REA Response to Ofgem RIIO-2 sector specific methodology consultation (RIIO-2 Sector Specific Methodology Annex: Gas Distribution)

1. Introduction & Context

The Renewable Energy Association (REA) is pleased to submit this response to the above consultation.

The REA represents renewable electricity, heat and transport, as well as Electric Vehicle companies and Energy Storage. Members encompass a wide variety of organisations, including generators, project developers, fuel and power suppliers, investors, equipment producers and service providers. Members range in size from major multinationals to sole traders. There are around 550 corporate members of the REA, making it the largest renewable energy trade association in the UK.

Ofgem sets price controls for the companies that operate the gas and electricity networks in Great Britain using the RIIO Framework, determining the outputs that the gas and electricity companies deliver for consumers and the revenues they are allowed to recover in doing so.

They are currently consulting on the methodology that will be applied for setting the RIIO-2 price controls for the gas distribution and gas and electricity transmission networks and the electricity system operator. These price controls will run from 2021-2026.

This response mainly focuses on the specific part of the consultation relevant to gas distribution (ie RIIO-2 Sector Specific Methodology Annex: Gas Distribution). The only exception is the consideration raised in section 3 below, which refers to section 8 of the main consultation document.

2. Our views and key recommendations on gas distribution

Ofgem have stated that the price control framework should enable the transition to decarbonised heat at the lowest cost for consumers. However, we are disappointed at the lack of stronger proposals within the document for GDNOs to act on opportunities within their regions to decarbonise their networks. We also don't share Ofgem's views, as stated in the paper, that it should be solely up to "government to determine what, if any, subsidy regime should support biomethane." GD2 is a critical period for the biomethane to grid industry and we believe that all sectors of the gas

80 Strand,
London, WC2R 0DT

Tel: 020 7925 3570 http://www.r-e-a.net/

industry need to work to ensure that the full potential of biomethane can be utilised to support UK decarbonisation, renewable energy production and security of supply priorities.

The Committee on Climate Change (CCC) and others have highlighted the likelihood of future supplies of bioSNG and renewable hydrogen through the gas network. The REA and GGCS are very supportive of these new energy sources but recognise that these may remain in the innovation phase for much of the GD2 period (CCC point to hydrogen beginning to play a role from 2030).

98 biomethane plants are now in operation with a potential of future supplies increasing four-fold (to at least 20TWh) by end next decade. RIIO GD2 will therefore play a fundamental role in helping achieve this. We do not believe that Ofgem should be waiting for future Government decisions as part of a 'heat policy re-opener' to support the greater production of biomethane.

We support the findings recently published in the Bright Blue report entitled 'Pressure in the pipeline' that the decarbonisation of the gas grid must be made a priority in the next price control framework from April 2021. We outline below our views on how this could be achieved by Ofgem.

1) Encourage established technologies such as biomethane from Anaerobic Digestion

As stated in the Gas Distribution Annex, Ofgem have decided not to propose a new output for biomethane connections as the Government should determine what, if any subsidy regime, should support biomethane. However we consider that the price control framework should include clear mechanisms to encourage more biomethane connections into the gas grid.

In his Spring Statement issued on 13th March 2019, the Chancellor announced that 'to meet climate targets, the Government will advance the decarbonisation of gas supplies by increasing the proportion of green gas in the grid, helping to reduce dependence on burning natural gas in homes and businesses.' BEIS will be publishing proposals later this year to require an increased proportion of green gas in the grid, advancing decarbonisation of our main gas supply. This is a clear and firm commitment from Government to support green gas to achieve the required carbon reductions.

In its recent evidence review entitled 'Clean Growth – Transforming heating' BEIS have made it clear that biomethane has an important role to play in the long-term decarbonisation of heat, although not as a standalone option.

We regret Ofgem's proposals to remove incentive elements current in place in GD1 for companies to report on biomethane connections and connection studies. Ofgem should instead be looking to parallels within the electricity distribution sector, where strong drivers are put in place to ensure that distribution networks are responding to the needs of customers, facilitating the process for new connections, providing transparent pricing structures in terms of connections, holding regulator customer 'surgeries' for generators, and the provision of 'heat maps' highlighting capacity opportunities, mapping tools, and data sharing routes.

The review infers that biomethane can achieve high GHG savings and that there is strong potential for further emission savings with technologies such as Bioenergy Carbon Capture Use and Storage (Bio-CCUS).

Biomethane from anaerobic digestion has been regarded by Government as a 'no or low-regrets' low carbon heating option. In the Government consultation on the RHI reforms in March 2016, BEIS stated that 'biogas (including biomethane) has an important role to play both now and in the longer term, in decarbonising heat and the gas grid, reducing greenhouse gas emissions and supporting jobs in rural areas.'

Most importantly, biomethane from AD is an established and commercially ready technology. This means it is one of the few technologies that can help in the short- and medium-term to make progress towards decarbonising the gas grid, whilst other technologies become technically and commercially ready to be deployed.

In addition, biomethane is an enabler for other technologies for decarbonising the gas grid. For example, encouraging increased biomethane production would stimulate the development of new technologies, such as Methanation (but this must only be incentivised when from renewable sources), where CO_2 is reacted with hydrogen to create methane, effectively reducing emissions whilst also producing renewable fuel. It could also enable the production of renewable hydrogen from Steam Methane Reforming (SMR) of biomethane.

However, there is currently significant uncertainty on whether there will be continuity of support for this sector after the existing RHI comes to an end in March 2021.

Future development of the sector is dependent upon the biomethane sector supply chain being maintained up to and beyond the 2021 end date for the current RHI. There is a danger that the supply chain will start to be disbanded (or specialists are re-directed to other sectors) as we approach the deadline if clear signals on future support are not communicated early enough.

In addition to a highly uncertain policy landscape, there are significant technical barriers to biomethane connections that need to be overcome and could be addressed within the price control framework.

The most important ones are highlighted in the report entitled Distributed gas sources' published by Element Energy on 25th January 2017, which was procured by National Grid Gas Distribution Ltd (now Cadent Gas), SGN and Wales and West Utilities.

In our view and based on the findings of the above report, the two barriers that must be addressed within the price control framework are:

- The high and highly variable cost of connection due to the lack of standardisation of specification across the gas networks.
- Capacity constraints on the distribution network, leading to high connection costs associated with connecting at a point with sufficient capacity, or the inability to connect.

We have described the two challenges below alongside a solution to address them.

Lack of standardisation across the gas networks

All Gas Distribution Networks (GDNs) have different standards, contracts, policies for biomethane with significantly different costs.

There have now been around 98 biomethane to grid projects in Great Britain since the first in 2012.

In 2011 -12 there was an Ofgem supported series of workshops known as EMIB which set the basic regime for biomethane.

The purpose of the group was to provide a forum for informed debate on the potential barriers to the commercial development of biomethane projects within the energy market and the appropriate means of addressing such barriers.

The concept was for all 4 GDNs to adopt common policies (see https://www.gasgovernance.co.uk/emib). At the time, it was too late to have any specific incentives within RIIO.

The published EMIB report (May 2012) states that '*It was recognised that establishing a single national set of standards would remove uncertainty and hence a potential barrier to entry. It would also support the development of competitive infrastructure provisions since different providers could develop competing products to deliver the common specification, and cost reductions should also be delivered as a result of requirements being replicated at all sites*'.

Unfortunately, industry has seen major divergences amongst the 4 GDNs with significant additional cost.

The table below gives our indicative estimate of the costs (£) in the 4 GDN areas:

GDN	Capex for Grid Entry Unit (GEU)	GDN Charge (for auditing)	Estimated cost to satisfy wider GDN requirements	Total cost
GDN1	400,000	15,000	25,000	440,000
GDN2	430,000	85,000	60,000	575,000
GDN3	450,000	40,000	50,000	540,000
GDN4	470,000	40,000	60,000	570,000

Examples of where there are technical divergences:

- Odorant system ownership and location in GEU
- Separate shut down plc
- Ownership of RTU (telemetry system)
- Time of flight system
- Design details of upstream plant

A complete list of differences in the policies adopted by the networks is shown in Annex 1. This list was compiled in 2016 but it is still largely relevant.

We understand that the gas networks have recently been working to harmonise their specifications, but this needs to happen faster as discussions around these issues have been taking place for a long time and recommendations made in 2012, and yet little progress has been made so far by the networks. We believe the only way to address this is by having a strong mechanism within the price control framework that incentivises the GDNs to provide standard, consistent specifications. This should also incentive the GDNs to innovate – for example, persuading Ofgem to make technical changes to energy measurement regulations which could reduce the costs by £100K per site with no adverse impact to consumers.

We therefore recommend that the next RIIO2 price control framework include a mechanism/incentive to make it easier to connect for biomethane projects and lower the costs.

In our view Ofgem should accept the GDN1 system as the most economic and efficient as this complies with HSE and Ofgem requirements at least cost. The other GDNs should either have the option to adopt the GDN1 design, or maintain their designs but make a funding contribution equal to the difference between the total cost in their area and the GDN1 total cost. As per the table above, GDN3 for example, would make a contribution of £100K per project, GDN2 would pay £135K.

The same would apply to annual maintenance and compliance costs with a difference of around £10K between the highest and GDN1's approach.

This would provide a strong incentive for the gas networks to harmonise their specifications and innovate. If Ofgem implemented this, it is possible that all the GDNs would decide to adopt the GDN1 design as their shareholders may not see the business case for the additional investment not required to satisfy Ofgem and HSE.

Currently, there is much uncertainty around:

- the justification for the main areas of difference between a GEU in all GDNs except WWU, and the ones in WWU which are commonly accepted to be the lowest cost designs to comply with HSE and Ofgem requirements.
- The reason why biomethane producers should pay more than the WWU frontier cost.
- What steps are being taken by the networks to ensure biomethane connections are 'economic and efficient'.

In addition it would be useful to have from the networks feedback on:

- What biomethane flow each network had by month by Local Distribution Zone (LDZ) since their first project. It would be useful for each network to put this in a table with domestic customer gas demand and total gas demand by LDZ, and show the ratio by month of biomethane/total gas demand and biomethane/domestic customer gas demand.
- The number of biomethane gas quality excursions the networks had to notify to HSE.
- How many examples of low CV gas entering the GDN they had, which have led to CV capping and what have the costs been as a result of these.
- Anonymous information on O2 and H2S in the biomethane injected into the grid for all projects
- A list of all the NIA/NIC projects completed for biomethane with all the reports published.

It is important to note that the Renewable Energy Directive II specifies that:

'The costs of connecting new producers of gas from renewable energy sources to the gas grids should be based on objective, transparent and non-discriminatory criteria and due account should be taken of the benefit that embedded local producers of gas from renewable sources bring to the gas grids. (Recital 67, Article 20 (1)))

- Member States shall require transmission system operators and distribution system operators in their territory to publish technical rules in line with Article 6 of Directive 2003/55/EC of the European Parliament and of the Council, in particular regarding network connection rules that include gas quality, gas odoration and gas pressure requirements. Member States shall also require transmission and distribution system operators to publish the connection tariffs to connect renewable gas sources based on transparent and non-discriminatory criteria.'

Capacity constraints

The maximum injection capacity offered by the GDNs to biomethane producers for injection is limited to the minimum demand downstream of the potential gas entry point. This varies significantly at different points of the network, but it is becoming increasingly common that the closest network segment to a proposed biomethane facility does not have sufficient capacity to allow injection.

Pipelines can be installed to carry the gas from the point of production, either to a higher pressure tier which has more downstream demand, or to a location where the network has sufficient capacity at that tier. However pipeline costs, which are typically covered by the biomethane producer, can be very high and adversely affect the business case for connection and injection to the grid.

There is therefore a strong argument for introducing a mechanism to incentivise the networks to provide a cost effective solution to capacity constraints.

For example, in-grid compression is a potential solution to the issue of capacity which is used widely in Europe. At times when there is insufficient demand on the network to allow all gas sources to inject, compressors can be operated to 'pump' gas to a higher pressure tier. This solution is considered to be the most effective solution, especially where there are severe constraints in the capacity available. There are other solutions that are more cost effective where the constraints in capacity are less severe.

We are also aware that some of the gas networks members of the REA will be putting forward proposals on incentives on the gas network operators to connect gas entry projects as quickly as possible and as close as possible to their full requested output, whilst also incentivising efficient delivery.

Our recommendation is to include a mechanism within the price control framework for the period 2021 to 2026 that incentives the networks to provide effective solutions for gas network capacity constraints, such as in-grid compression.

2) <u>Encourage less established technologies such as Hydrogen</u>

RIIO2 should also provide appropriate innovation funding and incentives to support the ongoing work on the scope for H_2 injection – with suitable consultation/engagement of wider industry stakeholders. We agree with the findings of the Bright Blue report that available funding through the 'Network Innovation Competition' and 'Network Innovation Allowance' should be increased to enable the necessary innovation and testing.

3) <u>Fully engage with the relevant Government departments in the development of the RIIO2 cost control framework</u>

It is absolutely crucial that the relevant department within Government are actively engaged in this consultation, to ensure key barriers to biomethane growth such as capacity and costs can be overcome. We recommend that the BEIS team that is working on the 'Heat Strategy'[1] as well as the Department for Transport are fully

[1] In its December 2018 publication entitled 'Clean Growth – Transforming heating', the Government stated it will develop a new roadmap for policy on heat decarbonisation, taking into account the views received in response to the report, and the outcomes of the next Spending Review.

engaged in this process so that a joined-up approach across Government and the regulator is taken.

4) **Encourage more green gas connections to the network**

Currently the Gas Distribution Networks do not have a specific target on how much renewable gas should be injected into their network or another specific mechanism or measures that encourage (or reward GDNs) to bring new Biomethane to Grid plants onto their network .

It is difficult to have targets for volumes / proportion of renewable gas to enter the system as the fundamental driver for biomethane relates to the sources of feedstock which the networks cannot influence. However, networks can be supportive of biomethane, can reduce costs and simplify processes to make it easier for projects to go ahead and Ofgem should develop a mechanism to incentivise good performance in this area.

In its response to BEIS's evidence review report entitled 'Clean Growth – Transforming heating', amongst other options the REA has recommended that a green gas obligation is placed on gas suppliers after the existing RHI comes to an end.

Joined-up thinking is required across Government, Ofgem, the green gas sector and the gas networks to ensure this is workable and that additional costs imposed on suppliers are not simply passed onto consumers. Some mechanism, in addition to the capped buy-out price, will likely need to be implemented to control costs borne by consumers and to protect vulnerable groups such as the fuel poor.

For Ofgem's convenience, we have set out our proposals on how a green gas obligation would operate in Annex 2.

3. Section 8 - Driving Innovation through competition

We strongly support section eight's approach to encouraging more innovation as "Business As Usual". We understand that RIIO-ED2 (the price control for the electricity distribution networks), which has not yet been launched, intends to contain measures to remove barriers and improve the price signals for flexibility, and we recognise that consideration has been made in the sector specific consultation to promote flexibility through the early and late competitions section.

Linked to the above, Ofgem should consider that flexibility be considered at all decision points, not just when making a reinforcement decision, and should rapidly be considered a "BAU" activity.

We support specific consideration towards competition incentives aimed at procuring flexibility. We would support introducing a robust overall framework, something along the lines of a "flexibility market" that could take place every day, not every year.

Flexibility should be considered at the point the constraint on the network is identified as an ongoing management activity. A price signal should be ongoing to ensure the industry continues to invest.

Annex II

REA's proposal for a green gas obligation on gas suppliers

What we have proposed to BEIS is an obligation placed on licenced gas suppliers[2] to source an increasing proportion of the gas they supply from renewable sources. The obligation would work in a similar manner to how the Renewables Obligation works for electricity, but for renewable gas injected into the UK gas network.

The trajectory for this obligation over time should be consistent with meeting the UK's carbon budgets.

This is in line with one of the key recommendations highlighted in the Bright Blue report.

Eligible gases – Biomethane, BioSNG, Renewable hydrogen, and other renewable gases of non-biological origin (e.g. methane and propane). These gases have very different production costs and the Green Gas Obligation would need to be banded to accommodate this. It is envisaged that biomethane would be eligible for 1 certificate/MWh of gas, whilst others have multiples (similar to different numbers of ROCs/MWh in the RO). The GHG and sustainability requirements would replicate those used in other schemes. An officially-recognised body for administering the scheme would be required. This could be Ofgem or it could be done by expanding the existing Green Gas Certification Scheme (GGCS). The GGCS has been operational since 2010, working with all key industry players and has over 60 biomethane to grid schemes now signed up as members of the Scheme. GGCS Renewable Gas Guarantees of Origin (RGGOs) are already accepted by the Department of Transport (DfT) in terms of securing support under their Low Carbon Emission Bus (LCEB) programme and the Renewable Transport Fuel Obligation (RTFO). The GGCS has a comprehensive management and audit system in place and is the UK member of the European Renewable Gas Registry (ERGaR).

Target levels

The Obligation could start out as X certificates required / volume of gas supplied, and thereafter be set at a certain margin (e.g. 10%) higher than the projected renewable gas certificate generation, so the market would always be short and the certificates will always have a value[3]. Alternatively annually increasing targets could be set in advance.

The total cost of the policy would be capped by the buy-out price, which is the maximum possible cost to consumers.

Gas suppliers would meet their obligation by a combination of:

- Presenting Renewable Gas Guarantee of Origin (RGGO) certificates bought from green gas producers to the scheme administrator

[2] Any entity which holds a Gas Supply Licence, which is a licence granted or treated as granted under section 7A(1) of the Gas Act 1986. This is restricted gas which has been conveyed through pipes to the relevant premises. Very small gas suppliers could be exempted.

[3]If the obligation exceeds the available quantity of low carbon gas, the market would be short and the certificate value would be close to the buy-out price

- Where suppliers do not have sufficient RGGOs to cover their obligation, they would pay into a buy-out fund.

The proceeds of the buy-out fund could be paid back to the gas suppliers in proportion to how many RGGOs certificates they have presented. For example, if they were to submit 5% of the total number of RGGOs submitted they would receive 5% of the total funds that defaulting supply companies paid into the buy-out fund.

Green gas production facilities would be registered/accredited and issued with RGGO certificates for the green gas they supply, which they then sell on (ultimately to the suppliers).

For green gas producers, this would in effect be a premium on top of the revenue from the sale of the green gas.

It is envisaged that (at least initially) gas will be injected into the UK network, but clearly there is scope for international trade in green gas certificates and if there are similar obligations in operation in the EU, then mass balancing across the European gas network could be explored.

An additional point is that it is imperative additional costs imposed on suppliers are not simply passed onto consumers. Some mechanism, in addition to the capped buy-out price, will likely need to be implemented to control costs borne by consumers and to protect vulnerable groups such as the fuel poor.

Annex I (08/03/2016)

This Annex represents a list of divergences in the specifications and procedures between the networks as at 8th March 2016. Our understanding is that most of these divergences are still in existence today, but we are prepared to provide an up to date list in due course, if this is required by Ofgem.

1. Grid Entry Unit Design

   - BNEF - Functional Specification V5.6 (14-05-2012) agreed as part of EMIB has been largely overtaken by GDN's deciding to implement different functionality and p0rovide additional details without any industry consultation.
   - One GDN has fundamentally different control system with a separate PC controlling the Remotely Operable Valve (ROV), adds around £50K. Means GEU specific to that GDN and its a more complex system
   - All the GDN's have various functional specifications that have an effect on cost e.g. requirement for ROV bypass valve (or not), RTU functionality.
     - One GDN has recently withdrawn their functional requirement specification making compliance from kiosk manufacturers difficult. Vagueness of some specifications take additional hidden time and resources to sort out after contract award. e.g. a GDN fundamentally changed their RTU functionality recently mid kiosk design.
   - One GDN requires additional fast acting gas analysis equipment, hence additional costs
   - One GDN requires pressure to be measured and tyransmitted downstream of the ROV
   - One GDN will not allow any flow with an ROV bypass, one GDN will not allow any flow unless there is an ROV bypass.
   - One GDN insists on taking ownership of the Odorant system and wants this in a separate compartment so the GEU design is specific to that GDN
     - This leads to different testing regime for odorant system and significantly more complexity
   - One GDN requires a different specification for valves that the others (high specification V6 valves for 7 bar)
   - One GDN has a different pipework spec for 7 bar
   - One GDN specifies the electricity supply to the ROV/RTU
   - GDN's have different requirements and processes for back up communications and HPMIS (GMIST) data transfer.

2. Metering Calibration
   - Two GDN requires a rotary meter to be calibrated on natural gas (expensive), two are ok with N2

3. Gas Quality Analysis
   - One GDN requires daily calibration of O2 and H2S monitors, irrespective of risk assessment

4. Design Assurance
    - Three GDNs require a G17 type approval and appraisal with 3 levels:
        - Designer
        - Approver (from specified list)
        - Appraiser (from specified list)
    - One GDN requires 2 level appraisal (GL/5) on ROV/RTU only
    - One GDN also carries out an additional review of the Appraised Design using an outside Design House
    - One GDN requires an Appraisal of the Hazop carried out on the ROV/RTU design
    - G/17 and GL/5 approach different for each GDN in addition to the points already noted.
    - One GDN has replaced G/17 with another suite of documents (PS/5 and PS/6)

5. Costs in Connection Quotation
    - Lowest cost £15-£20K
    - Highest cost £90K

6. Project Timetable
    - Two GDNs require all G17 to be completed prior to End to End (E2E) test
    - One GDN requires 2 weeks from E2E to grid injection
    - One GDN insists on carrying out the activities using linear approach with limited flexibility to change the process when circumstances change
    - One GDN insists on having a deep level of technical information for items upstream of their adopted equipment and upstream of the GEU, which adds to costs and project time

7. Biogas and Biomethane Testing
    - One GDN requires one biogas sample and 3 biomethane samples prior to flow to grid
    - One GDN requires just one biomethane sample

8. Commissioning
    - All the GDN's have different requirements for testing and witnessing various activities. e.g. FAT, SAT, ME/2, ISO10723, End to End tests, etc.
    - NRO requirements differ across the GDN's

9. LTS Connections

    - One GDN allows LTS connections to be carried out using the Self-lay process for >7 bar and there have been 7 LTS projects in the past 18 months in that GDN area using this model
    - No other GDN allows this approach which means that many biomethane projects with the LTS option have not been able to proceed due to cost and time

10. General Comments

- FWACV Daninit software is outdated (based on 1996 programme, 32 bit computers) and the Letter of Direction rules are not fit for purpose
    - Very limited industry knowledge of the Danint software, apparent reliance on one person in the UK
- The Danalyser (that has been used since 1996) appears to be towards the end of its life with technical issues arising and multiple failures of calibration accuracy
- The G17 process makes it expensive and time consuming to make any changes and this acts to stop innovation
- There is a lot of gas quality knowledge now and the risk analysis for gas quality (GQ/8) monitoring could be done without spending a day in review unless a new feedstock is used.

REA, March 2019