27/05/2024

REA Response:

Green Gas Support Scheme 2024 Annual Tariff Review: call for evidence

The Association for Renewable Energy & Clean Technologies (REA) is pleased to submit this response to the above call for evidence. The REA represents industry stakeholders from across the whole heat sector and includes dedicated member forums focused on green gas (including biomethane and hydrogen), biomass heat, biomass power, renewable transport fuels and energy from waste (including advanced conversion technologies). Our members include generators, project developers, heat suppliers, investors, equipment producers and service providers. Members range in size from major multinationals to sole traders. There are over 500 corporate members of the REA, making it the largest renewable energy trade association in the UK.

1. **In your opinion, has the attractiveness of developing anaerobic digestion capacity increased, decreased or is unchanged overall in the last year? If so, why and to what extent? Do you expect changes to be long or short term?**

   In our view, the attractiveness is relatively unchanged since the last review. As the only support mechanism, its useful to gauge this by the number of project applications made under the Green Gas Support Scheme (GGSS). Since the last review applications are now up to 38 which is an increase of 10 or nearly 25% since September 2023. The reason for this increase may be due to a number of factors as detailed below.

   - Since the last review, Tier 3 tariff has increased from 1.72p/kWh to 3.45p/kWh. This took effect from 1 October 2023 such that the rate is now comparable to Tier 2. This can make the scheme more attractive to those that are producing biomethane beyond 100,000 MWh wither for anew large-scale plant or a request for increased volume.
   - However, of these new applications **5** are resubmissions and **3** are new applications. This is based on 8 applications confirmed in March 2024 and information is not known currently about the further 2 applications reported on the Ofgem site in April[1]. Either way this means at least 50% were reapplications. This could be because the projects were not likely to or did not meet their deadline date for injection and so were either withdrawals or rejections. This may have been an impact from delays in supply chain issues, as indicated in the REA response to the mid scheme review although we understand this situation is now easing. Alternatively, they may have reapplied to benefit from the change in tariffs.
   - Generally, only larger plants have been applying under the scheme so far and as confirmed by Ofgem, of the 8 applications mentioned above, currently 3 will reach tier 3 during their production process period, each with a Maximum Initial Capacity of 13,1400,000m3. If of the 3 new applications, this corresponds to the 3 higher tier applications it could be said that the tier 3 rate increase has influenced these applications however it could similar be that the plants were due to apply and have either been encouraged to scale accordingly for the new rate or were already planning so regardless.

[1] Green Gas Support Scheme and Green Gas Levy - Applicants | Ofgem

- The attractiveness for investors would be boosted once the amendments, particularly to the extension, has been introduced (due 4th June as reported by government and indicated through draft guidance documents from Ofgem[2]). Although this may be masked by a shift in applications already made and reapplying to benefit from a longer commissioning date.

However, there is still a number of potential barriers and considerations that need to be addressed to make AD plant developments attractive. Many of these points were originally included in the REA Mid Scheme Review response but also in the more recent Future Biomethane Framework Call for evidence REA response but the main ones are summarised.

- There is significant potential to increase biogas output and improve energy security based on a range of industrial and farming bio-residues that have not yet been fully accessed. After the closure of the RHI there is no support for smaller off-grid biogas production - with the GGSS excluding/disincentivising smaller off-grid biogas plants. So, the attractiveness is still restricted to the larger scale of operator rather than the smaller and medium scale plants and those that may convert or extend their previous operation to biomethane production. However, this is hoped to have been accounted for under the future biomethane framework. It is also worth noting the sector continues to see a certain level of consolidation, with fewer developers planning greenfield projects and more acquisitions[3] and improvements to existing assets taking place and/or on existing site land for other processes such as in the case of Severn Trent green power[4].
- As was the case in previous reviews, the attractiveness of the scheme for new development is likely to increase once mandatory food waste collections are rolled out in England which is not due until 2025/6. The delay in this process and uncertainty in feedstock supply also indicate that the market conditions still need to be right to proceed with an application and therefore also indicate that the current tariffs are not excessive. It's important to note that from the mid scheme review the current threshold of 50% waste feedstock was not increased as was proposed and this provided some assurance to industry that they would be able to meet eligibility where the food waste collections were still unknown, particularly where transition arrangements have been permitted.
- Some of the barriers will be discussed in question 2 as they have implications on costs, however it is important to note that locational access to gas grid connections, costs, delays, Propanation for CV quality and restrictions to gas injection remains an issue and is yet unresolved. Therefore, the attractiveness for a developer is much the same and with choices of location thereby limited.
- Planning continues to be a barrier, not only for delays but also for local objections. This is particularly felt where sites are larger where the perceived issues of eyesore and traffic as well as nuisances can be cited as reasoning. This can be easier for sites where there is exiting operations such as a sewage treatment works rather than a new site.
- In addition, while there remain issues with added value through certificates (RGGO/GGCS) this remains an area that has limited potential at present. Assurance of biomethane in the GHGP and SBTI etc along with inclusion in the UK ETS will help raise a value and provide attractiveness for investors/ developers as well as in the market for certificate offtake.

In conclusion, there has been some progress but overall, there remains enough barriers to balance the progress at this stage. Also, biomethane from AD is not the only route for

[2] Green Gas Support Scheme guidance | Ofgem
[3] Biogen acquires five AD plants from Ingenious | Biogen
[4] Severn Trent Green Power: Food and Garden... | Severn Trent Green Power (stgreenpower.co.uk)

production and the current scheme is limiting on the ability for landfill gas, sewage gas, small and on farm AD as well as expansions and conversions, thereby limiting growth.

2. **Has the context for developing and/or operating anaerobic digestion plants improved or become more challenging in the last year in the following areas? Please provide details to specify whether you expect the changes to be short term (1 year or less) or long term (more than 1 year)?**
    a. **Operating costs**
    b. **Financing costs**
    c. **Supply chain**
    d. **Feedstock availability and/or price**

<u>Energy prices</u>

There was a significant surge in energy prices (both gas and electricity) that was noted over recent years, peaking in October 2023 and since returning to more low and stable levels. This will have had a positive impact on biomethane project capital, as well as revenues for currently operational plant during this time. It may also have contributed to a period of high Green Gas Certificates for a period.

However, a company looking to develop new biomethane projects will not be able to use this in their financial models due to the extremely volatile market conditions. It can now be seen that gas prices did not stay as high, and it would be extremely risky to use for a model that is for a period of 15 years. A new project being developed under the Scheme is expected to be commissioned (roughly) 18 months from financial close and the gas prices used in financial models will need to be predicted for 15 years from the point of commissioning.

<u>Inflation rates</u>

The current rate of inflation is reported as 3.2%[5]. This rose from 0.5% (for both RPI and CPHI) in Aug 2020 to a high of 14.2% RPI (9.6% CPHI) in October 2022. Although there has been as sharp a deflation as there was a rise in the inflation over the past few years, levels are unlikely to return to the low of 2020. Although inflation has been reflected in increases in tariff rates in 2023, there has undoubtedly been an impact of project income and costs with implications on the ability to fund projects in the future. The impact would have been felt by developers/ operators during the development phase and expected costs would have increased for both opex and capex. Given the wider macroeconomic picture, these effects should possibly be considered in the 2024 review as the impacts of higher gas prices were temporary.

There are many areas, however, where increased inflation will harm project returns by increasing opex and capex. Where the project capex has increased significantly, the increased cost can be permanently locked in. Higher inflation will have an impact on equipment costs as well as labour and construction materials, such as concrete. Some of these sectors were already facing surges in demand prior to the war in Ukraine and will continue to impact on the costs.

[5] Monetary policy | Bank of England

Inflation rates will also have a greater impact on operational costs than capital costs as the former are recurring over the lifetime of a project. Financial models will be vulnerable to inflation increases in a number of areas where these risks appear high:

- Fertiliser, labour and diesel costs for crop cultivation (agricultural AD plants)
- Labour and diesel costs for the waste sectors
- Broadly similar increased costs for digestate spreading.
- Diesel costs since the removal of entitlement to red diesel from the waste sector but also some agricultural processes.
- Electricity costs – very few new projects will be generating their own electricity so they will be exposed to increases in electricity prices as higher costs.
- The cost of propane – added to the biomethane to bring up its calorific value - will have also gone up, balancing any benefit gained from increased income on gas sales.

However, we welcome the amendment to allow the use of eligible heat pumps for plant operation, which will help reduce the significant costs for process required heat.

<u>Environmental management</u>

EA has been progressively tightening its expectations from all AD plants in terms of design and operation. Full implementation of the farming rules for water and the challenges of removing contamination from the feedstock provided to plants (especially, but not limited to plastic) means digestate is getting ever harder to spread to land. This is affecting opex of handling and applying digestate to land. We acknowledge this has formed a significant part of the call for evidence on the future biomethane framework, so barriers are being investigated.

In addition, the methane leakage from plants is being more stringently monitored by the EA having procured enhanced detection equipment, and with potential changes to requirements for leak detection and repair. Plants which have been built to a BAT specification suitable at the time of commissioning may in the future be required to maintain to a higher standard and at higher costs. We fully support efforts to improve quality so the comments above merely highlight that this may likely to lead to increases in costs – and uncertainty over them can weigh heavily on the viability of projects.

<u>Supply Chain</u>

Most specialist equipment for biomethane projects is manufactured in continental Europe and supply chain impacts immediately following Brexit caused significant delays for critical equipment and spares. Although we understand that this has reduced somewhat, there are still lead time extensions for some equipment, which adds to the upfront cost of the project, especially where the options have been to buy in spares to avoid unnecessary downtime. and hence affect cash flow.

<u>Business rates</u>

As part of a wider government business rates review, the HMRC's Valuation Office Agency (VOA) reviewed its business rates assessments. The change of methodology and the calculations used to work out business rates have triggered significant increases for AD plant owners, particularly biomethane producers. These have seen annual charges rise substantially over the last few years, with some reporting a backdated stance.

We are aware that DESNZ has been investigating the impact of this having had conversations accordingly. Therefore, although we make mention here, we assume this has already been evidenced and therefore has/will be considered as part of the tariff reviews.

Insurance

Insurance represents a significant cost and biomethane projects are finding it harder and harder to get insurance – both in terms of a reduction in the number of insurers in the market and an increase in the premiums charged.

Feedstock

The introduction of separate food and garden waste collections in England has been delayed some time although we have some roll out dates for 2026/27 dependant on whether this is domestic or business food waste although with some at transitional dates set from 2027 up to 2043. This delay has created significant uncertainty amongst biomethane project developers on the sources and volumes of wastes they will be able to secure. Even accepting that mandatory food waste collections will eventually be rolled out, projects can only go so far without the specifics on feedstock being known, otherwise the cost to transport from further afield would have to be factored in. In terms of the transitional arrangements this amounts to 31 LA's but although this only amounts to 10%, we are unaware of how many properties this would amount to proportionately and also the impact in certain areas where plants may be operational/ planning to develop could be more significant.

The costs on feedstock varies significantly across the sector and will be dependent on particular locations. We as a trade association are unable to obtain specific information about feedstock costs and availability, particularly in the short turnaround of this review but can survey members for this information is needed. However, we have been made aware that as energy costs increased so too did costs for feedstock. As the energy costs have more recently fallen, we understand that a corresponding reduction in feedstock costs has not also been seen at the same rate, at least in all locations.

3. **Have there been any technological developments or improvements in equipment since July 2020 which have materially affected the cost profiles of biomethane anaerobic digestion plants?**

New plants are considering the need to move from venting CO2 to capturing. The costs of this will be not only be the equipment to carbon capture, but the transport and storage, unless otherwise utilised. Currently access to long term storage is not possible through the track 1 and 2 CCUS clusters, with some members having to look further afield for future carbon storage contracts[6]. This will hopefully become more accessible and less of a financial deterrent with the current call for evidence on non-pipeline transport as this is a means to open up new opportunities outside of clusters (such as where storage is not near current industrial hubs) whilst also considering adding access to the agreed clusters.

For existing plants not yet capturing, any changes would mean retrofitting which would bring its own potential variations in costs. Obviously, the costs for doing this would only be justified with some balance of income such as from carbon accounting/ UK ETS. In addition, there have been updates to the requirements for carbon dioxide storage based on the EA's RPS 255 [7] which may have further cost implications. There have also been some developments in the use of biochar for sequestration as well as performance.

[6] UK Biomethane Production & AD Plant Management - Future Biogas

[7] Treating, storing, and using carbon dioxide from anaerobic digestion: RPS 255 - GOV.UK (www.gov.uk)

In addition, although we strongly support the need to ensure emissions are curtailed, methane leakage from plants is potentially being more stringently monitored by the EA having procured enhanced detection equipment. Plants which have been built to a BAT specification suitable for the time of commissioning may in the future be required to maintain to a higher standard and at higher costs particularly where remediation may be required.

4. **Does the GGSS tariff appropriately compensate plant development for the following:**
    a. **Tier 1 (<60GWh)**
    b. **Tier 2 (60-100GWh)?**
    c. **Tier 3 (100-250GWh)?**

Is the maximum of 250GWh limiting?

Yes, we believe they are appropriate.

As mentioned in response to question 1, since the last review, Tier 3 tariff has increased to be similar in rate to Tier 2 (from the previous 1.72p/kWh to 3.45p/kWh wef. 1 October 2023). As this is likely to attract those producing biomethane beyond 100,000 MWh, it will likely encourage newer plants designed reaching the tier 3 capacity, as seems to be the case. As plants reaching this value would have the higher tier 1 and a more equalled tiers 2 and 3 rate, this along with the economies of scale is likely to provide sufficient compensation without requiring a further change to tier 3.

As has been mentioned previously, after the closure of the RHI there is no support for smaller off-grid biogas production - the Green Gas Support Scheme excludes smaller off-grid biogas plants. Although the right weighting has been placed on the tariffs, with tier 1 holding the higher rate, raising this further is unlikely to be enough to incentivise small scale plants unless the rate were to be more comparable with compensation through the RHI and FIT and only therefore reward those who would be applying and likely to also benefit from tier 2 and maybe 3. Therefore, there is no evidence for this to be increased other than to reflect the rising operational costs as mentioned in question 3.

We are unaware that the maximum levels of 250GWh is considered limiting and if any plants reach beyond this capacity any additional biomethane could likely capture revenue through additional schemes such as the RTFO.

We would also strongly discourage DESNZ from using the annual tariff review mechanism to make significant changes to the GGSS tariffs (e.g. decrease) as doing so could unsettle developers and undermine future investments in this sector at a time we really need to boost our domestic biomethane supplies, we do not believe there is a good justification for decreasing the tariffs at this time. With the changes that have been made to date along with adjustments for inflation that were made last year we believe this will help attract some developers but still not overly compensating.

Previous comments provided by the REA on tariff reviews indicated that the tariffs were set about right due to the lack of a surge in applications, but equally with a reasonable number of applications spread out over time. This remains the case, especially considering that of the new applications, 50% were reapplicants.

5. Are the levels of Expenditure Thresholds for triggering a tariff degression appropriate?

The degression thresholds seem to be roughly right, as far as we can tell at this stage. As stated on relevant GGSS budget management page, the expenditure forecast at 1 Jan 2024 was £53.09 against a degression level of £166 which indicates sufficient room as reflected by the current number of registered participants/applicants. Although it true there have been some increases in applications since the changes last year, there are a large number of tariff guarantees that have been waiting some time to progress and accounted for in the budget allocation.

No change to the degressions levels were made in the 2023 review and its currently difficult to understand how many of the applications will make it all the way to the registered user status and therefore it remains a similar position as in previous years. It is more likely to impact in the next tariff review. However, the Department for Energy Security and Net Zero reduced the application budget cap for 2024/25 from £88 million to £51.7 million from April 2024, as announced on 22 December 2023. Ofgem have stated on their website that the reduction in the Application Budget cap may affect applicants planning to commission in 2024/25.

6. To what extent are revenue from Renewable Transport Fuel Certificates a planned or realised revenue stream for your biomethane anaerobic plant(s)?

It is difficult to see the potential value of RTFCs making much difference to funding of new AD projects (as opposed to expansions of existing ones). RTFC values are set entirely by the market, which itself is driven by the decisions of those putting petrol and diesel fuels on the market. Demand for biomethane as a transport fuel is therefore dependent on:

- the market demand for that fuel:
- Decisions of the oil companies:
- Biomethane produced elsewhere: unsubsidised biomethane from anywhere with a physical connection to the UK gas grid can be used to meet the RTFO obligation.

The RTFO makes made most sense when a project is no longer able to get tier one of RHI or GGSS. Given the increase in Tier 1 threshold limits under the GGSS, it's unlikely that many projects would go into tier 2 on a substantial part of their production. Renewable fuels and particularly Biomethane, Bio- CNG and Bio-LNG are an increasingly viable option, not only for those already upgrading for grid injection but those that are currently under the FIT scheme, looking at options when their contracts end or an additional revenue.

RTFO mechanism is unlike the GGSS scheme in that the fuel has to move from the production plant to the refueling point and is demonstrated as entering a vehicle (usually using Fuel Duty records as evidence) in comparison to the GGSS scheme where the gas only has to enter the grid.

Some already operational sites use the value in the RTFCs to provide a flexible option in conjunction with the RHI and GGSS, particularly where an expansion of the plant would not be able to receive increased revenues from the RHI or GGSS. Even where the existing subsidy would support increased injection, the RTFO is likely to prove particularly attractive when compared to the lower (tier 2 and 3 tariffs). These rewards are also greater where most or all of the feedstock used is waste or residue, since biomethane produced from these feedstocks currently receives double rewards under the RTFO. The work on GGSS and RTFO, with the implications of many plants gaining ISCC registration (the main mechanism for biofuel recognition) has provided a strong evidence base to establish split claims but also mass balancing through the gas system in a highly regulated environment between OFGEM and DFT.

Despite the useful flexibility that the RTFO provides for existing plant, the RTFO is a relatively weak policy in terms of supporting investment in new production capacity. This can be seen in the RTFO as a whole, not just from the biomethane side.

There are a number of reasons for this:

- The RTFO does not accredit or register individual plants – it just creates an overall market in which there is demand for renewable transport fuels and the Renewable Transport Fuel Certificates (RTFCs) which are the means of accounting for them.
- Increasing targets have only been set out to 2032. Although the Department for Transport has consistently stressed that this does not necessarily mean the scheme closes on that date, they have yet to set out their medium-long term ambition. Given the lack of protection for individual plant noted above, this means new investments are entirely dependent on the wider market.
- Unlike the Renewables Obligation, the RTFO buy out price is not effectively a guaranteed minimum value per certificate. In fact, the buy out price sets a ceiling for the maximum possible value, with the actual value entirely dependent on the market. Unlike all other production support schemes for renewables, the buy out price is not indexed to any measure of inflation[8]
- A gaseous fuel can only obtain RTFCs if there is demand for methane as a vehicle fuel. So, a funder considering a biomethane plant for which RTFCs form an essential part of the income is obliged to take a view on overall demand for methane as a transport fuel. Since RTFCs can be obtained from biomethane produced outside the UK, they must also take a view on their likely competitiveness with other producers both within and beyond the UK.
- The market is dominated by a handful of large, obligated parties and the vast majority of the RTFO targets are met through liquid biofuels blended into liquid fossil fuels. This means that the procurement and commercial priorities of those parties have far greater impact on the value of support than other revenue support schemes.
- As a result of the changes to the RTFO rules around importing all the biomethane not just the green credentials of the gas, meant that non-UK gas was paying a premium as the gas element in Europe was at a higher level than UK, and was incentivising increase in UK supply.

Until or unless these points are addressed, we do not believe it is likely that a new project could be funded if dependent to any significant extent on revenues from the sale of RTFCs. We note that DfT has a legal obligation (via the Energy Act 2023) to publish a consultation on ways to provide confidence in future revenues for UK producers looking to supply the Sustainable Aviation Fuel mandate and it may be that there are useful proposals that can also be applied to the RTFO itself.

[8] The buy out price increased from 30ppl to 50ppl in January 2021, so DfT could fairly state that they have taken action when it looked like the buy out price might be too low to incentivise the continuing supply of renewable transport fuels. The difficulty is that, without a set process in place for adjusting it, there is no guarantee they would do so again in future.

7. **If revenues from Renewable Transport Fuel Certificates are a planned or realised revenue stream for your biomethane anaerobic plant(s), how have you taken this into account in your finance planning?**

    a. **As a proportion of biomethane production at a particular GGSS tariff tier level**
    b. **As a proportion of all biomethane production**
    c. **Other Please specify**

    As a trade association we are unable to answer this question. Please see question 6 response.

8. **What are your expectations for the future development of Renewable Transport Fuel Certificate prices?**

    Although the RTFO has been an additional option for plants that can combine with RHI and GGSS or considered when the FIT is nearing the end of contract, it is unlikely to provide enough revenue for a newly built plant. Please see response to Question 6 for more information.

9. **How do Green Gas Certificates impact the attractiveness of developing biomethane anaerobic digestion plants?**

    The value of Green Gas Certificates is likely to be considered in new project financial models. However, it should be noted that the revised GGSS Financial Impact Assessment published by BEIS in 2021 already includes '*Green Gas Certificate revenue in the tariff setting in light of new evidence to suggest that anaerobic digestion (AD) plants account for Green Gas Certificates in their cost models. Including this new revenue stream has a minor impact on the GGSS tariff.*'

    However, it is important to note that although there is a good market for trading Green Gas Certificates or GGCS/RGGO including in Europe, this has at present been limited to provide only a modest amount. The Green Gas Certification Scheme is run by REAL, which is a wholly owned subsidiary of REA. The GGCS has stated on their website that,

    "*Sale of RGGOs – prices have historically been over £1/MWh. This means that the RGGO market has never suffered from the extremely low values seen in the electricity GoO system, which underpin many of the accusations of greenwash and the lack of additionality in that sector. In the £1-3/MWh range RGGOs represent a small percentage of the total income secured by biomethane producers but do represent a useful value stream to help ensure the economic operation of plants.*"

    Despite a high of ~£20/MWh last year, likely due to the high gas prices, this has already fallen to just below £5/MWh, which although shows higher values are possible and have been achieved from certificates. This confirms that at present although an important revenue stream, it can fluctuate so forecast would need to be made with low expectations.

    It's therefore important to note that to be the basis of long-term investment assurance of a high enough value and consistent income stream would be needed in order to feature significantly in financial models. If biomethane is included in the UK ETS and certificates are clearly defined for use within the GHG schemes such as GHGP and SBTi, then values could/should increase, and this may improve the attractiveness for developing AD plants based on this revenue stream.

10. **Do you expect revenues from Green Gas Certificates to become more or less important to biomethane plants in future, or for their importance to remain unchanged? More important Less important Their importance will remain unchanged?**

To attract more investment into the biomethane industry, a scheme which sees a significantly valuable and dependable revenue from the green credential is vital. The ability to engage and therefore trade within the EU ETS and the current stance on the Union database for third countries would significantly affect the possible revenue opportunities. Significant clarity is needed on this along with the urgent need for assurance that companies can use biomethane in their Market Based reporting for the GHG protocol and SBTi. In these circumstances then expected revenues from certificates will become more important.

11. Have any developments in organic fertiliser markets altered the revenue or selling potential of digestate in the last year?

Digestate market is very regional. The increase in the cost of inorganic fertilisers has certainly led to a higher demand for organic fertilisers (digestate and animal slurries) in some parts of the country, but this has not happened consistently across the UK.

The cost of inorganic fertilisers has dropped from the previous high, however there is still demand from farmers looking at digestate as a suitable biofertiliser. The weather over winter 23/24 has been particularly wet, which has led to challenges around accessing landbank for digestate spreading. Some farms are reporting being a month or two behind where they would normally be, due to the weather conditions. The weather impacts the ability to spread digestate, which in turn leads to an increased need for storage. This can add to the costs both for storage but also for transport and spreading when there is greater demand over a shorter period of time.

In addition to this, the EA are planning to tighten the limits for plastics in digestate through the revision of the Quality Protocol. This may result in an improvement in the quality of digestate and in turn an increase in market demand (for a higher quality product), but some operators may find they face increased operational costs (both for removal of contamination and its subsequent disposal) to achieve the tighter standards.

12. Have any market developments altered the revenue potential from selling carbon dioxide produced by biomethane plants in the last year?

In September 2021, as the global gas prices spiked, two key fertiliser plants (CF Fertilisers) shut down raising significant concerns around a sudden reduced supply of carbon dioxide from these plants for industrial applications. Given these significant shortages, Government said they want to see measurers implemented to improve resilience and security of supply of carbon dioxide in the long term and engaged with the sector to ensure this happens.

Bio-CO2 captured at biomethane plants provides an opportunity to improve market resilience and security of supply. Our members that have employed carbon capture technology on their AD plants have said they saw an increased demand for this commodity due to shortages and that there seems to be a slight, positive shift in the way bio-CO2 from AD plants is seen by the Food and Drink sector.

Market intelligence also suggests that average market prices haven't increased significantly. These are still relatively low and not sufficient to justify the investment in the capital and operational costs required to deploy carbon capture at these plants. However, the current consultation on non-pipeline transport[9] is likely to help the carbon dioxide market through improved access and infrastructure for CO2 movement, which should help both storage and

[9] CCUS: non-pipeline transport and cross-border CO2 networks - call for evidence - GOV.UK (www.gov.uk)

utilisation. There is concern that until such time that biogenic CO2 use is increased/ incentivised and also until storage demand volumes rise, that a potential overcapacity for a period of between 2-5 yrs could be a risk that will impact the pricing. This could have a significant impact on a plants ability to fund the CO2 capture infrastructure. In addition, plants capturing the carbon will likely have to modify their environmental permits and there may be additional costs incurred to comply with requirements (such as RPS 255).