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Response template for consultation on the Administration of the Green Gas Support Scheme

This template contains all the questions posed within the Administration of the Green Gas Support Scheme (GGSS) consultation document. Through this template we're aiming to collect your feedback on our proposals on how we will administer the Green Gas Support Scheme. We welcome your views and encourage you to respond to the questions that are of most interest. Please provide your contact details in the fields below. To respond, please provide your views in the space below the relevant question.

Organisation Name:	**Anaerobic Digestion and Bioresources Association (ADBA)**
Organisational Type:	**National Association**
Completed by:	**Nick Primmer**
Contact details:	Nick.primmer@adbioresources.org

Consultation Questions

1. **Is there any additional information that you think should be included in Provisional Tariff Guarantee Notices (PTGNs)?**
No.
2. **Do you agree or disagree with our proposed approach to the administration of tariff guarantees? If you disagree, please provide alternative suggestions, including any evidence, to support your response.**
Mixed response.

Overall, tariff guarantees (TG) have greatly supported applications for biomethane plants under the RHI. They provided the much-needed financial certainty to progress with project development. By securing a tariff rate, investment could be confirmed, and robust economic modelling improved the confidence of estimated ROI, thus reducing interesting rates and total expenditure. In general, the implementation and administration of TGs for GGSS, as proposed in the consultation, are well supported by ADBA members.

However, some ADBA members have expressed concerns with the time requirement of TG applications, particularly Stage 1. This stage requires projects to evidence that they have been granted planning permission from the local authority and established a network entry agreement with the relevant gas distribution network. Acquiring both of these permissions can take a significant amount of time and money. On average, members might expect these permits to take around 12 months, but others report wait times of up to 18 months. It is expensive to work on an application over these time periods, and risky considering the application could ultimately be declined.

This top-heavy application process also incurs an administrative burden across multiple stakeholders. To grant planning permission, local authorities typically require detailed audits demonstrating that the proposed plant would comply with all manner of environmental and municipal regulations. To agree a gas grid connection, distribution networks need to assess grid capacity and suitable connection points, balancing connection suitability with proposed proximity to the gas grid. Again, this incurs a significant time and work from numerous organisations, including the public sector – all of which could be wasted if the GGSS application is declined.

A disproportionate amount of work is required for stage 1. The intention of stage is to provide a plant with a provision tariff guarantee notice such that a project can continue in its planning and development with financial security (subject to the development matching application). Consequently, Ofgem should consider reducing the evidence required for stage 1. Submitted applications for planning permission and grid connection should be sufficient; proposed plants can subsequently continue with its development, and only submit evidence of granted permits for the TG's Stage 2. Either way a plant would not be able to progress without these permits but spreading the evidence across stage 1 and 2 can minimise wasted time from all stakeholders.

ADBA members also expressed concern over the GGSS's application window (2021-2025). With stage 1 evidence taking up to 18 months to obtain, members suggest that the vast majority of applications will be from projects originally started with the aim of securing RHI support – i.e. much of the planning has already been completed. This competitive advantage will mean completely new projects will not be able to secure GGSS funding until post-2022/3. This setup favours established companies/projects and potentially prevents new industry players from entering the market. Again, reducing the evidence requirements for stage 1, and shifting evidence to stage 2, can support a fairer application process for new biomethane plants.

3. Do you agree or disagree with the proposed evidence requirements for demonstrating that a plant has commissioned? If you disagree, please provide alternative suggestions, including any evidence, to support your response.

Agree.

However, ADBA recommends additional lee-way should be added to the commissioning deadlines to account for potential delays from Covid-19. Many plants import specialist AD equipment from Europe, and this supply chain has experienced notable delays over the last 18 months due to the pandemic (and Brexit). A plant's ability to meet strict commissioning deadlines should not be dependent on international import/export capabilities across Europe.

Much like the deadline extension allocated to non-TG plants for the RHI, projects should be able to apply for a deadline extension by providing evidence of covid-derived delays. Again, it is recommended that this extension should be 12 months in length to fully ensure enough time to overcome delays. The time and money spent developing and constructing a plant should not be jeopardised by unforeseen changes to the Covid-19 pandemic, both within the UK and beyond.

4. In relation to providing evidence of commissioning, are there other standards, practices, procedures or tests that should be considered? Please provide evidence to support your response.

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5. Do you agree or disagree with the equipment we have suggested is included in our interpretation of 'equipment used to produce biomethane' and therefore must not have been previously used to produce biomethane? Please provide evidence to support your response.

Somewhat agree.

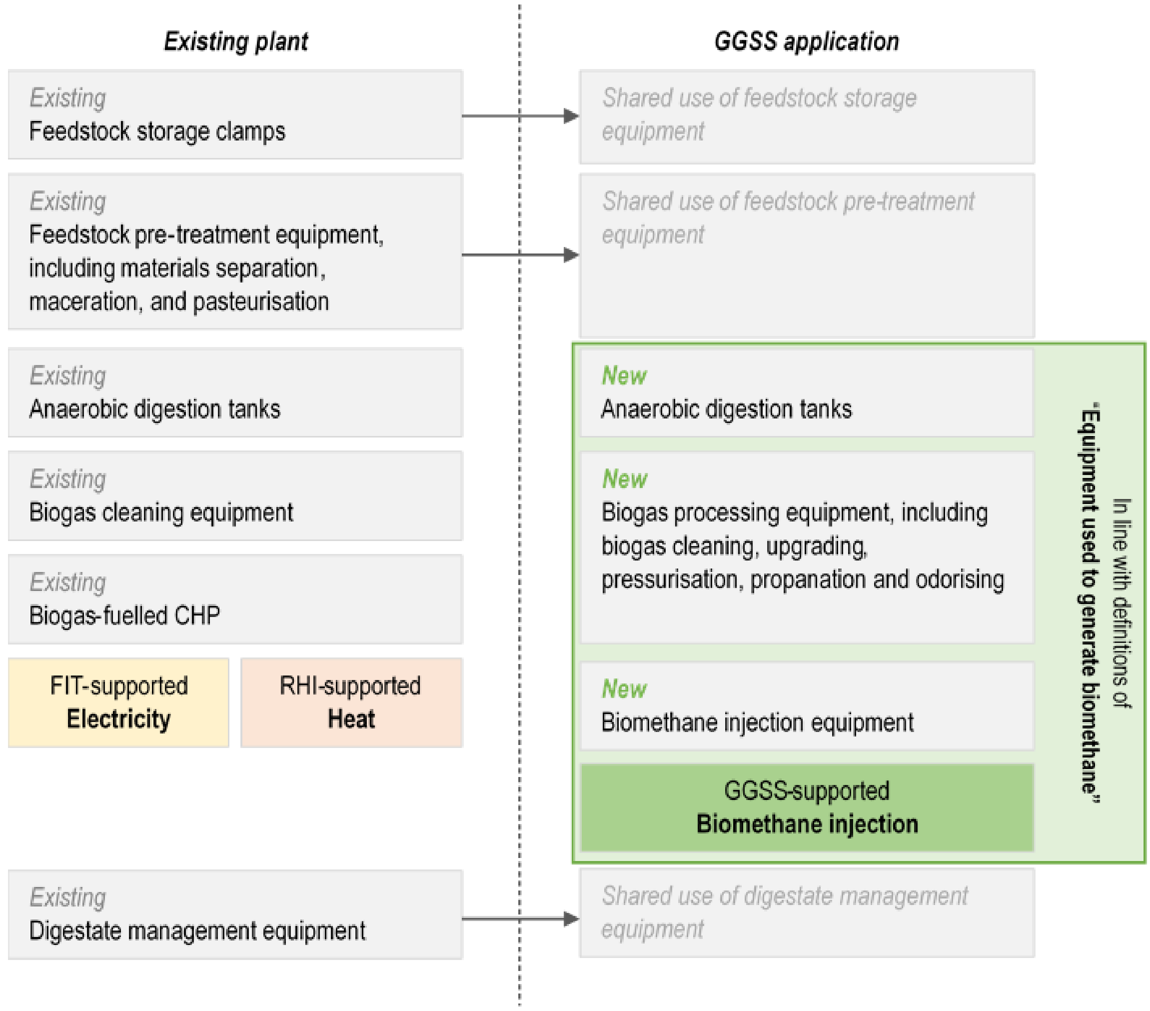
BEIS has clearly stipulated that the GGSS has been designed to support the development of <u>new</u> biomethane plants. It is imperative that Ofgem clearly establishes the definition of a new plant. The current approach of defining 'equipment used to produce biomethane' is a good start, but further clarification is required.

Listed within the integral equipment is the 'anaerobic digester'. While the consultation specifies that its definition does not include adjacent equipment within the broader AD process – namely 'feedstock treatment and pre-processing equipment' and 'digestate treatment equipment' – Ofgem should provide more detail on the definition of 'anaerobic digester(s)', constraining the definition to a fixed list of items. It is presumed that this definition relates only to the primary and secondary digestion tanks and the materials/equipment therein (i.e. tank walls and liners, gas dome, internal mixers, pressure valves) and does not include equipment external to these tanks necessary for AD operation – for example:

- Pumps used to move organic material:
  - From the feedstock pre-treatment equipment to the digestion tanks
  - From the primary tank to the secondary/tertiary digestion tanks
  - From the digestion tanks to the digestate treatment equipment
- Pipework (gaseous) connecting the digester to biogas treatment equipment
- Pipework (feedstock) connecting the digester to feedstock pre-treatment and digestate post-treatment equipment
- Secondary containment area constructed around the anaerobic digesters to contain organic material unintentionally leaked from tanks

In additional, almost all AD plants currently injecting biomethane to grid have installed a CHP to cover the plant's parasitic load. Would existing CHPs be able to heat/power new digesters under the GGSS?

Ofgem should clarify whether these types of equipment would be included in the definition of the 'anaerobic digester'. Based on the definitions outlined in the consultations, the following AD plant schematic depicts the maximum amount of equipment which could be shared with an existing AD plant, and remain eligible for the GGSS:



As suggested by the diagram, a new GGSS-supported biomethane plant could be built alongside an existing CHP plant, sharing all equipment which has not been deemed 'used to produce biomethane'. While BEIS has stated that "expansions and conversions from CHP equipment will not be eligible [for GGSS]", this diagram portrays two AD plants working together to enhance operational efficiency, mitigate economic risk, and optimise the production of renewable energy.

ADBA believes that this example AD plant (see diagram) would not constitute an 'expansion or conversion' of an existing CHP plant. The CHP would continue to operate business as usual, generating renewable electricity in line with its FIT accreditation; the original digesters would continue generating biogas to fuel the FIT accredited CHPs. The same feedstocks are processed with the same potential for renewable electricity generation. The GGSS accredited development would run alongside this existing plant, sharing equipment only where possible. The construction of new digesters would increase the feedstock capacity, and all their biogas upgraded to biomethane ready for injection.

Under this scenario, biogas should *not* be mixed or redistributed between the FIT accredited and the GGSS accredited digesters. Ofgem's annual sustainability audit can verify that all biogas is correctly diverted to the appropriate end-use – i.e. CHP or grid injection in line with the relevant support schemes.

In addition, when building a new biomethane plant, the vast majority of capital expenditure is derived from the biomethane-producing equipment covered by Ofgem's definition (~85%) – i.e. from the anaerobic digestion to grid injection site. Opportunities to share equipment pertaining to feedstock and digestate management with existing AD plants should be encouraged. This relatively small cost savings available from sharing infrastructure can support the longevity and productivity of both the existing plant and the newer GGSS development.

If this is correct, ADBA members *strongly support* Ofgem's proposed definitions and the eligibility of projects which may share infrastructure with existing FIT/RHI accredited AD plants. It would be counterproductive for Ofgem to decline these GGSS applications, and result in the development of neighbouring AD plants, doubling infrastructure requirements and incurring unnecessary costs*.

**These costs also include environmental permits and planning permissions. These authorisations are expensive to obtain and can take months to confirm, delaying development progress. Constructing an GGSS plant alongside an existing plant can streamline this application process by sharing permits with existing infrastructure, minimising costs and administrative burden across multiple organisations (e.g. councils, EA, Ofgem).*

ADBA also strongly urges Ofgem to amend the consultation's proposal to include three key changes – enabling the following to be eligible for the GGSS:

1. **Allow for the centralised injection of biomethane**.
Centralised injection offers multiple benefits across the supply chain and should be encouraged wherever possible.

First, AD plants benefit from reduced capital costs. Connecting to the gas grid is highly expensive. Anecdotal evidence indicates a cost of £500,000 per km of pipeline required to connect to the grid – if a plant is further than 6km away from the gas grid, it is typically deemed unviable to inject 'on-site' – and grid entry units may also cost a further £500,000 (regardless of the quantity of biomethane). Moreover, the injection requirements can vary between gas distribution networks, due to differing gas pressures, standards and fail-safe systems, which can consequently mean that the price to connect to grid can vary substantially, from £40,000 to £250,000.

Centralised injection sites help split these costs across multiple plants, reducing biomethane's total cost of production. Lower capital costs further support industry investment, reducing financial risk and interest rates, thus improving value for money across the AD industry.

Second, centralised injection can negate the need to add propane to biomethane. At specific locations on the gas grid, gas flow is high enough that biomethane injection does not significantly impact the local flow weighted average calorific value (CV). Depending on the regional CV within the grid, propane can present up to 10% of the biomethane-propane mix injected to the grid. Removing the need for propanation not only presents another cost saving, but also removes the needless addition of fossil propane to the renewable gas – thus enhancing the decarbonisation delivered from biomethane injection.

Third, centralised injection can circumvent issues around gas grid capacity resulting in the flaring of biomethane. During periods of high natural gas supply and low demand, sections of the gas grid may be operating near full capacity. Consequently, biomethane plants may be unable to inject their valuable renewable gas into the grid, resulting in the flaring of biomethane. Again, centralised injection sites located at points of high total capacity can minimise the need to flare and waste biomethane.

And finally, centralised injection provides more AD plants with access to the gas grid. As mentioned above, proximity to the gas grid is a limiting factor to the development of biomethane plants across the UK. Improving the operational feasibility of biomethane production could provide the AD industry access to new feedstocks, recycling organic wastes into valuable bio-products.

Ofgem haves suggested that the use of Xoserve data to verify the quantity of biomethane injected precludes the ability of meter readings to be assigned to a specific plant. However, this is not the case. The system has been proven possible for the RHI and centralised biomethane injection. Operated by SGN, Portsdown Hill is a

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centralised injection site in which RHI support can be claimed by nearby AD plants injecting biomethane. ADBA recommends that Ofgem explores this setup to ensure that centralised injection is eligible for GGSS.

It has been suggested that biomethane injection may be liquefied or compressed and transported to the centralised injection site. Here, the vehicle can be matched to the AD production site, and the meter readings linked to its GGSS accreditation.

2. **Allow for provision of biomethane via private pipe (or private 'wire').**
   The GGSS is designed to support biomethane production with the purpose of decarbonising the UK's gas network. Various industries demand gas, typically importing it from the national gas grid. However, biomethane could be supplied directly to these companies via a private pipe, acting to indirectly decarbonise the gas grid. Demand for fossil natural gas from the grid can be replaced with renewable biomethane from a neighbouring AD plant.

   A private pipe provides all benefits listed above: removes costs associated with gas grid connection; removes the need for propanation; circumvents grid capacity issues and the need to flare gas; and enables more AD plants access to GGSS. It can maximise the amount of biomethane, thus displacing the maximum amount of fossil natural gas.

   A private pipe fulfils the goals of the GGSS and should be eligible for its support. Meter readings and Xoserve data can continue to provide adequate evidence necessary for support.

3. **Allow for biomethane plants which have already commissioned biomethane, but not accredited under RHI (or any other scheme)**
   There are a small number of plants which were constructed with the purpose of obtaining RHI support but failed to become accredited. While they might have commissioned biomethane in the past, these plants are typically not generating biomethane consistently without financial support – for example, ADBA is aware of one such plant which is currently for sale, not producing any gas.

   The GGSS is an opportunity to prevent this existing infrastructure from being wasted. They are not accredited under any other scheme and so the GGSS can still subsidise the capex and opex of the plant, incentivising its long-term operation.

6. **In addition to any points made in relation to questions above relating to specific aspects of registration (questions 3-5), do you agree or disagree with our proposed approach to registration? Please provide alternative suggestions, including any evidence to support your response.**

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7. Do you agree or disagree with the proposed approach to making payments? If you disagree, please provide alternative suggestions, including any evidence, to support your response.
Agree. However, experience from the NDRHI has made the AD industry wary of Ofgem's ability to complete payments in a timely fashion. Delays in payments have adversely impacted the supply chain economy underpinning the biomethane financial model; perceived financial risk has increased, inflating insurance premiums, interest rates and total operational costs. Consequently, ADBA recommends that Ofgem maintain sufficient headroom in the budget to help account for unforeseen events and ensure GGSS are always completed on time.
8. Do you have any comments on the proposed process for submitting injection data?
See question 5 regarding centralised injection and private pipe
9. Do you agree or disagree with the proposed fuel measurement and sampling (FMS) process? Do you have any suggestions on how it could be improved?
Agree.
10. We propose that the FMS questionnaire for the GGSS will be a similar format to the existing FMS questionnaire on the NDRHI scheme. Do you have any comments on the NDRHI FMS questionnaire and/or any suggestions on how it could be improved?
Ofgem should seek to align the FMS questionnaire with the DfT assessment of feedstocks. Inconsistent evaluations between the RHI and RTFO presents a significant barrier to the dual participation– needlessly preventing AD plants from flexibly switching between the two schemes and optimising income for biomethane. With both GGSS and RTFO using GHG values listed within RED II, these streamlining of feedstock assessment should be possible, and should reduce the total administrative of Ofgem and/or the DfT.
11. Do you have any comments on the overall arrangements for reporting on the waste and fossil fuel content of feedstocks?

In line with RHI requirements, Ofgem periodic data displays the carbon intensity of different feedstocks However, under this regulation, all waste feedstocks were deemed to have a carbon intensity of 0 gCO2e/MJ. Ofgem must ensure that these fields are updated for the GGSS to demonstrate the carbon intensity of waste feedstocks, and the potential for these wastes to be carbon *negative* (i.e. <0 gCO2e/MJ). By use the REDII methodology and GHG values, biomethane derived from manures and slurries can be carbon negative. As markets increasingly value carbon emissions, the trade of carbon negative biomethane certificates can support the treatment of the lower biogas yielding feedstocks, which are typically overlooked by the energy-focused support schemes. To support the issuance of these biomethane certificates, ADBA also recommends that periodic data should include the proportion of biomethane derived from each feedstock – for example, 50% of the biomethane is derived from manure (carbon intensity of -10 gCO2e/MJ) and 50% from bioenergy crops (carbon intensity of 15 gCO2e/MJ).
12. **Do you agree or disagree with the proposed approach to the greenhouse gas criteria? If you disagree, please provide alternative suggestions, including any evidence, to support your response.**
Agree. The proposed approach aligns well with current practice for the RHI, supporting usability and industry understanding.
13. **Do you agree or disagree with the proposed approach to the land criteria? If you disagree, please provide alternative suggestions, including any evidence, to support your response.**
Agree.
14. **Do you agree or disagree with the proposals for preparing and submitting annual sustainability audit reports? If you disagree, please provide alternative suggestions, including any evidence, to support your response.**
Agree.
15. **Do you agree or disagree with our proposal to require annual, independently assured audit information as further validation of GGSS/RTFO interaction by biomethane producers? Please give your reasons and any appropriate evidence to support your response.**
ADBA and its members support Ofgem's decision to require an annual, independent audit to verify that biomethane plants are not double claiming under RHI and RTFO for any consignments of gas. However, when designing this audit process, Ofgem should seek to minimise administrative requirements from AD operators.

First, by utilising readily available data, the need to install additional software or systems to record necessary information can be negated. The audit should be able to gather sufficient information from plants' existing administrative requirements, from recording meter readings to submitting claims under the RHI and RTFO respectively; these consignments of gas can be cross-referenced with the relevant government registries to minimise input from plant operators.

Second, it has been suggested that biomethane plants should have the choice to opt out of RTFO support for a fixed period of time. These plants would therefore *only* claim RHI support over this defined period, removing any administrative costs/requirements associated with an audit.

This option would likely be most applicable to crop-based AD plants and/or plants with an injection capacity <500m^3/hr. Under these conditions, the RTFO's income potential is unlikely to compete with RHI tariff rates, particularly those higher levels initially offered pre-2015. Moreover, plants claiming support via the RHI are able to earn additional biomethane certificates (BMCs) on the private market, meaning the income from the RTFO would have to exceed the joint revenue from RHI+BMCs to be worthwhile. The following details the conditions in which plants would be highly unlikely to opt for RTFO support over the RHI:

- **Crop-based biomethane**. Biomethane derived from crops are supported with a single allocation of RTFCs[1]. Despite the high (and increasing) trading price of RTFCs, the revenue available from this single allocation of certificates is much less than RHI tariff rates – for example, with RTFC prices of 30p/certificate, a plant gaining a single allocation of certificates for biomethane would earn a maximum of 4.2p/kWh. In practice, the plant would receive just a fraction of this trading price, depending on the pre-arranged contract to supply biomethane as a transport fuel.

- **Capacity less than 500 m^3/hr**. A biomethane plant with a capacity <500 m^3/hr will not exceed its RHI tier 1 allocation of 40 GWh per year. Most biomethane plants have secure tier 1 rates between 4.8 p/kWh and 7.9 p/kWh. This income is reliable and predictable, thus providing all plant stakeholders will a high degree of financial certainty. While the RTFO can offer a higher income potential to waste-based biomethane plants, compared to RHI, the market-based mechanism introduces risk. Again, this income risk can be mitigated within RTFC supply contracts, but this also reduces the proportion of certificate value earnt by the plant – reducing its ability to compete with tier 1 RHI support.

Anecdotal evidence from members suggests that most biomethane plants will only switch to RTFO support if the RTFC price exceeds 25p, biomethane is derived from wastes/residues (double certificates) and the plant has already fulfilled its RHI tier 1 allocation. However, if the certificate price continues to rise and remain steady, waste-based plants will increasingly seek to switch between the RHI and RTFO to boost income potential.

Nevertheless, it remains that a proportion of biomethane plants will not be interested in switching between the two schemes. ADBA suggests that these plants should be able to declare that they will *not* gain RTFO support for a specified period of time, removing the need for any additional administrative requirements – saving time and money from both operators and Ofgem/DfT.

16. **Do you agree or disagree with the proposal to require independently assured audit information on GGSS/RTFO interaction as an additional**

[1] Under the RFTO scheme, biomethane derived from crops is awarded 1.9 certificates per kilogram of gas used as a transport fuel; whereas, if the biomethane is derived from wastes/residues this certificate allocation is doubled to 3.8 certificates per kg of green gas.

section to an Annual Sustainability Audit rather than as a separate stand-alone report instead? Please provide reasons and any appropriate evidence to support your answer.
Agree. It makes sense to minimise auditing time requirements by adding the RTFO/GGSS interaction to the existing sustainability report.
17. **Are you aware of any reason why an auditor could not assess the proposed additional requirements, and do you think both the current sustainability reporting requirement and the proposed RTFO interaction section could be provided by the same auditor? Please provide reasons for your answer/s.**
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18. **What documentation and/or evidence would you be able to provide to an independent auditor to demonstrate that dual claiming for the same biomethane is not taking place?**
There are three key sources of evidence which should provide sufficient evidence: - Meter readings submitted to the gas distribution network (GDN). The GDNs highly regulate gas injection and should indicate total biomethane injection to the gas grid. - Meter readings submitted to Ofgem for RHI support. - Meter readings submitted to DfT for RTFCs claims. Note, that the RHI supports AD plants based on the HHV of biomethane injected to grid, while the RTFO uses the LHV. Any data pertaining to the energy content of gas should be adjusted accordingly to account for any apparent discrepancies. For this reason, members suggest that volumetric data should be preferentially used over energy values during the audit process.
19. **Can you suggest any different approaches that could be taken to evidence GGSS/RTFO interaction by biomethane producers? Please provide reasons for your answer/s and supporting evidence.**
20. **Do you have any additional comments on our proposed administration of GGSS/RTFO interaction?**
21. **Do you have any feedback on our proposal that all registered producers will be subject to a site audit during the first year of operation? Please provide evidence and examples to support your response.**

22. **Do you have any comments on the process for addressing overpayment?**
23. **Do you agree or disagree with our proposed administration of the right of review? If you disagree, please provide alternative suggestions, including any evidence, to support your response.**
24. **Do you agree or disagree with the proposal that new producers should be able to meet outstanding obligations on behalf of the previous registered producer? If you disagree, please provide alternative suggestions, including any evidence, to support your response.**
Agree.
25. **Do you have any additional comments on how we will administer the change of registration process?**
26. **Do you have any comments on the process for withdrawing from the scheme?**
27. **Do you have any suggestions for additional information that could be included in quarterly and annual reports, or on the format of the reports?**
28. **Do you agree or disagree with the proposed approach to managing a shortfall in scheme funding? If you disagree, please provide alternative suggestions, including any evidence, to support your response.**