includes onshore wind (33.7 per cent of RO generation), offshore wind (27.1 per cent), fuelled technologies such as biomass (22.8 per cent), and solar PV (8.8 per cent).[4]

While the RO closed to new applicants in 2017, qualifying generating stations will continue to be supported until their accreditation expires. The ‘early years’ generators (amongst the first to be accredited under the RO) retire from the scheme in 2027. The RO will close entirely in 2037. Support for new capacity in GB is available under the Contracts for Difference scheme, and a new renewable electricity support scheme is being developed for Northern Ireland.

Overview of current arrangements

The RO currently operates as a market-based system of tradable green certificates. The scheme places an obligation on UK electricity suppliers to present a certain number of ROCs to the scheme administrator, in respect of each MWh of electricity they supplied to non-exempt customers during an obligation year (1 April to 31 March).[5] The obligation is calculated by the Department for Energy Security and Net Zero (DESNZ), with the agreement of the Scottish Government and the Northern Ireland Executive. The number of ROCs to be supplied per MWh of electricity (the ‘level’ of the obligation) is set each year, six months in advance of the obligation year starting. Accredited generators obtain ROCs free of charge from Ofgem in relation to the eligible renewable electricity they generate. Suppliers buy ROCs from generators (or from ROC traders/brokers), giving generators extra income in addition to the wholesale price of their renewable electricity. The precise value of a ROC is a matter for negotiation between generator and supplier/trader.

[4] Ofgem, 30 March 2023. Renewables Obligation (RO) Annual Report: Scheme Year 20 (2021-22). Available at: https://www.ofgem.gov.uk/publications/renewables-obligation-ro-annual-report-scheme-year-20-2021-22
[5] Qualifying energy-intensive businesses can claim an exemption up to 85 per cent of RO costs, due to increase to 100 per cent.

Due to intermittent generation of technologies, such as wind and solar, there is uncertainty surrounding the number of ROCs likely to be generated. To a lesser degree, there is also uncertainty around suppliers' electricity sales. It is assumed that, if the number of ROCs generated was above the number of ROCs suppliers were obligated to present, there would be a danger of a crash in the value of the ROC market. To minimise this risk, the obligation is set 10 per cent higher than the expected number of ROCs. This ensures ROCs remain in short supply, thereby ensuring that generators have buyers for their ROCs and that ROCs maintain their value. In the event of ROCs not being available, or if suppliers prefer not to purchase them, suppliers can make a cash 'buy-out payment' to Ofgem in lieu of each ROC owed. The 'buy-out price' is currently set at £59.01 per ROC for 2023/24 and it is adjusted annually in line with the Retail Price Index (RPI). Due to the in-built headroom, the expectation is that on average around 10 per cent of the obligation is met via buy-out payments, with the rest met with ROCs.

Once Ofgem has deducted its administration costs, it redistributes the money collected in both the buy-out and late payment funds to suppliers, in proportion to the number of ROCs each supplier presented. Suppliers that do not present ROCs do not receive any portion of the redistributed fund, thus encouraging the purchase of ROCs over making a cash payment.

The cost of the RO to suppliers is passed onto consumers via their electricity bills (alongside other levies). For 2021, based on average annual UK household consumption and total electricity consumption data, it is estimated that the RO added £71 per average household (in nominal prices).

In practice, generators typically sell their ROCs to suppliers (often via Power Purchase Agreements (PPAs)) and at a small discount, with the expectation or agreement to receive some or all of the buy-out fund 'recycled' payments. These transactions can take place at year end or at intervals during the year, with more frequent (e.g. monthly) payments typically associated with a higher discount to reflect the cost of capital benefit to the generator at the cost of the supplier. Alternatively, generators can sell their ROCs at a single price via traders or auctions. In this case, generators could expect the price of their ROCs to be lower than the buy-out price plus recycled money due to administrative charges, volume risk, and cost of capital.

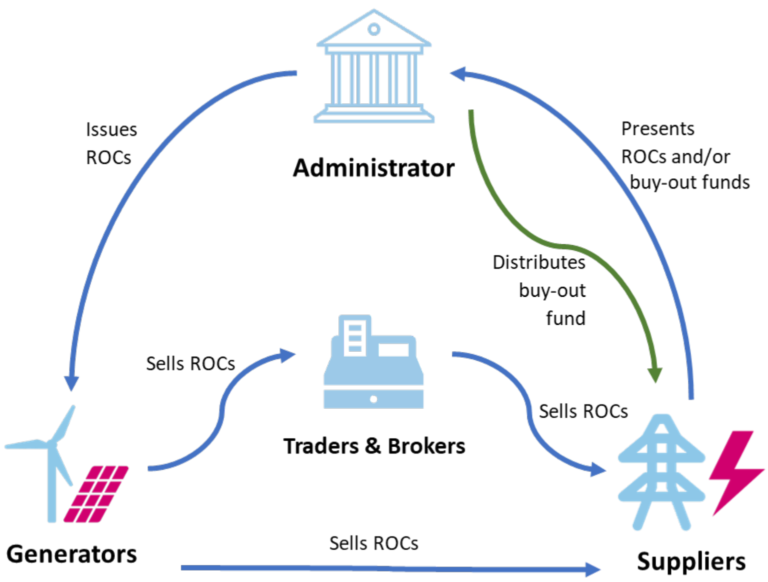

Figure 1: The RO cycle, under current arrangements

The annual schedule

The RO year runs from the 1st of April to the 31st of March. Under existing processes, generators must submit monthly output data to Ofgem by the close of the second month after generation (e.g. 30 June 2022 for electricity generated in April 2022), and can expect to be issued with ROCs by Ofgem approximately three weeks later (21 July 2022). While the monthly frequency at which ROCs are awarded does not align with the annual supplier obligation, suppliers may be incentivised to buy credits early to gain a price advantage (that reflects cost of capital). Additionally, the introduction by Ofgem of new ring-fencing requirements may also encourage suppliers to purchase ROCs early. Generators can also sell their ROCs at their preferred frequency, whether directly to suppliers or through traders. Available data indicates that many generators receive monthly payments for their ROCs through PPAs.

Suppliers submit their estimated data on the total electricity supplied to customers during the obligation period by 1 June of the subsequent obligation period and finalise that data by 1 July; Ofgem will confirm each supplier's obligation shortly thereafter. Suppliers must then submit ROCs by 1 September and any buy-out payment by 31 August, or, failing that, make a late payment to Ofgem by 31 October. Late payments attract interest charges which are levied at 5 per cent above the Bank of England base rate.

Ofgem will, by 1 November, redistribute the buy-out fund to suppliers in proportion to the number of ROCs each submitted, and, by 1 January, redistribute the late payment fund to suppliers following the same proportions.

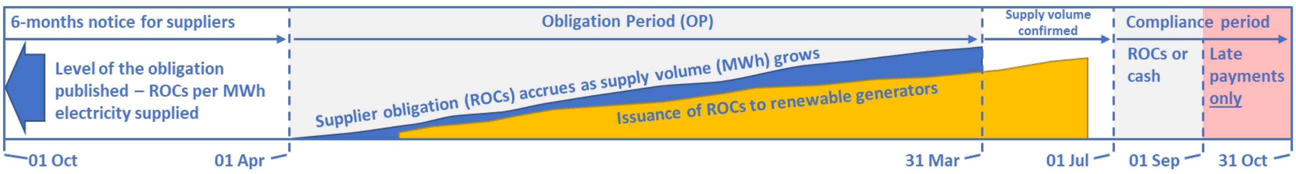

Figure 2: The RO annual schedule, under current arrangements

The mutualisation process and threshold

Mutualisation is a process which requires all suppliers who met their obligation to make additional payments into a fund to cover a shortfall caused by one or several suppliers defaulting on their obligation. This mechanism is necessary for the scheme's administrator to recoup the costs associated with a supplier defaulting, when those are above a specified threshold. When the mutualisation process was first introduced for the 2005/06 obligation year for the RO in England and Wales, the threshold was set at around 1 per cent of total scheme costs at that time. But over the years, the threshold failed to keep pace with the growth in the scheme. By 2019/20, the threshold was £15.4m, which was equivalent to only 0.24 per cent of total costs. Such a low threshold caused mutualisation to be triggered each year from 2017/2018 to 2021/2022. As a result, from 2021/22 onwards, the threshold was restored to 1 per cent of total costs, putting the threshold for that year at £63.7m. The figure will rise or fall each year as the cost of the scheme changes. This arrangement lowers the likelihood of mutualisation being triggered in the event of low levels of supplier payment default. A similar amendment was introduced by the Scottish Government to the ROS in 2023 to reduce the likelihood of mutualisation being triggered, with the threshold now set at 0.1 per cent of total scheme costs (this reflects the smaller scale of the ROS scheme as compared to the England and Wales scheme).

Recent and upcoming changes to the RO

Ring-fencing of the suppliers' obligation

From 2023/24 onwards, Ofgem will require electricity suppliers to "ring-fence" their obligation attributed to domestic electricity supply. On a quarterly basis, suppliers must purchase ROCs from generators, or protect funds equivalent to their obligation via a range of protection mechanisms (including for example letters of credit, trust accounts etc.), or a combination thereof. The details are available on Ofgem's website.[6] The ring-fencing of each supplier's obligation was motivated by the need to safeguard other suppliers against high mutualisation payments, in the event of non-payment by a supplier. It was also to discourage risk-taking behaviour from suppliers that were over-reliant on these funds as working capital and failing to settle their consumer tariffs accordingly. Depending on the frequency of settlements under a new FPC model, ring-fencing may no longer be required.

Energy intensive industries and rebalancing of gas and electricity prices

The cost to suppliers of funding the UK Government's renewable electricity support schemes is passed onto consumers through electricity bills. These pass-through costs may place UK energy intensive industries (EIIs) at a competitive disadvantage compared to their competitors abroad, who have lower industrial electricity prices. The Government has therefore introduced relief schemes for EIIs so that eligible businesses in sectors such as steel, chemicals, paper, cement, and glass receive an exemption from a proportion of the costs of the RO. This relief currently stands at 85 per cent, however, the package of measures within the British Industry Supercharger[7] includes an increase to 100 per cent relief from the costs of the renewable levies (including the RO). This is planned to take effect from April 2024. Under an FPC system funded via electricity bills, the EII exemption would remain in force and the levy on suppliers to fund the purchase of ROCs will need to continue to take account of that exemption.

In addition, the UK Government is committed to rebalancing the costs added to energy bills to match the broader objectives of incentivising decarbonisation and strengthening energy security[8]. Economic incentives must align with environmental incentives when it comes to the everyday choices that customers make about the energy they consume and the products they buy. Continuing to place the cost burden of the energy transition on the consumption of comparatively cleaner sources of energy adversely distorts the market. The Government wants to remove these distortions by rebalancing prices between electricity and gas, to make it easier for consumers to switch from gas to more energy efficient technologies such as electric heat pumps. This rebalancing strategy must also sit alongside the government's continued efforts to manage the challenges caused by the Covid-19 pandemic and Russia's illegal invasion of Ukraine, and ensure a competitive market that works for households and businesses. This includes efforts to tackle fuel poverty and protect vulnerable customers, who are currently supported through schemes such as the Energy Price Guarantee, Winter Fuel Payment, Cold Weather payments, and the Warm Homes Discount. The UK Government is working to develop its approach to rebalancing to meet these commitments and will provide further information in the coming year.

---

[6] Ofgem's decision on Strengthening Financial Resilience sets out the details for ring-fencing and is available at: https://www.ofgem.gov.uk/publications/decision-strengthening-financial-resilience
Guidance for suppliers on the new ring-fencing arrangements is available at: https://www.ofgem.gov.uk/publications/renewables-obligation-guidance-suppliers

[7] The Government Response was published on 18 May 2023 and is available at: https://www.gov.uk/government/consultations/british-industry-supercharger-capacity-market-consultation-and-eiis-government-response

[8] DESNZ's rebalancing commitment is set out in: https://www.gov.uk/government/publications/powering-up-britain.

Rationale for the introduction of FPCs

The following potential benefits and drawbacks have been set out by the UK Government. However, authorities in Scotland and Northern Ireland are cognisant that these potential benefits and drawbacks are applicable to the ROS and NIRO and as such are also relevant to the introduction of FPCs in those jurisdictions.

Several benefits potentially associated with moving to an FPC system are outlined below.

Price Stability: As generators' accreditations expire, the number of ROCs diminishes, leading to a reduced obligation for all suppliers. Given a lower obligation and associated administrative costs of purchase, more suppliers may decide to pay into the buy-out fund to fulfil their obligation, leading to an oversupply of certificates in the market and a subsequent crash in the price of certificates. With fewer accredited generators, there will also be a greater uncertainty around the number of ROCs generated, which may bring volatility of prices under the current scheme and increase the risk of a crash in price. These scenarios could be avoided through an FPC model. Price volatility was initially anticipated to emerge in 2027, however, with a large number of generators accredited during the last two years the scheme was open to applications (2015-2017), it is now not expected to present a significant challenge until the early-to-mid-2030s. Nevertheless, the introduction of a new model guaranteeing price stability would provide confidence in the final years of RO income from 2027 to 2037, removing the perception that a shrinking obligation could be volatile in quantity and hence render generators vulnerable to price volatility.

Reducing the risk of supplier payment default and mutualisation: As suggested in the 2021 joint consultation between Ofgem and then-BEIS, a move to FPCs could be helpful in addressing supplier payment default by enabling more frequent payments by suppliers, which would reduce the amount of money at risk under the RO, and thereby reduce the risk of significant mutualisation occurring.

Reducing the cost of the scheme: The live-traded nature of the scheme incorporates a degree of financial headroom to ensure continued demand for ROCs despite fluctuations in generation. Depending on the design of the new FPC model, this headroom may no longer be necessary, and could therefore be reduced or removed. In the context of unprecedented energy prices, due in no small part to Russia's illegal and unprovoked invasion of Ukraine, government must consider every opportunity to act on high electricity costs for consumers. Given the total value of the scheme, considering the reduction or removal of the in-built headroom represents a significant cost reduction opportunity, which would have a positive impact on consumers through reduced bills.

Rebalancing electricity costs: In 'Powering Up Britain', the UK government accepted the recommendation from the *Independent Review of Net Zero* that government should commit to outlining a clear approach to gas and electricity price rebalancing by the end of 2023/24 and should make significant progress affecting relative prices by the end of 2024. The UK Government is working to develop its approach to rebalancing to meet these commitments and will provide further information in the coming year. For the RO, moving the cost of the scheme could be significantly easier once the scheme has been converted to an FPC system and the trading element has been removed.

There may be downsides to adopting an FPC model however, considered below.

Risk of short-term disruption: transitioning to a new model could lead to short-term disruption for generators, suppliers, and/or the scheme administrator. This could be mitigated by a notice period long enough to allow adequate preparations by all parties.

Design redundancies: following a joint consultation with BEIS in 2021, Ofgem introduced a new requirement for suppliers to 'ring-fence' their obligation attributed to domestic supply, effective from the obligation year 2023/2024. This, combined with the recent revision of the mutualisation threshold,[9] lowers the likelihood of mutualisation being triggered in the event of supplier payment default. These mechanisms may be sufficient to achieve the objective of avoiding supplier default and mutualisation, potentially making the introduction of more regular payments under an FPC model redundant for this purpose alone.

Reduction in suppliers' working capital: depending on scheme design, an FPC model could lead to more frequent supplier settlements, which could reduce suppliers' working capital. We recognise that suppliers may have to raise other funds to secure cash flow and therefore the new model could indirectly lead to an increase in consumer bills. This could however arguably already be the case since the introduction of the new 'ring-fencing' requirement. It is also important to note that RO revenues were never intended to provide additional cash flow to suppliers.

Reduction in scheme value: cost reduction opportunities related to possible new headroom and indexation arrangements would result in changes in the value of the scheme, which could impact generators. The government is balancing the need to ensure that generators receive an appropriate return on their investments, with costs to consumers. With the introduction of FPCs eliminating the possibility of a ROC price crash, it is appropriate to review headroom arrangements, to ensure the right balance is retained. Reviewing indexing arrangements is also important to ensure that the scheme continues to deliver on its aims at best value for money to the billpayer.

[9] The rise in the mutualisation threshold came into effect in the 2021-2022 for the RO and NIRO, and in 2022/2023 for the ROS.

Options for RO scheme design with FPCs

Primary legislative powers to introduce an FPC scheme under the RO are currently provided by ss32N-32Z2 of the Energy Act 2013. This Call for Evidence and any subsequent consultation will enable us to assess whether these powers would need to be amended or replaced to introduce a preferred FPC model. Any new FPC model would also be assessed under the Subsidy Control Act, Windsor Framework and as per other applicable legal requirements.

Model 1 – Central counterparty, no trading in certificates

Under this model, a central counterparty could be appointed that would be responsible for paying generators for the certificates they have earned and settling suppliers' obligations by collecting funds owed. The total obligation (i.e. the total number of FPCs expected to be issued) would be set annually, with an obligation period running from 1 April to 31 March. The scheme administrator would confirm the total number of FPCs each generator had earned and a central counterparty would pay each generator outright for the value of the FPCs which they had earned. The scheme administrator would confirm the total cost of each suppliers' obligation and the central counterparty would collect payment from each supplier accordingly.

The frequency and sequencing of generator payments and supplier settlements will be discussed in the next section.

We propose maintaining the same compliance and enforcement mechanism for supplier non-payment as exists under the current system, with the administrator retaining its compliance and enforcement role.

Unlike the current system, under this model there would be no trading of FPCs, as payment would be given directly by and to the central counterparty. This model could enable increased revenue certainty for generators, create long term administrative savings for suppliers and reduced costs for consumers as third-party traders' fees would be eliminated. However, any benefits which result from the trading of certificates (e.g. stronger relationships between generators and suppliers) may also be eliminated.

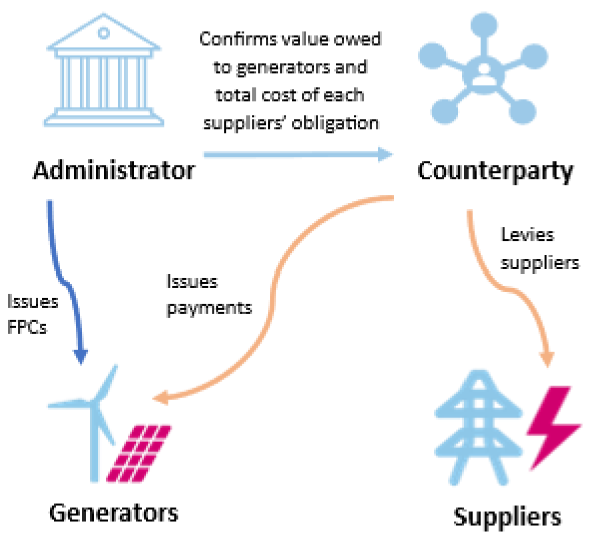

Figure 3: The RO cycle, under a FPC model with a counterparty, with no trading in certificates

Frequency and sequencing of generator payments and supplier settlements

If a central counterparty were appointed, it would be necessary to reassess the suitability of the current settlement schedule and ensure adequate cashflow. Ensuring close alignment between the schedule for issuing payments to generators and the schedule for settling supplier obligations would minimise capital requirements and risks for the counterparty. However, a shorter supplier obligation period would reduce the working capital available to suppliers, and may result in them experiencing cashflow challenges due to seasonal variations in renewable generation and consumer demand. Suppliers may in turn be incentivised to raise their tariffs and/or be required to take out loans to smooth seasonal peaks and troughs and protect themselves against unpredictability of their obligation costs, both of which may result in higher costs to consumers. A more frequent obligation periods would also carry a greater administrative burden for suppliers, the administrator and central counterparty, with more granular data required and more frequent reporting processes.

Under this model, we propose that generators would receive monthly payments from the central counterparty.

We propose a series of options for frequency of supplier settlements, summarised in Table 1 and outlined in more detail in the text below. Supplier settlements could be either retrospective or advanced, and they could be monthly, quarterly, or yearly. Depending on whether the obligation is retrospective or advanced, the administrator would confirm each supplier’s obligation based on suppliers’ figures for the amount of actual or expected electricity supplied to customers across the UK, with a monthly, quarterly, or yearly obligation as appropriate. This would enable suppliers to estimate their likely costs for each settlement period and so factor the appropriate amounts into their consumer tariffs.

Table 1: Summary of frequency and sequencing options for supplier settlements

	Retrospective	**Advanced**
Monthly	Option 1	Option 3
Quarterly	Option 2a	Option 4a
Annually	Option 2b	Option 4b

A further section of this document will discuss options for a reconciliation mechanism (necessary to bridge any gap arising between the supplier obligation as forecast and the actual obligation owed, in advance payment options) and for a bridging fund (necessary in options where suppliers settle less frequently than payments are made to generators).

Option 1: Retrospective monthly settlement by suppliers and retrospective monthly payment to generators

Under this option, generators would submit their generation data for validation monthly by the administrator, as under current processes (i.e., the data could be submitted up to two months after the month of generation, with validation being completed three weeks after that two-month deadline). Suppliers would be subject to a retrospective monthly obligation period, rather than the annual one under the current system. Data submission and validation timelines would be adjusted to reflect this: rather than submitting retrospective supply data annually, as under current processes, suppliers would submit retrospective supply data monthly. This would represent a significant administrative activity for suppliers, the administrator, and the central counterparty.

Once the administrator had validated each supplier’s data, the obligation for each supplier would be confirmed, and settlement would be due – paid to the central counterparty. The central counterparty would then pay generators the funds owed.

Option 1 is associated with a significant increase in the administrative burden for suppliers, which could lead to ongoing cost increases for consumers. The absence of a buy-out fund could expose generators to more volume risk. As the payment frequencies align, if processes are smooth enough to pass payments from suppliers to generators within a reasonable timeline, there may not be a need for a fund to finance the first payment to generators. As the settlement of the obligation is retrospective, this option would not require a headroom or reserve fund to be in place, which could lead to savings and positively impact consumers.

Option 2: Retrospective settlement, with suppliers settling less frequently than generators receive payment

2a: Retrospective quarterly settlement by suppliers and retrospective monthly payment to generators

2b: Retrospective annual settlement by suppliers and retrospective monthly payment to generators

Under these options, as under Option 1, generators would submit their generation data for validation monthly, and be paid monthly (i.e., three weeks after the two-month deadline for submitting generation data). The key distinction between these options and Option 1 is the schedule of the suppliers’ obligation. Whereas in Option 1, suppliers would be subject to a monthly obligation, under Option 2a suppliers would be subject to a quarterly obligation, and under Option 2b, suppliers would be subject to an annual obligation. They would submit supply data quarterly (2a) or annually (2b), and once this had been validated, would also submit payment on this timeline.

Option 2a is associated with an increase in the administrative burden for suppliers – albeit to a lesser extent than with Option 1 – which could lead to ongoing cost increases. As generators are paid more frequently than suppliers, the counterparty would require funds to cover payments over the first quarter. (Design options for this fund are detailed in later sections of this document). As with Option 1, as this option entails a retrospective settlement, no headroom or reserve fund would be required, which could result in scheme-wide savings.

Option 2b is associated with a low administrative burden for suppliers and would also not require a built-in headroom or reserve fund. However, as generators are paid more frequently than suppliers, the counterparty would require funds to cover payments over the first year, increasing the risk compared to Option 2a. This means consumers may experience a substantial one-off levy when establishing the bridging fund ahead of the first year of the new system. This option does not provide benefits in terms of mitigating the risk of supplier default.

Option 3: Advance monthly settlement by suppliers and retrospective monthly payment to generators

Under Option 3, generators would submit their generation data for validation monthly, and receive payment monthly (i.e., three weeks after the two-month deadline for submitting generation data). In contrast to the aforementioned options, suppliers would be levied for payment monthly in advance of the obligation period with an estimated suppliers' obligation being determined by the scheme administrator based on best available data. (Options for a reconciliation mechanism are explored in later sections of this document, which would ensure funds are available in instances where actual generator awards outstrip predictions and so where the actual obligation is greater than initially forecasted).

This option would ensure prompt payment to generators. However, advance payment carries the risk of misalignment between suppliers' payment and the actual funds required. The scale of the potential gap is likely to be relatively small, due to the short settlement period. Similarly, this option would also require a headroom or reserve fund to be levied on consumers, although this again would likely be relatively small. As this option entails advance settlement, cashflow risk for the central counterparty would be low. As with Option 1, monthly settlements are associated with a significant increase in administrative burden for suppliers, which could lead to ongoing cost increases for consumers.

Option 4: Advance settlement, with suppliers settling less frequently than generators receive payment

4a: Advance quarterly settlement by suppliers and retrospective monthly payment to generators

4b: Advance annual settlement by suppliers and retrospective monthly payment to generators

Under this option, as under Option 3, generators would submit their generation data for validation monthly, and receive payment monthly. Suppliers would also be levied for payment in advance of the obligation period, but unlike in Option 3, this levy would relate to either the subsequent quarter (Option 4a) or the subsequent year (Option 4b).

As with Option 3, Options 4a and 4b would ensure prompt payment to generators and cashflow risks for the counterparty would remain low. A lengthier settlement schedule may result in easier and more accurate forecasting of generation and supplier obligation, which would in turn reduce the pressure on the reconciliation mechanism (explored below). However, advance payments are associated with a risk of misalignment between the suppliers' payment and the actual funds required. This is exacerbated in options with longer settlement periods (with Option 4b carrying a higher risk). They may also require measures to ensure sufficient funds are available for the central counterparty to pay generators (discussed below), which would result in funds levied on consumers. Unlike Option 4b, Option 4a is associated with an increase in suppliers' administrative burden, which could lead to ongoing cost increases for consumers.

Questions:

The questions in this Call for Evidence are applicable against the three schemes (RO, ROS, NIRO). Please specify in your answers if your comments apply to a specific jurisdiction, otherwise they will be treated as general answers applying equally to all three schemes.

Q1. What are the benefits and drawbacks associated with Model 1?

Q2. On balance, which option for frequency of payment and settlements do you think strikes the best balance of benefits for all market participants and why?

Q3. For your preferred option, which measures are most important to minimise the risks associated with this option?

Q4. What would the impact of each option be on scheme administration, including costs?

Q5. What broad impact would Model 1 have over the sector? We welcome evidence specifically on cost of capital, risk premiums, and administrative costs to relevant market participants.

Model 2 – Central counterparty, trading in certificates

Under this model, the administrator would retain its current functions related to issuing certificates to generators and confirming the total cost of each suppliers' obligation. The central counterparty's role would be to purchase certificates from market participants at a fixed price, either quarterly or annually (this is discussed in more depth later in this section of the document).

Trading of FPCs would still be allowed, and so generators could either choose to hold their certificates and sell them to the central counterparty, or alternatively to sell them to suppliers (either directly or through traders) who would then sell these to the central counterparty. This model maintains the current 'portability' of certificates and could allow market participants more leeway to manage their cashflow. This would be particularly beneficial to generators if the settlement process was annual rather than quarterly.

The counterparty would levy suppliers according to their individual obligation confirmed by the administrator. As explored in more depth later in this section, payments could be levied either retrospectively or in advance, and could be quarterly or yearly.

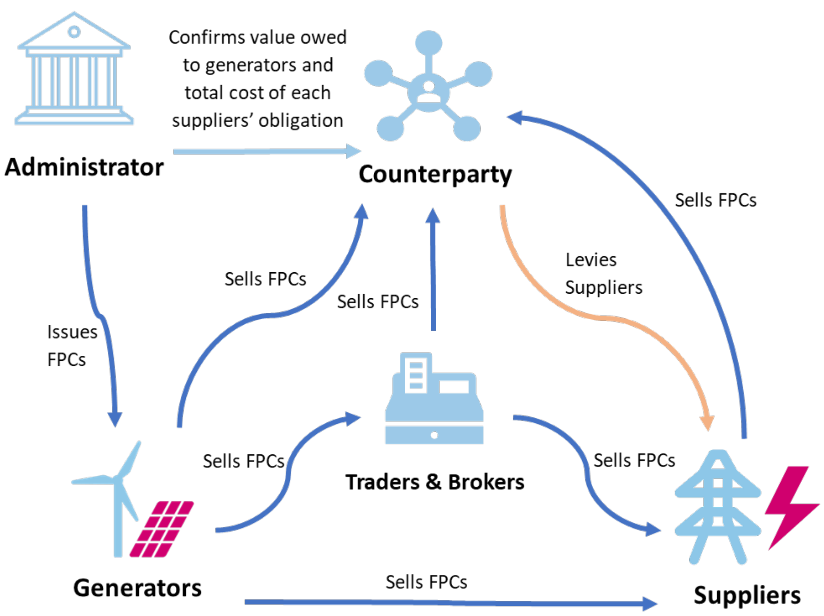

Figure 4: The RO cycle under a FPC model with a counterparty featuring certificate trading

Frequency and sequencing of generator payments and supplier settlements

Under this model, we propose that the central counterparty could purchase certificates from market participants during windows occurring quarterly or yearly. A monthly schedule is not considered, as it would provide little incentive for market participants to trade certificates.

We propose several options for frequency of supplier settlements, summarised in Table 2 and outlined in more detail in the text below. As under Model 1, supplier settlements could be either retrospective or advanced, and either quarterly or yearly.

Table 2: Summary of frequency and sequencing options for certificate purchasing and supplier settlements

	Quarterly certificate purchase windows	Yearly certificate purchase windows
Quarterly supplier settlements – Retrospective	Option 5a	Option 5c
Yearly supplier settlements – Retrospective	Option 5b	Option 5d
Quarterly supplier settlements – Advanced	Option 6a	Option 6c
Yearly supplier settlements – Advanced	Option 6b	Option 6d

Option 5: Options where suppliers settle retrospectively to certificate purchasing windows occurring

5a: Quarterly certificate purchasing windows, retrospective quarterly supplier settlement

5b: Quarterly certificate purchasing windows, retrospective yearly supplier settlement

5c: Yearly certificate purchasing windows, retrospective quarterly supplier settlement

5d: Yearly certificate purchasing windows, retrospective yearly supplier settlement

Under these options, the administrator would issue FPCs to generators based on generation data that they would submit monthly. The counterparty would purchase certificates from market participants (generators, suppliers, traders/brokers) either quarterly (Options 5a and 5b) or yearly (Options 5c and 5d). Suppliers would be subject to a retrospective obligation, either quarterly (Options 5a and 5c) or yearly (Options 5b and 5d).

For Option 5a and 5d, the retrospective settlement by suppliers could be due shortly after the purchasing windows close. For Option 5b, suppliers could settle yearly after the end of the obligation year. For option 5c, suppliers could settle in quarters for the obligation accumulated for the previous year, essentially dividing retrospective payments (compared to Option 5d) in quarters over the course of the next obligation year.

All options would require a bridging reserve to be established to cover the first payments to generators during the launch of the new schedule. Options for this mechanism are outlined later in this document.

Option 6: Options where suppliers settle in advance of certificate purchasing windows occurring

6a: Quarterly certificate purchasing windows, advanced quarterly supplier settlement

6b: Quarterly certificate purchasing window, advanced yearly supplier settlement

6c: Yearly certificate purchasing windows, advanced quarterly supplier settlement

6d: Yearly certificate purchasing windows, advanced yearly supplier settlement

Under these options, generators would submit their generation data for validation monthly, and the administrator would issue FPCs accordingly. The central counterparty would purchase certificates from market participants during windows occurring quarterly (Options 6a and 6b) or yearly (Options 6c and 6d). It would do so using funds levied from suppliers in advance, either on a quarterly schedule (Option 6a and 6c) or a yearly schedule (Options 6b and 6d).

For options 6a and 6d, the advanced settlement by suppliers could be due shortly before each purchasing window opening. Similarly, for option 6b, it could be due shortly before the first purchasing window opening. For option 6c, supplier settlements could be due every quarter, with the full amount collected before the annual purchasing window opens, effectively dividing advanced payments (compared to Option 5d) in quarters over the course of the previous obligation year.

All options would require a reconciliation mechanism to bridge any gaps between the supplier payments and the actual funds required. (Options for this mechanism are outlined in the next section of this document).

Questions:

Q6. What are the benefits and drawbacks associated with Model 2?

Q7. On balance, which option for frequency of payments and settlements do you think strikes the best balance of benefits for all market participants, and why?

Q8. For your preferred option, which measures are most important to minimise the risks associated with this option?

Q9. What would the impact of each option be on scheme administration, including costs?

Q10. What broad impact would Model 2 have over the sector? We welcome evidence specifically on cost of capital, risk premiums, and administrative costs to relevant market participants.

Q11. Of the two models presented in this document, which would you favour, and why?

Reconciliation mechanism

Several of the options above entail advance settlement by suppliers (Options 3,4, and 6). In these instances, there is an inherent risk of a misalignment between the supplier obligation as forecast and the actual obligation owed, given that the latter is based on realised generation and actual supply delivered in the relevant period. A solution will be required to ensure adequate funds are available to the central counterparty to pay generators in instances where actual generator awards outstrip predictions under advance settlement options. The scale of reconciliation required would be greater in options which involve longer settlement periods (Options 4a and 4b in Model 1, Options 6 in Model 2).

We have identified two options for a reconciliation system: the inclusion of headroom within the supplier obligation and a reserve fund. These are discussed below.

Headroom:

Under this option, a buffer would be added prospectively to the suppliers' obligation to account for any discrepancy between the forecast and actual level owed. If some or all of these funds were ultimately not required to pay generators (because generation levels were equal to or below predictions), the surplus could be redistributed, either to generators or suppliers. If redistributed to generators, the surplus funds would provide a degree of protection against volume risks – shielding generators somewhat from low receipts during periods of limited generation. If redistributed to suppliers, the surplus funds could be reflected in lower consumer tariffs during the subsequent period.

Reserve fund:

Alternatively, to avoid adding headroom to each suppliers' obligation period, a reserve fund could be established prior to the launch of the scheme, which the central counterparty could draw from as required to meet any shortfall between receipts from suppliers and monies owed to generators. This reserve fund would be established through an initial levy on suppliers in the settlement period(s) prior to the launch of the scheme and would be greater than the likely maximum shortfall (based on historic trends) in any one settlement period. The central counterparty would levy suppliers for their anticipated obligation – without headroom – and if this proved insufficient, they would dip into the reserve fund. If the reserve fund had been drawn upon, the central counterparty would levy suppliers to top the fund back up to its original level in a subsequent obligation period, giving appropriate notice for suppliers to factor the cost of the top up into their pricing.

However, under this model generators would no longer benefit from the top-up provided by the redistribution of surplus funds, which is particularly helpful during low generation years. Additionally, suppliers would contend with greater volatility and decreased predictability of the level of their obligation payments.

Questions:

Q12. What are the respective benefits and drawbacks of having advanced payment by suppliers and reconciliation? On balance, do you consider that the benefits outweigh the drawbacks?

Q13. What are the benefits and risks of adding headroom to the supplier obligation to manage any potential discrepancy between the forecasted supplier obligation and actual generator receipts?

Q14. How should the surplus headroom be redistributed, and why?

Q15. What benefits and drawbacks would a reserve fund have as compared to a headroom?

Q16. Besides headroom and a reserve fund, are there other options for dealing with the risk of misalignment under advanced settlement options?

Bridging reserve

Under options involving advanced settlement by suppliers, and assuming one of the above reconciliation options has been adopted, the central counterparty should have sufficient funds to hand to pay generators (under Model 1) or purchase certificates from market participants (under Model 2). However, under certain retrospective settlement options, the central counterparty will require funds to pay generators or purchase certificates from market participants during the first payment period, prior to suppliers having settled. This is the case for Model 1 Options 2a and 2b, and Model 2 Options 5.

Establishing a capital reserve would be necessary to cover the first payments to generators during the launch of the new schedule. We propose that the counterparty could levy suppliers to provide the required funds. Suppliers would receive sufficient notice of this levy to be able to set consumer tariffs appropriately in the preceding year. If calculated correctly and with sufficient headroom, the bridge funding would only need to be accumulated once, so would not result in an ongoing increase in consumer bills; this is an important difference between this bridging reserve and the headroom built into the current scheme, which is included in the level of every year’s supplier obligation.

Questions:

Q17. What risks might this option present for suppliers, consumers, or the central counterparty?

Transitional arrangements

Under a number of proposed options above in Models 1 and 2, suppliers will be required to make payments under the new schedule in advance of having settled their obligation for the previous year. This may present cashflow challenges if consumer tariffs have not been set accordingly for the preceding period.

Questions:

Q18. What information regarding the introduction of the new schedule will suppliers require and by when to set consumer tariffs and manage PPA arrangements appropriately?

Central Counterparty and Administrator roles

The role of the central counterparty would be distinct from that of the scheme administrator, though the responsibilities of both roles could be undertaken by a single entity. There could be benefits to centralising the role of the scheme administrator and the central counterparty, including the streamlining and faster delivery of services to both suppliers and generator and facilitate compliance monitoring. It may also result in lower overall administrative costs and contributing to the scheme's value-for-money. However, there may be value in the central counterparty remaining a separate body.

Questions:

Q19. What are the potential benefits and drawbacks of centralising both functions of administrator and central counterparty into a same entity?

Pricing

This section explores the question of how a suitable price for FPCs should be determined. When the then UK Government first committed to transitioning the RO to a system of FPCs in 2011, it stated that an equivalent level of compensation to that offered under the existing arrangements (the buy-out price, plus 10 per cent headroom) would be maintained. However, this headroom may no longer be necessary, as the price stability associated with FPCs removes the original rationale for introducing the headroom (to avoid a ROC price crash should there be an oversupply of certificates). Depending on the design of the new FPC model, this headroom could therefore be reduced or removed. This could represent a significant cost reduction opportunity, which could have a positive impact on consumers through reduced bills. In the context of unprecedented energy prices, government must seriously consider every opportunity to act on high electricity costs for consumers and return prices to affordable levels, whilst balancing the need to ensure that generators receive an appropriate return on their investment. The introduction of FPCs is one such opportunity, and we are seeking feedback on how a suitable price for FPCs could be determined, including considerations related to headroom and indexation arrangements.

Current arrangements

Under the current system, the price of a ROC is a matter of negotiation between the generator and trader/supplier, influenced in part by the buy-out price and expected ‘recycled’ payments from the buy-out fund. The obligation is set by the Secretary of State, with the agreement of the Scottish and Northern Irish authorities, and published six months ahead of the beginning of each obligation year. DESNZ forecasts the number of ROCs likely to be issued, factoring in assumptions about capacity, load factors and more. Ten per cent headroom is then added to this number, with the aim of ensuring that the forecast is above actual generation and therefore that ROCs maintain their value. This total is then divided by DESNZ’s forecast for electricity sales to set the number of ROCs/MWh that suppliers must present. Ofgem use this rate to determine the total number of ROCs each supplier should present to fulfil their obligation.

If generation is higher than forecast, more ROCs are available, resulting in a lower price for ROCs traded on the open market. The opposite is true if generation is lower than expected. If electricity sales are higher than forecast, suppliers must present more ROCs, resulting in higher costs for suppliers (which are passed onto consumers). The opposite is true if electricity sales are lower than forecast.

Headroom

The live-traded nature of the scheme incorporates a degree of headroom to ensure that demand for ROCs always remains higher than supply despite fluctuations in generation (which would lead to a crash in certificate price). The move to a FPC model is associated with price stability and thus reduces or removes the need for this headroom. Therefore, when setting the price of certificates under a future fixed price scheme, government could choose a price which equates to the current buy-out price and does not include an uplift to compensate for the lack of redistributed buy-out fund payments.

As discussed above, this would only be possible under options which involve retrospective supplier obligation calculations, or if a reserve fund were chosen as the preferred approach to managing misalignment between the supplier obligation settlements levied and the payments issued to generators under advance payment models.

The levy on suppliers would include a small premium to account for the scheme's administration costs, including costs related to the counterparty's role.

Questions:

Q20. What factors should be taken into account when setting the price of FPCs?

Q21. Should the price of FPCs be set at a level which excludes the ten per cent headroom built into the current scheme? Please give reasons for your preference. As caveated above, please treat these questions as only applying to scenarios where the chosen FPC model does not involve the use of a new headroom designed to manage misalignment between the supplier obligation settlements levied and the payments issuing to generators.

Indexation

CPI or RPI

The RO indexation calculation applies the Retail Price Index (RPI), which according to the Office for National Statistics, is likely to overstate inflation and should therefore no longer be considered a suitable metric.[10] This has serious implications for the affordability of the RO scheme for consumers. Moving to using the Consumer Prices Index (CPI) would align with other government support schemes, such as the Contracts for Difference (CfD). CPI was chosen over RPI as an indexation measure for the CfD on the basis that it is an internationally established inflation measure which will be familiar and relevant to a wider range of investors. CPI is also recognised as having advantages over RPI as a measure of macroeconomic inflation, and thus is more suitable for inflating the strike price to reflect general changes in the economy.[11]

Questions:

Q22. Should the price of FPCs be indexed to the CPI instead of the RPI (as under the current scheme)?

Q23. What would be the implications for generators of a shift to CPI? How much of an impact would this have on the viability of continuous operation of accredited RO generating stations?

Annual indexation calculation

Under the current model, inflation is compounded year-on-year. Given recent high rates of inflation, the current indexation approach risks locking in ROC prices which are significantly higher than those which generators would have anticipated receiving when they took the decision to invest, at the expense of affordability to consumers. The introduction of FPCs could provide an opportunity to establish new indexation arrangements, which balance investor interests with costs to consumers.

There are several options for reforming the annual indexation approach:

---

[10] https://www.ons.gov.uk/economy/inflationandpriceindices/articles/shortcomingsoftheretailpricesindexasameasureofinflation/2018-03-08#:~:text=Ongoing%20work%20by%20the%20ONS,measure%20to%20benchmark%20it%20against.

[11] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/65635/7077-electricity-market-reform-annex-a.pdf

Option 1. Base price + previous year's inflation

As an alternative to prices compounding with inflation year-on-year, the price of FPCs could be calculated annually from the same base price, which is indexed only to the previous year's rate of inflation.

Option 2: Base price, adjusted to reflect previous year's electricity prices

Alternatively, the base price could be amended to balance out exceptional losses or gains experienced by generators due to the previous year's wholesale electricity prices. This would be calculated in consideration of the level of revenues which generators had forfeited through the Electricity Generator Levy (EGL). Whilst the levy is due to end on 31 March 2028, the methodology adopted under the EGL could be retained for this calculation.

Question:

Q24. What are the benefits and drawbacks associated with Option 1 and Option 2 of this section? Which option would you favour?

Timing

The UK Government, Scottish Government and Northern Ireland Executive are seeking views as to the best moment to introduce the new FPC model.

In 2011, the then UK Government committed to transitioning to an FPC model by 2027, to avoid the expected price volatility associated with early generating stations retiring from the scheme. However, with a large number of generators joining the scheme between 2015 and 2017, price volatility is not expected to materialise before the early to mid-2030s. As noted throughout this document, there are other benefits associated with transitioning by 2027, including enabling greater certainty over generator revenues and supplier settlement costs, improving affordability by reducing scheme costs, further mitigating the risk of supplier payment default, and facilitating the rebalancing of costs from electricity to gas bills. As such, government is minded to maintain the delivery of the new FPC model to 2027.

Proposed amendments to the scheme's legislation will be subject to further consultation as appropriate, in which detailed policy proposals will be outlined. These will include proposals regarding transitional arrangements, which would detail scheme mechanisms during the year prior to transition to FPCs, including considerations related to banked ROCs.

Questions:

Q25. Do you agree with the proposal to introduce the new FPC model in 2027?

Q26. What length of time would constitute a reasonable period of notice for market participants and other parties (e.g. administrator, counterparty) to prepare for the transition to the new model?

Summary of questions

We would welcome views on the below. Please provide evidence to support your response.

Model 1 – Central counterparty, no trading in certificates

Q1. What are the benefits and drawbacks associated with Model 1?

Q2. On balance, which option for frequency of payment and settlements do you think strikes the best balance of benefits for all market participants and why?

Q3. For your preferred option, which measures are most important to minimise the risks associated with this option?

Q4. What would the impact of each option be on scheme administration, including costs?

Q5. What broad impact would Model 1 have over the sector? We welcome evidence specifically on cost of capital, risk premiums, and administrative costs to relevant market participants.

Model 2 – Central counterparty, trading in certificates

Q6. What are the benefits and drawbacks associated with Model 2?

Q7. On balance, which option for frequency of payments and settlements do you think strikes the best balance of benefits for all market participants, and why?

Q8. For your preferred option, which measures are most important to minimise the risks associated with this option?

Q9. What would the impact of each option be on scheme administration, including costs?

Q10. What broad impact would Model 2 have over the sector? We welcome evidence specifically on cost of capital, risk premiums, and administrative costs to relevant market participants.

Q11. Of the two models presented in this document, which would you favour, and why?

Themes

Q12. What are the respective benefits and drawbacks of having advanced payment by suppliers and reconciliation? On balance, do you consider that the benefits outweigh the drawbacks?

Q13. What are the benefits and risks of adding headroom to the supplier obligation to manage any potential discrepancy between the forecasted supplier obligation and actual generator receipts?

Q14. How should the surplus headroom be redistributed, and why?

Q15. What benefits and drawbacks would a reserve fund have as compared to a headroom?

Q16. Besides headroom and a reserve fund, are there other options for dealing with the risk of misalignment under advanced settlement options?

Q17. What risks might this option present for suppliers, consumers, or the central counterparty?

Q18. What information regarding the introduction of the new schedule will suppliers require and by when to set consumer tariffs and manage PPA arrangements appropriately?

Q19. What are the potential benefits and drawbacks of centralising both functions of administrator and central counterparty into a same entity?

Pricing

Q20. What factors should be taken into account when setting the price of FPCs?

Q21. Should the price of FPCs be set at a level which excludes the ten per cent headroom built into the current scheme? Why and why not? As caveated above, please treat these questions as only applying to scenarios where the chosen FPC model does not involve the use of a new headroom designed to manage misalignment between the supplier obligation settlements levied and the payments issuing to generators.

Q22. Should the price of FPCs be indexed to the CPI instead of the RPI (as under the current scheme)?

Q23. What would be the implications for generators of a shift to CPI? How much of an impact would this have on the viability of continuous operation of RO plants?

Q24. What are the benefits and drawbacks associated with Option 1 and Option 2 of this section? Which option would you favour?

Timing

Q25. Do you agree with the proposal to introduce the new FPC model in 2027?

Q26. What length of time would constitute a reasonable period of notice for market participants and other parties (e.g. administrator, counterparty) to prepare for the transition to the new model?

Next steps

Responses provided to this Call for Evidence will be analysed and used to develop detailed policy proposals, which will be consulted on by all relevant authorities as appropriate in due course.

This Call for Evidence is available from: www.gov.uk/government/consultations/introducing-fixed-price-certificates-into-renewables-obligation-schemes-call-for-evidence

If you need a version of this document in a more accessible format, please email alt.formats@energysecurity.gov.uk. Please tell us what format you need. It will help us if you say what assistive technology you use.